EB-2012-0459

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

BEFORE: Cynthia Chaplin
Presiding Member

Emad Elsayed
Member

DECISION AND RATE ORDER

August 22, 2014

Enbridge Gas Distribution Inc. ("Enbridge") filed an application dated July 3, 2013 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, S.O. 1998* for an order or orders approving rates for a five year period commencing January 1, 2014. The Board has assigned file number EB-2012-0459 to the application. A record of all procedural matters in this proceeding is available on the Board's web site.

In accordance with the Board's Decision with Reasons dated July 17, 2014 ("Decision"), Enbridge filed a Draft Rate Order and Draft Accounting Order (collectively the "DRO") on July 31, 2014. The Board held a Technical Conference and provided for submissions of parties on the DRO. Parties filed submissions on August 14, 2014 and Enbridge filed its reply on August 19, 2014.

Three issues emerged from the submissions on the DRO.

1. How to determine of the cost of debt during each year of the 5 year Custom IR plan;
2. What annual amounts should be refunded in order to give effect to the Board's findings regarding Site Restoration Costs ("SRC"); and
3. How should the amount of the sufficiency for the period between January 1, 2014 and September 30, 2014 ("Rider E") be determined and what is the manner and timing of clearance of Rider E.

The Board will provide its findings on each issue.

Cost of Debt

A number of parties submitted that the forecast weighted average cost of debt should be determined each year by taking into consideration not only forecast cost rates for forecast debt issuances, but also by taking into account the actual cost rates and the influence of actual levels and timing of debt issuances that have occurred in years prior to the rate application year.

Enbridge was opposed to the use of actual debt information in the updates, submitting that the mixing of actual levels of debt and timing of debt issuances would result in an unmatched weighted average cost of capital to a capital structure that is matched to a forecast level of rate base.

Findings

The Board finds that the cost of debt shall be updated each year of the IR plan, using the most current information available, including information on the actual amounts and rates associated with any debt issued in the prior year. The Board concludes that this approach is consistent with the Board's Decision and consistent with the determination of the return on equity for three reasons. First, the Board's Decision states "the **cost** of debt should also be set each year through the annual rate adjustment proceeding" (emphasis added). "Cost" is a general term; "rate" is specific. "Rate" refers to the individual price of a specific debt instrument. "Cost" refers to the total cost (expressed as a %), which is a function of the amount and rates for outstanding debt and the forecast amount, timing and rate for forecast debt issues for the year. Therefore, the Board's Decision does not limit the scope in the manner suggested by Enbridge.

Second, the return on equity is set using information about recent actual interest rates. Therefore, updating the cost of debt to take into account recent actual interest rates on actual debt issues would be consistent with the approach used for return on equity. Third, the Decision noted that “there is evidence in this proceeding which provides an **indication of the expected timing** for future debt issues…” (emphasis added). Therefore, the Board did not expect that the timing for future debt issues would need to be fixed in advance.

Although the cost of debt will be set each year, the rate base is being fixed now for each year of the IR term. The Board acknowledges that there is the potential for some mismatch between the actual amount of debt issued and the level of debt in the capital structure based on the pre-set rate base. The Board concludes that this difference can be managed. Each year the total cost will be determined using the actual and forecast debt issues and rates. The level of forecast debt issues will be scaled so that the total of actual and forecast debt matches the pre-set rate base.

To reflect its findings, the Board has adjusted the proposed wording in Appendix E Annual Update Elements concerning the cost of debt. For information purposes, the Board is including an Appendix G - Updated Unplanned Debt Issuances with this Decision and Rate Order.

SRC Refund Profile

A number of parties proposed that the SRC refund profile should be changed to produce a smoother customer billing profile over the term of the Custom IR plan. These parties proposed adjustments to counter what they perceived as a front-end loaded refund in Enbridge’s proposal. They submitted that the approach proposed by Enbridge would result in a sharp bill decrease for 2014, followed by sharp bill increases in each of the next four years and that customers would prefer relatively stable annual rate changes.

Enbridge opposed any changes to the refund profile on the basis that its proposal for the SRC refund was an effort to avoid a large impact at the end of the plan term. Enbridge noted the absence of anything in the Decision to suggest that the Board directed any departure from the original Enbridge approach. Enbridge also pointed out that a revised profile would require at least several weeks of effort in view of the revised calculations that would be required.

Findings

The Board will not alter the refund pattern proposed by Enbridge. The Board reaches this conclusion for three reasons. First, the Decision directed a higher refund, but made no change to the refund pattern. Therefore, Enbridge's proposal is consistent with the Board's Decision. Second, the Board's expectation was that final rates should be implemented as soon as possible. Enbridge has indicated that changing the pattern of the refund has significant consequential impacts which would delay the implementation of final rates. Therefore, there would need to be compelling reasons to introduce additional complexity and delay at this late stage of the process. Third, the primary reason for the refund pattern was to avoid a significant increase in bills caused by the refund ending, and that concern remains valid. The School Energy Coalition ("SEC") asserted that the concern about bill impacts beyond the IR term is not as significant as the concern about bill variability in the current IR term. Energy Probe disagreed with SEC's analysis; as did Enbridge. The Board concludes that the level of bill variability during the current IR term (under the proposed refund pattern) is not so significant that it outweighs the concern about potentially large bill impacts at the end of the refund period (if the refund pattern were changed).

Ride E Amount

As a result of the Board's Decision, rates for 2014 will be lower than the interim rates which have been in place since January 1, 2014. As a result, Enbridge has collected extra revenue, and this revenue sufficiency is to be returned to customers. Two issues have arisen: how the revenue sufficiency should be calculated and how the amount should be returned to customers.

In deciding how the revenue sufficiency should be calculated, the Board is most concerned with ensuring fairness to customers. To the maximum extent possible, customers should end up paying what they would have paid had the final rates been set and implemented on January 1, 2014. The Board concludes, therefore, that while the rates should be set on the basis of the forecast volumes (as would have been done if the rates had been set in advance of January 1, 2014), the sufficiency should be calculated on the basis of actual volumes between January 1, 2014 and September 30, 2014. This approach also ensures that Enbridge collects the same revenue it would have collected had the rates been put in place and implemented on January 1, 2014, so there is no unfairness to Enbridge.

Enbridge and Board staff pointed out that this is contrary to how it has been done in other cases. However, in this case a very significant amount of time has passed between the effective date and the implementation date (nine months) and the difference between actual and forecast volumes is large. Most importantly, the approach to be adopted is fair to both customers and Enbridge, and is consistent with what customers would reasonably expect by the meaning of “interim” rates.

As a result, the revenue sufficiency cannot be calculated until after the actual volumes through September 30, 2014 are known. However, Enbridge has proposed, and the Board has accepted, that the refund should take place in January on the basis of actual customer volumes. This timing will enable the sufficiency to be calculated on the basis of actual volumes through the end of September 2014.

Rider E Clearance

Enbridge’s original proposal to refund the 2014 revenue sufficiency using October volumes gave rise to concerns about “winners and losers”. Enbridge acknowledged that concern and provided two alternatives in its reply argument:

1) A one-time disposition based on each customer’s actual volumes during the period January 1 through September 30, 2014. The refund would be made on January 2015 and would be implemented with the January 1, 2015 QRAM. A new deferral account would be required, and Enbridge provided the necessary information to establish the account.

2) A prospective disposition over three months (October, November and December 2014). A variance account would be used to capture any over-refund or under-refund.

Enbridge prefers the first alternative, and the Board will adopt this approach. This approach does not delay the implementation of final rates and facilitates the fairest treatment of customers. The one-time disposition in January can be easily explained to customers and will also serve to mitigate a winter bill. The deferral account proposed by Enbridge sets aside $43.9 million. The account will be adjusted so that as soon as actuals to the end of September 2014 are known, Enbridge will re-calculate the sufficiency on the basis of actual volumes and the new amount will be captured in the account for disposition in January 2015. Enbridge will file for Board review and approval in a timely manner, updated unit rates to give effect to this disposition to coincide with the January 2015 QRAM process.

To reflect its findings, the Board has adjusted the proposed wording in the Accounting Treatment for a Rider E Deferral Account ("2014 REDA"). The Accounting Order dated today contains all approved Deferral and Variance Accounts related to this proceeding.

With respect to all other uncontested matters in the DRO, the Board is satisfied that it's July 17, 2014 Decision is reflected appropriately in the DRO. The Board therefore considers it appropriate to issue its Rate Order.

The Board will also make provision for the Cost Award process.

THE BOARD ORDERS THAT:

1. The financial statements attached as Appendix A to this Order for the years 2014 to 2018 inclusive are accepted as the basis for the rates in this Order.

2. The rates in the Rate Handbook, attached as Appendix B to this Order, are hereby effective January 1, 2014 and shall be implemented on October 1, 2014.

3. The Estimated Bill Impacts are attached as Appendix C.

4. The Reporting Commitments covering the term of the Custom IR Plan are attached as Appendix D.

5. The Annual Update Elements for the Custom IR Plan are attached as Appendix E.

6. The Schedule of Depreciation Rates is attached as Appendix F.

7. The Updated Planned Debt Issuances are attached as Appendix G.

8. Parties eligible for cost awards shall file their cost claims with the Board, and serve them on Enbridge, by September 5, 2014. Cost claims must be prepared in accordance with the Board's *Practice Direction on Cost Awards*.

9. Enbridge shall file with the Board any objection to a cost claim, and serve it on the party that made the claim, by September 12, 2014.

10. Any party whose cost claim was objected to shall file any reply submission with the Board, and serve it on Enbridge, by September 19, 2014.

DATED at Toronto August 22, 2014

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX A

Enbridge Gas Distribution Inc.

EB-2012-0459

Financial Statements

CHANGE IN ALLOWED REVENUE
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Decision EGD Total ($Millions)
	Cost of capital					
1.	Rate base	4,339.7	23.9	4,363.6	57.8	4,421.4
2.	Required rate of return	6.77	0.02	6.79	6.44	6.79
3.		293.8	2.5	296.3	3.7	300.0
	Cost of service					
4.	Gas costs	1,455.9	0.4	1,456.3	-	1,456.3
5.	Operation and maintenance	332.7	-	332.7	92.6	425.3
6.	Depreciation and amortization	250.1	(14.3)	235.8	12.7	248.5
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	41.2	-	41.2	-	41.2
9.		2,081.8	(13.9)	2,067.9	105.3	2,173.2
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(40.5)	(2.2)	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(40.6)	(2.2)	(42.8)	-	(42.8)
	Income taxes on earnings					
14.	Excluding tax shield	64.3	(7.1)	57.2	8.7	65.9
15.	Tax shield provided by interest expense	(38.7)	(0.1)	(38.8)	(0.7)	(39.5)
16.		25.6	(7.2)	18.4	8.0	26.4
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	37.1	28.9	66.0	-	66.0
18.	Net sufficiency / (deficiency)	27.3	21.2	48.5	-	48.5
19.		(9.8)	(7.7)	(17.5)	-	(17.5)
20.	**Sub-total revenue requirement**	2,350.8	(28.5)	2,322.3	117.0	2,439.3
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(2.9)	(2.9)
22.	**Allowed revenue**	2,350.8	(28.5)	2,322.3	114.1	2,436.4
	Revenue at existing Rates					
23.	Gas sales	2,161.7	0.5	2,162.2	91.8	2,254.0
24.	Transportation service	224.4	-	224.4	18.4	242.8
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	-	(0.1)	(0.1)	-	(0.1)
27.	Revenue at existing rates	2,387.9	0.4	2,388.3	110.2	2,498.5
28.	**Gross revenue sufficiency / (deficiency)**	37.1	28.9	66.0	(3.9)	62.1

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 2, Page 1, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 2, Page 1, Filed: 2014-03-24.

UTILITY RATE BASE
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Decision Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	6,977.0	-	6,977.0	127.1	7,104.1
2.	Accumulated depreciation	(2,895.7)	23.9	(2,871.8)	(69.3)	(2,941.1)
3.		4,081.3	23.9	4,105.2	57.8	4,163.0
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
5.	Materials and supplies	32.8	-	32.8	-	32.8
6.	Mortgages receivable	0.1	-	0.1	-	0.1
7.	Customer security deposits	(65.7)	-	(65.7)	-	(65.7)
8.	Prepaid expenses	0.9	-	0.9	-	0.9
9.	Gas in storage	279.9	-	279.9	-	279.9
10.	Working cash allowance	9.1	-	9.1	-	9.1
11.	Total Working Capital	258.4	-	258.4	-	258.4
12.	Utility Rate Base	4,339.7	23.9	4,363.6	57.8	4,421.4

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 2, Page 2, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 2, Page 2, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2014 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
2.	23.9	Accumulated depreciation Change is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, and to increase the refund of previously collected net salvage amounts by $120M over the 2014 - 2018 term, as per the Board's decison on the Site Restoration Cost issue.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2014 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,469.5	2.8	11.3
2.	Items not subject to working cash allowance (Note 1)		(13.2)		
3.	Gas costs charged to operations	App A.S2.P5.Col.3.L8	1,456.3		
4.	Operation and Maintenance	App A.S2.P5.Col.3.L9	332.7		
5.	Less: Storage costs		(7.2)		
6.	Operation and maintenance costs subject to working cash		325.5		
7.	Ancillary customer services		-		
8.			325.5	(11.0)	(9.8)
9.	Sub-total				1.5
10.	Storage costs		7.2	65.9	1.3
11.	Storage municipal and capital taxes		1.3	23.3	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				6.2
14.	Total working cash allowance				9.1

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Decision Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,161.7	0.5	2,162.2	91.8	2,254.0
2.	Transportation of gas	224.4	-	224.4	18.4	242.8
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	40.5	2.2	42.7	-	42.7
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,428.5	2.7	2,431.2	110.2	2,541.4
8.	Gas costs	1,455.9	0.4	1,456.3	-	1,456.3
9.	Operation and maintenance	332.7	-	332.7	92.6	425.3
10.	Depreciation and amortization expense	250.1	(14.3)	235.8	12.7	248.5
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	41.2	-	41.2	-	41.2
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,081.8	(13.9)	2,067.9	105.3	2,173.2
16.	Ontario utility income before income taxes	346.7	16.6	363.3	4.9	368.2
17.	Income tax expense	25.6	(7.2)	18.4	8.0	26.4
18.	Utility net income	321.1	23.8	344.9	(3.1)	341.8

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 2, Page 5, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 2, Page 5, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2014 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	0.5	Gas sales The increase is due to the addition of two contract market customers as per the Board's decision on the Volumes and Revenues issue.
4.	2.2	Other operating revenue The increase is due to the Board's decision on Other Revenues, requiring other revenue/income to be set at the 2013 actual level of $42.8M.
8.	0.4	Gas costs The increase is due to the addition of two contract market customers as per the Board's decision on the Volumes and Revenues issue.
10.	(14.3)	Depreciation and amortization expense The reduction is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, as per the Board's decison on the Site Restoration Cost issue.
17.	(7.2)	Income tax expense deduction for site restoration costs, resulting from the Board's decision on the Site Restoration Cost issue which requires a $120M increase in the refund of previously collected net salvage amounts over the 2014 - 2018 term, and a larger interest tax shield credit resulting from a higher rate base. Partially offsetting these income tax reductions are income tax increases resulting from higher margin and other revenues, as noted in the changes above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2014 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Decision Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes (M1, T1, S2, P5)	346.7	16.6	363.3
	Add			
2.	Depreciation and amortization	250.1	(14.3)	235.8
3.	Accrual based pension and OPEB costs	37.3	-	37.3
4.	Other non-deductible items	1.4	-	1.4
5.	Total Add Back	288.8	(14.3)	274.5
6.	Sub total	635.5	2.3	637.8
	Deduct			
7.	Capital cost allowance - Federal	231.4	-	231.4
8.	Capital cost allowance - Provincial	231.4	-	231.4
9.	Items capitalized for regulatory purposes	45.9	-	45.9
10.	Deduction for "grossed up" Part VI.1 tax	3.5	-	3.5
11.	Amortization of share/debenture issue expense	3.9	-	3.9
12.	Amortization of cumulative eligible capital	0.3	-	0.3
13.	Amortization of C.D.E. and C.O.G.P.E	0.2	-	0.2
14.	Site restoration cost adjustment	68.1	28.7	96.8
15.	Cash based pension and OPEB costs	44.3	-	44.3
16.	Total Deduction - Federal	397.6	28.7	426.3
17.	Total Deduction - Provincial	397.6	28.7	426.3
18.	Taxable income - Federal	237.9	(26.4)	211.5
19.	Taxable income - Provincial	237.9	(26.4)	211.5
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	35.7	(4.0)	31.7
23.	Income tax provision - Provincial	27.4	(3.1)	24.3
24.	Income tax provision - combined	63.1	(7.1)	56.0
25.	Part V1.1 tax			1.2
26.	Total taxes excluding tax shield on interest expense			57.2
	Tax shield on interest expense			
27.	Rate base (M1.T1.S2.P2)			4,363.6
28.	Return component of debt (M1.T1.S2.P8)			3.35%
29.	Interest expense			146.4
30.	Combined tax rate			26.50%
31.	Income tax credit			(38.8)
32.	Total income taxes			18.4

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 2, page 7, Filed: 2014-03-24.

