Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND INTERIM RATE ORDER

EB-2015-0114

ENBRIDGE GAS DISTRIBUTION INC.

Application for natural gas distribution, transmission and storage rates commencing January 1, 2016

BEFORE: Emad Elsayed
Presiding Member

Christine Long
Member

Paul Pastirik
Member

December 10, 2015

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1 INTRODUCTION AND PROCESS

Enbridge Gas Distribution Inc. (Enbridge) is a natural gas distribution company, serving about 2.1 million residential, commercial and industrial customers in the Greater Toronto Area, the Niagara region, and the eastern Ontario region including Ottawa.

Enbridge filed an application on August 31, 2015 with the Ontario Energy Board (OEB) pursuant to section 36 of the *Ontario Energy Board Act, 1998*, for an order or orders approving rates for the distribution, transmission and storage of natural gas, effective January 1, 2016. Enbridge's application for a rate adjustment was based on the multi-year Custom Incentive Ratemaking framework approved by the OEB in EB-2012-0459 (Custom IR Decision).

In Procedural Order No. 1, the OEB established a process for filing and responding to interrogatories and set a date for a Settlement Conference. The OEB also accepted requests from parties for intervenor status.

On December 1, 2015, Enbridge filed a settlement proposal (Settlement Proposal) that included a Draft Rate Order and Draft Accounting Order as attachments. Enbridge and all parties who participated in the Settlement Conference reached a settlement on all of the issues in the proceeding and requested that the OEB approve the Settlement Proposal. OEB staff filed a submission on December 2, 2015 supporting the Settlement Proposal.

The OEB approves the Settlement Proposal because it is consistent with the Custom IR Decision.

The annual bill impact for an average residential customer resulting from the Settlement Proposal is an increase of $25. This amount does not reflect any changes resulting from proposed increases to the Demand Side Management (DSM) budget. This issue was removed from the Settlement Proposal and the impact on rates of any approved increase will be deferred until the DSM decision in EB-2015-0049 is released.

2 DECISION ON SETTLEMENT PROPOSAL

2.1 Settlement Proposal

Enbridge and the participating parties were able to settle all of the issues in the proceeding.

OEB staff reviewed the Settlement Proposal in the context of the Custom IR Decision and applicable OEB policies and practices. OEB staff submitted that the OEB's acceptance of the Settlement Proposal will adequately reflect the public interest and that the explanation and rationale accompanying the Settlement Proposal is sufficient to support its acceptance by the OEB.

Findings

The OEB approves the Settlement Proposal as submitted. The OEB finds that the Settlement Proposal is consistent with the Custom IR Decision. Enbridge has appropriately made the annual adjustments provided for in the Custom IR Decision. The OEB is particularly supportive of Enbridge's commitment to providing an enhanced understanding of its gas supply planning process starting with its 2017 rate adjustment application. The OEB finds that acceptance of the Settlement Proposal will adequately reflect the public interest.

2.2 Draft Rate Order

Enbridge included the Draft Rate Order as an appendix to the Settlement Proposal. Parties to the Settlement Proposal have reviewed and agreed with the Draft Rate Order. In addition, OEB staff submitted that it reviewed the Draft Rate Order and had no concerns.

Findings

The OEB accepts the Draft Rate Order as filed. The OEB finds that the Draft Rate Order accurately reflects the Settlement Proposal.

2.3 Draft Accounting Order

Enbridge included the Draft Accounting Order as an appendix to the Settlement Proposal. Parties to the Settlement Proposal have reviewed and agreed with the Draft

Accounting Order. In addition, OEB staff submitted that it reviewed the Draft Accounting Order and had no concerns.

Findings

The OEB accepts the Draft Accounting Order as filed. The OEB finds that the Draft Accounting Order is consistent with the Custom IR Decision and accurately reflects the Settlement Proposal. The OEB will issue the relevant Accounting Order under separate cover.

3 IMPLEMENTATION

The new rates resulting from this Decision and Interim Rate Order will be interim rates effective on January 1, 2016.

The OEB expects the interim rates resulting from this Decision and Interim Rate Order will be implemented in conjunction with Enbridge's January 1, 2016 Quarterly Rate Adjustment Mechanism application.

The OEB expects that the final rates for 2016 will be set after the 2016 DSM budget is established by the OEB in proceeding EB-2015-0049.

The OEB will make provision for the cost award process as part of this order.

4 ORDER

THE BOARD ORDERS THAT:

1. The Settlement Proposal shown in Schedule A is approved.

2. Interim rates, as shown in the Rate Handbook included with the Settlement Proposal at Appendix C, shall be effective January 1, 2016.

3. Parties eligible for cost awards shall file their cost claims with the OEB and serve them on Enbridge by **Friday, January 8, 2016**. Cost claims must be prepared in accordance with the OEB's *Practice Direction on Cost Awards*.

4. Enbridge shall file with the OEB any objection to a cost claim, and serve it on the party that made the claim, by **Friday, January 15, 2016**.

5. Any party whose cost claim was objected to shall file any reply submission with the OEB, and serve it on Enbridge, by **Friday, January 22, 2016**.

All filings to the OEB must quote file number **EB-2014-0114**, be made electronically through the OEB's web portal at www.pes.ontarioenergyboard.ca/eservice in searchable / unrestricted PDF format. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address, telephone number, fax number and e-mail address.

All filings shall use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available, parties may email their documents to the address below.

For all electronic correspondence and materials related to this proceeding, parties must include in their distribution lists the Case Manager, Colin Schuch at Colin.Schuch@ontarioenergyboard.ca, OEB Counsel, Michael Millar at Michael.Millar@ontarioenergyboard.ca and OEB Counsel, Ian Richler Ian.Richler@ontarioeneryboard.ca.

All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

ADDRESS
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary

E-mail: boardsec@ontarioenergyboard.ca
Tel: 1-888-632-6273 (Toll free)
Fax: 416-440-7656

DATED at Toronto December 10, 2015

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

SCHEDULE A

DECISION AND INTERIM ORDER

ENBRIDGE GAS DISTRIBUTION INC.

EB-2015-0114

SETTLEMENT PROPOSAL

DECEMBER 10, 2015

SETTLEMENT PROPOSAL

Enbridge Gas Distribution Inc.
2016 Rate Adjustment

December 1, 2015

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SETTLEMENT PROPOSAL CONTEXT

This Settlement Proposal is filed with the Ontario Energy Board (the “Board", or the “OEB”) in connection with the application by Enbridge Gas Distribution Inc. (“Enbridge”, or the “Company”), for an order or orders approving or fixing just and reasonable rates for the sale, transmission, distribution and storage of natural gas commencing January 1, 2016.

In Procedural Order No. 1 issued on October 16, 2015, the Board provided for a series of procedural steps, up to and including a Settlement Conference.

The Settlement Conference was held on November 18 and 19, 2015. Chris Haussmann acted as facilitator for the Settlement Conference. This Settlement Proposal arises from the Settlement Conference and subsequent discussions.

Enbridge and the following intervenors, as well as Ontario Energy Board technical staff (“OEB Staff”), participated in the Settlement Conference:

Association of Power Producers of Ontario (APPrO)
Building Owners and Managers Association – Greater Toronto (BOMA)
Canadian Manufacturers & Exporters (CME)
Consumers Council of Canada (CCC)
Energy Probe Research Foundation (Energy Probe)
Federation of Rental-Housing Providers of Ontario (FRPO)
Industrial Gas Users Association (IGUA)
School Energy Coalition (SEC)
Vulnerable Energy Consumers Coalition (VECC)

The Settlement Proposal deals with all of the relief sought in this proceeding. The parties have reached agreement on all relevant items, as set out herein. Should the Board approve this Settlement Proposal, there will not be any unsettled issues.

All intervenors listed above participated in the Settlement Conference and subsequent discussions.

OEB Staff also participated in the Settlement Conference. OEB Staff is not a party to the Settlement Proposal. Although it is not a party to the Settlement Proposal, OEB Staff will file a submission commenting on two aspects of the settlement: whether the settlement represents an acceptable outcome from a public interest perspective, and whether the accompanying explanation and rationale is adequate to support the settlement. Also, as noted in the Practice Direction on Settlement Conferences, OEB Staff who did participate in the Settlement Conference are bound by the same confidentiality and privilege rules that apply to the parties to the proceeding.

This document is called a “Settlement Proposal” because it is a proposal by the parties to the Board to settle the issues in this proceeding. It is termed a proposal as between the parties and the Board. However, as between the parties, and subject only to the Board’s approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Context section, this Settlement Proposal is subject to a condition subsequent, that if it is not accepted by the Board in its entirety, then unless amended by the parties it is null and void and of no further effect. In entering into this agreement, the parties understand and agree that, pursuant to the *Ontario Energy Board Act*, the Board has exclusive jurisdiction with respect to the interpretation or enforcement of the terms hereof.

Enbridge and all intervenors listed above have agreed to the settlement of the issues as described on the following pages. Any reference to “parties” in this Settlement Proposal is intended to refer to Enbridge and the intervenors listed above. The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise.

None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 30 of the Ontario Energy Board Rules of Practice and Procedure. Further, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions parties might take with respect to the same issue in future proceedings, whether during the term of Enbridge’s 2014 to 2018 Custom Incentive Regulation (“IR”) plan, or thereafter.

The parties acknowledge that this Settlement Conference (including subsequent related discussions) is confidential in accordance with the Board’s Practice Direction on Settlement Conferences. The parties understand that confidentiality in that context does not have the same meaning as confidentiality in the Board’s Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the parties have interpreted “confidential” to mean that the documents and other information provided during the course of the Settlement Conference, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the parties agree that “attendees” is deemed to include, in this context, persons who were not physically in attendance at the Settlement Conference but were a) any persons or entities that the parties engage to assist them with the settlement conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

It is fundamental to the agreement of the parties that none of the provisions of this Settlement Proposal are severable. If the Board does not accept the provisions of the Settlement Proposal in their entirety prior to the commencement of the hearing of the application, there is no Settlement Proposal (unless the parties agree that any portion of the Settlement Proposal that the Board does accept may continue as a valid Settlement Proposal).

The table at Appendix A identifies the evidence that supports each aspect of Enbridge's 2016 rate adjustment application. In relation to the items for which adjustment from Enbridge's pre-filed evidence has been agreed-upon, the specific supporting evidence is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit B, Tab 3, Schedule 1 is referred to as B-3-1. The identification and listing of the evidence that relates to each adjustment is provided to assist the Board.

Accordingly, this Settlement Proposal provides a direct link between each adjustment to the requested approvals and the evidence in support of that adjustment. The parties are of the view that the evidence supports the agreement embodied in this Settlement Proposal and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings leading to the acceptance by the Board of the Settlement Proposal.

SETTLEMENT PROPOSAL OVERVIEW

As set out below, the parties have reached agreement on all items in this proceeding. Primarily, this relates to the required 2016 rate adjustments to be undertaken in accordance with Enbridge's OEB-approved Custom IR plan. There are also two other items outside of the Custom IR plan upon which the parties have reached agreement. These relate to the allocation of certain costs to Enbridge's unregulated storage line of business, and to the agreed treatment of certain profits of sale in Enbridge's 2015 Earnings Sharing Mechanism ("ESM") calculations.

If this Settlement Proposal is accepted by the Board, then Enbridge will implement interim 2016 rates in conjunction with the January 1, 2016 QRAM. The only item that may be subject to later adjustment is the cost consequences of Enbridge's 2016 DSM budget. That budget has been presented to the Board in a separate proceeding, and no decision has yet been delivered. The parties have agreed that Enbridge's interim 2016 rates arising from this Settlement Proposal, which are set out in the draft Rate Order at Appendix C, will be subject to later adjustment to reflect the impact of Enbridge's DSM budget for 2016 that is approved by the Board in the separate proceeding.

(a) Custom IR Approvals Requested by Enbridge

In its EB-2012-0459 Decision with Reasons dated July 17, 2014 (the "Custom IR Decision") the Board approved a five-year Custom IR plan for Enbridge to begin on January 1, 2014.[1] In the Custom IR Decision, together with the subsequent Decision and Rate Order dated August 22, 2014 (the "Custom IR Rate Order"), the Board approved the Custom IR elements and forecast costs to be used for the purposes of determining Enbridge's 2014 Allowed Revenue and associated 2014 final rates.

Enbridge's Custom IR proposal contemplated an annual adjustment process for the years 2015 to 2018. The Board accepted this proposal in the Custom IR Decision: as stated by the Board, while most elements of Allowed Revenue were determined in the EB-2012-0459 proceeding, placeholder amounts were set for certain specific elements and these placeholder amounts are to be updated at the start of each rate year from 2015 to 2018.[2]

The Board directed Enbridge to provide a complete list of the elements of the Custom IR plan that will be updated annually from 2015 to 2018, for inclusion as part of the Draft Rate Order in EB-2012-0459. In the Custom IR Rate Order, the Board ordered that the "Annual Update Elements" for the Custom IR plan shall be as set out in Appendix E thereto. A copy of Appendix E from the Custom IR Rate Order was filed in this proceeding at Exhibit A1, Tab 3, Schedule 1, Appendix A. The list of Annual Update Elements set out in Appendix E to the Custom IR Rate Order is reproduced below:

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

Line	Element
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 re-forecast 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.

[1] Custom IR Decision, at page 4.
[2] Custom IR Decision, at page 83.

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.

In this proceeding, Enbridge requested approval of 2016 Allowed Revenue and associated 2016 final rates. At Appendix B of Exhibit A1, Tab 3, Schedule 1, Enbridge provided a table showing the derivation of the 2016 Allowed Revenue amount and associated sufficiency / deficiency proposed for approval by the Board. An updated version of this 2016 Test Year Allowed Revenue and Sufficiency/Deficiency table is included at Appendix A to this Settlement Proposal. The updated version of the table is the same as previously filed, except that it also includes two columns setting out the Allowed Revenue (and Sufficiency / Deficiency) impacts of this Settlement Proposal.