UTILITY CAPITAL STRUCTURE
2014 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,596.9	59.51	5.57	3.315
2.	Short term debt	95.8	2.20	1.78	0.039
3.		2,692.7	61.71		3.354
4.	Preference shares	100.0	2.29	2.96	0.068
5.	Common equity	1,570.9	36.00	9.36	3.370
6.		4,363.6	100.00		6.792
7.	Utility income	($Millions)			344.9
8.	Rate base	($Millions)			4,363.6
9.	Indicated rate of return				7.904%
10.	Sufficiency in rate of return				1.112 %
11.	Net sufficiency	($Millions)			48.5
12.	Gross sufficiency	($Millions)			66.0
13.	Customer Care/CIS deficiency	($Millions)			(3.9)
14.	Total gross sufficiency	($Millions)			62.1
15.	Revenue at existing rates	($Millions)			2,498.5
16.	Allowed revenue	($Millions)			2,436.4
17.	Total gross revenue sufficiency	($Millions)			62.1

CHANGE IN ALLOWED REVENUE
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Decision EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	4,735.3	66.6	4,801.9	45.1	4,847.0
2.	Required rate of return	6.91	(0.02)	6.89	6.44	6.89
3.		327.2	3.7	330.9	2.9	333.8
	Cost of service					
4.	Gas costs	1,606.8	-	1,606.8	-	1,606.8
5.	Operation and maintenance	332.0	(1.2)	330.8	96.5	427.3
6.	Depreciation and amortization	264.3	(15.3)	249.0	12.7	261.7
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	43.1	-	43.1	-	43.1
9.		2,248.1	(16.5)	2,231.6	109.2	2,340.8
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(40.9)	(1.8)	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.0)	(1.8)	(42.8)	-	(42.8)
	Income taxes on earnings					
14.	Excluding tax shield	47.1	(6.5)	40.6	8.3	48.9
15.	Tax shield provided by interest expense	(41.8)	(0.4)	(42.2)	(0.6)	(42.8)
16.		5.3	(6.9)	(1.6)	7.7	6.1
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(18.9)	29.1	10.2	-	10.2
18.	Net sufficiency / (deficiency)	(13.9)	21.4	7.5	-	7.5
19.		5.0	(7.7)	(2.7)	-	(2.7)
20.	**Sub-total revenue requirement**	2,544.6	(29.2)	2,515.4	119.8	2,635.2
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	(1.1)	(1.1)
22.	**Allowed revenue**	2,544.6	(29.2)	2,515.4	118.7	2,634.1
	Revenue at existing Rates					
23.	Gas sales	2,312.5	-	2,312.5	91.8	2,404.3
24.	Transportation service	211.2	-	211.2	18.4	229.6
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	0.2	(0.1)	0.1	-	0.1
27.	Revenue at existing rates	2,525.7	(0.1)	2,525.6	110.2	2,635.8
28.	**Gross revenue sufficiency / (deficiency)**	(18.9)	29.1	10.2	(8.5)	1.7

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 3, Page 1, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 3, Page 1, Filed: 2014-03-24.

UTILITY RATE BASE
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Decision Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	7,462.9	-	7,462.9	127.1	7,590.0
2.	Accumulated depreciation	(3,000.7)	66.5	(2,934.2)	(82.0)	(3,016.2)
3.		4,462.2	66.5	4,528.7	45.1	4,573.8
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.3	-	1.3	-	1.3
5.	Materials and supplies	33.7	-	33.7	-	33.7
6.	Mortgages receivable	0.1	-	0.1	-	0.1
7.	Customer security deposits	(65.1)	-	(65.1)	-	(65.1)
8.	Prepaid expenses	0.9	-	0.9	-	0.9
9.	Gas in storage	291.2	-	291.2	-	291.2
10.	Working cash allowance	11.0	0.1	11.1	-	11.1
11.	Total Working Capital	273.1	0.1	273.2	-	273.2
12.	Utility Rate Base	4,735.3	66.6	4,801.9	45.1	4,847.0

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 3, Page 2, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 3, Page 2, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2015 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
2.	66.5	Accumulated depreciation Change is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, and to increase the refund of previously collected net salvage amounts by $120M over the 2014 - 2018 term, as per the Board's decison on the Site Restoration Cost issue.
10.	0.1	Working cash allowance Change is due to the impact within working cash of updating operation and maintenance costs.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2015 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,621.1	2.7	12.0
2.	Items not subject to working cash allowance (Note 1)		(14.3)		
3.	Gas costs charged to operations	App A.S3.P5.Col.3.L8	1,606.8		
4.	Operation and Maintenance	App A.S3.P5.Col.3.L9	330.8		
5.	Less: Storage costs		(8.0)		
6.	Operation and maintenance costs subject to working cash		322.8		
7.	Ancillary customer services		-		
8.			322.8	(11.1)	(9.8)
9.	Sub-total				2.2
10.	Storage costs		8.0	60.4	1.3
11.	Storage municipal and capital taxes		1.3	23.1	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				7.5
14.	Total working cash allowance				11.1

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Decision Utility Income ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Decision Utility Income ($Millions)
1.	Gas sales	2,312.5	-	2,312.5	91.8	2,404.3
2.	Transportation of gas	211.2	-	211.2	18.4	229.6
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	40.9	1.8	42.7	-	42.7
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,566.5	1.8	2,568.3	110.2	2,678.5
8.	Gas costs	1,606.8	-	1,606.8	-	1,606.8
9.	Operation and maintenance	332.0	(1.2)	330.8	96.5	427.3
10.	Depreciation and amortization expense	264.3	(15.3)	249.0	12.7	261.7
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	43.1	-	43.1	-	43.1
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,248.1	(16.5)	2,231.6	109.2	2,340.8
16.	Ontario utility income before income taxes	318.4	18.3	336.7	1.0	337.7
17.	Income tax expense	5.3	(6.9)	(1.6)	7.7	6.1
18.	Utility net income	313.1	25.2	338.3	(6.7)	331.6

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 3, Page 5, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 3, Page 5, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2015 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
4.	1.8	Other operating revenue The increase is due to the Board's decision on Other Revenues, requiring other revenue/income to be set at the 2013 actual level of $42.8M.
9.	(1.2)	Operation and maintenance The reduction is due to the Board's decision on Other O&M and to set 2015 through 2018 annual increase at 1%.
10.	(15.3)	Depreciation and amortization expense The reduction is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, as per the Board's decison on the Site Restoration Cost issue.
17.	(6.9)	Income tax expense The reduction in income tax expense is due predominantly to an increase in the tax deduction for site restoration costs, resulting from the Board's decision on the Site Restoration Cost issue which requires a $120M increase in the refund of previously collected net salvage amounts over the 2014 - 2018 term, and a larger interest tax shield credit resulting from a higher rate base. Partially offsetting these income tax reductions are income tax increases resulting from higher other revenues and lower operation and maintenance costs, as noted in the changes above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2015 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Decision Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes (M1, T1, S3, P5)	318.4	18.3	336.7
	Add			
2.	Depreciation and amortization	264.3	(15.3)	249.0
3.	Accrual based pension and OPEB costs	33.8	-	33.8
4.	Other non-deductible items	1.1	-	1.1
5.	Total Add Back	299.2	(15.3)	283.9
6.	Sub total	617.6	3.0	620.6
	Deduct			
7.	Capital cost allowance - Federal	282.2	-	282.2
8.	Capital cost allowance - Provincial	282.2	-	282.2
9.	Items capitalized for regulatory purposes	46.8	-	46.8
10.	Deduction for "grossed up" Part VI.1 tax	4.2	-	4.2
11.	Amortization of share/debenture issue expense	3.3	-	3.3
12.	Amortization of cumulative eligible capital	5.6	-	5.6
13.	Amortization of C.D.E. and C.O.G.P.E	0.4	-	0.4
14.	Site restoration cost adjustment	63.1	27.3	90.4
15.	Cash based pension and OPEB costs	39.6	-	39.6
16.	Total Deduction - Federal	445.2	27.3	472.5
17.	Total Deduction - Provincial	445.2	27.3	472.5
18.	Taxable income - Federal	172.4	(24.3)	148.1
19.	Taxable income - Provincial	172.4	(24.3)	148.1
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	25.9	(3.7)	22.2
23.	Income tax provision - Provincial	19.8	(2.8)	17.0
24.	Income tax provision - combined	45.7	(6.5)	39.2
25.	Part V1.1 tax			1.4
26.	Total taxes excluding tax shield on interest expense			40.6
	Tax shield on interest expense			
27.	Rate base (M1.T1.S3.P2)			4,801.9
28.	Return component of debt (M1.T1.S3.P8)			3.31%
29.	Interest expense			159.1
30.	Combined tax rate			26.50%
31.	Income tax credit			(42.2)
32.	Total income taxes			(1.6)

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 3, page 7, Filed: 2014-03-24.

UTILITY CAPITAL STRUCTURE
2015 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,928.7	60.99	5.39	3.287
2.	Short term debt	44.5	0.93	2.75	0.026
3.		2,973.2	61.92		3.313
4.	Preference shares	100.0	2.08	3.68	0.077
5.	Common equity	1,728.7	36.00	9.72	3.499
6.		4,801.9	100.00		6.889
7.	Utility income	($Millions)			338.3
8.	Rate base	($Millions)			4,801.9
9.	Indicated rate of return				7.045%
10.	Sufficiency in rate of return				0.156 %
11.	Net sufficiency	($Millions)			7.5
12.	Gross sufficiency	($Millions)			10.2
13.	Customer Care/CIS deficiency	($Millions)			(8.5)
14.	Total gross sufficiency	($Millions)			1.7
15.	Revenue at existing rates	($Millions)			2,635.8
16.	Allowed revenue	($Millions)			2,634.1
17.	Total gross revenue sufficiency	($Millions)			1.7

CHANGE IN ALLOWED REVENUE
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Decision EGD Total
		($Millions)		($Millions)	($Millions)	($Millions)
	Cost of capital					
1.	Rate base	5,553.8	109.8	5,663.6	32.4	5,696.0
2.	Required rate of return	7.01	(0.01)	7.00	6.44	7.00
3.		389.3	7.2	396.5	2.1	398.6
	Cost of service					
4.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
5.	Operation and maintenance	339.1	(8.4)	330.7	100.4	431.1
6.	Depreciation and amortization	293.9	(17.7)	276.2	12.7	288.9
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	45.5	-	45.5	-	45.5
9.		2,312.9	(26.1)	2,286.8	113.1	2,399.9
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(41.2)	(1.5)	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.3)	(1.5)	(42.8)	-	(42.8)
	Income taxes on earnings					
14.	Excluding tax shield	43.4	(4.2)	39.2	7.9	47.1
15.	Tax shield provided by interest expense	(48.3)	(0.9)	(49.2)	(0.4)	(49.6)
16.		(4.9)	(5.1)	(10.0)	7.5	(2.5)
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(112.4)	34.5	(77.9)	-	(77.9)
18.	Net sufficiency / (deficiency)	(82.6)	25.3	(57.3)	-	(57.3)
19.		29.8	(9.1)	20.6	-	20.6
20.	**Sub-total revenue requirement**	2,685.8	(34.6)	2,651.1	122.7	2,773.8
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	0.8	0.8
22.	**Allowed revenue**	2,685.8	(34.6)	2,651.1	123.5	2,774.6
	Revenue at existing Rates					
23.	Gas sales	2,372.7	-	2,372.7	91.8	2,464.5
24.	Transportation service	198.7	-	198.7	18.4	217.1
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	0.2	(0.2)	-	-	-
27.	Revenue at existing rates	2,573.4	(0.2)	2,573.2	110.2	2,683.4
28.	**Gross revenue sufficiency / (deficiency)**	(112.4)	34.4	(77.9)	(13.3)	(91.2)

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 4, Page 1, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 4, Page 1, Filed: 2014-03-24.

UTILITY RATE BASE
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Decision Utility Rate Base ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Total Decision Rate Base Including CIS ($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	8,427.5	-	8,427.5	127.1	8,554.6
2.	Accumulated depreciation	(3,120.6)	109.5	(3,011.1)	(94.7)	(3,105.8)
3.		5,306.9	109.5	5,416.4	32.4	5,448.8
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3	-	276.3
10.	Working cash allowance	(1.8)	0.3	(1.5)	-	(1.5)
11.	Total Working Capital	246.9	0.3	247.2	-	247.2
12.	Utility Rate Base	5,553.8	109.8	5,663.6	32.4	5,696.0

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 4, Page 2, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 4, Page 2, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2016 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
2.	109.5	Accumulated depreciation Change is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, and to increase the refund of previously collected net salvage amounts by $120M over the 2014 - 2018 term, as per the Board's decison on the Site Restoration Cost issue.
10.	0.3	Working cash allowance Change is due to the impact within working cash of updating operation and maintenance costs.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2016 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,647.2	2.3	10.4
2.	Items not subject to working cash allowance (Note 1)		(14.7)		
3.	Gas costs charged to operations	App A.S4.P5.Col.3.L8	1,632.5		
4.	Operation and Maintenance	App A.S4.P5.Col.3.L9	330.7		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		322.3		
7.	Ancillary customer services		-		
8.			322.3	(10.9)	(9.6)
9.	Sub-total				0.8
10.	Storage costs		8.4	58.4	1.3
11.	Storage municipal and capital taxes		1.4	22.9	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				(3.7)
14.	Total working cash allowance				(1.5)

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Decision Utility Income ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Decision Utility Income ($Millions)
1.	Gas sales	2,372.7	-	2,372.7	91.8	2,464.5
2.	Transportation of gas	198.7	-	198.7	18.4	217.1
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	41.2	1.5	42.7	-	42.7
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,614.5	1.5	2,616.0	110.2	2,726.2
8.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
9.	Operation and maintenance	339.1	(8.4)	330.7	100.4	431.1
10.	Depreciation and amortization expense	293.9	(17.7)	276.2	12.7	288.9
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	45.5	-	45.5	-	45.5
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,312.9	(26.1)	2,286.8	113.1	2,399.9
16.	Ontario utility income before income taxes	301.6	27.6	329.2	(2.9)	326.3
17.	Income tax expense	(4.9)	(5.1)	(10.0)	7.5	(2.5)
18.	Utility net income	306.5	32.7	339.2	(10.4)	328.8

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 4, Page 5, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 4, Page 5, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2016 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
4.	1.5	Other operating revenue The increase is due to the Board's decision on Other Revenues, requiring other revenue/income to be set at the 2013 actual level of $42.8M.
9.	(8.4)	Operation and maintenance The reduction is due to the Board's decision on Other O&M and to set 2015 through 2018 annual increase at 1%.
10.	(17.7)	Depreciation and amortization expense The reduction is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, as per the Board's decison on the Site Restoration Cost issue.
17.	(5.1)	Income tax expense The reduction in income tax expense is due predominantly to an increase in the tax deduction for site restoration costs, resulting from the Board's decision on the Site Restoration Cost issue which requires a $120M increase in the refund of previously collected net salvage amounts over the 2014 - 2018 term, and a larger interest tax shield credit resulting from a higher rate base. Partially offsetting these income tax reductions are income tax increases resulting from higher other revenues and lower operation and maintenance costs, as noted in the changes above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2016 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Decision Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes (M1, T1, S4, P5)	301.6	27.6	329.2
	Add			
2.	Depreciation and amortization	293.9	(17.7)	276.2
3.	Accrual based pension and OPEB costs	30.9	-	30.9
4.	Other non-deductible items	1.0	-	1.0
5.	Total Add Back	325.8	(17.7)	308.1
6.	Sub total	627.4	9.9	637.3
	Deduct			
7.	Capital cost allowance - Federal	315.4	-	315.4
8.	Capital cost allowance - Provincial	315.4	-	315.4
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.0	-	5.0
11.	Amortization of share/debenture issue expense	3.8	-	3.8
12.	Amortization of cumulative eligible capital	5.2	-	5.2
13.	Amortization of C.D.E. and C.O.G.P.E	0.2	-	0.2
14.	Site restoration cost adjustment	58.1	25.8	83.9
15.	Cash based pension and OPEB costs	35.7	-	35.7
16.	Total Deduction - Federal	470.0	25.8	495.8
17.	Total Deduction - Provincial	470.0	25.8	495.8
18.	Taxable income - Federal	157.4	(15.9)	141.5
19.	Taxable income - Provincial	157.4	(15.9)	141.5
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	23.6	(2.4)	21.2
23.	Income tax provision - Provincial	18.1	(1.8)	16.3
24.	Income tax provision - combined	41.7	(4.2)	37.5
25.	Part V1.1 tax			1.7
26.	Total taxes excluding tax shield on interest expense			39.2
	Tax shield on interest expense			
27.	Rate base (M1.T1.S4.P2)			5,663.6
28.	Return component of debt (M1.T1.S4.P8)			3.28%
29.	Interest expense			185.8
30.	Combined tax rate			26.50%
31.	Income tax credit			(49.2)
32.	Total income taxes			(10.0)

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 4, page 7, Filed: 2014-03-24.

UTILITY CAPITAL STRUCTURE
2016 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	3,422.6	60.43	5.33	3.221
2.	Short term debt	102.1	1.80	3.35	0.060
3.		3,524.7	62.23		3.281
4.	Preference shares	100.0	1.77	4.32	0.076
5.	Common equity	2,038.9	36.00	10.12	3.643
6.		5,663.6	100.00		7.000
7.	Utility income	($Millions)			339.2
8.	Rate base	($Millions)			5,663.6
9.	Indicated rate of return				5.989%
10.	(Deficiency) in rate of return				(1.011)%
11.	Net (deficiency)	($Millions)			(57.3)
12.	Gross (deficiency)	($Millions)			(77.9)
13.	Customer Care/CIS deficiency	($Millions)			(13.3)
14.	Total gross (deficiency)	($Millions)			(91.2)
15.	Revenue at existing rates	($Millions)			2,683.4
16.	Allowed revenue	($Millions)			2,774.6
17.	Total gross revenue (deficiency)	($Millions)			(91.2)

CHANGE IN ALLOWED REVENUE
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Decision EGD Total ($Millions)
	Cost of capital					
1.	Rate base	5,775.9	153.0	5,928.9	19.7	5,948.6
2.	Required rate of return	7.03	0.01	7.04	6.44	7.04
3.		406.0	11.4	417.4	1.3	418.7
	Cost of service					
4.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
5.	Operation and maintenance	346.1	(13.6)	332.5	104.4	436.9
6.	Depreciation and amortization	303.5	(18.5)	285.0	12.7	297.7
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	47.9	-	47.9	-	47.9
9.		2,331.9	(32.1)	2,299.8	117.1	2,416.9
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(41.2)	(1.5)	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.3)	(1.5)	(42.8)	-	(42.8)
	Income taxes on earnings					
14.	Excluding tax shield	49.8	(2.5)	47.3	7.5	54.8
15.	Tax shield provided by interest expense	(50.4)	(1.4)	(51.8)	(0.2)	(52.0)
16.		(0.6)	(3.9)	(4.5)	7.3	2.8
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(154.1)	36.2	(117.9)	-	(117.9)
18.	Net sufficiency / (deficiency)	(113.3)	26.6	(86.7)	-	(86.7)
19.		40.8	(9.6)	31.3	-	31.3
20.	**Sub-total revenue requirement**	2,736.8	(35.7)	2,701.2	125.7	2,826.9
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	2.9	2.9
22.	**Allowed revenue**	2,736.8	(35.7)	2,701.2	128.6	2,829.8
	Revenue at existing Rates					
23.	Gas sales	2,388.5	-	2,388.5	91.8	2,480.3
24.	Transportation service	192.7	-	192.7	18.4	211.1
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	(0.3)	0.6	0.3	-	0.3
27.	Revenue at existing rates	2,582.7	0.6	2,583.3	110.2	2,693.5
28.	**Gross revenue sufficiency / (deficiency)**	(154.1)	36.3	(117.9)	(18.4)	(136.3)

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 5, Page 1, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 5, Page 1, Filed: 2014-03-24.

UTILITY RATE BASE
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments ($Millions)	Col. 3 Excl. CIS Adjusted Decision Utility Rate Base ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Total Decision Rate Base Including CIS ($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	8,792.2	-	8,792.2	127.1	8,919.3
2.	Accumulated depreciation	(3,263.0)	152.6	(3,110.4)	(107.4)	(3,217.8)
3.		5,529.2	152.6	5,681.8	19.7	5,701.5
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3	-	276.3
10.	Working cash allowance	(2.0)	0.4	(1.6)	-	(1.6)
11.	Total Working Capital	246.7	0.4	247.1	-	247.1
12.	Utility Rate Base	5,775.9	153.0	5,928.9	19.7	5,948.6

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 5, Page 2, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 5, Page 2, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2017 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
2.	152.6	Accumulated depreciation Change is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, and to increase the refund of previously collected net salvage amounts by $120M over the 2014 - 2018 term, as per the Board's decison on the Site Restoration Cost issue.
10.	0.4	Working cash allowance Change is due to the impact within working cash of updating operation and maintenance costs.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2017 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,647.2	2.3	10.4
2.	Items not subject to working cash allowance (Note 1)		(14.7)		
3.	Gas costs charged to operations	App A.S5.P5.Col.3.L8	1,632.5		
4.	Operation and Maintenance	App A.S5.P5.Col.3.L9	332.5		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		324.1		
7.	Ancillary customer services		-		
8.			324.1	(10.9)	(9.7)
9.	Sub-total				0.7
10.	Storage costs		8.4	58.4	1.3
11.	Storage municipal and capital taxes		1.4	22.9	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				(3.7)
14.	Total working cash allowance				(1.6)

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Decision Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,388.5	-	2,388.5	91.8	2,480.3
2.	Transportation of gas	192.7	-	192.7	18.4	211.1
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	41.2	1.5	42.7	-	42.7
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,624.3	1.5	2,625.8	110.2	2,736.0
8.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
9.	Operation and maintenance	346.1	(13.6)	332.5	104.4	436.9
10.	Depreciation and amortization expense	303.5	(18.5)	285.0	12.7	297.7
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	47.9	-	47.9	-	47.9
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,331.9	(32.1)	2,299.8	117.1	2,416.9
16.	Ontario utility income before income taxes	292.4	33.6	326.0	(6.9)	319.1
17.	Income tax expense	(0.6)	(3.9)	(4.5)	7.3	2.8
18.	Utility net income	293.0	37.5	330.5	(14.2)	316.3

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 5, Page 5, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 5, Page 5, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2017 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
4.	1.5	Other operating revenue The increase is due to the Board's decision on Other Revenues, requiring other revenue/income to be set at the 2013 actual level of $42.8M.
9.	(13.6)	Operation and maintenance The reduction is due to the Board's decision on Other O&M and to set 2015 through 2018 annual increase at 1%.
10.	(18.5)	Depreciation and amortization expense The reduction is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, as per the Board's decison on the Site Restoration Cost issue.
17.	(3.9)	Income tax expense The reduction in income tax expense is due predominantly to an increase in the tax deduction for site restoration costs, resulting from the Board's decision on the Site Restoration Cost issue which requires a $120M increase in the refund of previously collected net salvage amounts over the 2014 - 2018 term, and a larger interest tax shield credit resulting from a higher rate base. Partially offsetting these income tax reductions are income tax increases resulting from higher other revenues and lower operation and maintenance costs, as noted in the changes above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Decision Utility Tax
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes (M1, T1, S5, P5)	292.4	33.6	326.0
	Add			
2.	Depreciation and amortization	303.5	(18.5)	285.0
3.	Accrual based pension and OPEB costs	28.5	-	28.5
4.	Other non-deductible items	1.0	-	1.0
5.	Total Add Back	333.0	(18.5)	314.5
6.	Sub total	625.4	15.1	640.5
	Deduct			
7.	Capital cost allowance - Federal	298.2	-	298.2
8.	Capital cost allowance - Provincial	298.2	-	298.2
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.6	-	5.6
11.	Amortization of share/debenture issue expense	3.9	-	3.9
12.	Amortization of cumulative eligible capital	4.8	-	4.8
13.	Amortization of C.D.E. and C.O.G.P.E	0.1	-	0.1
14.	Site restoration cost adjustment	53.1	24.4	77.5
15.	Cash based pension and OPEB costs	32.2	-	32.2
16.	Total Deduction - Federal	444.5	24.4	468.9
17.	Total Deduction - Provincial	444.5	24.4	468.9
18.	Taxable income - Federal	180.9	(9.3)	171.6
19.	Taxable income - Provincial	180.9	(9.3)	171.6
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	27.1	(1.4)	25.7
23.	Income tax provision - Provincial	20.8	(1.1)	19.7
24.	Income tax provision - combined	47.9	(2.5)	45.4
25.	Part V1.1 tax			1.9
26.	Total taxes excluding tax shield on interest expense			47.3
	Tax shield on interest expense			
27.	Rate base (M1.T1.S5.P2)			5,928.9
28.	Return component of debt (M1.T1.S5.P8)			3.30%
29.	Interest expense			195.5
30.	Combined tax rate			26.50%
31.	Income tax credit			(51.8)
32.	Total income taxes			(4.5)

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 5, page 7, Filed: 2014-03-24.

UTILITY CAPITAL STRUCTURE
2017 FISCAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Principal Excl. CC/CIS	Component	Indicated Cost Rate	Return Component
		($Millions)	%	%	%
1.	Long term debt	3,591.4	60.57	5.32	3.222
2.	Short term debt	103.1	1.74	4.30	0.075
3.		3,694.5	62.31		3.297
4.	Preference shares	100.0	1.69	4.64	0.078
5.	Common equity	2,134.4	36.00	10.17	3.661
6.		5,928.9	100.00		7.036
7.	Utility income	($Millions)			330.5
8.	Rate base	($Millions)			5,928.9
9.	Indicated rate of return				5.574%
10.	(Deficiency) in rate of return				(1.462)%
11.	Net (deficiency)	($Millions)			(86.7)
12.	Gross (deficiency)	($Millions)			(117.9)
13.	Customer Care/CIS deficiency	($Millions)			(18.4)
14.	Total gross (deficiency)	($Millions)			(136.3)
15.	Revenue at existing rates	($Millions)			2,693.5
16.	Allowed revenue	($Millions)			2,829.8
17.	Total gross revenue (deficiency)	($Millions)			(136.3)

CHANGE IN ALLOWED REVENUE
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision ($Millions)	Col. 4 Cust. Care / CIS (Note 2) ($Millions)	Col. 5 Decision EGD Total ($Millions)
	Cost of capital					
1.	Rate base	5,955.3	190.3	6,145.6	7.0	6,152.6
2.	Required rate of return	7.10	0.02	7.12	6.44	7.12
3.		422.8	14.8	437.6	0.5	438.1
	Cost of service					
4.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
5.	Operation and maintenance	353.3	(19.0)	334.3	108.5	442.8
6.	Depreciation and amortization	312.1	(19.3)	292.8	12.7	305.5
7.	Fixed financing costs	1.9	-	1.9	-	1.9
8.	Municipal and other taxes	50.4	-	50.4	-	50.4
9.		2,350.2	(38.3)	2,311.9	121.2	2,433.1
	Miscellaneous operating and non-operating revenue					
10.	Other operating revenue	(41.2)	(1.5)	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	(0.1)
13.		(41.3)	(1.5)	(42.8)	-	(42.8)
	Income taxes on earnings					
14.	Excluding tax shield	59.3	1.8	61.1	7.2	68.3
15.	Tax shield provided by interest expense	(52.5)	(2.0)	(54.5)	(0.1)	(54.6)
16.		6.8	(0.2)	6.6	7.1	13.7
	Taxes on sufficiency / (deficiency)					
17.	Gross sufficiency / (deficiency)	(198.2)	34.6	(163.6)	-	(163.6)
18.	Net sufficiency / (deficiency)	(145.7)	25.4	(120.3)	-	(120.3)
19.		52.5	(9.2)	43.4	-	43.4
20.	**Sub-total revenue requirement**	2,791.0	(34.4)	2,756.7	128.8	2,885.5
21.	Customer Care Rate Smoothing V/A Adjustment	-	-	-	5.0	5.0
22.	**Allowed revenue**	2,791.0	(34.4)	2,756.7	133.8	2,890.5
	Revenue at existing Rates					
23.	Gas sales	2,404.4	-	2,404.4	91.8	2,496.2
24.	Transportation service	186.6	-	186.6	18.4	205.0
25.	Transmission, compression and storage	1.8	-	1.8	-	1.8
26.	Rounding adjustment	-	0.3	0.3	-	0.3
27.	Revenue at existing rates	2,592.8	0.3	2,593.1	110.2	2,703.3
28.	**Gross revenue sufficiency / (deficiency)**	(198.2)	34.7	(163.6)	(23.6)	(187.2)

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 6, Page 1, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 6, Page 1, Filed: 2014-03-24.

UTILITY RATE BASE
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision Utility Rate Base	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Total Decision Rate Base Including CIS
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment					
1.	Cost or redetermined value	9,147.8	-	9,147.8	127.1	9,274.9
2.	Accumulated depreciation	(3,439.0)	189.7	(3,249.3)	(120.1)	(3,369.4)
3.		5,708.8	189.7	5,898.5	7.0	5,905.5
	Allowance for Working Capital					
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	1.0
9.	Gas in storage	276.3	-	276.3	-	276.3
10.	Working cash allowance	(2.2)	0.6	(1.6)	-	(1.6)
11.	Total Working Capital	246.5	0.6	247.1	-	247.1
12.	Utility Rate Base	5,955.3	190.3	6,145.6	7.0	6,152.6

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 6, Page 2, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 6, Page 2, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY RATE BASE
2018 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
2.	189.7	Accumulated depreciation Change is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, and to increase the refund of previously collected net salvage amounts by $120M over the 2014 - 2018 term, as per the Board's decison on the Site Restoration Cost issue.
10.	0.6	Working cash allowance Change is due to the impact within working cash of updating operation and maintenance costs.

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2018 FISCAL YEAR

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,647.2	2.3	10.4
2.	Items not subject to working cash allowance (Note 1)		(14.7)		
3.	Gas costs charged to operations	App A.S6.P5.Col.3.L8	1,632.5		
4.	Operation and Maintenance	App A.S6.P5.Col.3.L9	334.3		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		325.9		
7.	Ancillary customer services		-		
8.			325.9	(10.9)	(9.7)
9.	Sub-total				0.7
10.	Storage costs		8.4	58.4	1.3
11.	Storage municipal and capital taxes		1.4	22.9	0.1
12.	Sub-total				1.4
13.	Harmonized sales tax				(3.7)
14.	Total working cash allowance				(1.6)

Note 1: Represents non cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

UTILITY INCOME
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1)	Col. 2 Decision Adjustments	Col. 3 Excl. CIS Adjusted Decision Utility Income	Col. 4 Cust. Care / CIS (Note 2)	Col. 5 Decision Utility Income
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Gas sales	2,404.4	-	2,404.4	91.8	2,496.2
2.	Transportation of gas	186.6	-	186.6	18.4	205.0
3.	Transmission, compression and storage revenue	1.8	-	1.8	-	1.8
4.	Other operating revenue	41.2	1.5	42.7	-	42.7
5.	Interest and property rental	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	0.1
7.	Total operating revenue	2,634.1	1.5	2,635.6	110.2	2,745.8
8.	Gas costs	1,632.5	-	1,632.5	-	1,632.5
9.	Operation and maintenance	353.3	(19.0)	334.3	108.5	442.8
10.	Depreciation and amortization expense	312.1	(19.3)	292.8	12.7	305.5
11.	Fixed financing costs	1.9	-	1.9	-	1.9
12.	Municipal and other taxes	50.4	-	50.4	-	50.4
13.	Interest and financing amortization expense	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-
15.	Total costs and expenses	2,350.2	(38.3)	2,311.9	121.2	2,433.1
16.	Ontario utility income before income taxes	283.9	39.8	323.7	(11.0)	312.7
17.	Income tax expense	6.8	(0.2)	6.6	7.1	13.7
18.	Utility net income	277.1	40.0	317.1	(18.1)	299.0

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 6, Page 5, Filed: 2014-03-24.
Note 2: Information from Col. 4 of Exhibit M1, Tab 1, Schedule 6, Page 5, Filed: 2014-03-24.

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2018 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
4.	1.5	Other operating revenue The increase is due to the Board's decision on Other Revenues, requiring other revenue/income to be set at the 2013 actual level of $42.8M.
9.	(19.0)	Operation and maintenance The reduction is due to the Board's decision on Other O&M and to set 2015 through 2018 annual increase at 1%.
10.	(19.3)	Depreciation and amortization expense The reduction is due to the impact of updating depreciation rates (net salvage component) to reduce the net salvage, or site restoration costs, collected over the 2014 - 2018 term by $85M, as per the Board's decison on the Site Restoration Cost issue.
17.	(0.2)	Income tax expense The reduction in income tax expense is due to an increase in the tax deduction for site restoration costs, resulting from the Board's decision on the Site Restoration Cost issue which requires a $120M increase in the refund of previously collected net salvage amounts over the 2014 - 2018 term, and a larger interest tax shield credit resulting from a higher rate base. Partially offsetting these income tax reductions are income tax increases resulting from higher other revenues and lower operation and maintenance costs, as noted in the changes above.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 FISCAL YEAR

Line No.		Col. 1 Excl. CIS Impact Statement Number 1 (Note 1) ($Millions)	Col. 2 Decision Adjustments ($Millions)	Col. 3 Excl. CIS Decision Utility Tax ($Millions)
1.	Utility income before income taxes (M1, T1, S6, P5)	283.9	39.8	323.7
	Add			
2.	Depreciation and amortization	312.1	(19.3)	292.8
3.	Accrual based pension and OPEB costs	26.2	-	26.2
4.	Other non-deductible items	1.0	-	1.0
5.	Total Add Back	339.3	(19.3)	320.0
6.	Sub total	623.2	20.5	643.7
	Deduct			
7.	Capital cost allowance - Federal	298.5	-	298.5
8.	Capital cost allowance - Provincial	298.5	-	298.5
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.6	-	5.6
11.	Amortization of share/debenture issue expense	4.0	-	4.0
12.	Amortization of cumulative eligible capital	4.5	-	4.5
13.	Amortization of C.D.E. and C.O.G.P.E	0.1	-	0.1
14.	Site restoration cost adjustment	17.4	13.7	31.1
15.	Cash based pension and OPEB costs	29.8	-	29.8
16.	Total Deduction - Federal	406.5	13.7	420.2
17.	Total Deduction - Provincial	406.5	13.7	420.2
18.	Taxable income - Federal	216.7	6.8	223.5
19.	Taxable income - Provincial	216.7	6.8	223.5
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
22.	Income tax provision - Federal	32.5	1.0	33.5
23.	Income tax provision - Provincial	24.9	0.8	25.7
24.	Income tax provision - combined	57.4	1.8	59.2
25.	Part V1.1 tax			1.9
26.	Total taxes excluding tax shield on interest expense			61.1
	Tax shield on interest expense			
27.	Rate base (M1.T1.S6.P2)			6,145.6
28.	Return component of debt (M1.T1.S6.P8)			3.34%
29.	Interest expense			205.5
30.	Combined tax rate			26.50%
31.	Income tax credit			(54.5)
32.	Total income taxes			6.6

Note 1: Information from Col. 3 of Exhibit M1, Tab 1, Schedule 6, page 7, Filed: 2014-03-24.