In connection with the approval of final 2016 Rates, Enbridge requested that the Board approve the establishment of 2016 Deferral and Variance Accounts, as set out in the evidence at Exhibit D2, Tab 1, Schedules 1 to 3. With four exceptions, all of the Deferral and Variance accounts proposed for 2016 were previously approved in the Custom IR Decision. One of the additional accounts is the Dawn Access Costs Deferral Account; this account was approved in the Board's EB-2014-0323 Accounting Order issued on December 4, 2014. The second of the additional accounts is the 2016 Credit Final Bill Deferral Account, which was approved within the EB-2014-0276 proceeding. There is one renewed account being proposed - the 2016 Unabsorbed Demand Cost deferral account. Finally, there is one new account being proposed, the 2016 Rate 332 deferral account.

(b) Settlement of Requested Custom IR Approvals

The parties have accepted and agreed upon Enbridge's requested Custom IR approvals, as set out in the pre-filed evidence, subject to: (i) four adjustments to be made in respect of Enbridge's requested approvals; and (ii) two other provisos.

The table at Appendix A provides references to the pre-filed evidence that supports the settlement of Enbridge's requested approvals. More generally, the evidence with regard to updated rate base is found in the "B" series of exhibits, the evidence regarding 2016 gas volumes and 2016 revenues is found in the "C" series of exhibits, the evidence regarding updates to certain operating cost elements (including gas costs) is found in the "D" series of exhibits, the evidence regarding updates to Cost of Capital is found in the "E" series of exhibits, the evidence regarding the 2016 revenue deficiency is found in the "F" series of exhibits and the evidence regarding proposed final 2016 rates is found in the "H" series of exhibits.

The four adjustments to Enbridge's requested approvals resulting from the settlement reached by all parties are as follows:

<u>Adjustment 1</u> – Reversion to prior UAF forecasting methodology

An adjustment to revert back to the previously used forecasting methodology for Unaccounted For Gas ("UAF"), rather than the proposed new forecasting methodology. This adjustment results in a decrease to the forecast UAF volumes for 2016.

<u>Adjustment 2</u> - Removal of Community Expansion Program customers

An adjustment to remove the inclusion of 1,590 additional customers who had been forecast to be added in the fourth quarter of 2016 as part of the Company's planned Community Expansion Program. This adjustment results in a decrease to customer numbers and volumes

<u>Adjustment 3</u> - Interim use of 2015 DSM budget, pending OEB decision in EB-2015-0049

An adjustment to use the 2015 Board-approved DSM budget included within 2015 rates on an interim basis until such time as the Board issues a decision on Enbridge's proposed 2016 DSM budget in the EB-2015-0049 proceeding. Enbridge will implement the full-year effect of any changes in the 2016 DSM budget (as compared to the 2015 DSM budget) as part of its next QRAM Application following the Board's decision in EB-2015-0049.

Adjustment 4 - Updates to Cost of Capital

(i) An adjustment to reflect an updated ROE of 9.19% (as compared to the forecast of 9.13% included within the pre-filed evidence), as determined in the Ontario Energy Board's Cost of Capital Parameter Updates for 2016 Applications published October 15, 2015. This adjustment results in an increase to 2016 Cost of Capital; and

(ii) An adjustment to update Enbridge's forecast 2016 Cost of Debt based on forecasts as of October 2015. This adjustment results in an increase to 2016 Cost of Capital.

The particulars of the agreements reached on each of the adjustments to Enbridge's requested Custom IR approvals are described below, under the heading *Details of Adjustments to Enbridge's Requested Approvals*.

In addition to the four adjustments described above, the parties also have comments relating to two specific Custom IR approvals sought by Enbridge.

First, in relation to Enbridge's 2016 gas costs (including transportation and storage), the parties agree that the Board should approve the Company's gas supply plan as set out in Exhibit D1, Tab 2 of the pre-filed evidence. The parties acknowledge that Exhibit D1, Tab 2 is largely a description of the implementation of Enbridge's gas supply plan and strategy. Enbridge agrees that, in its 2017 rate adjustment application, it will augment the gas supply evidence so that, in addition to the material provided in this proceeding, there is an explanation of the principles driving the gas supply plan, and how those principles are being implemented by the detailed evidence on gas procurement and transportation.

Second, in relation to the 2016 Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA"), the parties agree that Enbridge will continue to use the same account description as has been approved in 2014 and 2015. The parties acknowledge that there may be disagreement as to the scope of what expenses can be included in the GGEIDA, but agree that any such issues are properly addressed at the time that clearance of that account is requested.

(c) Storage Cost Allocation

In the Custom IR Decision, the Board directed Enbridge to file a proposal in 2015 or 2016 as to how costs should be allocated to Enbridge's unregulated storage line of business for Base Pressure Gas and LUF. In its Application, Enbridge requested Board Approval to continue, for the duration of the Custom IR term, to use the current incremental allocation approach for the allocation of costs to non-utility storage operations for Base Pressure Gas and LUF.

As part of an overall settlement, Enbridge has agreed to move to a fully allocated cost approach to allocate the costs of Base Pressure Gas and LUF between regulated and unregulated storage operations.

The parties agree that this change is without prejudice to any position that any party may take on the proper approach to allocation of storage costs (LUF, Base Gas and any other relevant items) between the regulated and unregulated storage operations if that question is raised or addressed after the end of this Custom IR term.

The impact of this change in cost allocation is to increase allocations of Base Pressure Gas and LUF to the unregulated line of business. For the regulated utility, this will reduce the rate base value for Base Pressure Gas and reduce gas costs.

(d) Profit from the sale of Base Pressure Gas

During 2015, the Company sold approximately 2 Bcf of Base Pressure Gas. This created additional storage space for Enbridge's unregulated storage line of business.

As part of an overall settlement in this proceeding, and without prejudice to the position that any party may take on any similar transaction in the future, the parties have agreed that the Company will include the profit from the Base Pressure Gas sale as part of the 2015 utility earnings that will be considered in the determination of any 2015 Earnings Sharing amount pursuant to the ESM in Enbridge's Custom IR model.

This aspect of the settlement has no impact on 2016 Allowed Revenue or rates, however, it will be reflected within any amount that is recorded in the 2015 ESM Deferral Account for later disposition to ratepayers.

(e) Impacts of Settlement Proposal

The changes to Enbridge's 2016 Allowed Revenue (and associated revenue deficiency) that result from the Settlement Proposal are set out within the updated 2016 Allowed Revenue and Sufficiency / Deficiency table that is found at Appendix A. The overall result of the implementation of the Settlement Proposal is a reduction in the revenue deficiency associated with Enbridge's requested approvals from $108 million to $79.3 million. It should be noted that the revenue deficiency will change when the cost consequences of Enbridge's Board-approved 2016 DSM budget are implemented into rates at a later date.

Details of the impact of the agreed-upon adjustments to Enbridge's requested approvals are set out in the Settlement Proposal Financial Statements included as Appendix B to this Settlement Proposal.

The average rate impacts that will result from the implementation of the Settlement Proposal are set out in the Draft Rate Order included at Appendix C to this Settlement Proposal.

DETAILS OF ADJUSTMENTS TO ENBRIDGE'S REQUESTED CUSTOM IR APPROVALS

Set out below are details of each of the agreed adjustments to Enbridge's Custom IR approvals.

Adjustment 1 - Reversion to prior UAF forecast methodology

In Enbridge's pre-filed evidence, the Company proposed to change the forecasting methodology for UAF to a new methodology that was determined to have greater predictive ability than the current forecasting methodology.

The parties have agreed that it is not appropriate to update this forecasting methodology during the Custom IR term. Therefore, the parties have agreed that Enbridge will maintain the previously used forecasting methodology for UAF, rather than adopting the proposed new forecasting methodology.

This agreement is without prejudice to the position that any party may take in respect of appropriate UAF forecast methodologies following the end of the current Custom IR term.

The effect of Adjustment 1, as seen in response to BOMA Interrogatory #19, is to decrease the 2016 forecast of UAF from 92,515 10^3m^3 to 84,766 10^3m^3. This decreases forecast 2016 volumes by a corresponding amount. This adjustment will reduce the 2016 revenue deficiency by approximately $1.5 million.

Evidence: The evidence in relation to this item includes the following:

D1-2-3	Unbilled and Unaccounted-for Gas Volumes
I.D1.EGDI.BOMA.19-21	BOMA Interrogatories #19 to 21
I.D1.EGDI.EP.5	Energy Probe Interrogatory #5
I.D1.EGDI.FRPO.17-18	FRPO Interrogatories #17 to 18
I.D1.EGDI.VECC.6	VECC Interrogatory #6

Adjustment 2 - Removal of Community Expansion Program customers

Enbridge's Customer Additions forecast for 2016 included 1,590 additional customers who had been forecast to be added in the fourth quarter of 2016 as part of the Company's planned Community Expansion Program. These customers were forecast to be added in the latter part of the year so, on a monthly averages basis, the result was an increase of 291 customers. That program will be the subject of a separate application to the Board early in 2016.

The parties have agreed to a proposal by the Company (found at Exhibit C2-1-4 and BOMA Interrogatory 15) to remove the forecast Customer Additions for 2016 from the Community Expansion Program from its customer and volumes forecasts, since the program has not yet been approved by the Board. There were no other Allowed Revenue impacts (costs) from the Community Expansion Program included in the 2016 Rate Adjustment Application. As noted in evidence, when a Leave to Construct Application for the Community Expansion Program is filed, Enbridge may propose separate treatment for the impacts of the Program (including capital spending, customer additions, volumes and revenues).

Adjustment 2 results in a decrease of 291 customers from the 2016 Gross Customer Additions (from 35,592 to 35,301), and a corresponding decrease in volumes (approximately 1904 10^3m^3) and a minor decrease in Customer Care / CIS costs. The overall change in the 2016 revenue deficiency arising from this adjustment is an increase of approximately $0.2 million.

Evidence: The evidence in relation to this item includes the following:

C2-1-4	Customer Additions
D1-3-1	2016 Customer Care/CIS Update
I.C2.EGDI.BOMA.15	BOMA Interrogatory #15
I.C2.EGDI.FRPO.24	FRPO Interrogatory #24
I.C2.EGDI.VECC.5	VECC Interrogatory #5

<u>Adjustment 3</u> - Interim use of 2015 DSM budget, pending OEB decision in EB-2015-0049

Enbridge's 2016 DSM budget will be determined in EB-2015-0049 (the proceeding in respect of Enbridge's Multi-Year Demand Side Management Plan – 2015-2020). The evidence and argument in that proceeding are complete, but the Decision has not been issued.

For the purposes of this Application, Enbridge used its proposed 2016 DSM budget of $63.5 million to update the 2016 placeholder DSM amount in 2016 Allowed Revenue.

The parties have agreed that Enbridge will wait until the Board issues its Decision in EB-2015-0049 before updating the 2016 DSM budget within Allowed Revenue. On an interim basis, Enbridge will continue to use the 2015 DSM budget of $35 million that was included in 2015 rates.

The parties agree that after the Board issues its Decision in EB-2015-0049, Enbridge will update its 2016 Allowed Revenue and rates to reflect the full-year impact of the difference between the approved 2016 DSM budget and the 2015 DSM budget that is being included in 2016 Allowed Revenue and rates as an interim amount. The parties agree that this change will be implemented into Enbridge's 2016 final rates as part of its next QRAM Application following the Board's decision in EB-2015-0049.

Adjustment 3 results in a reduction of approximately $28.5 million in Allowed Revenue. The corresponding reduction in the 2016 revenue deficiency arising from this adjustment is approximately $28.5 million. As noted these impacts will be subject to later adjustment to reflect Enbridge's 2016 DSM budget as approved by the Board.

Evidence: The evidence in relation to this item includes the following:

D1-1-1	Operating Cost Summary
D1-4-1	2016 DSM Forecast Budget

Adjustment 4 – Updates to Cost of Capital

Enbridge's Custom IR model contemplates that the Company will use the most current values for its Cost of Capital (ROE and Cost of Debt) within the rate adjustment process. Enbridge's pre-filed evidence included the most current Cost of Capital values at the time that the evidence was prepared.

The parties agree that it is appropriate for Enbridge to update its Cost of Capital to reflect the more current information that is now available.

In response to VECC Interrogatory #8, Enbridge updated its forecast Cost of Capital to reflect an updated ROE of 9.19% (as compared to the forecast of 9.13% included within the pre-filed evidence), as determined in the Ontario Energy Board's Cost of Capital Parameter Updates for 2016 Applications published October 15, 2015. The result is an increase in return from $190.0 million to approximately $191.2 million.

In its response to Energy Probe Interrogatory #7, Enbridge updated its forecast 2016 Cost of Debt based on forecasts as of October 2015. The result is an increase in the total Cost of Debt from $178.2 million to approximately $178.9 million.

The combined effect of the two components of Adjustment 4 is to increase the Cost of Capital by approximately $1.9 million, and to increase the 2016 revenue deficiency shown in Appendix A by approximately $1.9 million.

Evidence: The evidence in relation to this item includes the following:

E1-1-1	Cost of Capital Summary
E1-3-1	2016 Cost of Debt
I.E1.EGDI.EP.6-7	Energy Probe Interrogatories #6-7
I.E1.EGDI.VECC.8-9	VECC Interrogatories #8-9

SETTLEMENT ON OTHER ITEMS

In addition to the Custom IR Approvals, there were two other items agreed upon at the Settlement Conference. One of these (Storage Cost Allocation) has impacts on 2016 Allowed Revenue and rates, while the other (Base Pressure Sale Proceeds) has no rate impact in 2016.