UTILITY CAPITAL STRUCTURE
2018 FISCAL YEAR

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Indicated Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	3,734.3	60.76	5.39	3.275
2.	Short term debt	98.9	1.61	4.30	0.069
3.		3,833.2	62.37		3.344
4.	Preference shares	100.0	1.63	4.64	0.076
5.	Common equity	2,212.4	36.00	10.27	3.697
6.		6,145.6	100.00		7.117
7.	Utility income	($Millions)			317.1
8.	Rate base	($Millions)			6,145.6
9.	Indicated rate of return				5.160%
10.	(Deficiency) in rate of return				(1.957)%
11.	Net (deficiency)	($Millions)			(120.3)
12.	Gross (deficiency)	($Millions)			(163.6)
13.	Customer Care/CIS deficiency	($Millions)			(23.6)
14.	Total gross (deficiency)	($Millions)			(187.2)
15.	Revenue at existing rates	($Millions)			2,703.3
16.	Allowed revenue	($Millions)			2,890.5
17.	Total gross revenue (deficiency)	($Millions)			(187.2)

APPENDIX B

Enbridge Gas Distribution Inc.

EB-2012-0459

Rate Handbook

RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

Part I

GLOSSARY OF TERMS

In this Handbook of Rates and Distribution Services, each term set out below shall have the meaning set out opposite it:

Annual Turnover Volume ("ATV"): The sum of the contracted volumes injected into and withdrawn from storage by an applicant within a contract year.

Annual Volume Deficiency: The difference between the Minimum Annual Volume and the volume actually taken in a contract year, if such volume is less than the Minimum Annual Volume.

Applicant: The party who makes application to the Company for one or more of the services of the Company and such term includes any party receiving one or more of the services of the Company.

Authorized Volume: In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Back-stopping: A service whereby alternative supplies of gas may be available in the event that an Applicant's supply of gas is not available for delivery to the Company.

Banked Gas Account: A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits)

Billing Contract Demand: Applicable only to new customers who take Dedicated Service under Rate 125. The Company and the Applicant shall determine a Billing Contract Demand which would result in annual revenues over the term of the contract that would enable the Company to recover the invested capital, return on capital, and O&M costs of the Dedicated Service in accordance with its system expansion policies.

Billing Month: A period of approximately thirty (30) days following which the Company renders a bill to an applicant. The billing month is determined by the Company's monthly Reading and Billing Schedule. With respect to rate 135 LVDC's, there are eight summer months and four winter months.

Board: Ontario Energy Board. (OEB)

Bundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.

Buy/Sell Arrangement: An arrangement, the terms of which are provided for in one or more agreements to which one or more of an end user of gas (being a party that buys from the Company gas delivered to a Terminal Location), an affiliate of an end user and a marketer, broker or agent of an end user is a party and the Company is a party, and pursuant to which the Company agrees to buy from the end user or its affiliate a supply of gas and to sell to the end user gas delivered to a Terminal Location served from the gas distribution network. The Company will not enter into any new buy/sell agreement after April 1, 1999.

Buy/Sell Price: The Price per cubic meter which the Company would pay for gas purchased pursuant to a Buy/Sell Arrangement in which the purchase takes place in Ontario.

Commodity Charge: A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.

Company: Enbridge Gas Distribution Inc.

Contract Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.

Cubic Metre ("m^3"): That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre. "10^3m^3" means 1,000 cubic metres.

Curtailment: An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Curtailment Credit: A credit available to interruptible customers to recognize the benefits they provide to the system during the winter months.

Curtailment Delivered Supply (CDS): An additional volume of gas, in excess of the Applicant's Mean Daily Volume and determined by mutual agreement between the Applicant and the Company, which is Nominated and delivered by or on behalf of the Applicant to a point of interconnection with the Company's distribution system on a day of Curtailment.

Customer Charge: A monthly fixed charge that reflects being connected to the gas distribution system.

Daily Consumption VS Gas Quantity: The volume of natural gas taken on a day at a Terminal Location as measured by daily metering equipment or, where the Company does not own and maintain daily metering equipment at a Terminal Location, the volume of gas taken within a billing period divided by the number of days in the billing period.

Daily Delivered Volume: The volume of gas accepted by the Company as having been delivered by an Applicant to the Company on a day.

Dedicated Service: An Unbundled Service provided through a gas distribution pipeline that is initially constructed to serve a single customer, and for which the volume of gas is measured through a billing meter that is directly connected to a third party transporter or other third party facility, when service commences.

Delivery Charge: A component of the Rate Schedule through which the Company recovers its operating costs.

Demand Charge: A fixed monthly charge which is applied to the Contract Demand specified in a Service Contract.

Demand Overrun: The amount of gas taken at a Terminal Location exceeding the Contract Demand.

Direct Purchase: Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.

Disconnect and Reconnect Charges: The charges levied by the Company for disconnecting or reconnecting an Applicant from or to the Company's distribution system.

Diversion: Delivery of gas on a day to a delivery point different from the normal delivery point specified in a Service Contract.

Firm Service: A service for a continuous delivery of gas without curtailment, except under extraordinary circumstances.

Firm Transportation ("FT"): Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.

Force Majeure: Any cause not reasonably within the control of the Company and which the Company cannot prevent or overcome with reasonable due diligence, including:

(a) physical events such as an act of God, landslide, earthquake, storm or storm warning such as a hurricane which results in evacuation of an affected area, flood, washout, explosion, breakage or accident to machinery or equipment or lines of pipe used to transport gas, the necessity for making repairs to or alterations of such machinery or equipment or lines of pipe or inability to obtain materials, supplies (including a supply of services) or permits required by the Company to provide service;

(b) interruption and/or curtailment of firm transportation by a gas transporter for the Company;

(c) acts of others such as strike, lockout or other industrial disturbance, civil disturbance, blockade, act of a public enemy, terrorism, riot, sabotage, insurrections or war, as well as physical damage resulting from the negligence of others;

(d) in relation to Load Balancing, failure or malfunction of any storage equipment or facilities of the Company; and

(e) governmental actions, such as necessity for compliance with any applicable laws.

Gas: Natural Gas.

Gas Delivery Agreement: A written agreement pursuant to which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Gas Distribution Network: The physical facilities owned by the Company and utilized to contain, move and measure natural gas.

Gas Sale Contract: A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Gas Supply Charge: A charge for the gas commodity purchased by the applicant.

Gas Supply Load Balancing Charge: A charge in the Rate Schedules where the Company recovers the cost of ensuring gas supply matches consumption on a daily basis.

General Service Rates: The Rate Schedules applicable to those Bundled Services for which a specific contract between the Company and the Applicant is not generally required. The General Service Rates include Rates 1, 6, and 9 of the Company.

Gigajoule ("GJ"): See Joule.

Hourly Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule which is the maximum volume of gas the Company is required to deliver to an Applicant on a hourly basis under a Service Contract.

Imperial Conversion Factors:

Volume:		
1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$
Pressure:		
1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa
Energy:		
1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ
Monetary Value:		
$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

Interruptible Service: Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Intra-Alberta Service: Firm transportation service on the Nova pipeline system under which volumes are delivered to an Intra-Alberta point of acceptance.

Joule ("J"): The amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force. One megajoule ("MJ") means 1,000,000 joules; one gigajoule ("GJ") means 1,000,000,000 joules.

Large Volume Distribution Contract: (LVDC): A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Large Volume Distribution Contract Rates: The Rate Schedules applicable for annual consumption exceeding 340,000 cubic metres of gas per year and for which a specific contract between the Company and the Applicant is required.

Load-Balancing: The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.

Make-up Volume: A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.

Mean Daily Volume (MDV): The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement.

Metric Conversion Factors:

Volume:

1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf

Pressure:

1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere

Energy:

1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu

Monetary Value:

\$1 per 10^3m^3	=	\$0.02832784 per Mcf
\$1 per gigajoule	=	\$1.055056 per MMBtu

Minimum Annual Volume: The minimum annual volume as stated in the customer's contract, also Section E.

Natural Gas: Natural and/or residue gas comprised primarily of methane.

Nominated Volume: The volume of gas which an Applicant has advised the Company it will deliver to the Company in a day.

Nominate, Nomination: The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.

Ontario Energy Board: An agency of the Ontario Government which, amongst other things, approves the Company's Rate Schedules (Part V of this HANDBOOK) and the matters described in Parts III and IV of this HANDBOOK.

Point of Acceptance: The point at which the Company accepts delivery of a supply of natural gas for transportation to, or purchase from, the Applicant.

Rate Schedule: A numbered rate of the Company as fixed or approved by the OEB. that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Seasonal Credit: A credit applicable to Rate 135 customers to recognize the benefits they provide to the storage operations during the winter period.

Service Contract: An agreement between the Company and the Applicant which describes the responsibilities of each party in respect to the arrangements for the Company to provide Sales Service or Transportation Service to one or more Terminal Locations.

System Sales Service: A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.

T-Service: Transportation Service.

Terminal Location: The building or other facility of the Applicant at or in which natural gas will be used by the Applicant.

Transportation Service: A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Unbundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.

Western Canada Buy Price: The price per cubic metre which the Company would pay for gas pursuant to a Buy/Sell Agreement in which the purchase takes place in Western Canada.

PART II

RATES AND SERVICES AVAILABLE

The provisions of this PART II are intended to provide a general description of services offered by the Company and certain matters relating thereto. Such provisions are not definitive or comprehensive as to their subject matter and may be changed by the Company at any time without notice.

SECTION A - INTRODUCTION

1. In Franchise Services

Enbridge Gas Distribution provides in franchise services for the transportation of natural gas from the point of its delivery to Enbridge Gas Distribution to the Terminal Location at which the gas will be used. The natural gas to be transported may be owned by the Applicant for service or by the Company. In the latter case, it will be sold to the customer at the outlet of the meter located at the Terminal Location.

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, 315, and 316 ("the Unbundled Service Rates").

Service to residential locations is provided pursuant to Rate 1.

Service which may be interrupted at the option of the Company is available, at rates lower than would apply for equivalent service under a firm rate schedule, pursuant to Rates 145, 170. Under all other rate schedules, service is provided upon demand by the Applicant, i.e., on a firm service basis.

2. Ex-Franchise Services

Enbridge Gas Distribution provides ex-franchise services for the transportation of natural gas through its distribution system to a point of interconnection with the distribution system of other distributors of natural gas. Such service is provided pursuant to Rate 200 and provides for the bundled transportation of gas owned by the Company, owned by customers of that distributor, or owned by that distributor.

For the purposes of interpreting the terms and conditions contained in this Handbook of Rates and Distribution Services the ex - franchise distributor shall be considered to be the applicant for the transportation of its customer owned gas and shall assume all the obligations of transportation as if it owned the gas.

Nominations for transportation service must specify whether the volume to be transported is to displace firm or interruptible demand or general service.

In addition, the Company provides Compression, Storage, and Transmission services on its Tecumseh system under Rates 325, 330 and 331.

SECTION B - DIRECT PURCHASE ARRANGEMENTS

Applicants who purchase their natural gas requirements directly from someone other than the Company or who are brokers or agents for an end user, may arrange to transport gas on the Company's distribution network in conjunction with a Western Buy/Sell Arrangement or pursuant to an Ontario Delivery Transportation Service Arrangement, whether Bundled or Unbundled, or a Western Bundled Transportation Service Arrangement.

B. Western Canada

Buy/Sell in a Western Canada Buy/Sell Arrangement the Applicant delivers gas to a point in Western Canada which connects with the transmission pipeline of TransCanada PipeLines Limited. At that point, the Company purchases the gas from the Applicant at a price specified in Rider 'B' of the rate schedules less the costs for transmission of the gas from the point of purchase to a point in Ontario at which the Company's gas distribution network connects with a transmission pipeline system. The Company will not be entering into any new Western Canada buy/sell arrangements after April 1, 1999.

C. Ontario Delivery T-Service Arrangements

In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.

Delivery from the point of direct interconnection with the Company's gas distribution network to a Terminal Location served from the Company's gas distribution network may be obtained by the Applicant either under the Bundled Service Rate Schedules or under the Unbundled Service Rate Schedules.

(i) Bundled T-Service

Bundled T-Service is so called because all of the services required by the Applicant (delivery and load balancing) are provided for the prices specified in the applicable Rate Schedule. In a Bundled T-Service arrangement the Applicant contracts to deliver each day to the Company a Mean Daily Volume of gas. Fluctuations in the demand for gas at the Terminal Location are balanced by the Company.

(ii) Unbundled T-Service

The Unbundled Service Rates allow an Applicant to contract for only such kinds of service as the Applicant chooses. The potential advantage to an Applicant is that the chosen amounts of service may be less than the amounts required by an average customer represented in the applicable Rate Schedule, in which case the Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

The provisions of this PART III are applicable to, and only to, Sales Service and Transportation Service.

SECTION A - AVAILABILITY

Unless otherwise stated in a Rate Schedule, the Company's rates and services are available throughout the entire franchised area serviced by the Company. Transportation service and/or sales service will be provided subject to the Company having the capacity in its gas distribution network to provide the service requested. When the Company is requested to supply the natural gas to be delivered, service shall be available subject to the Company having available to it a supply of gas adequate to meet the requirement without jeopardizing the supply to its existing customers.

Service shall be made available after acceptance by the Company of an application for service to a Terminal Location at which the natural gas will be used.

SECTION B - ENERGY CONTENT

The price of natural gas sold at a Terminal Location is based on the assumption that each cubic metre of such natural gas contains a certain number of megajoules of energy which number is specified in the Rate Schedules. Variations in cost resulting from the energy content of the gas actually delivered to the Company by its supplier(s) differing from the assumed energy content will be recorded and used to adjust future bills. Such adjustments shall be made in accordance with practices approved from time to time by the Ontario Energy Board.

SECTION C - SUBSTITUTION PROVISION

The Company may deliver gas from any standby equipment provided that the gas so delivered shall be reasonably equivalent to the natural gas normally delivered.

SECTION D - BILLS

Bills will be mailed or delivered monthly or at such other time period as set out in the Service Contract. Gas consumption to which the Company's rates apply will be determined by the Company either by meter reading or by the Company's estimate of consumption where meter reading has not occurred. The rates and charges applicable to a billing month shall be those applicable to the calendar month which includes the last day of the billing month.

SECTION E - MINIMUM BILLS

The minimum bill per month applicable to service under any particular Rate Schedule shall be the Customer Charge plus any applicable Contract Demand Charges for Delivery, Gas Supply Load Balancing, and Gas Supply and any applicable Direct Purchase Administration Charge, all as provided for in the applicable Rate Schedule.

In addition, for service under each of the Large Volume Distribution Contact Rates, if in a contract year a volume of gas equal to or greater than the product of the Contract Demand multiplied by a contractually specified multiple of the Contract Demand ("Minimum Annual Volume") is not taken at the Terminal Location the Applicant shall pay, in addition to the minimum monthly bills, the amount obtained when the difference between the Minimum Annual Volume and the volume taken in the contract year (such difference being the Annual Volume Deficiency) is multiplied by the applicable Minimum Bill Charge(s) as provided for in the applicable Rate Schedule. Notwithstanding the foregoing, the Minimum Annual Volume shall be the greater of the Minimum Annual Volume as determined above and 340,000 m^3.

If gas deliveries to the Terminal Location have been ordered to be curtailed or discontinued in a contract year at the request of the Company and have been curtailed or discontinued as ordered, the Minimum Annual Volume shall be reduced for each day of curtailment or discontinuance by the excess of the Contract Demand over the volume delivered to the Terminal Location on such day.

SECTION F - PAYMENT CONDITIONS

Enbridge Gas Distribution charges are due when the bill is received, which is considered to be three days after the date the bill is rendered, or within such other time period as set out in the Service Contract. A late payment charge of 1.5% per month (19.56% effectively per annum) of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17th) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

When gas service is provided and there is no written agreement in effect relating to the provision of such service, the term for which such service is to continue shall be one year. The term shall automatically be extended for a further year immediately following the expiry of any initial one year term or one year extension unless reasonable notice to terminate service is given to the Company, in a manner acceptable to the Company, prior to the expiry of the term. An Applicant receiving such service who temporarily discontinues service in the initial one year term or any one year extension and does not pay all the minimum bills for the period of such temporary discontinuance of service shall, upon the continuance of service, be liable to pay an amount equal to the unpaid minimum bills for such period. When a written agreement is in effect relating to the provision of gas service, the term for which such service is to continue shall be as provided for in the agreement.

SECTION H - RESALE PROHIBITION

Gas taken at a Terminal Location shall not be resold other than in accordance with all applicable laws and regulations and orders of any governmental authority or OEB having jurisdiction.

SECTION I - MEASUREMENT

The Company will install, operate and maintain at a Terminal Location such measurement equipment of suitable capacity and design as is required to measure the volume of gas delivered. Any special conditions for measurement are contained in the General Terms and Conditions which form part of each Large Volume Distribution Contract.

SECTION J - RATES IN CONTRACTS

Notwithstanding any rates for service specified in any Service Contract, the rates and charges provided for in an applicable Rate Schedule shall apply for service rendered on and after the effective date stated in such Rate Schedule until such Rate Schedule ceases to be applicable.

SECTION K - ADVICE RE: CURTAILMENT

The Company, if requested, will advise Applicants taking interruptible service of its estimate of service curtailment for the forthcoming winter. Such estimate will be provided as guidance to the Applicant in arranging for alternate fuel supply requirements. Abnormal weather and/or other unforeseen events may cause greater or lesser curtailment of service than expected.

SECTION L - DAILY DELIVERED VOLUMES

For purposes including that of calculating daily overrun gas volumes, the Company will recognize as having been delivered to it on a given day the sum of:

a) the volume of gas delivered under Intra-Alberta transportation arrangements, if any, plus;

b) the volume of gas delivered under FT transportation arrangements, if any, plus;

SECTION M - AUTHORIZED OVERRUN GAS

If an Applicant requests permission to exceed the Authorized Volume for a day, and such authorization is granted, such gas shall constitute Authorized Overrun Gas. Such gas shall either be sold by the Company to the Applicant pursuant to the provisions of Rate 320 applicable on such day, or, at the Company's sole discretion, under the Rate Schedule the customer is purchasing prior to such request. If the Applicant is supplying their own gas requirements and if the Applicant request and at the Company's sole discretion, such Overrun Gas will be debited to the Applicant's Banked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

If an Applicant for Transportation Service pursuant to the General Service Rates on any day delivers to the Company a Daily Delivered Volume which is less than the Mean Daily Volume, the volume of gas by which the Mean Daily Volume applicable to such day exceeds the Daily Delivered Volume delivered by the Applicant to the Company on such day shall constitute Unauthorized Supply Overrun Gas and shall be deemed to have been taken and purchased on such day. The rate applicable to such volume shall be 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under the Large Volume Distribution Contract Rates is:

(a) the volume of gas by which the Daily Gas Quantity under the Service Contract on such day exceeds the Authorized Volume for such day, if any

plus

(b) if the day is in the months of December to March inclusive for an Applicant taking service on Rate 135 under Option a) or if the day is in the month of December under Option b), or if the day is a day on or in respect of which the Applicant has been requested in accordance with the Service Contract to curtail or discontinue the use of gas and the Service Contract is in whole or in part for interruptible Transportation Service, the volume of gas, if any, by which

(i) the Mean Daily Volume set out in the Service Contract and is applicable to such day exceeds

(ii) the Daily Delivered Volume delivered by the Applicant to the Company on such day, which excess volume of gas shall be deemed to have been taken and purchased by the Applicant on such day.

The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

An Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate must provide two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean Daily Volume for a specified time period. Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under Rate 125 or Rate 300 shall be determined from the provisions of the applicable Rate Schedule. The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

This Section O applies only to gas distribution service under Rates 1, 6 and 9, and does not replace or supercede the terms in any applicable Service Contract.
The Company shall make reasonable efforts to maintain, but does not guarantee, continuity of gas service to its customers. The Company may, in its sole discretion, terminate or interrupt gas service to customers;

to maintain safety and reliability on, or to facilitate construction, installation, maintenance, repair, replacement or inspection of the Company's facilities; or

for any reason related to dangerous or hazardous circumstances, emergencies or Force Majeure.

The Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether direct, indirect, special or consequential in nature, (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising from or connected with any failure, defect, fluctuation or interruption in the provision of gas service by the Company to its customers.

SECTION P – OBLIGATION FOR LARGE CUSTOMERS TO PROVIDE CONSUMPTION AND EMERGENCY CONTACT INFORMATION

All customers whose annual consumption exceeds 1,000,000 m3 are obligated to provide their expected annual consumption, peak demand, and emergency contact information to the Company annually.

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

Any Applicant, at the time of applying for service, may elect, in and for the term of any Service Contract, to deliver its own natural gas requirements to the Company and the Company shall deliver gas to a Terminal Location as required by the Applicant, subject to the terms and conditions contained in the applicable Rate Schedule and in the Service Contract. For Buy/Sell Arrangements and Bundled T-Service the deliveries by the Applicant to the Company shall be at the Applicant's estimated mean daily rate of consumption.

Backstopping of an Applicant's natural gas supply for Transportation Service arrangements will be available pursuant to Rate 320 subject to the Company's ability to do so using reasonable commercial efforts. Gas Purchase Agreements in respect to Buy/Sell Arrangements shall specify terms and conditions available to the Company to alleviate certain consequences of the Applicant's failure to deliver the required volume of gas.

The following Terms and Conditions shall apply to, and only to, Transportation Service and/or Gas Purchase Agreements.

SECTION A - NOMINATIONS

An Applicant delivering gas to the Company pursuant to a contract is responsible for advising the Company, by means of a contractually specified Nomination procedure, of the daily volume of gas to be delivered to the Company by or on behalf of the Applicant.

An initial daily volume must be Nominated by a contractually specified time before the first day on which gas is to be delivered to the Company. Any Nomination, once accepted by the Company, shall be considered as a standing nomination applicable to each subsequent day in a contract term unless specifically varied by written notice to the Company.

A contract may specify certain contractual provisions that are applicable in the event that an Applicant either fails to advise of a revised daily nomination or fails to deliver the daily volume so nominated.

A Nominated Volume in excess of the Applicant's Maximum Daily Volume as specified in the Service Contract will not be accepted except as specifically provided for in any contract.

SECTION B - OBLIGATION TO DELIVER

During any period of curtailment or discontinuance of Bundled interruptible Transportation Service as ordered by the Company, any Applicant supplying its own gas requirements must, on such day, deliver to the Company the Mean Daily Volume of gas specified in any Service Contract.

Each Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate is obligated to deliver the Mean Daily Volume of gas as specified in any Service Contract, unless the Applicant provides two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean daily Volume for a specified time period.

An Applicant taking service on Rate 135 under Option a) must deliver to the Company the Mean Daily Volume of gas specified in the Service Contract in the months of December to March, inclusive.

An Applicant taking service on Rate 135 under Option b) must deliver to the Company the Modified Mean Daily Volume of gas specified in the Service Contract in the month of December.

Applicants taking service on General Service rates pursuant to a Direct Purchase Agreement must, on each day in the term of such agreement, deliver to the Company the Mean Daily Volume of gas specified in such agreement.

SECTION C - DIVERSION RIGHTS

Subject to compliance with the Terms and Conditions of all Required Orders, an Applicant who has entered into a Transportation Service Agreement or Agreements which provide(s) for deliveries to the Company for more than one Terminal Location shall have the right, on such terms and only on such terms as are specified in the applicable Transportation Service Agreement, to divert deliveries from one or more contractually specified Terminal Locations to other contractually specified Terminal Locations.

SECTION D - BANKED GAS ACCOUNT (BGA)

For T-Service Applicants, the Company shall keep a record ("Banked Gas Account") of the volume of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of the volume of gas taken by the Applicant at the Terminal Location (debits). (Any volume of gas sold by the Company to the Applicant in respect to the Terminal Location shall not be debited to the Banked Gas Account). The Company shall periodically report to the Applicant the net balance in the Applicant's Banked Gas Account.

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT (BGA) BALANCES

A. The following Terms and Conditions shall apply to Bundled T-Service:

(a) At the end of each contract year, disposition of any net debit balance in the Banked Gas Account (BGA) shall be made as follows:

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year, that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

(1) for *Bundled Western T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

(2) for *Bundled Ontario T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus the Company's average transportation cost to its franchise area over the contract year.

(b) A credit balance in the Banked Gas Account as at the end of the contract year must be eliminated in one or more of the following manners, namely:

(i) Subject to clause (ii), if the Applicant continues to take service from the Company under a contract pursuant to which the Applicant delivers gas to the Company and the Applicant so elects (by written notice to the Company within thirty (30) days of the end of the contract year), that portion of such balance which the Applicant stipulates in such written notice and which does not exceed twenty times the Applicant's Mean Daily

Volume may be carried forward as a credit to the Banked Gas Account for the next succeeding contract year. Any volume duly elected to be carried forward under this clause shall, and may only, be reduced within the period of one hundred and eighty (180) days ("Adjustment Period") immediately following the contract year, by the Applicant delivering to the Company, on days in the Adjustment Period agreed upon by the Company and the Applicant ("Adjustment Days"), a volume of gas less than the Mean Daily Volume applicable to such day under a Service Contract. Subject to the foregoing, the credit balance in the Banked Gas Account shall be deemed to be reduced on each Adjustment Day by the volume ("Daily Reduction Volume") by which the Mean Daily Volume applicable to such day exceeds the greater of the volume of gas delivered by the Applicant on such day and the Nominated Volume for such day which was accepted by the Company.

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at:

(1) for *Bundled Western T*-Service, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the Company's average transportation cost to its franchise area over the contract year.

(2) for *Bundled Ontario T-Service*, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

During the Adjustment Period the Company shall use reasonable efforts to accept the Applicant's reduced gas deliveries. Any credit balance in the Banked Gas Account not eliminated as aforesaid in the Adjustment Period shall be forfeited to, and be the property of, the Company, and such volume of gas shall be debited to the Banked Gas Account as at the end of the Adjustment Period.

Subject to its ability to do so, the Company will attempt to accommodate arrangements which would permit adjustments to Banked Gas Account balances at times and in a manner which are mutually agreed upon by the Applicant and the Company.

B. The following Terms and Conditions shall apply to Unbundled Service:

The Terms and Conditions for disposition of Cumulative Imbalance Account balances shall be as specified in the applicable Service Contracts.

RATE NUMBER: **1**	**RESIDENTIAL SERVICE**

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a residential building served through one meter and containing no more than six dwelling units ("Terminal Location").

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$20.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**7.3614 ¢/m³**
For the next 55 m³ per month	**6.9289 ¢/m³**
For the next 85 m³ per month	**6.5900 ¢/m³**
For all over 170 m³ per month	**6.3375 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.2962 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider “F”.
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: 6	GENERAL SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") for non-residential purposes.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$70.00**
Delivery Charge per cubic metre	
For the first 500 m³ per month	**7.4786 ¢/m³**
For the next 1050 m³ per month	**5.8443 ¢/m³**
For the next 4500 m³ per month	**4.7000 ¢/m³**
For the next 7000 m³ per month	**3.9645 ¢/m³**
For the next 15250 m³ per month	**3.6379 ¢/m³**
For all over 28300 m³ per month	**3.5559 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.3215 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider “F”.
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: 9	CONTAINER SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") at which, such gas is authorized by the Company to be resold by filling pressurized containers.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$235.95**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**10.3497 ¢/m³**
For all over 20,000 m³ per month	**9.6885 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.2498 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: 100	FIRM CONTRACT SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), to be delivered at a specified maximum daily volume of not less than 10,000 cubic metres and not more than 150,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$122.01**
Delivery Charge	
Per cubic metre of Contract Demand	**36.0000 ¢/m³**
Per cubic metre of gas delivered	**0.1473 ¢/m³**
Gas Supply Load Balancing Charge	**0.5400 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.3215 ¢/m³**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Contract Demand Charge.

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **100**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: 110	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 146 times a specified maximum daily volume of not less than 1,865 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$587.37**
Delivery Charge	
Per cubic metre of Contract Demand	**22.9100 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5278 ¢/m³**
For all over 1,000,000 m³ per month	**0.3778 ¢/m³**
Gas Supply Load Balancing Charge	**0.0810 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.2498 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **110**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.2218 ¢/m³

In determining the Annual Volume Deficiency, the minimum bill multiplier shall not be less than 146.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: 115	LARGE VOLUME LOAD FACTOR SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 292 times a specified maximum daily volume of not less than 1,165 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$622.62**
Delivery Charge	
Per cubic metre of Contract Demand	**24.3600 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.1799 ¢/m³**
For all over 1,000,000 m³ per month	**0.0799 ¢/m³**
Gas Supply Load Balancing Charge	**0.0384 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.2498 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **115**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

4.8313 ¢/m³

In determining the Annual Volume Deficiency the minimum bill multiplier shall not be less than 292.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: 125	EXTRA LARGE FIRM DISTRIBUTION SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified maximum daily volume of natural gas. The maximum daily volume for billing purposes, Contract Demand or Billing Contract Demand, as applicable, shall not be less than 600,000 cubic metres. The Service under this rate requires Automatic Meter Reading (AMR) capability.

CHARACTER OF SERVICE:

Service shall be firm except for events specified in the Service Contract including force majeure.

For Non-Dedicated Service the monthly demand charges payable shall be based on the Contract Demand which shall be 24 times the Hourly Demand and the Applicant shall not exceed the Hourly Demand.

For Dedicated Service the monthly demand charges payable shall be based on the Billing Contract Demand or the Contract Demand specified in the Service Contract. The Applicant shall not exceed an hourly flow calculated as 1/24th of the Contract Demand specified in the Service Contract.

DISTRIBUTION RATES:

The following rates and charges, as applicable, shall apply for deliveries to the Terminal Location.

Monthly Customer Charge	**$500.00**
Demand Charge	
Per cubic metre of the Contract Demand or the Billing Contract Demand, as applicable, per month	**8.0942 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.7%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a). In the case of a Dedicated Service, the Unaccounted for Gas volume requirement is not applicable.

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG. Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 125 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

   Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA) or other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed the Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 125 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

The Company permits pooling of Rate 125 contracts for legally related customers who meet the Business Corporations Act (Ontario) ("OBCA") definition of "affiliates" to allow for the management of those contracts by a single manager. The single manager is jointly liable with the individual customers for all of their obligations under the contracts, while the individual customers are severally liable for all of their obligations under their own contracts.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery (the sum of the customer's Contract Demand and the authorized overrun amount) required to serve the customer's daily load, plus the UFG. In the event that gas usage exceeds the gas delivery on a day where demand overrun is authorized, the excess gas consumption shall be deemed Supply Overrun Gas.
Such service shall not exceed 5 days in any contract year. Based on the terms of the Service Contract, requests beyond 5 days will constitute a request for a new Contract Demand level with retroactive charges. The new Contract Demand level may be restricted by the capability of the local distribution facilities to accommodate higher demand.

Automatic authorization of transportation overrun over the Billing Contract Demand will be given in the case of Dedicated Service to the Terminal Location provided that pipeline capacity is available and subject to the Contract Demand as specified in the Service Contract.

Authorized Demand Overrun Rate	**0.27 ¢/m³**

The Authorized Demand Overrun Rate may be applied to commissioning volumes at the Company's sole discretion, for a contractual period of not more than one year, as specified in the Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas may establish a new Contract Demand effective immediately and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Based on capability of the local distribution facilities to accommodate higher demand, different conditions may apply as specified in the applicable Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below*****.

RATE NUMBER: **125**

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following day's Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including the load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location or at the location of the meter installation for a customer served from a dedicated facility. In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources including where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed the Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's Terminal Location or in the event of combined nominations at the Terminal Locations specified.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery since the date the customer last balanced or was deemed to have balanced its Cumulative Imbalance account.

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Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand for non dedicated service and 60% of the Billing Contract Demand for dedicated service.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = 0.7827 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 0.9392 cents/m3 applied to Daily Imbalance of greater than 10% but less than the Maximum Contractual Imbalance

In addition for Tier 2, instances where the Daily Imbalance represents an under delivery of gas during the winter season shall constitute Unauthorized Supply Overrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. Where the Daily Imbalance represents an over delivery of gas during the summer season, the Company reserves the right to deem as Unauthorized Supply Underrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. The Company will issue a 24-hour advance notice to customers of its intent to impose cash out for over delivery of gas during the summer season.

RATE NUMBER: **125**

For customers delivering to a Primary Delivery Area other than EGD's CDA or EGD's EDA, the Tier 1 Fee is applied to Daily Imbalance of greater than 0% but less than 10% of the Maximum Contractual Imbalance

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rates 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances. The Company will provide the customer with a derivation of any such charges.