Storage Cost Allocation

In the Custom IR Decision, the Board directed Enbridge to file a proposal in 2015 or 2016 as to how costs should be allocated to Enbridge's unregulated storage line of business for Base Pressure Gas and LUF. As the Board noted, Enbridge has been allocating these costs on an incremental cost basis. In the Custom IR Decision, the Board also directed Enbridge to file information that would be necessary to make an allocation of Base Pressure Gas and LUF on a fully allocated cost basis.

Enbridge's pre-filed evidence set out its proposal to continue to apply an incremental cost approach to allocate cost related to Base Pressure Gas and LUF.

As part of an overall settlement, Enbridge has agreed to apply a fully allocated cost approach to allocate the costs of Base Pressure Gas and LUF between regulated and unregulated storage operations.

The impact of this change in cost allocation is to increase allocations of Base Pressure Gas and LUF to the unregulated line of business. For the regulated utility, this will reduce the rate base value for Base Pressure Gas and reduce gas costs.

As explained in the pre-filed evidence, Enbridge's regulated storage operations have a capacity of 97.96 Bcf, and the unregulated storage operations have a capacity of 16.33 Bcf. On a relative basis, the unregulated storage operations represent 14.3% of the total storage capacity. Under a fully allocated cost approach, the unregulated storage line of business will be responsible for 14.3% of the costs associated with Base Pressure Gas and LUF.

For Base Pressure Gas, the change to fully allocated costs means that the unregulated storage line of business will be allocated $5.6 million in Base Pressure Gas value, which amounts have been part of the rate base for the regulated storage operations. This will reduce the rate base associated with Base Pressure Gas for regulated storage from $41.0 million to $35.4 million. The reduction in 2016 Allowed Revenue associated with this change is approximately $0.4 million.

For LUF, the change to fully allocated costs means that the unregulated storage line of business will be allocated 0.12 Bcf of LUF volumes, which volumes have been part of the regulated storage operations volumes and costs. This will result in a reduction of around $.67 million in gas costs for the regulated storage operations, based on July 2015 QRAM prices.

On an overall basis, the impact of the change in storage cost allocation for Base Pressure Gas and LUF is to reduce the revenue deficiency by approximately $1.1 million.

The parties agree that this change is without prejudice to any position that any party may take on the proper approach to allocation of storage costs (LUF, Base Gas and any other relevant items) between the regulated and unregulated storage operations if that question is raised or addressed after the end of this Custom IR term.

Evidence: The evidence in relation to this item includes the following:

A1-5-1	Allocation of Costs (Lost and Unaccounted For & Base Pressure Gas) to Non-utility (Unregulated) Storage
I.A1.EGDI.STAFF.1	Board Staff Interrogatory #1
I.A1.EGDI.APPrO.1-3	APPrO Interrogatories #1-3
I.A1.EGDI.BOMA.2-10	BOMA Interrogatories #2-10
I.A1.EGDI.CCC.1-2	CCC Interrogatories #1-2
I.A1.EGDI.FRPO.1	FRPO Interrogatory #1
I.A1.EGDI.SEC.1-2	SEC Interrogatories #1-2
I.A1.EGDI.VECC.1-3	VECC Interrogatories #1-3

Profit from sale of Base Pressure Gas

During 2015, the Company sold 1.93 Bcf of Base Pressure Gas. This created additional storage space for Enbridge's unregulated storage line of business. The profit (proceeds less book value) from the sale was approximately $5.8 million.

As part of an overall settlement in this proceeding, and without prejudice to the position that any party may take on any similar transaction in the future, the parties have agreed that the Company will include the profits from the Base Pressure Gas sale as part of the 2015 utility earnings that will be considered in the determination of any 2015 Earnings Sharing amount pursuant to the ESM in Enbridge's Custom IR model.

This aspect of the settlement has no impact on 2016 Allowed Revenue or rates, however, it will be reflected within any amount that is recorded in the 2015 ESM Deferral Account for later disposition to ratepayers.

Evidence: The evidence in relation to this item includes the following:

A1-5-1	Allocation of Costs (Lost and Unaccounted For & Base Pressure Gas) to Non-utility (Unregulated) Storage
I.A1.EGDI.BOMA.10	BOMA Interrogatory #10

IMPLEMENTATION

Subject to the one later adjustment related to the 2016 DSM budget, the parties have agreed upon all items that support Enbridge's 2016 rates.

Appendix C is a Draft Rate Order for interim rates effective as of January 1, 2016. The Draft Rate Order reflects Enbridge's Application, as updated to take account of the adjustments set out in this Settlement Proposal.

Also included, as Appendix D, is Enbridge's Draft Accounting Order for 2016.

The parties request that the Board consider and approve this Settlement Proposal, including the Draft Rate Order and the Draft Accounting Order, in sufficient time to permit the new interim 2016 rates to be implemented in conjunction with Enbridge's January 1, 2016 QRAM Application.

After the Board issues its Decision on Enbridge's 2016 DSM budget in EB-2015-0049, then Enbridge will update its 2016 Allowed Revenue and rates to reflect the full-year impact of the difference between the approved 2016 DSM budget and the 2015 DSM budget that is being included in 2016 Allowed Revenue and rates as an interim amount. The parties agree that this change will be implemented into Enbridge's 2016 final rates as part of its next QRAM Application following the Board's Decision in EB-2015-0049.

APPENDIX A : 2016 TEST YEAR ALLOWED REVENUE AND SUFFICIENCY/DEFICIENCY

ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY)
2016 TEST YEAR

Line No.		Col. 1 EB-2012-0459 Total 2016 Allowed Revenue Placeholder ($Millions)	Col. 2 2016 Required Updates ($Millions)	Col. 3 Total Final 2016 Test Year Allowed Revenue ($Millions)	Col. 4 2016 Settlement Proposal Adjustments	Col. 5 Adjusted Total Final 2016 Test Year Allowed Revenue ($Millions)	Col. 6 Explanation See Page 2	Col. 7 Evidence Exhibit Reference
	Cost of capital							
1.	Rate base	5,696.0	116.3	5,812.3	(4.8)	5,807.5	a)	B Series of Exhibits
2.	Required rate of return	7.00	(0.63)	6.37	0.03	6.40	b)	E Series of Exhibits
3.		398.6	(28.3)	370.3	1.6	371.9		
	Cost of service							
4.	Gas costs	1,632.5	134.8	1,767.3	(2.5)	1,764.8	c)	D1-1-1 and D1-2-1 to D1-2-8
5.	Operation and maintenance	431.1	32.6	463.7	(28.5)	435.2	d)	D1-1-1 and D1-3-1 to D1-5-1
6.	Depreciation and amortization	288.9	-	288.9	-	288.9		
7.	Fixed financing costs	1.9	-	1.9	-	1.9		
8.	Municipal and other taxes	45.5	-	45.5	-	45.5		
9.		2,399.9	167.4	2,567.3	(31.0)	2,536.3		
	Misc. operating and non-operating revenue							
10.	Other operating revenue	(42.7)	-	(42.7)	-	(42.7)		
11.	Interest and property rental	-	-	-	-	-		
12.	Other income	(0.1)	-	(0.1)	-	(0.1)		
13.		(42.8)	-	(42.8)	-	(42.8)		
	Income taxes on earnings							
14.	Excluding tax shield	47.1	(3.9)	43.2	7.8	51.0	e)	D1-1-1 and D1-6-1 to D1-6-2
15.	Tax shield provided by interest expense	(49.6)	2.6	(47.0)	(0.2)	(47.2)	e)	D1-1-1 and D1-6-1 to D1-6-2
16.		(2.5)	(1.3)	(3.8)	7.6	3.8		
	Taxes on sufficiency / (deficiency)							
17.	Gross sufficiency / (deficiency)	(77.9)	(25.8)	(103.7)	28.7	(75.0)		
18.	Net sufficiency / (deficiency)	(57.3)	(19.0)	(76.2)	21.1	(55.2)		
19.		20.6	6.8	27.5	(7.6)	19.9	e)	D1-1-1 and D1-6-1 to D1-6-2
20.	**Sub-total revenue requirement**	2,773.8	144.6	2,918.5	(29.4)	2,889.1		
21.	Customer Care Rate Smoothing V/A Adjustment	0.8	-	0.8	-	0.8		
22.	**Allowed revenue**	2,774.6	144.6	2,919.3	(29.4)	2,889.9		
	Revenue at existing Rates							
23.	Gas sales	2,464.5	85.5	2,550.0	(0.6)	2,549.4	f)	C Series of Exhibits
24.	Transportation service	217.1	42.2	259.3	-	259.3	f)	C Series of Exhibits
25.	Transmission, compression and storage	1.8	0.1	1.9	-	1.9		
26.	Rounding adjustment	-	0.1	0.1	(0.1)	-		
27.	Revenue at existing rates	2,683.4	127.9	2,811.3	(0.7)	2,810.6		
28.	**Gross revenue sufficiency / (deficiency)**	(91.2)	(16.7)	(108.0)	28.7	(79.3)		F Series of Exhibits

App.B Pg.1 Ref.	Required updates to 2016 Placeholder Allowed Revenue per Appendix E of the EB-2012-0459 Final Rate Order
a)	Adjustment to rate base arising from the gas cost and O&M updates and the related impact on gas in storage and working cash
b)	Adjustment to forecast cost of capital rates, based upon the updated forecast ROE and updated forecast cost of debt
c)	Adjustment to forecast gas cost based upon the updated gas cost forecast and the 2016 gas volume forecast
d)	Adjustment to O&M in relation to updated forecasts of DSM, Pension/OPEB, and CIS/Customer Care costs
e)	Adjustment to income taxes in relation to all other Board required / permitted adjustments to achieve final 2016 Allowed Revenue
f)	Adjustment to revenue forecasts resulting from updating the 2016 volume forecast and use of July 1, 2015 Board Approved rates

APPENDIX B : SETTLEMENT PROPOSAL FINANCIAL STATEMENTS

ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY)
2016 FISCAL YEAR

Line No.		Col. 1 As Filed Excl. CIS 2016 Allowed Revenue ($Millions)	Col. 2 As Filed CIS 2016 Allowed Revenue ($Millions)	Col. 3 As Filed Total 2016 Allowed Revenue ($Millions)	Col. 4 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 5 CIS Settlement Proposal Adjustments ($Millions)	Col. 6 Adjusted 2016 Allowed Revenue Excl. CIS ($Millions)	Col. 7 Adjusted 2016 CIS Allowed Revenue ($Millions)	Col. 8 Total Adjusted 2016 Allowed Revenue ($Millions)
	Cost of capital								
1.	Rate base	5,779.9	32.4	5,812.3	(4.8)	-	5,775.1	32.4	5,807.5
2.	Required rate of return	6.37	6.44	6.37	0.03	-	6.40	6.44	6.40
3.		368.2	2.1	370.3	1.6	-	369.8	2.1	371.9
	Cost of service								
4.	Gas costs	1,767.3	-	1,767.3	(2.5)	-	1,764.8	-	1,764.8
5.	Operation and maintenance	364.4	99.3	463.7	(28.5)	-	335.9	99.3	435.2
6.	Depreciation and amortization	276.2	12.7	288.9	-	-	276.2	12.7	288.9
7.	Fixed financing costs	1.9	-	1.9	-	-	1.9	-	1.9
8.	Municipal and other taxes	45.5	-	45.5	-	-	45.5	-	45.5
9.		2,455.3	112.0	2,567.3	(31.0)	-	2,424.3	112.0	2,536.3
	Miscellaneous operating and non-operating revenue								
10.	Other operating revenue	(42.7)	-	(42.7)	-	-	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	-	(0.1)	-	(0.1)
13.		(42.8)	-	(42.8)	-	-	(42.8)	-	(42.8)
	Income taxes on earnings								
14.	Excluding tax shield	35.3	7.9	43.2	7.8	-	43.1	7.9	51.0
15.	Tax shield provided by interest expense	(46.6)	(0.4)	(47.0)	(0.2)	-	(46.8)	(0.4)	(47.2)
16.		(11.3)	7.5	(3.8)	7.6	-	(3.7)	7.5	3.8
	Taxes on sufficiency / (deficiency)								
17.	Gross sufficiency / (deficiency)	(103.7)	-	(103.7)	28.7	-	(75.0)	-	(75.0)
18.	Net sufficiency / (deficiency)	(76.2)	-	(76.2)	21.1	-	(55.2)	-	(55.2)
19.		27.5	-	27.5	(7.6)	-	19.9	-	19.9
20.	**Sub-total revenue requirement**	2,796.9	121.6	2,918.5	(29.4)	-	2,767.5	121.6	2,889.1
21.	Customer Care Rate Smoothing V/A Adjustment	-	0.8	0.8	-	-	-	0.8	0.8
22.	**Allowed revenue**	2,796.9	122.4	2,919.3	(29.4)	-	2,767.5	122.4	2,889.9
	Revenue at existing Rates								
23.	Gas sales	2,446.5	103.5	2,550.0	(0.6)	-	2,445.9	103.5	2,549.4
24.	Transportation service	244.7	14.6	259.3	-	-	244.7	14.6	259.3
25.	Transmission, compression and storage	1.9	-	1.9	-	-	1.9	-	1.9
26.	Rounding adjustment	0.1	-	0.1	(0.1)	-	-	-	-
27.	Revenue at existing rates	2,693.2	118.1	2,811.3	(0.7)	-	2,692.5	118.1	2,810.6
28.	**Gross revenue sufficiency / (deficiency)**	(103.7)	(4.3)	(108.0)	28.7	-	(75.0)	(4.3)	(79.3)

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2016 FISCAL YEAR

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	(4.8)	Rate base
		The column 4 decrease results from the allocation of $5.6 million in base pressure gas to Unregulated Storage operations, as described in the Settlement Proposal, partially offset by a $0.8 million increase in working cash allowance resulting from the gas cost and operation and maintenance cost adjustments described below.
3.	1.6	Cost of capital
		The column 4 increase results from an increase in the required rate of return, which has been updated to reflect the 2016 Board determined ROE of 9.19%, and to reflect the capital structure updates described in Adjustment 4 of the Settlement Proposal. The increase in the cost of capital resulting from the increase in the required rate of return was partially offset by the reduction in rate base described above.
4.	(2.5)	Gas costs
		The column 4 decrease results from the removal of community expansion volumes ($0.4 million), as described in Adjustment 2 of the Settlement Proposal, a reduction in unaccounted for volumes ($1.5 million), as described in Adjustment 1 of the Settlement Proposal, and a reduction in lost and unaccounted for volumes reflecting the allocation to Unregulated Storage operations ($0.7 million), as described in the Settlement Proposal.
5.	(28.5)	Operation and maintenance
		The column 4 decrease results from the reduction in DSM operation and maintenance costs to reflect the amount included within 2015 approved rates, as described in Adjustment 3 of the Settlement Proposal.
16.	7.6	Income taxes on earnings
		The column 4 increase is due to a higher taxable income resulting from the impact of the Settlement Proposal partially offset by a higher interest tax shield resulting from the capital structure adjustments described in Adjustment 4 of the Settlement Proposal.
23.	(0.6)	Gas sales
		The column 4 decrease results from the removal of community expansion volumes, as described in Adjustment 2 of the Settlement Proposal.

UTILITY RATE BASE
2016 FISCAL YEAR

Line No.		Col. 1 As Filed Excl. CIS Rate Base ($Millions)	Col. 2 As Filed CIS Rate Base ($Millions)	Col. 3 As Filed Total 2016 Rate Base ($Millions)	Col. 4 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 5 CIS Settlement Proposal Adjustments ($Millions)	Col. 6 Adjusted 2016 Rate Base Excl. CIS ($Millions)	Col. 7 Adjusted 2016 CIS Rate Base ($Millions)	Col. 8 Total Adjusted 2016 Rate Base ($Millions)
	Property, Plant, and Equipment								
1.	Cost or redetermined value	8,427.5	127.1	8,554.6	(5.6)	-	8,421.9	127.1	8,549.0
2.	Accumulated depreciation	(3,011.1)	(94.7)	(3,105.8)	-	-	(3,011.1)	(94.7)	(3,105.8)
3.		5,416.4	32.4	5,448.8	(5.6)	-	5,410.8	32.4	5,443.2
	Allowance for Working Capital								
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	-	1.0	-	1.0
9.	Gas in storage	391.1	-	391.1	-	-	391.1	-	391.1
10.	Working cash allowance	-	-	-	0.8	-	0.8	-	0.8
11.	Total Working Capital	363.5	-	363.5	0.8	-	364.3	-	364.3
12.	Utility Rate Base	5,779.9	32.4	5,812.3	(4.8)	-	5,775.1	32.4	5,807.5

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2016 FISCAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Reference	Disburs-ements ($Millions)	Net Lag-Days (Days)	Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,808.5	2.1	10.4
2.	Items not subject to working cash allowance (Note 1)		(43.7)		
3.	Gas costs charged to operations		1,764.8		
4.	Operation and Maintenance		335.9		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		327.5		
7.	Ancillary customer services		-		
8.			327.5	(10.9)	(9.8)
9.	Sub-total				0.6
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				(1.2)
14.	Total working cash allowance				0.8

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 As Filed Excl. CIS 2016 Utility Income ($Millions)	Col. 2 As Filed CIS 2016 Utility Income ($Millions)	Col. 3 As Filed Total 2016 Utility Income ($Millions)	Col. 4 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 5 CIS Settlement Proposal Adjustments ($Millions)	Col. 6 Adjusted 2016 Utility Income Excl. CIS ($Millions)	Col. 7 Adjusted 2016 CIS Utility Income ($Millions)	Col. 8 Total Adjusted 2016 Utility Income ($Millions)
1.	Gas sales	2,446.5	103.5	2,550.0	(0.6)	-	2,445.9	103.5	2,549.4
2.	Transportation of gas	244.7	14.6	259.3	-	-	244.7	14.6	259.3
3.	Transmission, compression and storage revenue	1.9	-	1.9	-	-	1.9	-	1.9
4.	Other operating revenue	42.7	-	42.7	-	-	42.7	-	42.7
5.	Interest and property rental	-	-	-	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	-	0.1	-	0.1
7.	Total operating revenue	2,735.9	118.1	2,854.0	(0.6)	-	2,735.3	118.1	2,853.4
8.	Gas costs	1,767.3	-	1,767.3	(2.5)	-	1,764.8	-	1,764.8
9.	Operation and maintenance	364.4	99.3	463.7	(28.5)	-	335.9	99.3	435.2
10.	Depreciation and amortization expense	276.2	12.7	288.9	-	-	276.2	12.7	288.9
11.	Fixed financing costs	1.9	-	1.9	-	-	1.9	-	1.9
12.	Municipal and other taxes	45.5	-	45.5	-	-	45.5	-	45.5
13.	Interest and financing amortization expense	-	-	-	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-	-	-	-
15.	Total costs and expenses	2,455.3	112.0	2,567.3	(31.0)	-	2,424.3	112.0	2,536.3
16.	Ontario utility income before income taxes	280.6	6.1	286.7	30.4	-	311.0	6.1	317.1
17.	Income tax expense	(11.3)	7.5	(3.8)	7.6	-	(3.7)	7.5	3.8
18.	Utility net income	291.9	(1.4)	290.5	22.8	-	314.7	(1.4)	313.3

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

Line No.		Col. 1 As Filed Excl. CIS 2016 Utility Tax ($Millions)	Col. 2 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 3 Adjusted 2016 Excl. CIS Utility Tax ($Millions)
1.	Utility income before income taxes	280.6	30.4	311.0
	Add			
2.	Depreciation and amortization	276.2	-	276.2
3.	Accrual based pension and OPEB costs	34.6	-	34.6
4.	Other non-deductible items	1.0	-	1.0
5.	Total Add Back	311.8	-	311.8
6.	Sub total	592.4	30.4	622.8
	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	3.0	-	3.0
11.	Amortization of share/debenture issue expense	1.1	1.1	2.2
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	83.9	-	83.9
15.	Cash based pension and OPEB costs	7.1	-	7.1
16.	Total Deduction - Federal	462.5	1.1	463.6
17.	Total Deduction - Provincial	462.5	1.1	463.6
18.	Taxable income - Federal	129.9	29.3	159.2
19.	Taxable income - Provincial	129.9	29.3	159.2
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	19.5	4.4	23.9
23.	Income tax provision - Provincial	14.9	3.4	18.3
24.	Income tax provision - combined	34.4	7.8	42.2
25.	Part V1.1 tax	0.9	-	0.9
26.	Total taxes excluding tax shield on interest expense	35.3	7.8	43.1
	Tax shield on interest expense			
27.	Rate base	5,779.9	(4.8)	5,775.1
28.	Return component of debt	3.05%	0.01%	3.06%
29.	Interest expense	176.0	0.7	176.7
30.	Combined tax rate	26.50%	0.00%	26.50%
31.	Income tax credit	(46.6)	(0.2)	(46.8)
32.	Total income taxes	(11.3)	7.6	(3.7)

UTILITY CAPITAL STRUCTURE
2016 FISCAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Principal Excl. CC/CIS	Component	Indicated Cost Rate	Return Component
		($Millions)	%	%	%
1.	Long term debt	3,546.1	61.40	4.96	3.045
2.	Short term debt	50.0	0.87	1.57	0.014
3.		3,596.1	62.27		3.059
4.	Preference shares	100.0	1.73	2.16	0.037
5.	Common equity	2,079.0	36.00	9.19	3.308
6.		5,775.1	100.00		6.404
7.	Utility income	($Millions)			314.7
8.	Rate base	($Millions)			5,775.1
9.	Indicated rate of return				5.449%
10.	(Deficiency) in rate of return				(0.955)%
11.	Net (deficiency)	($Millions)			(55.2)
12.	Gross (deficiency)	($Millions)			(75.0)
13.	Customer Care/CIS deficiency	($Millions)			(4.3)
14.	Total gross (deficiency)	($Millions)			(79.3)
15.	Revenue at existing rates	($Millions)			2,810.6
16.	Allowed revenue	($Millions)			2,889.9
17.	Total gross revenue (deficiency)	($Millions)			(79.3)

APPENDIX C: DRAFT RATE ORDER

APPENDIX “C”

ATTACHMENT 1 – SETTLEMENT PROPOSAL

SETTLEMENT PROPOSAL

Enbridge Gas Distribution Inc.
2016 Rate Adjustment

December 1, 2015

TABLE OF CONTENTS

SETTLEMENT PROPOSAL CONTEXT

This Settlement Proposal is filed with the Ontario Energy Board (the “Board", or the “OEB”) in connection with the application by Enbridge Gas Distribution Inc. (“Enbridge”, or the “Company”), for an order or orders approving or fixing just and reasonable rates for the sale, transmission, distribution and storage of natural gas commencing January 1, 2016.

In Procedural Order No. 1 issued on October 16, 2015, the Board provided for a series of procedural steps, up to and including a Settlement Conference.

The Settlement Conference was held on November 18 and 19, 2015. Chris Haussmann acted as facilitator for the Settlement Conference. This Settlement Proposal arises from the Settlement Conference and subsequent discussions.

Enbridge and the following intervenors, as well as Ontario Energy Board technical staff (“OEB Staff”), participated in the Settlement Conference:

Association of Power Producers of Ontario (APPrO)
Building Owners and Managers Association – Greater Toronto (BOMA)
Canadian Manufacturers & Exporters (CME)
Consumers Council of Canada (CCC)
Energy Probe Research Foundation (Energy Probe)
Federation of Rental-Housing Providers of Ontario (FRPO)
Industrial Gas Users Association (IGUA)
School Energy Coalition (SEC)
Vulnerable Energy Consumers Coalition (VECC)

The Settlement Proposal deals with all of the relief sought in this proceeding. The parties have reached agreement on all relevant items, as set out herein. Should the Board approve this Settlement Proposal, there will not be any unsettled issues.

All intervenors listed above participated in the Settlement Conference and subsequent discussions.

OEB Staff also participated in the Settlement Conference. OEB Staff is not a party to the Settlement Proposal. Although it is not a party to the Settlement Proposal, OEB Staff will file a submission commenting on two aspects of the settlement: whether the settlement represents an acceptable outcome from a public interest perspective, and whether the accompanying explanation and rationale is adequate to support the settlement. Also, as noted in the Practice Direction on Settlement Conferences, OEB Staff who did participate in the Settlement Conference are bound by the same confidentiality and privilege rules that apply to the parties to the proceeding.

This document is called a “Settlement Proposal” because it is a proposal by the parties to the Board to settle the issues in this proceeding. It is termed a proposal as between the parties and the Board. However, as between the parties, and subject only to the Board’s approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Context section, this Settlement Proposal is subject to a condition subsequent, that if it is not accepted by the Board in its entirety, then unless amended by the parties it is null and void and of no further effect. In entering into this agreement, the parties understand and agree that, pursuant to the *Ontario Energy Board Act*, the Board has exclusive jurisdiction with respect to the interpretation or enforcement of the terms hereof.

Enbridge and all intervenors listed above have agreed to the settlement of the issues as described on the following pages. Any reference to “parties” in this Settlement Proposal is intended to refer to Enbridge and the intervenors listed above. The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise.

None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 30 of the Ontario Energy Board Rules of Practice and Procedure. Further, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions parties might take with respect to the same issue in future proceedings, whether during the term of Enbridge’s 2014 to 2018 Custom Incentive Regulation (“IR”) plan, or thereafter.

The parties acknowledge that this Settlement Conference (including subsequent related discussions) is confidential in accordance with the Board’s Practice Direction on Settlement Conferences. The parties understand that confidentiality in that context does not have the same meaning as confidentiality in the Board’s Practice Direction on Confidential Filings, and the rules of that latter document do not apply. Instead, in this Settlement Conference, and in this Settlement Proposal, the parties have interpreted “confidential” to mean that the documents and other information provided during the course of the Settlement Conference, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the parties agree that “attendees” is deemed to include, in this context, persons who were not physically in attendance at the Settlement Conference but were a) any persons or entities that the parties engage to assist them with the settlement conference, and b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

It is fundamental to the agreement of the parties that none of the provisions of this Settlement Proposal are severable. If the Board does not accept the provisions of the Settlement Proposal in their entirety prior to the commencement of the hearing of the application, there is no Settlement Proposal (unless the parties agree that any portion of the Settlement Proposal that the Board does accept may continue as a valid Settlement Proposal).

The table at Appendix A identifies the evidence that supports each aspect of Enbridge's 2016 rate adjustment application. In relation to the items for which adjustment from Enbridge's pre-filed evidence has been agreed-upon, the specific supporting evidence is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit B, Tab 3, Schedule 1 is referred to as B-3-1. The identification and listing of the evidence that relates to each adjustment is provided to assist the Board.

Accordingly, this Settlement Proposal provides a direct link between each adjustment to the requested approvals and the evidence in support of that adjustment. The parties are of the view that the evidence supports the agreement embodied in this Settlement Proposal and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings leading to the acceptance by the Board of the Settlement Proposal.

SETTLEMENT PROPOSAL OVERVIEW

As set out below, the parties have reached agreement on all items in this proceeding. Primarily, this relates to the required 2016 rate adjustments to be undertaken in accordance with Enbridge's OEB-approved Custom IR plan. There are also two other items outside of the Custom IR plan upon which the parties have reached agreement. These relate to the allocation of certain costs to Enbridge's unregulated storage line of business, and to the agreed treatment of certain profits of sale in Enbridge's 2015 Earnings Sharing Mechanism ("ESM") calculations.