Customer’s Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer’s Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area. Customers may also nominate to transfer gas from their Cumulative Imbalance Account into an unbundled (Rate 315 or Rate 316) storage account of the customer subject to their storage contract parameters.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed the Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds the Contract Demand.

The customer’s Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. In the event that the customer's imbalance exceeds their Maximum Contractual Imbalance the Company shall deem the excess imbalance to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 1.0672 cents/m3 per unit of imbalance.

In addition, on any day that the Company declares an Operational Flow Order, negative Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance in the winter season shall be deemed to be Unauthorized Overrun Gas. The Company reserves the right to deem positive Cumulative Imbalances greater than 10% of Maximum Contractual Imbalance in the summer season as Unauthorized Supply Underun Gas. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders including cash out instructions for Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RATE NUMBER: **135**	**SEASONAL FIRM SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 340,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure. A maximum of five percent of the contracted annual volume may be taken by the Applicant in a single month during the months of December to March inclusively.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month	
	December to March	**April to November**
Monthly Customer Charge	**$115.08**	**$115.08**
Delivery Charge		
For the first 14,000 m³ per month	**6.6670 ¢/m³**	**1.9670 ¢/m³**
For the next 28,000 m³ per month	**5.4670 ¢/m³**	**1.2670 ¢/m³**
For all over 42,000 m³ per month	**5.0670 ¢/m³**	**1.0670 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.2880 ¢/m³**	**12.2880 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

The applicant has the option of delivering either Option a) a Mean Daily Volume ("MDV") based on 12 months, or Option b) a Modified Mean Daily Volume ("MMDV") based on nine months of deliveries. Authorized Volumes for the months of January, February and March would be zero under option b).

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Failure to deliver a volume of gas equal to the Mean Daily Volume under Option a) set out in the Service Contract during the months of December to March inclusive may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

Failure to deliver a volume of gas equal to the Modified Mean Daily Volume under Option b) set out in the Service Contract during the month of December may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

RATE NUMBER: **135**

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March	$	**0.77 /m^3**
Rate per cubic metre of Modified Mean Daily Volume for December	$	**0.77 /m^3**

SEASONAL OVERRUN CHARGE:

During the months of December through March inclusively, any volume of gas taken in a single month in excess of five percent of the annual contract volume (Seasonal Overrun Monthly Volume) will be subject to Seasonal Overrun Charges in place of both the Delivery and Gas Supply Load Balancing Charges. The Seasonal Overrun Charge applicable for the months of December and March shall be calculated as 2.0 times the sum of the Gas Supply Load Balancing Charge, Transportation Charge and the maximum Delivery Charge. The Seasonal Overrun Charge applicable for the months of January and February shall be calculated as 5.0 times the sum of the Load Balancing Charge, Transportation Charge and the maximum Delivery Charge.

Seasonal Overrun Charges:

December and March	**22.6340 ¢/m^3**
January and February	**56.5850 ¢/m^3**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.1467 ¢/m^3**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: **145**	**INTERRUPTIBLE SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source. Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 16 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$123.34**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.7404 ¢/m³**
For the next 28,000 m³ per month	**1.3814 ¢/m³**
For all over 42,000 m³ per month	**0.8224 ¢/m³**
Gas Supply Load Balancing Charge	**0.1501 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.4086 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.50 /m³**

RATE NUMBER: **145**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**7.5035 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: **170**	**LARGE INTERRUPTIBLE SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$279.31**
Delivery Charge	
Per cubic metre of Contract Demand	**4.0900 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.4623 ¢/m³**
For all over 1,000,000 m³ per month	**0.2623 ¢/m³**
Gas Supply Load Balancing Charge	**0.0833 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.2498 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

RATE NUMBER: **170**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **5.1586 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: **200**	**WHOLESALE SERVICE**

APPLICABILITY:

To any Distributor who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of an annual supply of natural gas to customers outside of the Company's franchise area.

CHARACTER OF SERVICE:

Service shall be continuous (firm), except for events as specified in the Service Contract including force majeure, up to the contracted firm daily demand and subject to curtailment or discontinuance, of demand in excess of the firm contract demand, upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month **January to December**
Monthly Customer Charge	
The monthly customer charge shall be negotiated with the applicant and shall not exceed:	**$2,000.00**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**14.7000 ¢/m³**
Per cubic metre of gas delivered	**1.2373 ¢/m³**
Gas Supply Load Balancing Charge	**0.3644 ¢/m³**
Transportation Charge per cubic metre	**4.6500 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.2498 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**12.2258 ¢/m³**

The rates quoted above shall be subject to the Gas Inventory Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable to volumes of natural gas purchased from the Company. The volumes purchased shall be the volumes delivered at the Point of Delivery less any volumes, which the Company does not own and are received at the Point of Acceptance for delivery to the Applicant at the Point of Delivery.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

RATE NUMBER: **200**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to receive interruptible service under this rate schedule.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**6.2148 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates as the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: 300	FIRM OR INTERRUPTIBLE DISTRIBUTION SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation to a single Terminal Location of a specified maximum daily volume of natural gas. The Company reserves the right to limit service under this schedule to customers whose maximum contract demand does not exceed 600,000 m3. The Service under this rate requires Automatic Meter Reading (AMR) capability. Service under this schedule is firm unless a customer is currently served under interruptible distribution service or the Company, in its sole judgment, determines that existing delivery facilities cannot adequately serve the load on a firm basis.

The unitized Monthly Contract Demand Charge is also applicable to volumes delivered to any Applicant taking service under a Curtailment Delivered Supply contract with the Company. The unitized rate equals the applicable Monthly Contract Demand Charge times 12/365.

CHARACTER OF SERVICE:

The Service shall be continuous (firm) except for events specified in the Service Contract including force majeure. The Applicant is neither allowed to take a daily quantity of gas greater than the Contract Demand nor an hourly amount in excess of the Contract Demand divided by 24, without the Company's prior consent. Interruptible Distribution Service is provided on a best efforts basis subject to the events identified in the service contract including force majeure and, in addition, shall be subject to curtailment or discontinuance of service when the Company notifies the customer under normal circumstances 4 hours prior to the time that service is subject to curtailment or discontinuance. Under emergency conditions, the Company may curtail or discontinue service on one-hour notice. The Interruptible Service Customer is not allowed to exceed maximum hourly flow requirements as specified in Service Contract.

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**24.4780 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3193 ¢/m³**
Maximum Delivery Charge	**0.9657 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.7%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Contract Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a).

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG, net of No-Notice Storage Service provisions under Rate 315, if applicable. The amount of gas delivered under No-Notice Storage Service will also be reduced by the UFG adjustment factor for delivery to the customer's meter.

   Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 300 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA) *or* other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 300 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery required to serve the customer's daily load, including quantities of gas in excess of the Contract Demand, plus the UFG. The Load Balancing Provisions and/or No-Notice Storage Service provisions under Rate 315 cannot be used for Authorized Demand Overrun. Failure to nominate gas deliveries to match Authorized Demand Overrun shall constitute Unauthorized Supply Overrun.

The rate applicable to Authorized Demand Overrun shall equal the applicable Monthly Demand Charge times 12/365 provided, however, that such service shall not exceed 5 days in any contract year. Requests beyond 5 days will constitute a request for a new Contract Demand level, with retroactive charges based on terms of Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas will establish a new Contract Demand and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions. Where a customer receives interruptible service hereunder and consumes gas during a period of interruption, such gas shall be deemed Unauthorized Supply Overrun. In addition to charges for Unauthorized Supply Overrun, interruptible customers consuming gas during a scheduled interruption shall pay a penalty charge of $18.00 per m3.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below*.

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable Rate 300 Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following days Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including interruptible service and load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

Load Balancing:

Any difference between actual daily-metered consumption and the actual daily volume of gas delivered to the system less the UFG shall first be provided under the provisions of Rate 315 - Gas Storage Service, if applicable. Any remaining difference will be subject to the Load Balancing Provisions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location.

In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources plus, where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's premise.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery.

RATE NUMBER: **300**

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance and shall be subject to a charge of 0.7827 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 0.9392 cents/m3

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rate 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances.

RATE NUMBER: **300**

A Daily Imbalance in excess of the Maximum Contractual Imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

Customer's Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer's Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds Contract Demand.

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. The excess imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 0.7058 cents/m3 per unit of imbalance.

The customer's Cumulative Imbalance shall be equal to zero within five (5) days from the last day of the Service Contract.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RATE NUMBER 315	GAS STORAGE SERVICE

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. In addition, the customer shall maintain a positive balance of gas in storage at all times or forfeit the use of Storage Services for Load Balancing and No-Notice Storage Service.

A daily nomination for storage injection and withdrawal except for No-Notice Storage Service, hereunder, which is used automatically for daily Load Balancing, shall also be required.

The maximum hourly injections / withdrawals shall equal 1/24th of the daily Storage Demand. No-Notice Storage Service is available up to the maximum daily withdrawal rights less the nominated withdrawal or the maximum daily injection rights less the nominated injections.

Storage space shall be based on either of two storage allocation methodologies: (customer's average winter demand - customer's average annual demand) x 151, or [(17 x customers's maximum hourly demand) / 0.1] x 0.57. Customers have the option to select from these two storage space allocation methods the one that best suits their requirements.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is available on two bases:

(1) Service nominated daily based on the available capacity and gas in storage up to the maximum contracted daily deliverability; and

(2) No-Notice Storage Service for daily Load Balancing consistent with the maximum hourly deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0515 ¢/m³**
Monthly Storage Deliverability Demand Charge	**18.5650 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.2979 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations and No-Notice Storage Service quantities.

All deemed withdrawal quantities under the No-Notice Storage Service provisions of this rate will be adjusted for the UFG provisions applicable to the distribution service rates.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

1. **Nominated Storage Service**:

Nominations under this rate shall only be accepted at the standard North American Energy Standards Board ("NAESB") nomination windows. The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area, which may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). All volumes nominated from storage are delivered first for purposes of daily Load Balancing of available supply assets. When system conditions permit, the customer may nominate all or a portion of the available withdrawal capacity for delivery to Dawn or to the customer's Primary Delivery Area for purposes other than consumption at the customer's own meter.

Storage not nominated for delivery will be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's Contract Demand (CD).

The customer may also nominate gas for delivery into storage by nominating the storage delivery area as the Primary Delivery Area. Gas nominated for storage delivery will not be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's CD.
Any gas in excess of the contract demand will be subject to cash out as injection overrun gas.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

2. **No-Notice Storage Service**:

The Company, at its sole discretion based on operating conditions, may provide a No-Notice Storage Service that allows customers taking gas under distribution service rates to balance daily deliveries using this Storage Service. No-Notice Storage Service requires that the customer grant the Company the exclusive right to use unscheduled service available from storage to reduce the daily imbalance associated with the actual consumption of the customer.

No-Notice Storage Service is limited to the available, unscheduled withdrawal or injection capacity under contract to serve a customer. Where the customer serves multiple delivery locations from a single storage Service Contract, the customer shall specify the order in which gas is to be delivered to each Terminal Location served under a distribution Service Contract. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location.

The availability of No-Notice Storage Service is subject to and reduced by any service schedule from or to storage. To the extent that the quantity of gas available in storage is insufficient to meet the requirements of the customer under a No-Notice Storage Service, the customer will be unable to use the service on a no-notice basis for Load Balancing service. To the extent that the scheduled injections into storage plus No-Notice Storage Service exceed the maximum limit for injection, No-Notice Storage Service will be reduced and the remainder of the gas will constitute a daily imbalance. Gas delivered in excess of the maximum injection quantity shall be deemed injection overrun gas and cashed out at 50% of the lowest index price of gas.

RATE NUMBER **315**

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RATE NUMBER: 316	GAS STORAGE SERVICE AT DAWN

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. The customer shall maintain a positive balance of gas in storage at all times. In addition, the customer must arrange for pipeline delivery service from Dawn to the applicable Primary Delivery Area.

This service is not a delivered service and is only available when the relevant pipeline confirms the delivery.

The maximum hourly injections / withdrawals shall equal 1/24th of the daily Storage Demand.

Storage space shall be based on either of two storage allocation methodologies: (customer's average winter demand - customer's average annual demand) x 151, or [(17 x customers's maximum hourly demand) / 0.1] x 0.57. Customers have the option to select from these two storage space allocation methods the one that best suits their requirements.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is nominated based on the available capacity and gas in storage up to the maximum contracted daily deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0515 ¢/m³**
Monthly Storage Deliverability Demand Charge	**5.3152 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.0903 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

RATE NUMBER: **316**

TERMS AND CONDITIONS OF SERVICE:

Nominated Storage Service:

The customer shall nominate storage injections and withdrawals daily. The customer may change daily nominations based on the nomination windows within a day as defined by the customer contract with Union Gas Limited and TransCanada PipeLines (TCPL).

The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

The customer may transfer the title of gas in storage.

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RATE NUMBER: **320**	**BACKSTOPPING SERVICE**

APPLICABILITY:

To any Applicant whose delivery of natural gas to the Company for transportation to a Terminal Location has been interrupted prior to the delivery of such gas to the Company.

CHARACTER OF SERVICE:

The volume of gas available for backstopping in any day shall be determined by the Company exercising its sole discretion. If the aggregate daily demand for service under this Rate Schedule exceeds the supply available for such day, the available supply shall be allocated to firm service customers on a first requested basis and any balance shall be available to interruptible customers on a first requested basis.

RATE:

The rates applicable in the circumstances contemplated by this Rate Schedule, in lieu of the Gas Supply Charges specified in any of the Company's other Rate Schedules pursuant to which the Applicant is taking service, shall be as follows:

	Billing Month **January to December**
Gas Supply Charge	
Per cubic metre of gas sold	**17.2454 ¢/m³**

provided that if upon the request of an Applicant, the Company quotes a rate to apply to gas which is delivered to the Applicant at a particular Terminal Location on a particular day or days and to which this Rate Schedule is applicable (which rate shall not be less than the Company's avoided cost in the circumstances at the time nor greater than the otherwise applicable rate specified above), then the Gas Supply Charge applicable to such gas shall be the rate quoted by the Company.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2014 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295, effective October 1, 2013.

RATE NUMBER: **325**	**TRANSMISSION, COMPRESSION AND POOL STORAGE SERVICE**

APPLICABILITY AND CHARACTER OF SERVICE:

Service under this rate schedule shall apply to the Transmission and Compression Service Agreement with Union Gas Limited dated April 1, 1989, and the Transmission, Compression and Pool Storage Service Agreement with Centra Gas Ontario Inc. dated May 30, 1994. Service shall be provided subject to the terms and conditions specified in the Service Agreement.

RATE:

The Customer shall pay for service rendered in each month in a contract year, the sum of the following applicable charges:

	Transmission & Compression $\$/10^3m^3$	**Pool Storage $\$/10^3m^3$**
Demand Charge for:		
Annual Turnover Volume	**0.1945**	**0.1865**
Maximum Daily Withdrawal Volume	**21.3765**	**20.7353**
Commodity Charge	**0.9631**	**0.1594**

FUEL RATIO REQUIREMENT:

Fuel Ratio applicable to per unit of gas injected and withdrawn is 0.35%.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges as stated in Rate Section above.

EXCESS VOLUME AND OVERRUN RATES:

In addition to the charges provided for in the Rate Section above, the Customer shall pay, for services rendered, the sum of the following applicable charges as they are incurred:

TERMS AND CONDITIONS OF SERVICE:

1. Excess Volumes will be billed at the total of the Excess Volume Charges as stated above.

2. Transmission and Compression, and Pool Storage Overrun Service will be billed according to the following:
   (a) At the end of each month, in a contract year, the Company will make a determination, for each day in the month, of

      (i) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account into the Company System, at the Point of Delivery and the Customer's Maximum Daily Injection Volume, and

      (ii) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account from the Company System, at the Point of Delivery, and the Customer's Maximum Daily Withdrawal Volume.

RATE NUMBER: **325**

	Excess Volume Charge $/10³m³ / Year	Overrun Charge $/10³m³ / Day
Transmission & Compression		
Authorized		**0.7028**
Unauthorized	**-**	**282.1692**
Pool Storage		
Authorized	**2.4623**	**0.6817**
Unauthorized	**-**	**273.7055**

(b) For each day of the month, where any such differences exceed 2.0 percent of the Customer's relevant Maximum Daily Injection Volume and/or Maximum Daily Withdrawal Volume, the Customer shall pay a charge equal to the relevant Overrun rates, as stated above, for such differences.

BILLING ADJUSTMENT:

1. Injection deficiency - If at the beginning of any Withdrawal Period the Customer's Storage Balance is less than the Customer's Annual Turnover Volume, due solely to the Company's inability to inject gas for any reason other than the fault of the Customer, then the applicable Demand Charge for Annual Turnover Volume for the contract year beginning the prior April 1 as stated in Rate Section as applicable, shall be adjusted by multiplying each by a fraction, the numerator of which shall be the Customer's Storage Gas Balance as of the beginning of such Withdrawal Period and the denominator shall be the Customer's Annual Turnover Volume as it may have been established for the then current year.