If this Settlement Proposal is accepted by the Board, then Enbridge will implement interim 2016 rates in conjunction with the January 1, 2016 QRAM. The only item that may be subject to later adjustment is the cost consequences of Enbridge's 2016 DSM budget. That budget has been presented to the Board in a separate proceeding, and no decision has yet been delivered. The parties have agreed that Enbridge's interim 2016 rates arising from this Settlement Proposal, which are set out in the draft Rate Order at Appendix C, will be subject to later adjustment to reflect the impact of Enbridge's DSM budget for 2016 that is approved by the Board in the separate proceeding.

(a) Custom IR Approvals Requested by Enbridge

In its EB-2012-0459 Decision with Reasons dated July 17, 2014 (the "Custom IR Decision") the Board approved a five-year Custom IR plan for Enbridge to begin on January 1, 2014.[1] In the Custom IR Decision, together with the subsequent Decision and Rate Order dated August 22, 2014 (the "Custom IR Rate Order"), the Board approved the Custom IR elements and forecast costs to be used for the purposes of determining Enbridge's 2014 Allowed Revenue and associated 2014 final rates.

Enbridge's Custom IR proposal contemplated an annual adjustment process for the years 2015 to 2018. The Board accepted this proposal in the Custom IR Decision: as stated by the Board, while most elements of Allowed Revenue were determined in the EB-2012-0459 proceeding, placeholder amounts were set for certain specific elements and these placeholder amounts are to be updated at the start of each rate year from 2015 to 2018.[2]

The Board directed Enbridge to provide a complete list of the elements of the Custom IR plan that will be updated annually from 2015 to 2018, for inclusion as part of the Draft Rate Order in EB-2012-0459. In the Custom IR Rate Order, the Board ordered that the "Annual Update Elements" for the Custom IR plan shall be as set out in Appendix E thereto. A copy of Appendix E from the Custom IR Rate Order was filed in this proceeding at Exhibit A1, Tab 3, Schedule 1, Appendix A. The list of Annual Update Elements set out in Appendix E to the Custom IR Rate Order is reproduced below:

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

Line	Element
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 re-forecast 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.

[1] Custom IR Decision, at page 4.
[2] Custom IR Decision, at page 83.

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.

In this proceeding, Enbridge requested approval of 2016 Allowed Revenue and associated 2016 final rates. At Appendix B of Exhibit A1, Tab 3, Schedule 1, Enbridge provided a table showing the derivation of the 2016 Allowed Revenue amount and associated sufficiency / deficiency proposed for approval by the Board. An updated version of this 2016 Test Year Allowed Revenue and Sufficiency/Deficiency table is included at Appendix A to this Settlement Proposal. The updated version of the table is the same as previously filed, except that it also includes two columns setting out the Allowed Revenue (and Sufficiency / Deficiency) impacts of this Settlement Proposal.

In connection with the approval of final 2016 Rates, Enbridge requested that the Board approve the establishment of 2016 Deferral and Variance Accounts, as set out in the evidence at Exhibit D2, Tab 1, Schedules 1 to 3. With four exceptions, all of the Deferral and Variance accounts proposed for 2016 were previously approved in the Custom IR Decision. One of the additional accounts is the Dawn Access Costs Deferral Account; this account was approved in the Board's EB-2014-0323 Accounting Order issued on December 4, 2014. The second of the additional accounts is the 2016 Credit Final Bill Deferral Account, which was approved within the EB-2014-0276 proceeding. There is one renewed account being proposed - the 2016 Unabsorbed Demand Cost deferral account. Finally, there is one new account being proposed, the 2016 Rate 332 deferral account.

(b) Settlement of Requested Custom IR Approvals

The parties have accepted and agreed upon Enbridge's requested Custom IR approvals, as set out in the pre-filed evidence, subject to: (i) four adjustments to be made in respect of Enbridge's requested approvals; and (ii) two other provisos.

The table at Appendix A provides references to the pre-filed evidence that supports the settlement of Enbridge's requested approvals. More generally, the evidence with regard to updated rate base is found in the "B" series of exhibits, the evidence regarding 2016 gas volumes and 2016 revenues is found in the "C" series of exhibits, the evidence regarding updates to certain operating cost elements (including gas costs) is found in the "D" series of exhibits, the evidence regarding updates to Cost of Capital is found in the "E" series of exhibits, the evidence regarding the 2016 revenue deficiency is found in the "F" series of exhibits and the evidence regarding proposed final 2016 rates is found in the "H" series of exhibits.

The four adjustments to Enbridge's requested approvals resulting from the settlement reached by all parties are as follows:

<u>Adjustment 1</u> – Reversion to prior UAF forecasting methodology

An adjustment to revert back to the previously used forecasting methodology for Unaccounted For Gas ("UAF"), rather than the proposed new forecasting methodology. This adjustment results in a decrease to the forecast UAF volumes for 2016.

<u>Adjustment 2</u> - Removal of Community Expansion Program customers

An adjustment to remove the inclusion of 1,590 additional customers who had been forecast to be added in the fourth quarter of 2016 as part of the Company's planned Community Expansion Program. This adjustment results in a decrease to customer numbers and volumes

<u>Adjustment 3</u> - Interim use of 2015 DSM budget, pending OEB decision in EB-2015-0049

An adjustment to use the 2015 Board-approved DSM budget included within 2015 rates on an interim basis until such time as the Board issues a decision on Enbridge's proposed 2016 DSM budget in the EB-2015-0049 proceeding. Enbridge will implement the full-year effect of any changes in the 2016 DSM budget (as compared to the 2015 DSM budget) as part of its next QRAM Application following the Board's decision in EB-2015-0049.

Adjustment 4 - Updates to Cost of Capital

(i) An adjustment to reflect an updated ROE of 9.19% (as compared to the forecast of 9.13% included within the pre-filed evidence), as determined in the Ontario Energy Board's Cost of Capital Parameter Updates for 2016 Applications published October 15, 2015. This adjustment results in an increase to 2016 Cost of Capital; and

(ii) An adjustment to update Enbridge's forecast 2016 Cost of Debt based on forecasts as of October 2015. This adjustment results in an increase to 2016 Cost of Capital.

The particulars of the agreements reached on each of the adjustments to Enbridge's requested Custom IR approvals are described below, under the heading *Details of Adjustments to Enbridge's Requested Approvals*.

In addition to the four adjustments described above, the parties also have comments relating to two specific Custom IR approvals sought by Enbridge.

First, in relation to Enbridge's 2016 gas costs (including transportation and storage), the parties agree that the Board should approve the Company's gas supply plan as set out in Exhibit D1, Tab 2 of the pre-filed evidence. The parties acknowledge that Exhibit D1, Tab 2 is largely a description of the implementation of Enbridge's gas supply plan and strategy. Enbridge agrees that, in its 2017 rate adjustment application, it will augment the gas supply evidence so that, in addition to the material provided in this proceeding, there is an explanation of the principles driving the gas supply plan, and how those principles are being implemented by the detailed evidence on gas procurement and transportation.

Second, in relation to the 2016 Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA"), the parties agree that Enbridge will continue to use the same account description as has been approved in 2014 and 2015. The parties acknowledge that there may be disagreement as to the scope of what expenses can be included in the GGEIDA, but agree that any such issues are properly addressed at the time that clearance of that account is requested.

(c) Storage Cost Allocation

In the Custom IR Decision, the Board directed Enbridge to file a proposal in 2015 or 2016 as to how costs should be allocated to Enbridge's unregulated storage line of business for Base Pressure Gas and LUF. In its Application, Enbridge requested Board Approval to continue, for the duration of the Custom IR term, to use the current incremental allocation approach for the allocation of costs to non-utility storage operations for Base Pressure Gas and LUF.

As part of an overall settlement, Enbridge has agreed to move to a fully allocated cost approach to allocate the costs of Base Pressure Gas and LUF between regulated and unregulated storage operations.

The parties agree that this change is without prejudice to any position that any party may take on the proper approach to allocation of storage costs (LUF, Base Gas and any other relevant items) between the regulated and unregulated storage operations if that question is raised or addressed after the end of this Custom IR term.

The impact of this change in cost allocation is to increase allocations of Base Pressure Gas and LUF to the unregulated line of business. For the regulated utility, this will reduce the rate base value for Base Pressure Gas and reduce gas costs.

(d) Profit from the sale of Base Pressure Gas

During 2015, the Company sold approximately 2 Bcf of Base Pressure Gas. This created additional storage space for Enbridge's unregulated storage line of business.

As part of an overall settlement in this proceeding, and without prejudice to the position that any party may take on any similar transaction in the future, the parties have agreed that the Company will include the profit from the Base Pressure Gas sale as part of the 2015 utility earnings that will be considered in the determination of any 2015 Earnings Sharing amount pursuant to the ESM in Enbridge's Custom IR model.

This aspect of the settlement has no impact on 2016 Allowed Revenue or rates, however, it will be reflected within any amount that is recorded in the 2015 ESM Deferral Account for later disposition to ratepayers.

(e) Impacts of Settlement Proposal

The changes to Enbridge's 2016 Allowed Revenue (and associated revenue deficiency) that result from the Settlement Proposal are set out within the updated 2016 Allowed Revenue and Sufficiency / Deficiency table that is found at Appendix A. The overall result of the implementation of the Settlement Proposal is a reduction in the revenue deficiency associated with Enbridge's requested approvals from $108 million to $79.3 million. It should be noted that the revenue deficiency will change when the cost consequences of Enbridge's Board-approved 2016 DSM budget are implemented into rates at a later date.

Details of the impact of the agreed-upon adjustments to Enbridge's requested approvals are set out in the Settlement Proposal Financial Statements included as Appendix B to this Settlement Proposal.

The average rate impacts that will result from the implementation of the Settlement Proposal are set out in the Draft Rate Order included at Appendix C to this Settlement Proposal.

DETAILS OF ADJUSTMENTS TO ENBRIDGE'S REQUESTED CUSTOM IR APPROVALS

Set out below are details of each of the agreed adjustments to Enbridge's Custom IR approvals.

Adjustment 1 - Reversion to prior UAF forecast methodology

In Enbridge's pre-filed evidence, the Company proposed to change the forecasting methodology for UAF to a new methodology that was determined to have greater predictive ability than the current forecasting methodology.

The parties have agreed that it is not appropriate to update this forecasting methodology during the Custom IR term. Therefore, the parties have agreed that Enbridge will maintain the previously used forecasting methodology for UAF, rather than adopting the proposed new forecasting methodology.

This agreement is without prejudice to the position that any party may take in respect of appropriate UAF forecast methodologies following the end of the current Custom IR term.

The effect of Adjustment 1, as seen in response to BOMA Interrogatory #19, is to decrease the 2016 forecast of UAF from 92,515 10^3m^3 to 84,766 10^3m^3. This decreases forecast 2016 volumes by a corresponding amount. This adjustment will reduce the 2016 revenue deficiency by approximately $1.5 million.

Evidence: The evidence in relation to this item includes the following:

D1-2-3	Unbilled and Unaccounted-for Gas Volumes
I.D1.EGDI.BOMA.19-21	BOMA Interrogatories #19 to 21
I.D1.EGDI.EP.5	Energy Probe Interrogatory #5
I.D1.EGDI.FRPO.17-18	FRPO Interrogatories #17 to 18
I.D1.EGDI.VECC.6	VECC Interrogatory #6

Adjustment 2 - Removal of Community Expansion Program customers

Enbridge's Customer Additions forecast for 2016 included 1,590 additional customers who had been forecast to be added in the fourth quarter of 2016 as part of the Company's planned Community Expansion Program. These customers were forecast to be added in the latter part of the year so, on a monthly averages basis, the result was an increase of 291 customers. That program will be the subject of a separate application to the Board early in 2016.

The parties have agreed to a proposal by the Company (found at Exhibit C2-1-4 and BOMA Interrogatory 15) to remove the forecast Customer Additions for 2016 from the Community Expansion Program from its customer and volumes forecasts, since the program has not yet been approved by the Board. There were no other Allowed Revenue impacts (costs) from the Community Expansion Program included in the 2016 Rate Adjustment Application. As noted in evidence, when a Leave to Construct Application for the Community Expansion Program is filed, Enbridge may propose separate treatment for the impacts of the Program (including capital spending, customer additions, volumes and revenues).

Adjustment 2 results in a decrease of 291 customers from the 2016 Gross Customer Additions (from 35,592 to 35,301), and a corresponding decrease in volumes (approximately 1904 10^3m^3) and a minor decrease in Customer Care / CIS costs. The overall change in the 2016 revenue deficiency arising from this adjustment is an increase of approximately $0.2 million.

Evidence: The evidence in relation to this item includes the following:

C2-1-4	Customer Additions
D1-3-1	2016 Customer Care/CIS Update
I.C2.EGDI.BOMA.15	BOMA Interrogatory #15
I.C2.EGDI.FRPO.24	FRPO Interrogatory #24
I.C2.EGDI.VECC.5	VECC Interrogatory #5

Adjustment 3 - Interim use of 2015 DSM budget, pending OEB decision in EB-2015-0049

Enbridge's 2016 DSM budget will be determined in EB-2015-0049 (the proceeding in respect of Enbridge's Multi-Year Demand Side Management Plan – 2015-2020). The evidence and argument in that proceeding are complete, but the Decision has not been issued.

For the purposes of this Application, Enbridge used its proposed 2016 DSM budget of $63.5 million to update the 2016 placeholder DSM amount in 2016 Allowed Revenue.

The parties have agreed that Enbridge will wait until the Board issues its Decision in EB-2015-0049 before updating the 2016 DSM budget within Allowed Revenue. On an interim basis, Enbridge will continue to use the 2015 DSM budget of $35 million that was included in 2015 rates.

The parties agree that after the Board issues its Decision in EB-2015-0049, Enbridge will update its 2016 Allowed Revenue and rates to reflect the full-year impact of the difference between the approved 2016 DSM budget and the 2015 DSM budget that is being included in 2016 Allowed Revenue and rates as an interim amount. The parties agree that this change will be implemented into Enbridge's 2016 final rates as part of its next QRAM Application following the Board's decision in EB-2015-0049.

Adjustment 3 results in a reduction of approximately $28.5 million in Allowed Revenue. The corresponding reduction in the 2016 revenue deficiency arising from this adjustment is approximately $28.5 million. As noted these impacts will be subject to later adjustment to reflect Enbridge's 2016 DSM budget as approved by the Board.

Evidence: The evidence in relation to this item includes the following:

D1-1-1	Operating Cost Summary
D1-4-1	2016 DSM Forecast Budget

<u>Adjustment 4</u> – Updates to Cost of Capital

Enbridge's Custom IR model contemplates that the Company will use the most current values for its Cost of Capital (ROE and Cost of Debt) within the rate adjustment process. Enbridge's pre-filed evidence included the most current Cost of Capital values at the time that the evidence was prepared.

The parties agree that it is appropriate for Enbridge to update its Cost of Capital to reflect the more current information that is now available.

In response to VECC Interrogatory #8, Enbridge updated its forecast Cost of Capital to reflect an updated ROE of 9.19% (as compared to the forecast of 9.13% included within the pre-filed evidence), as determined in the Ontario Energy Board's Cost of Capital Parameter Updates for 2016 Applications published October 15, 2015. The result is an increase in return from $190.0 million to approximately $191.2 million.

In its response to Energy Probe Interrogatory #7, Enbridge updated its forecast 2016 Cost of Debt based on forecasts as of October 2015. The result is an increase in the total Cost of Debt from $178.2 million to approximately $178.9 million.

The combined effect of the two components of Adjustment 4 is to increase the Cost of Capital by approximately $1.9 million, and to increase the 2016 revenue deficiency shown in Appendix A by approximately $1.9 million.

Evidence: The evidence in relation to this item includes the following:

E1-1-1	Cost of Capital Summary
E1-3-1	2016 Cost of Debt
I.E1.EGDI.EP.6-7	Energy Probe Interrogatories #6-7
I.E1.EGDI.VECC.8-9	VECC Interrogatories #8-9

SETTLEMENT ON OTHER ITEMS

In addition to the Custom IR Approvals, there were two other items agreed upon at the Settlement Conference. One of these (Storage Cost Allocation) has impacts on 2016 Allowed Revenue and rates, while the other (Base Pressure Sale Proceeds) has no rate impact in 2016.

Storage Cost Allocation

In the Custom IR Decision, the Board directed Enbridge to file a proposal in 2015 or 2016 as to how costs should be allocated to Enbridge's unregulated storage line of business for Base Pressure Gas and LUF. As the Board noted, Enbridge has been allocating these costs on an incremental cost basis. In the Custom IR Decision, the Board also directed Enbridge to file information that would be necessary to make an allocation of Base Pressure Gas and LUF on a fully allocated cost basis.

Enbridge's pre-filed evidence set out its proposal to continue to apply an incremental cost approach to allocate cost related to Base Pressure Gas and LUF.

As part of an overall settlement, Enbridge has agreed to apply a fully allocated cost approach to allocate the costs of Base Pressure Gas and LUF between regulated and unregulated storage operations.

The impact of this change in cost allocation is to increase allocations of Base Pressure Gas and LUF to the unregulated line of business. For the regulated utility, this will reduce the rate base value for Base Pressure Gas and reduce gas costs.

As explained in the pre-filed evidence, Enbridge's regulated storage operations have a capacity of 97.96 Bcf, and the unregulated storage operations have a capacity of 16.33 Bcf. On a relative basis, the unregulated storage operations represent 14.3% of the total storage capacity. Under a fully allocated cost approach, the unregulated storage line of business will be responsible for 14.3% of the costs associated with Base Pressure Gas and LUF.

For Base Pressure Gas, the change to fully allocated costs means that the unregulated storage line of business will be allocated $5.6 million in Base Pressure Gas value, which amounts have been part of the rate base for the regulated storage operations. This will reduce the rate base associated with Base Pressure Gas for regulated storage from $41.0 million to $35.4 million. The reduction in 2016 Allowed Revenue associated with this change is approximately $0.4 million.

For LUF, the change to fully allocated costs means that the unregulated storage line of business will be allocated 0.12 Bcf of LUF volumes, which volumes have been part of the regulated storage operations volumes and costs. This will result in a reduction of around $.67 million in gas costs for the regulated storage operations, based on July 2015 QRAM prices.

On an overall basis, the impact of the change in storage cost allocation for Base Pressure Gas and LUF is to reduce the revenue deficiency by approximately $1.1 million.

The parties agree that this change is without prejudice to any position that any party may take on the proper approach to allocation of storage costs (LUF, Base Gas and any other relevant items) between the regulated and unregulated storage operations if that question is raised or addressed after the end of this Custom IR term.

Evidence: The evidence in relation to this item includes the following:

A1-5-1	Allocation of Costs (Lost and Unaccounted For & Base Pressure Gas) to Non-utility (Unregulated) Storage
I.A1.EGDI.STAFF.1	Board Staff Interrogatory #1
I.A1.EGDI.APPrO.1-3	APPrO Interrogatories #1-3
I.A1.EGDI.BOMA.2-10	BOMA Interrogatories #2-10
I.A1.EGDI.CCC.1-2	CCC Interrogatories #1-2
I.A1.EGDI.FRPO.1	FRPO Interrogatory #1
I.A1.EGDI.SEC.1-2	SEC Interrogatories #1-2
I.A1.EGDI.VECC.1-3	VECC Interrogatories #1-3

Profit from sale of Base Pressure Gas

During 2015, the Company sold 1.93 Bcf of Base Pressure Gas. This created additional storage space for Enbridge's unregulated storage line of business. The profit (proceeds less book value) from the sale was approximately $5.8 million.

As part of an overall settlement in this proceeding, and without prejudice to the position that any party may take on any similar transaction in the future, the parties have agreed that the Company will include the profits from the Base Pressure Gas sale as part of the 2015 utility earnings that will be considered in the determination of any 2015 Earnings Sharing amount pursuant to the ESM in Enbridge's Custom IR model.

This aspect of the settlement has no impact on 2016 Allowed Revenue or rates, however, it will be reflected within any amount that is recorded in the 2015 ESM Deferral Account for later disposition to ratepayers.

Evidence: The evidence in relation to this item includes the following:

A1-5-1	Allocation of Costs (Lost and Unaccounted For & Base Pressure Gas) to Non-utility (Unregulated) Storage
I.A1.EGDI.BOMA.10	BOMA Interrogatory #10

IMPLEMENTATION

Subject to the one later adjustment related to the 2016 DSM budget, the parties have agreed upon all items that support Enbridge's 2016 rates.

Appendix C is a Draft Rate Order for interim rates effective as of January 1, 2016. The Draft Rate Order reflects Enbridge's Application, as updated to take account of the adjustments set out in this Settlement Proposal.

Also included, as Appendix D, is Enbridge's Draft Accounting Order for 2016.

The parties request that the Board consider and approve this Settlement Proposal, including the Draft Rate Order and the Draft Accounting Order, in sufficient time to permit the new interim 2016 rates to be implemented in conjunction with Enbridge's January 1, 2016 QRAM Application.

After the Board issues its Decision on Enbridge's 2016 DSM budget in EB-2015-0049, then Enbridge will update its 2016 Allowed Revenue and rates to reflect the full-year impact of the difference between the approved 2016 DSM budget and the 2015 DSM budget that is being included in 2016 Allowed Revenue and rates as an interim amount. The parties agree that this change will be implemented into Enbridge's 2016 final rates as part of its next QRAM Application following the Board's Decision in EB-2015-0049.

APPENDIX A : 2016 TEST YEAR ALLOWED REVENUE AND SUFFICIENCY/DEFICIENCY

ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY)
2016 TEST YEAR

Line No.		Col. 1 EB-2012-0459 Total 2016 Allowed Revenue Placeholder ($Millions)	Col. 2 2016 Required Updates ($Millions)	Col. 3 Total Final 2016 Test Year Allowed Revenue ($Millions)	Col. 4 2016 Settlement Proposal Adjustments	Col. 5 Adjusted Total Final 2016 Test Year Allowed Revenue ($Millions)	Col. 6 Explanation See Page 2	Col. 7 Evidence Exhibit Reference
	Cost of capital							
1.	Rate base	5,696.0	116.3	5,812.3	(4.8)	5,807.5	a)	B Series of Exhibits
2.	Required rate of return	7.00	(0.63)	6.37	0.03	6.40	b)	E Series of Exhibits
3.		398.6	(28.3)	370.3	1.6	371.9		
	Cost of service							
4.	Gas costs	1,632.5	134.8	1,767.3	(2.5)	1,764.8	c)	D1-1-1 and D1-2-1 to D1-2-8
5.	Operation and maintenance	431.1	32.6	463.7	(28.5)	435.2	d)	D1-1-1 and D1-3-1 to D1-5-1
6.	Depreciation and amortization	288.9	-	288.9	-	288.9		
7.	Fixed financing costs	1.9	-	1.9	-	1.9		
8.	Municipal and other taxes	45.5	-	45.5	-	45.5		
9.		2,399.9	167.4	2,567.3	(31.0)	2,536.3		
	Misc. operating and non-operating revenue							
10.	Other operating revenue	(42.7)	-	(42.7)	-	(42.7)		
11.	Interest and property rental	-	-	-	-	-		
12.	Other income	(0.1)	-	(0.1)	-	(0.1)		
13.		(42.8)	-	(42.8)	-	(42.8)		
	Income taxes on earnings							
14.	Excluding tax shield	47.1	(3.9)	43.2	7.8	51.0	e)	D1-1-1 and D1-6-1 to D1-6-2
15.	Tax shield provided by interest expense	(49.6)	2.6	(47.0)	(0.2)	(47.2)	e)	D1-1-1 and D1-6-1 to D1-6-2
16.		(2.5)	(1.3)	(3.8)	7.6	3.8		
	Taxes on sufficiency / (deficiency)							
17.	Gross sufficiency / (deficiency)	(77.9)	(25.8)	(103.7)	28.7	(75.0)		
18.	Net sufficiency / (deficiency)	(57.3)	(19.0)	(76.2)	21.1	(55.2)		
19.		20.6	6.8	27.5	(7.6)	19.9	e)	D1-1-1 and D1-6-1 to D1-6-2
20.	**Sub-total revenue requirement**	2,773.8	144.6	2,918.5	(29.4)	2,889.1		
21.	Customer Care Rate Smoothing V/A Adjustment	0.8	-	0.8	-	0.8		
22.	**Allowed revenue**	2,774.6	144.6	2,919.3	(29.4)	2,889.9		
	Revenue at existing Rates							
23.	Gas sales	2,464.5	85.5	2,550.0	(0.6)	2,549.4	f)	C Series of Exhibits
24.	Transportation service	217.1	42.2	259.3	-	259.3	f)	C Series of Exhibits
25.	Transmission, compression and storage	1.8	0.1	1.9	-	1.9		
26.	Rounding adjustment	-	0.1	0.1	(0.1)	-		
27.	Revenue at existing rates	2,683.4	127.9	2,811.3	(0.7)	2,810.6		
28.	**Gross revenue sufficiency / (deficiency)**	(91.2)	(16.7)	(108.0)	28.7	(79.3)		F Series of Exhibits

App.B Pg.1 Ref.	Required updates to 2016 Placeholder Allowed Revenue per Appendix E of the EB-2012-0459 Final Rate Order
a)	Adjustment to rate base arising from the gas cost and O&M updates and the related impact on gas in storage and working cash
b)	Adjustment to forecast cost of capital rates, based upon the updated forecast ROE and updated forecast cost of debt
c)	Adjustment to forecast gas cost based upon the updated gas cost forecast and the 2016 gas volume forecast
d)	Adjustment to O&M in relation to updated forecasts of DSM, Pension/OPEB, and CIS/Customer Care costs
e)	Adjustment to income taxes in relation to all other Board required / permitted adjustments to achieve final 2016 Allowed Revenue
f)	Adjustment to revenue forecasts resulting from updating the 2016 volume forecast and use of July 1, 2015 Board Approved rates