2. Withdrawal deficiency - If in any month in a contract year for any reason other than the fault of the Customer, the Company fails or is unable to deliver during any one or more days, the amount of gas which the Customer has nominated, up to the maximum volumes which the Company is obligated by the Agreement to deliver to the Customer, then the Demand Charge for maximum Contract Daily Withdrawal Volume in the contract year otherwise payable for the month in which such failure occurs, as stated in Rate Section above, as applicable, shall be reduced by an amount for each day of deficiency to be calculated as follows: The Demand Charge for maximum Contract Daily Withdrawal Volume for the contract year for the month will be divided by 30.4 and the result obtained will then be multiplied by a fraction, the numerator being the difference between the nominated volume for such day and the delivered volume for such day and the denominator being the Customer's maximum Contract Daily Withdrawal Volume for such contract year.

TERMS AND EXPRESSIONS:

In the application of this Rate Schedule to each of the Agreements, terms and expressions used in this Rate Schedule have the meanings ascribed thereto in such Agreement.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RATE NUMBER: 330	TRANSMISSION AND COMPRESSION AND POOL STORAGE

APPLICABILITY:

To any Applicant who enters into a Storage Contract with the Company for delivery by the Applicant to the Company and re-delivery by the Company to the Applicant of a volume of natural gas owned by the Applicant.

CHARACTER OF SERVICE:

Service under this rate is for Full Cycle or Short Cycle storage service; with firm or interruptible injection and withdrawal service, all as may be available from time to time.

RATE:

The following rates and charges shall apply in respect of all gas received by the Company from and re-delivered by the Company to the Applicant.

	Full Cycle		Short Cycle
	Firm	**Interruptible**	
	$/10³m³	**$/10³m³**	**$/10³m³**
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.3810**	**0.3810**	**-**
Maximum	**1.9050**	**1.9050**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**42.1117**	**33.6894**	**-**
Maximum	**210.5586**	**168.4469**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**1.1225**	**1.1225**	**0.4038**
Maximum	**5.6126**	**5.6126**	**39.0122**

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

TRANSACTING IN ENERGY:

The conversion factor is 37.74MJ/m3, which corresponds to Union Gas' System Wide Average Heating Value, as per the Board's RP-1999-0017 Decision with Reasons.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges.

RATE NUMBER: **330**

OVERRUN RATES:

The units rates stated below will apply to overrun volumes. The provision of Authorized Overrun service will be at the Company's sole discretion.

	Full Cycle Firm $\$/10^3m^3$	Full Cycle Interruptible $\$/10^3m^3$	Short Cycle $\$/10^3m^3$
Authorized Overrun			
Annual Turnover Volume			
Negotiable, not to exceed:	**39.0122**	**39.0122**	**39.0122**
Authorized Overrun			
Daily Injection/Withdrawal			
Negotiable, not to exceed:	**39.0122**	**39.0122**	**39.0122**
Unauthorized Overrun			
Annual Turnover Volume			
Excess Storage Balance			
September 1 - November 30	**390.1221**	**390.1221**	**390.1221**
December 1 - October 31	**39.0122**	**39.0122**	**39.0122**
Unauthorized Overrun			
Annual Turnover Volume			
Negative Storage Balance			

TERMS AND CONDITIONS OF SERVICE:

1. All Services are available at the Company's sole discretion.

2. Delivery and Re-delivery of the volume of natural gas shall be from/to the facilities of Union Gas Limited and / or TransCanada PipeLines Limited in Dawn Township and/or Niagara Gas Transmission Limited in Moore Township.

3. The Customers daily injections or withdrawals will be adjusted to provide for the fuel ratio stated in the Fuel Ratio Section. In the event that a Short Cycle service does not require fuel for injection and/or withdrawal, the fuel ratio commodity charge may be waived.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RATE NUMBER 331	TECUMSEH TRANSPORTATION SERVICE

APPLICABILITY:

To any Applicant who enters into an agreement with the Company pursuant to the Rate 331 Tariff ("Tariff") for transportation service on the Company's pipelines extending from Tecumseh to Dawn ("Tecumseh Pipeline"). The Company will receive gas at Tecumseh and deliver the gas at Dawn. Capitalized terms used in this Rate Schedule shall have the meanings ascribed to those terms in the Tariff.

CHARACTER OF SERVICE:

Transportation service under this Rate Schedule may be available on a firm basis ("FT Service") or an interruptible basis ("IT Service"), subject to the terms and conditions of service set out in the Tariff and the applicable rates set out below.

RATE:

The following rates, effective January 1, 2014, shall apply in respect of FT and IT Service under this Rate Schedule:

	Demand Rate $/10³m³	Commodity Rate $/10³m³
FT Service	**5.3030**	**-**
IT Service	**-**	**0.2090**

FT Service: The monthly demand charge shall be the products obtained by multiplying the applicable Maximum Daily Volume by the above demand rate.

IT Service: The monthly commodity charge shall be the product obtained by multiplying the applicable Delivery Volume for the Month by the above commodity rate.

TERMS AND CONDITIONS OF SERVICE:

The terms and conditions of FT and IT Service are set out in the Tariff. The provisions of PARTS I to IV of the Company's HANDBOOK OF RATES AND DISTRIBUTION SERVICES do not apply to Rate 331 service.

EFFECTIVE DATE:

The Tariff was approved by the Board in Board Order EB-2010-0177, dated July 12, 2010, and is posted and available on the Company's website. In accordance with Section 1.6.2 of the Board's Storage and Transportation Access Rule, the Tariff does not apply to any Rate 331 service agreements executed prior to June 16, 2010.

APPENDIX: A	AREAS OF CAPACITY CONSTRAINT

Applicants located off the piping networks noted below or off piping systems supplied from these networks may be curtailed to maintain distribution system integrity.

The Town of Collingwood
The Town of Midland

RIDER: A	TRANSPORTATION SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate other than Rates 125 and 300.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

AVERAGE COST OF TRANSPORTATION:

The average cost of transportation effective October 1, 2014:

Point of Acceptance	**Firm Transportation (FT)**
CDA, EDA	4.6500 ¢/m³

<u>TCPL FT CAPACITY TURNBACK:</u>

APPLICABILITY:

To Ontario T-Service and Western T-Service customers who have been or will be assigned TCPL capacity by the Company.

TERMS AND CONDITIONS OF SERVICE:

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:
   i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;
   ii. The amount of turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs resulting from the loss of STS capacity arising from any turnback request; and
   iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.
2. Requests for TCPL FT turnback must be made in writing to the attention of Enbridge's Direct Purchase group.
3. All TCPL FT capacity turnback requests will be treated on an equitable basis.
4. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

RIDER: **A**

5. Written notice to turnback capacity must be received by the Company the earlier of:

   (a) Sixty days prior to the expiry date of the current contract.

   or

   (b) A minimum of one week prior to the deadline specified in TransCanada tariff for FT contract extension.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RIDER: B	BUY / SELL SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who entered into a Gas Purchase Agreement with the Company, prior to April 1, 1999, to sell to the Company a supply of natural gas.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

BUY / SELL PRICE:

In Buy/Sell Arrangements between the Company and an Applicant, the Company shall buy the Applicants gas at the Company's actual FT-WACOG price determined on a monthly basis in the manner approved by the Ontario Energy Board. For Western Buy/Sell arrangements the FT-WACOG price shall be reduced by pipeline transmission costs.

FT FUEL PRICE:

The FT fuel price used to establish the Buy price in Western Buy/Sell arrangements without fuel will be determined monthly based upon the actual FT-WACOG.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after October 1, 2014. This rate schedule is effective January 1, 2014 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2013 and that indicates the Board Order, EB-2013-0295 effective October 1, 2013.

RIDER: C	GAS COST ADJUSTMENT RIDER

RIDER: D	SITE RESTORATION COST CLEARANCE

The following adjustment is applicable to volumes during the period of October 1, 2014 to December 31, 2014.

Bundled Services

Rate Class	(¢/m³)
Rate 1	(6.5211)
Rate 6	(2.1419)
Rate 9	(0.7776)
Rate 100	(2.1419)
Rate 110	(0.6149)
Rate 115	(0.3543)
Rate 135	(0.0390)
Rate 145	(0.4411)
Rate 170	(0.1383)
Rate 200	(0.2829)

Unbundled Services

Rate Class	(¢/m³)
Rate 125 - per m³ of contract demand	(3.2527)
Rate 300 - per m³ of contract demand	(13.7590)
Rate 300 (Interruptible)	(0.4500)

RIDER: E	REVENUE ADJUSTMENT RIDER

RIDER: F	ATMOSPHERIC PRESSURE FACTORS

The following elevation factors shall be applicable to metered volumes measured by a meter that does not correct for atmospheric pressure.

Zone	Elevation Factor
1	0.9644
2	0.9652
3	0.9669
4	0.9678
5	0.9686
6	0.9703
7	0.9728
8	0.9745
9	0.9762
10	0.9771
11	0.9839
12	0.9847
13	0.9856
14	0.9864
15	0.9873
16	0.9881
17	0.9890
18	0.9898
19	0.9907
20	0.9915
21	0.9932
22	0.9941
23	0.9949
24	0.9958
25	0.9960
26	0.9966
27	0.9975
28	0.9981
29	0.9983
30	0.9992
31	0.9997
32	1.0000
33	1.0017
34	1.0025
35	1.0034
36	1.0051
37	1.0059
38	1.0170

RIDER: G	SERVICE CHARGES

	Rate (excluding HST)
New Account Or Activation	
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied	$25.00
Appliance Activation Charge - Commercial Customers Only Commercial customers are charged an appliance activation charge on unlock and red unlock orders, except on the very first unlock and service unlock at a premise.	$70.00 minimum 1/2 hour work. Total Amount depends on time required
Meter Unlock Charge - Seasonal or Pool Heater Seasonal for all other revenue classes, or Pool Heater for residential only	$70.00
Statement of Account	
Lawyer Letter Handling Charge Provide the customer's lawyer with gas bill information.	$15.00
Statement of Account Charge (for one year history)	$10.00
Cheques Returned Non-Negotiable Charge	$20.00
Gas Termination	
Red Lock Charge Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by Field Collector)	$70.00
Removal of Meter Removing meter by Construction & Maintenance crew	$280.00
Cut Off At Main Charge Cutting service off at main by Construction & Maintenance Crew	$1,300.00
Valve Lock Charge Shutting off service by closing the street	
shut-off valve - work performed by Field Investigator	$135.00
- work performed by Construction & Maintenance	$280.00

RIDER: **G**

Safety Inspection

Inspection Charge For inspection of gas appliances; the Company provides only one inspection free of charge, upon first time introduction of gas to a premise.	$70.00
Inspection Reject Charge (safety inspection) Energy Board Inspection rejects are billed to the meter installer or homeowner.	$70.00

Meter Test

Meter Test Charge When a customer disputes the reading on his/her meter, he/she may request to have the meter tested. This charge will apply if the test result confirms the meter is recording consumption correctly.	
Residential meters	$105.00
Non-Residential meters	Time & Material per Contractor

Street Service Alteration

Street Service Alteration Charge For installation of service line beyond allowable guidelines (for new residential services only)	$32.00

NGV Rental

NGV Rental Cylinder (weighted average)	$12.00

Other Customer Services (ad-hoc request)

Labour Hourly Charge-Out Rate	$140.00
Cut Off At Main Charge - Commercial & Special Requests Cut Off At Main charges for commercial services and other residential services that involve significantly more work than the average will be custom quoted.	custom quoted
Cut Off At Main Charge - Other Customer Requests Other residential Cut Off At Main requests due to demolitions, fires, inactive services, etc. will be charged at the standard COAM rate.	$1,300.00
Meter In-Out (Residential Only)) Relocate the meter from inside to outside per customer request	$280.00
Request For Service Call Information Provide written information of the result of a service call as requested by home owners.	$30.00
Temporary Meter Removal As requested by customers.	$280.00
Damage Meter Charge	$380.00

RIDER: H	BALANCING SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Delivery Agreement with the Company under any rate.

IN FRANCHISE TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, an Applicant may elect to initiate a transfer of natural gas from one of its pools to the pool of another Applicant for the purposes of reducing an imbalance between the Applicant's deliveries and consumption as recorded in its Banked Gas Account or Cumulative Imbalance Account. Elections must be made in accordance with the Company's policies and procedures related to transaction requests under the Gas Delivery Agreement.

The Company will not apply an Administration charge for transfers between pools that have similar Points of Acceptance (i.e. both Ontario or both Western Points of Acceptance). For transfers between pools that have dissimilar Points of Acceptance (i.e. one an Ontario and one a Western Point of Acceptance), the Company will apply the following Administration Charge per transaction to the Applicant transferring the natural gas (i.e. the seller or transferor).

Administration Charge:	$169.00	per transaction

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to an Applicant with an Ontario Point of Acceptance.
The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from an Applicant with an Ontario Point of Acceptance.

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, the Applicant may elect to initiate a transfer of natural gas between the Company and another utility, regulated by the Ontario Energy Board, at Dawn for the purposes of reducing an imbalance between the customer's deliveries and consumption within the Enbridge Gas Distribution franchise areas. The ability of the Company to accept such an election may be constrained at various points in time for customers obtaining services under any rate other than Rate 125 or 300 due to operational considerations of the Company.

The cost for this service is separated between an Adminstration Charge that is applicable to all Applicants and a Bundled Service Charge that is only applicable to Applicants obtaining services under any rate other than Rate 125 or 300.

Administration Charge:		
Base Charge	$50.00	per transaction
Commodity Charge	$0.5613	per 10^3m^3

Bundled Service Charge:
The Bundled Service Charge shall be equal to the absolute difference between the Eastern Zone and Southwest Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% Load Factor.

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to another party. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from another party.

RIDER: **H**

GAS IN STORAGE TITLE TRANSFER:

An Applicant that holds a contract for storage services under Rate 315 or 316 may elect to initiate a transfer of title to the natural gas currently held in storage between the storage service and another storage service held by the Applicant, or any other Applicant that has contracted with the Company for storage services under Rate 315 or 316. The service will be provided on a firm basis up to the volume of gas that is equivalent to the more restrictive firm withdrawal and injection parameters of the two parties involved in the transfer. Transfer of title at rates above this level may be done on at the Company's discretion.

For Applicants requesting service between two storage service contracts that have like services, each party to the request shall pay an Administration Charge applicable to the request. Services shall be considered to be alike if the injection and deliverability rate at the ratchet levels in effect at the time of the request are the same and both services are firm or both services are interruptible. In addition to like services, the Company, at its sole discretion based on operational conditions, will also allow for the transfer of gas from a storage service contract that has a level of deliverability that is higher than the level of deliverability of the storage service contract the gas is being transfered to with only the Administration Charge being applicable to each party.

In addition to the Administration Charge, Applicants requesting service between two storage service contracts not addressed in the preceding paragraph would be subject to the injection and withdrawal charges specified in their contracts.

Administration Charge:	$25.00 per transaction

APPENDIX C

Enbridge Gas Distribution Inc.