APPENDIX B : SETTLEMENT PROPOSAL FINANCIAL STATEMENTS

ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY)
2016 FISCAL YEAR

Line No.		Col. 1 As Filed Excl. CIS 2016 Allowed Revenue ($Millions)	Col. 2 As Filed CIS 2016 Allowed Revenue ($Millions)	Col. 3 As Filed Total 2016 Allowed Revenue ($Millions)	Col. 4 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 5 CIS Settlement Proposal Adjustments ($Millions)	Col. 6 Adjusted 2016 Allowed Revenue Excl. CIS ($Millions)	Col. 7 Adjusted 2016 CIS Allowed Revenue ($Millions)	Col. 8 Total Adjusted 2016 Allowed Revenue ($Millions)
	Cost of capital								
1.	Rate base	5,779.9	32.4	5,812.3	(4.8)	-	5,775.1	32.4	5,807.5
2.	Required rate of return	6.37	6.44	6.37	0.03	-	6.40	6.44	6.40
3.		368.2	2.1	370.3	1.6	-	369.8	2.1	371.9
	Cost of service								
4.	Gas costs	1,767.3	-	1,767.3	(2.5)	-	1,764.8	-	1,764.8
5.	Operation and maintenance	364.4	99.3	463.7	(28.5)	-	335.9	99.3	435.2
6.	Depreciation and amortization	276.2	12.7	288.9	-	-	276.2	12.7	288.9
7.	Fixed financing costs	1.9	-	1.9	-	-	1.9	-	1.9
8.	Municipal and other taxes	45.5	-	45.5	-	-	45.5	-	45.5
9.		2,455.3	112.0	2,567.3	(31.0)	-	2,424.3	112.0	2,536.3
	Miscellaneous operating and non-operating revenue								
10.	Other operating revenue	(42.7)	-	(42.7)	-	-	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	-	(0.1)	-	(0.1)
13.		(42.8)	-	(42.8)	-	-	(42.8)	-	(42.8)
	Income taxes on earnings								
14.	Excluding tax shield	35.3	7.9	43.2	7.8	-	43.1	7.9	51.0
15.	Tax shield provided by interest expense	(46.6)	(0.4)	(47.0)	(0.2)	-	(46.8)	(0.4)	(47.2)
16.		(11.3)	7.5	(3.8)	7.6	-	(3.7)	7.5	3.8
	Taxes on sufficiency / (deficiency)								
17.	Gross sufficiency / (deficiency)	(103.7)	-	(103.7)	28.7	-	(75.0)	-	(75.0)
18.	Net sufficiency / (deficiency)	(76.2)	-	(76.2)	21.1	-	(55.2)	-	(55.2)
19.		27.5	-	27.5	(7.6)	-	19.9	-	19.9
20.	**Sub-total revenue requirement**	2,796.9	121.6	2,918.5	(29.4)	-	2,767.5	121.6	2,889.1
21.	Customer Care Rate Smoothing V/A Adjustment	-	0.8	0.8	-	-	-	0.8	0.8
22.	**Allowed revenue**	2,796.9	122.4	2,919.3	(29.4)	-	2,767.5	122.4	2,889.9
	Revenue at existing Rates								
23.	Gas sales	2,446.5	103.5	2,550.0	(0.6)	-	2,445.9	103.5	2,549.4
24.	Transportation service	244.7	14.6	259.3	-	-	244.7	14.6	259.3
25.	Transmission, compression and storage	1.9	-	1.9	-	-	1.9	-	1.9
26.	Rounding adjustment	0.1	-	0.1	(0.1)	-	-	-	-
27.	Revenue at existing rates	2,693.2	118.1	2,811.3	(0.7)	-	2,692.5	118.1	2,810.6
28.	**Gross revenue sufficiency / (deficiency)**	(103.7)	(4.3)	(108.0)	28.7	-	(75.0)	(4.3)	(79.3)

EXPLANATION OF ADJUSTMENTS TO UTILITY INCOME
2016 FISCAL YEAR

Line No. Adj'd	Adjustments ($Millions)	Explanation
1.	(4.8)	Rate base
		The column 4 decrease results from the allocation of $5.6 million in base pressure gas to Unregulated Storage operations, as described in the Settlement Proposal, partially offset by a $0.8 million increase in working cash allowance resulting from the gas cost and operation and maintenance cost adjustments described below.
3.	1.6	Cost of capital
		The column 4 increase results from an increase in the required rate of return, which has been updated to reflect the 2016 Board determined ROE of 9.19%, and to reflect the capital structure updates described in Adjustment 4 of the Settlement Proposal. The increase in the cost of capital resulting from the increase in the required rate of return was partially offset by the reduction in rate base described above.
4.	(2.5)	Gas costs
		The column 4 decrease results from the removal of community expansion volumes ($0.4 million), as described in Adjustment 2 of the Settlement Proposal, a reduction in unaccounted for volumes ($1.5 million), as described in Adjustment 1 of the Settlement Proposal, and a reduction in lost and unaccounted for volumes reflecting the allocation to Unregulated Storage operations ($0.7 million), as described in the Settlement Proposal.
5.	(28.5)	Operation and maintenance
		The column 4 decrease results from the reduction in DSM operation and maintenance costs to reflect the amount included within 2015 approved rates, as described in Adjustment 3 of the Settlement Proposal.
16.	7.6	Income taxes on earnings
		The column 4 increase is due to a higher taxable income resulting from the impact of the Settlement Proposal partially offset by a higher interest tax shield resulting from the capital structure adjustments described in Adjustment 4 of the Settlement Proposal.
23.	(0.6)	Gas sales
		The column 4 decrease results from the removal of community expansion volumes, as described in Adjustment 2 of the Settlement Proposal.

UTILITY RATE BASE
2016 FISCAL YEAR

Line No.		Col. 1 As Filed Excl. CIS Rate Base ($Millions)	Col. 2 As Filed CIS Rate Base ($Millions)	Col. 3 As Filed Total 2016 Rate Base ($Millions)	Col. 4 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 5 CIS Settlement Proposal Adjustments ($Millions)	Col. 6 Adjusted 2016 Rate Base Excl. CIS ($Millions)	Col. 7 Adjusted 2016 CIS Rate Base ($Millions)	Col. 8 Total Adjusted 2016 Rate Base ($Millions)
	Property, Plant, and Equipment								
1.	Cost or redetermined value	8,427.5	127.1	8,554.6	(5.6)	-	8,421.9	127.1	8,549.0
2.	Accumulated depreciation	(3,011.1)	(94.7)	(3,105.8)	-	-	(3,011.1)	(94.7)	(3,105.8)
3.		5,416.4	32.4	5,448.8	(5.6)	-	5,410.8	32.4	5,443.2
	Allowance for Working Capital								
4.	Accounts receivable rebillable projects	1.4	-	1.4	-	-	1.4	-	1.4
5.	Materials and supplies	34.6	-	34.6	-	-	34.6	-	34.6
6.	Mortgages receivable	-	-	-	-	-	-	-	-
7.	Customer security deposits	(64.6)	-	(64.6)	-	-	(64.6)	-	(64.6)
8.	Prepaid expenses	1.0	-	1.0	-	-	1.0	-	1.0
9.	Gas in storage	391.1	-	391.1	-	-	391.1	-	391.1
10.	Working cash allowance	-	-	-	0.8	-	0.8	-	0.8
11.	Total Working Capital	363.5	-	363.5	0.8	-	364.3	-	364.3
12.	Utility Rate Base	5,779.9	32.4	5,812.3	(4.8)	-	5,775.1	32.4	5,807.5

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2016 FISCAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		Reference	Disburs-ements ($Millions)	Net Lag-Days (Days)	Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,808.5	2.1	10.4
2.	Items not subject to working cash allowance (Note 1)		(43.7)		
3.	Gas costs charged to operations		1,764.8		
4.	Operation and Maintenance		335.9		
5.	Less: Storage costs		(8.4)		
6.	Operation and maintenance costs subject to working cash		327.5		
7.	Ancillary customer services		-		
8.			327.5	(10.9)	(9.8)
9.	Sub-total				0.6
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				(1.2)
14.	Total working cash allowance				0.8

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 As Filed Excl. CIS 2016 Utility Income ($Millions)	Col. 2 As Filed CIS 2016 Utility Income ($Millions)	Col. 3 As Filed Total 2016 Utility Income ($Millions)	Col. 4 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 5 CIS Settlement Proposal Adjustments ($Millions)	Col. 6 Adjusted 2016 Utility Income Excl. CIS ($Millions)	Col. 7 Adjusted 2016 CIS Utility Income ($Millions)	Col. 8 Total Adjusted 2016 Utility Income ($Millions)
1.	Gas sales	2,446.5	103.5	2,550.0	(0.6)	-	2,445.9	103.5	2,549.4
2.	Transportation of gas	244.7	14.6	259.3	-	-	244.7	14.6	259.3
3.	Transmission, compression and storage revenue	1.9	-	1.9	-	-	1.9	-	1.9
4.	Other operating revenue	42.7	-	42.7	-	-	42.7	-	42.7
5.	Interest and property rental	-	-	-	-	-	-	-	-
6.	Other income	0.1	-	0.1	-	-	0.1	-	0.1
7.	Total operating revenue	2,735.9	118.1	2,854.0	(0.6)	-	2,735.3	118.1	2,853.4
8.	Gas costs	1,767.3	-	1,767.3	(2.5)	-	1,764.8	-	1,764.8
9.	Operation and maintenance	364.4	99.3	463.7	(28.5)	-	335.9	99.3	435.2
10.	Depreciation and amortization expense	276.2	12.7	288.9	-	-	276.2	12.7	288.9
11.	Fixed financing costs	1.9	-	1.9	-	-	1.9	-	1.9
12.	Municipal and other taxes	45.5	-	45.5	-	-	45.5	-	45.5
13.	Interest and financing amortization expense	-	-	-	-	-	-	-	-
14.	Other interest expense	-	-	-	-	-	-	-	-
15.	Total costs and expenses	2,455.3	112.0	2,567.3	(31.0)	-	2,424.3	112.0	2,536.3
16.	Ontario utility income before income taxes	280.6	6.1	286.7	30.4	-	311.0	6.1	317.1
17.	Income tax expense	(11.3)	7.5	(3.8)	7.6	-	(3.7)	7.5	3.8
18.	Utility net income	291.9	(1.4)	290.5	22.8	-	314.7	(1.4)	313.3

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

Line No.		Col. 1 As Filed Excl. CIS 2016 Utility Tax ($Millions)	Col. 2 Excl. CIS Settlement Proposal Adjustments ($Millions)	Col. 3 Adjusted 2016 Excl. CIS Utility Tax ($Millions)
1.	Utility income before income taxes	280.6	30.4	311.0
	Add			
2.	Depreciation and amortization	276.2	-	276.2
3.	Accrual based pension and OPEB costs	34.6	-	34.6
4.	Other non-deductible items	1.0	-	1.0
5.	Total Add Back	311.8	-	311.8
6.	Sub total	592.4	30.4	622.8
	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	3.0	-	3.0
11.	Amortization of share/debenture issue expense	1.1	1.1	2.2
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	83.9	-	83.9
15.	Cash based pension and OPEB costs	7.1	-	7.1
16.	Total Deduction - Federal	462.5	1.1	463.6
17.	Total Deduction - Provincial	462.5	1.1	463.6
18.	Taxable income - Federal	129.9	29.3	159.2
19.	Taxable income - Provincial	129.9	29.3	159.2
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	19.5	4.4	23.9
23.	Income tax provision - Provincial	14.9	3.4	18.3
24.	Income tax provision - combined	34.4	7.8	42.2
25.	Part V1.1 tax	0.9	-	0.9
26.	Total taxes excluding tax shield on interest expense	35.3	7.8	43.1
	Tax shield on interest expense			
27.	Rate base	5,779.9	(4.8)	5,775.1
28.	Return component of debt	3.05%	0.01%	3.06%
29.	Interest expense	176.0	0.7	176.7
30.	Combined tax rate	26.50%	0.00%	26.50%
31.	Income tax credit	(46.6)	(0.2)	(46.8)
32.	Total income taxes	(11.3)	7.6	(3.7)

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
		($Millions)	%	%	%
1.	Long term debt	3,546.1	61.40	4.96	3.045
2.	Short term debt	50.0	0.87	1.57	0.014
3.		3,596.1	62.27		3.059
4.	Preference shares	100.0	1.73	2.16	0.037
5.	Common equity	2,079.0	36.00	9.19	3.308
6.		5,775.1	100.00		6.404
7.	Utility income	($Millions)			314.7
8.	Rate base	($Millions)			5,775.1
9.	Indicated rate of return				5.449%
10.	(Deficiency) in rate of return				(0.955)%
11.	Net (deficiency)	($Millions)			(55.2)
12.	Gross (deficiency)	($Millions)			(75.0)
13.	Customer Care/CIS deficiency	($Millions)			(4.3)
14.	Total gross (deficiency)	($Millions)			(79.3)
15.	Revenue at existing rates	($Millions)			2,810.6
16.	Allowed revenue	($Millions)			2,889.9
17.	Total gross revenue (deficiency)	($Millions)			(79.3)

APPENDIX “C”

ATTACHMENT 2 – 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 (17^{th}) 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	**9.4875 ¢/m³**
For the next 55 m³ per month	**8.9671 ¢/m³**
For the next 85 m³ per month	**8.5598 ¢/m³**
For all over 170 m³ per month	**8.2561 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.1312 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**9.1697 ¢/m³**
For the next 1050 m³ per month	**7.3212 ¢/m³**
For the next 4500 m³ per month	**6.0268 ¢/m³**
For the next 7000 m³ per month	**5.1950 ¢/m³**
For the next 15250 m³ per month	**4.8255 ¢/m³**
For all over 28300 m³ per month	**4.7328 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.1566 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**10.6911 ¢/m³**
For all over 20,000 m³ per month	**10.0080 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.0894 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**0.1660 ¢/m³**
Gas Supply Load Balancing Charge	**1.3216 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.1566 ¢/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.

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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**0.6564 ¢/m³**
For all over 1,000,000 m³ per month	**0.5064 ¢/m³**
Gas Supply Load Balancing Charge	**0.2622 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.0894 ¢/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.

MINIMUM BILL:

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

7.1394 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**0.2629 ¢/m³**
For all over 1,000,000 m³ per month	**0.1629 ¢/m³**
Gas Supply Load Balancing Charge	**0.0946 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.0894 ¢/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.

MINIMUM BILL:

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

6.5783 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**9.0545 ¢/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	**0.30 ¢/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***.**

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.

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 = 0.9396 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 1.1275 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.

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 1.0589 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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

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	**6.8538 ¢/m³**	**2.1538 ¢/m³**
For the next 28,000 m³ per month	**5.6538 ¢/m³**	**1.4538 ¢/m³**
For all over 42,000 m³ per month	**5.2538 ¢/m³**	**1.2538 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.1002 ¢/m³**	**12.1002 ¢/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	**26.2184 ¢/m^3**
January and February	**65.5460 ¢/m^3**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **9.9413 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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 Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.6806 ¢/m³**
For the next 28,000 m³ per month	**1.3216 ¢/m³**
For all over 42,000 m³ per month	**0.7626 ¢/m³**
Gas Supply Load Balancing Charge	**0.5805 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.0930 ¢/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**

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):	**9.4819 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**0.4465 ¢/m³**
For all over 1,000,000 m³ per month	**0.2465 ¢/m³**
Gas Supply Load Balancing Charge	**0.2764 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.0894 ¢/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**

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):	**6.9438 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**1.1516 ¢/m³**
Gas Supply Load Balancing Charge	**1.1522 ¢/m³**
Transportation Charge per cubic metre	**6.2554 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**12.0894 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**12.0684 ¢/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**

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):	**8.5246 ¢/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, 2016 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates as the Board Order, EB-2015-0242, effective October 1, 2015.