EB-2012-0459

Estimated Bill Impacts

Table 1: Estimated Average Bill Impacts 2015 to 2018 with SRC

Rate Class	Col. 1 2014 DRO T-Service Bill Impact	Col. 2 2015 Estimated T-Service Bill Impact	Col. 3 2016 Estimated T-Service Bill Impact	Col. 4 2017 Estimated T-Service Bill Impact	Col. 5 2018 Estimated T-Service Bill Impact
1	-10.5%	3.1%	5.8%	3.2%	6.2%
6	-7.2%	2.3%	4.9%	3.0%	4.5%
9	-3.2%	1.1%	3.5%	1.8%	2.3%
100*	-16.9%	0.0%	0.0%	0.0%	0.0%
110	-4.1%	1.4%	2.2%	1.2%	2.0%
115	-2.1%	1.4%	2.0%	1.1%	1.8%
135	-0.8%	1.0%	2.0%	1.0%	1.1%
145	-3.2%	1.3%	2.4%	1.1%	1.8%
170	-1.7%	1.1%	1.9%	0.9%	1.2%
200	-3.9%	1.2%	2.1%	1.0%	1.2%

	Delivery Bill Impact DRO	Delivery Bill Impact Estimated	Delivery Bill Impact Estimated	Delivery Bill Impact Estimated	Delivery Bill Impact Estimated
125	-19.0%	4.1%	11.8%	11.3%	14.7%
300	-16.0%	4.7%	12.6%	12.0%	16.7%

*Rate 100 redesign

Witness: J. Collier

Sample Typical Customer Estimated T-Service 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
Item No.	Rate class	Annual Consumption m³	**2013 Oct QRAM Annual T-Service Bill $**	Change from 2013 October Q4 to 2014	**2014 DRO Annual T-Service Bill $**	Change from 2014 to 2015	**2015 Estimated Annual T-Service Bill $**	Change from 2015 to 2016	**2016 Estimated Annual T-Service Bill $**	Change from 2016 to 2017	**2017 Estimated Annual T-Service Bill $**	Change from 2017 to 2018	**2018 Estimated Annual T-Service Bill $**
			EB-2013-0045		**EB-2012-0459**								
1.0	Rate 1	1,955	476	(15)	461	9	471	21	491	11	503	13	515
2.0	SRC Credits		-		(30)		(28)		(25)		(24)		(9)
3.0	Rate 1 with SRC		476	(45)	431	12	443	23	466	13	479	27	506
1.0	Rate 1	2,480	540	(19)	521	12	533	26	559	15	574	16	590
2.0	SRC Credits		-		(38)		(35)		(32)		(30)		(12)
3.0	Rate 1 with SRC		540	(57)	483	15	498	29	527	17	544	34	578
1.0	Rate 1	3,064	609	(23)	586	15	601	32	633	18	651	20	670
2.0	SRC Credits		-		(47)		(43)		(40)		(37)		(15)
3.0	Rate 1 with SRC		609	(70)	539	18	557	36	593	21	614	42	655
1.0	Rate 6	22,606	3,304	(103)	3,200	57	3,257	135	3,393	86	3,479	91	3,570
2.0	SRC Credits		-		(115)		(107)		(98)		(90)		(36)
3.0	Rate 6 with SRC		3,304	(219)	3,085	66	3,151	144	3,295	94	3,388	145	3,533
1.0	Rate 6	29,278	4,016	(133)	3,883	73	3,956	174	4,130	111	4,241	117	4,359
2.0	SRC Credits		-		(150)		(138)		(127)		(117)		(47)
3.0	Rate 6 with SRC		4,016	(283)	3,733	85	3,818	186	4,004	121	4,125	187	4,312
1.0	Rate 6	43,285	5,381	(190)	5,191	105	5,296	249	5,545	159	5,704	168	5,872
2.0	SRC Credits		-		(221)		(204)		(187)		(173)		(69)
3.0	Rate 6 with SRC		5,381	(411)	4,970	122	5,092	267	5,358	173	5,531	271	5,802
1.0	Rate 110	598,568	48,319	(742)	47,577	571	48,148	963	49,111	491	49,602	496	50,098
2.0	SRC Credits		-		(917)		(848)		(779)		(719)		(289)
3.0	Rate 110 with SRC		48,319	(1,659)	46,660	639	47,299	1,033	48,332	551	48,883	926	49,809
1.0	Rate 110	9,976,121	691,108	(12,364)	678,744	8,145	686,889	13,738	700,626	7,006	707,633	7,076	714,709
2.0	SRC Credits		-		(15,280)		(14,142)		(12,979)		(11,981)		(4,816)
3.0	Rate 110 with SRC		691,108	(27,644)	663,464	9,283	672,747	14,900	687,647	8,005	695,652	14,241	709,893
1.0	Rate 115	69,832,850	4,072,259	(24,472)	4,047,787	52,621	4,100,408	82,008	4,182,416	41,824	4,224,241	42,242	4,266,483
2.0	SRC Credits		-		(60,998)		(56,476)		(57,295)		(52,888)		(21,259)
3.0	Rate 115 with SRC		4,072,259	(85,470)	3,986,789	57,143	4,043,932	81,189	4,125,121	46,231	4,171,353	73,871	4,245,224
1.0	Rate 145	339,188	26,040	(305)	25,735	309	26,044	573	26,617	266	26,883	269	27,152
2.0	SRC Credits		-		(391)		(363)		(333)		(308)		(124)
3.0	Rate 145 with SRC		26,040	(695)	25,345	336	25,681	603	26,284	292	26,576	453	27,029
1.0	Rate 145	598,567	41,521	(538)	40,983	492	41,475	912	42,387	424	42,811	428	43,239
2.0	SRC Credits		-		(689)		(641)		(588)		(543)		(218)
3.0	Rate 145 with SRC		41,521	(1,227)	40,294	540	40,834	965	41,799	469	42,268	753	43,021
1.0	Rate 170	9,976,120	423,054	(3,772)	419,282	4,193	423,475	7,623	431,097	3,449	434,546	3,476	438,022
2.0	SRC Credits		-		(3,493)		(3,264)		(2,991)		(2,761)		(1,110)
3.0	Rate 170 with SRC		423,054	(7,265)	415,789	4,422	420,211	7,895	428,106	3,679	431,785	5,128	436,913
1.0	Rate 170	69,832,850	2,825,702	(26,407)	2,799,295	27,993	2,827,288	50,891	2,878,179	23,025	2,901,205	23,210	2,924,415
2.0	SRC Credits		-		(24,449)		(22,847)		(20,938)		(19,327)		(7,769)
3.0	Rate 170 with SRC		2,825,702	(50,856)	2,774,846	29,595	2,804,441	52,801	2,857,242	24,636	2,881,878	34,768	2,916,646

Witness: J. Collier

APPENDIX D

Enbridge Gas Distribution Inc.

EB-2012-0459

Reporting Commitments

Reporting Commitments 2014 to 2018

Line	Item	Reporting Information	Filing Timing	Annual Stakeholder Meeting (prior to ESM filing)
1	Company Information	Company Operations Overview: - review yearly earnings, capital spend and key operating items of interest, SQR's - Explain Market Conditions - Changes and trends impacting Operations - Customer Surveys/Feedback	ESM / Def. & Var. Account disposition application	Yes
2	Company Information	Year End Financial Results / Earnings info: - Revenue Sufficiency/Deficiency Schedules - Rate Base Schedules - Utility Earnings, Tax Schedules - Additional Information aligning to Section 12.1 of Union Gas Settlement EB-2013-0202	ESM / Def. & Var. Account disposition application	Yes
3	Performance Measurement / Benchmarking	Performance Measurement Reporting: - Capital productivity progress report - O&M productivity progress report	ESM / Def. & Var. Account disposition application	Yes
		Benchmarking Report Capital & O&M (ReBasing): - consultation and independent expert opinion to inform methodology for filing upon rebasing	Rebasing 2019	Yes
4	Capital	Annual Capital Management Report: - Asset Planning Update: Progress in Asset Plan improvement with 3rd party assessment - GTA Project (Actual Cost and Schedule vs Forecast) - WAMS Project (Actual Cost and Schedule vs Forecast) - Capital Expenditures Update (Actual vs Plan Spending) - System Integrity Capital	ESM / Def. & Var. Account disposition application	Yes
5	Gas Supply	Gas Supply Memorandum: - Consistent with Union Gas April 2014 Gas Supply Plan memorandum - A summary of the current natural gas market situation - The results of the design day demand forecast with a discussion of the underpinning assumptions - An overview of the current gas supply portfolio - The identifaction of near term portfolio decisions and a description of how the Enbridge strategy for the specific portfolio decision conforms to the gas supply plannning principles - A summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g.RH-003-2011); physical infrastructure projects that will likely impact Enbridge; and the implications associated with gas supply basins	ESM / Def. & Var. Account disposition application	Yes
6	Gas Supply	Monthly UDC Report: Use of new FT services and associated UDC, monthly storage targets, capacity assigned to third parties through UDC related "outright release", revenues generated	Monthly	No
7	Reporting and Record keeping Requirements	Filings that are relevant to the regulated utility such as SQRs and affiliate transaction reporting	Annual - April 30	No

Other Non-Reporting Obligations

8	Allocation of costs to Non-utility storage	Prepare necessary evidence and proposal in time for 2015 or 2016 application. Information to make an allocation of base pressure gas and LUF to Non-utility storage on a fully allocated basis and on a volumetric basis	2015 or 2016	No
9	Regulatory Cost Allocation Methodology	Consultation in 2014 or 2015 for review of 2013 and 2014 data	2015	No
10	Sustainable Efficiency Incentive Mechanism	Consultation in 2015 to stakeholder an acceptable model	2016	No
11	Site Restoration Costs	Enbridge to look at discount rate to be used and examine issue of establishment of segregated fund of site restoration collections.	Rebasing 2019	No

APPENDIX E

Enbridge Gas Distribution Inc.

EB-2012-0459

Annual Update Elements

Appendix E

Elements to be Updated within 2015 through 2018 Custom Incentive Rate Processes and Applications

1. Volumes will be re-forecast annually through following the established processes of updating forecasts of; customer additions, probability weighted large volume customer forecasts, customer meter unlocks, economic outlook and gas prices, average use and approved heating degree days using the approved degree day methodologies.

2. Resulting from the annual volumes re-forecast, revenues will be re-forecast using approved rates.

3. Resulting from the annual volumes re-forecast, the annual gas supply plan will be re-determined, and annual projected gas costs as well as annual gas in storage volume requirements and related rate base gas in storage values and any gas cost related working cash allowance impacts will be reforecast within annual revenue requirements.

4. O&M related Customer Care/CIS costs will be updated annually in accordance with the Board Approved EB-2011-0226 Settlement Agreement.

5. O&M related DSM costs will be updated annually to reflect where available, updated Board Approved DSM costs resulting within the DSM Policy Consultation, EB-2014-0134 proceeding or subsequent proceedings. Any related rate base working cash allowance impacts will be re-forecast within annual revenue requirements.

6. O&M related Pension and OPEB expense amounts will be updated annually through the use of re-forecasts performed by Enbridge's external pension Consultant, Mercer Canada Limited. Any related rate base working cash allowance impacts will be re-forecast within annual revenue requirements.

7. Utility income taxes will be re-forecast annually to reflect impacts to taxable income stemming from the updating of revenues, gas costs, O&M and the re-determined approved overall rate of return on rate base.

8. Return on Equity will be re-set each year within the results included in the Board Final Rate Order to reflect the Board Policy produced ROE%.

9. The cost of debt will be updated each year of the IR plan, using the most current information available, including information on the actual amounts and rates associated with any debt issued in the prior year.

APPENDIX F

Enbridge Gas Distribution Inc.

EB-2012-0459

Schedule of Depreciation Rates

SCHEDULE OF DEPRECIATION RATES

Effective January 1, 2014

Account Number	Account Description	Existing Depreciation Rate	Proposed Depreciation Rate	Decision Depreciation Rate
Storage Plant				
451	Land Rights	1.16%	1.16%	1.16%
452	Structures & Improvements	1.84%	1.84%	1.84%
453	Wells	1.49%	1.55%	1.52%
454	Well Equipment	5.56%	5.56%	5.56%
455	Gathering Lines	1.46%	1.55%	1.49%
456	Compressor Equipment	2.56%	2.69%	2.60%
457	Regulating Equipment	2.94%	3.04%	2.99%
Distribution Plant				
471	Land Rights	1.18%	1.18%	1.18%
472	Structures & Improvements			
	472 VPC	9.93%	9.93%	9.93%
	472 Ottawa (Coventry)	4.81%	4.81%	4.81%
	472 Thorold	3.61%	3.61%	3.61%
	472 Other	2.98%	2.98%	2.98%
	472 Ottawa Depot (SMOC)	7.08%	7.08%	7.08%
	472 Old Kennedy Rd	23.53%	23.53%	23.53%
	472 Eastern Ave (Stn B)	6.86%	6.86%	6.86%
	472 Kelfield	7.54%	7.54%	7.54%
	472 Arnprior	4.42%	4.42%	4.42%
	472 Brockville	4.89%	4.89%	4.89%
	472 Tech Training (Markham)	2.18%	2.18%	2.18%
	472 Casselman/Pembroke	2.98%	2.98%	2.98%
	472 New Kennedy/Fleet Garage	2.13%	2.13%	2.13%
473/474	Service/Meter Installations	2.98%	2.45%	2.27%
475	Mains - Plastic	2.74%	2.17%	1.85%
	- Coated & Wrapped Steel	3.46%	2.80%	2.44%
	- Cast Iron	91.75%	100.31%	99.18%
	- Other	23.27%	21.38%	20.63%
	- Envision	4.03%	4.03%	4.03%
476	Company NGV Refueling Stations	5.97%	5.97%	5.97%
477	Regulating Equipment	2.14%	2.10%	2.05%
478	Meters	9.22%	9.22%	9.22%

Witness: R. Small

Account Number	Account Description	Existing Depreciation Rate	Proposed Depreciation Rate	Decision Depreciation Rate
General Plant				
482.5	Leasehold Improvements	Amortized over the life of the lease	Amortized over the life of the lease	Amortized over the life of the lease
483.01	Office Equipment	0.15%	0.15%	0.15%
483.02	Office Furniture	10.74%	10.74%	10.74%
484	Transportation Equipment	10.56%	10.56%	10.56%
484.01	NGV Conversion Kits	9.00%	9.00%	9.00%
484.02	NGV Cylinders	2.10%	2.10%	2.10%
485	Heavy Work Equipment	3.58%	3.58%	3.58%
486	Small Tools and Work Equipment	4.08%	4.08%	4.08%
487.7	NGV Rental Refueling Appliances	0.74%	0.74%	0.74%
487.8	NGV Rental Refueling Stations	8.01%	8.01%	8.01%
487.9	NGV Rental Cylinders	18.93%	18.93%	18.93%
488	Communications Equipment	9.71%	9.71%	9.71%
489	Software Applications - CIS	10.00%	10.00%	10.00%
490	Computer Equipment			
490	IT - Hardware	36.63%	36.63%	36.63%
490	IT - Software Acquired	26.32%	26.32%	26.32%
490	IT - Software Developed	21.24%	21.24%	21.24%

Witness: R. Small

APPENDIX G

Enbridge Gas Distribution Inc.

EB-2012-0459

Updated Planned Debt Issuances

Enbridge Gas Distribution
Decision Updated Forecast New Debt Issuances of MTN's

Principal	1 2014	2 2014	3 2014	4 2014	5 2015	6 2015	7 2015	8 2015	9 2016	10 2016	11 2017	12 2017	13 2018
Face value	195,000,000	20,000,000	130,000,000	85,000,000	130,000,000	170,000,000	130,000,000	170,000,000	162,000,000	20,000,000	150,000,000	150,000,000	65,000,000
Issuance date	15-Sep-14	15-Sep-14	15-Sep-14	15-Sep-14	15-Jun-15	15-Oct-15	15-Oct-15	15-Oct-15	15-Sep-16	15-Sep-16	15-Nov-17	15-Nov-17	15-Jan-18
Maturity date	15-Sep-24	15-Sep-24	15-Sep-44	15-Sep-44	15-Jun-25	15-Oct-25	15-Oct-45	15-Oct-45	15-Sep-26	15-Sep-26	15-Nov-27	15-Nov-47	15-Jan-28
Year	10	10	30	30	10	10	30	30	10	10	10	30	10
Mths	120	120	360	360	120	120	360	360	120	120	120	360	120
Coupon rate	3.80%	3.90%	4.30%	4.70%	4.30%	5.00%	4.60%	5.60%	4.60%	5.80%	5.80%	6.40%	5.80%
Hedged (Y/N)	Y	N	Y	N	Y	N	Y	N	Y	N	N	N	N
Coupon payments (annual)	7,410,000	780,000	5,590,000	3,995,000	5,590,000	8,500,000	5,980,000	9,520,000	7,452,000	1,160,000	8,700,000	9,600,000	3,770,000
Issuance Costs	931,794	162,876	776,196	533,474	632,594	804,162	762,594	974,162	868,700	172,988	756,844	906,844	498,688
All-in Effective rate	**3.85%**	**3.98%**	**4.32%**	**4.72%**	**4.35%**	**5.05%**	**4.62%**	**5.62%**	**4.65%**	**5.89%**	**5.85%**	**6.42%**	**5.88%**

Table 2

Enbridge Gas Distribution
As Filed Forecast New Debt Issuances of MTN's

Principal	1 2014	2 2014	3 2014	4 2014	5 2015	6 2015	7 2015	8 2015	9 2016	10 2017	11 2018
Face value	195,000,000	20,000,000	130,000,000	85,000,000	130,000,000	145,000,000	130,000,000	145,000,000	162,000,000	250,000,000	65,000,000
Issuance date	15-Sep-14	15-Sep-14	15-Sep-14	15-Sep-14	15-Jun-15	15-Oct-15	15-Oct-15	15-Oct-15	15-Sep-16	15-Nov-17	15-Jan-18
Maturity date	15-Sep-24	15-Sep-24	15-Sep-44	15-Sep-44	15-Jun-25	15-Oct-25	15-Oct-45	15-Oct-45	15-Sep-26	15-Nov-27	15-Jan-28
Year	10	10	30	30	10	10	30	30	10	10	10
Mths	120	120	360	360	120	120	360	360	120	120	120
Coupon rate	3.80%	3.90%	4.30%	4.70%	4.30%	5.00%	4.60%	5.60%	4.60%	5.80%	5.80%
Hedged (Y/N)	Y	N	Y	N	Y	N	Y	N	Y	N	N
Coupon payments (annual)	7,410,000	780,000	5,590,000	3,995,000	5,590,000	7,250,000	5,980,000	8,120,000	7,452,000	14,500,000	3,770,000
Issuance Costs	931,794	162,876	776,196	533,474	636,012	700,744	766,012	845,744	886,688	1,238,688	498,688
All-in Effective rate	**3.85%**	**3.98%**	**4.32%**	**4.72%**	**4.35%**	**5.05%**	**4.62%**	**5.62%**	**4.65%**	**5.85%**	**5.88%**