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	**25.6543 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3343 ¢/m³**
Maximum Delivery Charge	**1.0121 ¢/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.

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 0.9396 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 1.1275 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.

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 0.6725 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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

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	**0.0479 ¢/m³**
Monthly Storage Deliverability Demand Charge	**22.4303 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.3162 ¢/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.

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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

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 $1/24^{th}$ 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	**0.0479 ¢/m³**
Monthly Storage Deliverability Demand Charge	**5.0657 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.0877 ¢/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.

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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

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	**18.8677 ¢/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, 2016 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242, effective October 1, 2015.

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	**0.2022**	**0.1905**
Maximum Daily Withdrawal Volume	**22.2507**	**21.1873**
Commodity Charge	**0.9465**	**0.1570**

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.

	Excess Volume Charge $/10³m³ / Year	Overrun Charge $/10³m³ / Day
Transmission & Compression		
Authorized	**2.6695**	**0.7315**
Unauthorized	**-**	**293.7093**
Pool Storage		
Authorized	**2.5148**	**0.6966**
Unauthorized	**-**	**279.6719**

(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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

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	
	$/10^3m^3$	$/10^3m^3$	$/10^3m^3$
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.3927**	**0.3927**	**-**
Maximum	**1.9637**	**1.9637**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**43.4380**	**34.7504**	**-**
Maximum	**217.1898**	**173.7519**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**1.1035**	**1.1035**	**0.4063**
Maximum	**5.5177**	**5.5177**	**41.1539**

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.

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		Short Cycle
	Firm	**Interruptible**	
	$\$/10^3m^3$	**$\$/10^3m^3$**	**$\$/10^3m^3$**
Authorized Overrun **Annual Turnover Volume** **Negotiable, not to exceed:**	**41.1539**	**41.1539**	**41.1539**
Authorized Overrun **Daily Injection/Withdrawal** **Negotiable, not to exceed:**	**41.1539**	**41.1539**	**41.1539**
Unauthorized Overrun **Annual Turnover Volume** **Excess Storage Balance**			
September 1 - November 30	**411.5391**	**411.5391**	**411.5391**
December 1 - October 31	**41.1539**	**41.1539**	**41.1539**
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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

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, 2016, shall apply in respect of FT and IT Service under this Rate Schedule:

	Demand Rate $\$/10^3m^3$	**Commodity Rate** $\$/10^3m^3$
FT Service	**5.6430**	**-**
IT Service	**-**	**0.2230**

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.

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

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 January 1, 2016:

Point of Acceptance	Firm Transportation (FT)
CDA, EDA	6.2554 ¢/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.

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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

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 January 1, 2016. This rate schedule is effective January 1, 2016 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2015 and that indicates the Board Order, EB-2015-0242 effective October 1, 2015.

RIDER: D	SITE RESTORATION COST CLEARANCE

The following adjustment is applicable to volumes during the period of January 1, 2016 to December 31, 2016.

Bundled Services

Rate Class	(¢/m³)
Rate 1	(1.2315)
Rate 6	(0.4373)
Rate 9	(0.1838)
Rate 100	(0.4373)
Rate 110	(0.1396)
Rate 115	(0.1078)
Rate 135	(0.0126)
Rate 145	(0.0829)
Rate 170	(0.0280)
Rate 200	(0.0914)

Unbundled Services

Rate Class	(¢/m³)
Rate 125 - per m³ of contract demand	(0.9120)
Rate 300 - per m³ of contract demand	(3.0640)
Rate 300 (Interruptible)	(0.0788)

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

	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
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) and Third Party Services (damages investigation and repair)

Labour Hourly Charge-Out Rate Other Services (including ad-hoc customer requests and charges to customers and third parties for responding, investigating and repairing damages to Company facilities)	$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

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	$0.5518	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.

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”

ATTACHMENT 3 – SUPPORTING DOCUMENTATION

DOCUMENTATION FOR WORKING PAPERS SUPPORTING THE DRAFT RATE ORDER: EB-2015-0114

The attached working papers provide support for the Rate Handbook filed as Attachment 2 to the Draft Rate Order. The Rate Handbook reflects the Settlement Proposal dated December 1, 2015 under EB-2015-0114, Exhibit N1, Tab 1.

The rates shown in the Rate Handbook are designed to recover the revenue requirement stemming from the EB-2015-0114 Settlement Proposal and incorporate the July 1, 2015 (EB-2015-0163) rates as the base rates. As per the Minimum Filing Requirements, July 1, 2015 QRAM rates were the most recent rates approved by the OEB at the time the Company filed its 2016 rates application.

The EB-2015-0114 Settlement Proposal results in a revenue deficiency of $79.3. million as outlined in Exhibit N1, Tab 1, Schedule 1, Appendix A, Page 2, line 28. The impact on revenues is as follows:

	($'000)	Reference: Draft Rate Order
Revenue at Existing Rates (EB-2015-0163)	2,812.1	H2, T2, S1, Including DPAC
Revenue Requirement (EB-2015-0114)	2,891.4	H2, T2, S1, Including DPAC
Gross Revenue Deficiency	(79.3)	

The working papers are laid out as follows:

H2: Design of Rates using Fully Allocated Cost Study (FACS) shown at G2
G2: Fully Allocated Cost Study (FACS)

Description of H2 Exhibits

The rates shown in the H2 exhibits are designed to recover the revenue requirement in the EB-2015-0114 Settlement Proposal using the fully allocated cost study as a guide.

All exhibits in the H2 series follow the same format as in previous rate filings and rate orders and are listed below:

a) Tab 1, Schedule 1 of this exhibit summarizes, by rate class, and rate component, the revenues at existing base rates (EB-2015-0163) QRAM and 2016 Settlement Proposal rates found in EB-2015-0114. The forecast of billed revenues at 2016 base rates (EB-2015-0163) is shown in columns 1 through 5. The billed revenues at the 2016 Settlement Proposal rates are shown in columns 11 through 15.

b) The net change in revenue, or the revenue deficiency/sufficiency, by component, is shown in columns 6 to 10. The total in column 10 indicates the forecast revenue deficiency that will be recovered from billed revenues. Schedule 2 displays the revenue requirement, unit rates and associated volumes by rate class and component.

c) The Tab 2 schedule summarizes the revenues shown in Schedule 1 and presents the unbilled revenues at EB-2015-0163 base rates and 2016 Settlement Proposal rates to yield calendar year revenues.

d) The schedules at Tab 3 compares the unit rates from EB-2015-0163 Base to the 2016 Settlement Proposal unit rates.

e) Exhibits under Tab 4 show the derivation of gas supply commodity, gas supply load balancing rates and transportation rates from the cost allocated to the rate classes in the FACS which is found at Exhibit G2. The derivation of the Seasonal credits is found at page 3.

f) The schedules under Tab 5 show the detailed revenue calculations by rate class.

g) Annual bill comparisons indicating the impact of the 2016 Settlement Proposal rates on typical customers relative to the base EB-2015-0163 rates are shown at Tab 7, Schedule 1.

   Table 1 below provides a summary of the average rate impacts by rate class. Rate impacts for customers taking service under bundled rates are expressed on a T-service basis (i.e. total bill excluding gas supply charges). Rate impacts for customers taking unbundled rates are expressed on a delivery rate basis. Column 1 below depicts the 2016 average rate impact for each customer class on a T-Service basis as filed by the Company. Column 2 below depicts the 2016 average rate impact for each customer class on a T-Service basis as a result of the Settlement Agreement.

Table 1: Summary of Average Rate Impact by Customer Rate Class

	Col. 1	Col. 2
	As Filed	**Settlement Proposal**
Rate Class	**T-Service Rate Impact**	**T-Service Bill Impact**
1	5.8%	4.3%
6	5.7%	4.1%
9	3.2%	1.1%
100	2.0%	1.7%
110	2.5%	1.9%
115	1.7%	1.1%
135	2.8%	2.3%
145	2.5%	1.9%
170	1.7%	1.4%
200	3.3%	2.9%
	Delivery Rate	Delivery Rate
125	9.9%	9.9%
300	3.0%	3.0%

Average residential bill impact resulting from the Settlement Agreement is approximately $25 annually (versus approximately $34 annually based on the pre-filed evidence).

Description of Cost Allocation (G2) Exhibits

The G2 exhibits, also referred to as the Fully Allocated Cost Study (“FACS”), allocate the test year revenue requirement to the customer rate classes.

All G2 series exhibits have been updated to reflect the impact of agreed-upon adjustments as per the Settlement Proposal, under EB-2015-0114, Exhibit N1, Tab 1.

The cost of service total of $2,891.4 million shown at Exhibit G2, Tab 2, Schedule 1, page 1, Line 4, Column 1 equals revenues at existing rates of $2,812.1 million (Exhibit H2, Tab 2, Schedule 1, Page 1, Line 17, Column 4) plus a gross deficiency in the amount of $79.3 million (Exhibit H2, Tab 2, Schedule 1, Page 1, Line 17, Column 8).

The updated G2 exhibits in this filing reflect the following adjustments as requested in the Settlement Proposal:

a) Decrease to volume and gas costs to reflect reversion to prior Unaccounted for Gas (“UAF”) forecasting methodology
b) Decrease to volume, customer numbers, and gas costs to reflect removal of remote community expansion program customers
c) Decrease to DSM costs to reflect the interim use of the 2015 DSM budget, pending OEB decision in EB-2015-0049
d) Increase to return and taxes to reflect changes to ROE, cost of capital, and income tax on earnings
e) Updated allocation of base pressure gas and Lost and Unaccounted for Gas (“LUF”) between regulated and unregulated storage operations

With respect to parts a) and b) above, the total change in volume in the Settlement Proposal, as compared to the Original Filing, is equal to a decrease of 13,051.5 10^3m^3, as seen at Exhibit G2, Tab 6, Schedule 2, Page 1, Line 8, Column 1. This decrease is the sum of: a decrease in UAF volume equal to 7,749.0 10^3m^3; a decrease in LUF volume of 3,398.2 10^3m^3; and a decrease in delivery volumes associated with removal of community expansion program customer forecast, equal to 1,904.3 10^3m^3. Changes to UAF and LUF are embedded within the Exhibits, and will be further addressed in Table 1, below. The decrease in delivery volume resulting from removal of community expansion program customers can be referenced at Exhibit G2, Tab 6, Schedule Page 1, Line 1.3, Column 1.

Further details on the proposed adjustments can be referenced in Exhibit N1, Tab 1, Schedule 1, Pages 11 to15.

The deficiency at the Original Filing was $108.0 million. Adjustments from the Settlement Proposal reduce the deficiency to $79.3 million as follows:

Sufficiency / (Deficiency) at Original Filing	(108.0)
Adjustment from Settlement Proposal	28.7
Sufficiency / (Deficiency) at the Settlement Proposal	(79.3)
Adjustments to Return and Taxes	(1.8)
Adjustments to Tecumseh Return and Taxes	0.3
Adjustments to O&M	28.5
Adjustments to Gas Costs	2.5
Adjustments to Revenues	(0.7)
Subtotal of Adjustments (Reduction to Deficiency)	28.7
Deficiency outcome to be Recovered in Rates Effective Jan. 01, 2016	(79.3)

The adjustments to Return and Taxes, Gas Costs, and Revenues reflect the specific impacts of the Settlement Proposal.

The following three tables illustrate how the adjustments were made in the FACS to capture sufficiency/deficiency consequences from the Settlement Proposal.

Table 1: Adjustments to Gas Costs

#	Item	Settlement Proposal	Reference
1.1	Gas Costs	(1.9) [1]	G2/T6/S2/P1/L10.1/C11
1.2	LUF	(0.7) [2]	G2/T6/S2/P1/L9.2/C11 & G2/T7/S3/P1/L2.1.6
2.0	Total	(2.5)	

Notes:

(1) The decrease of $1.9 million corresponds to a decrease of 7,749.0 10^3m^3 (in UAF volumes), and a decrease of 1,904.3 10^3m^3 (reflecting remote community volume removal), at the PGVA reference price of $196.253/$10^3m^3$

(2) The decrease of $0.7 million corresponds to a decrease in LUF volume of 3,398.2 10^3m^3, at the PGVA reference price of $196.253/$10^3m^3$

Table 2: Adjustments to Return and Taxes

#	Item	Settlement Proposal	Reference
1.0	Return & Taxes	1.8	G2/T5/S2/P1/L7/C2 & G2/T5/S3/P1/L6/C3
2.0	Total	1.8	

Table 3: Adjustments to Tecumseh Return and Taxes

#	Item	Settlement Proposal	Reference
1.1	Base Pressure Gas	(0.4)	G2/T7/S1/P1/L2.7/C1 [1]
1.2	Return (cost of capital)	0.1	
2.0	Total	(0.3)	G2/T7/S2/P1/L1.1/C1

Notes:

(1) This note references the decrease in Base Pressure Gas Rate Base shown at G2/T7/S1/P1/L2.7/C1 and the associated impact on return shown at G2/T7/S2/P1/L1.1/C1.

Table 4: Adjustments to O&M

#	Item	Settlement Proposal	Reference
1.0	DSM – Program & General	(28.5)	G2/T6/S4/P1
2.0	Total	(28.5	

The G2 exhibits provided in this filing follow the same format as in previous rate filings or rate orders:

a) Tab 2 exhibits provide a summary of the FACS results. They outline the allocation of the proposed revenue requirement, return on the allocated rate base and the revenue to cost ratio by rate class.

b) Tab 3 exhibits functionalize rate base, working capital, net investment, and O&M costs into similar operating functions to facilitate identification of costs that are associated with a distinct aspect of the Company. The functionalization of costs allows for consistent treatment of similar costs.

c) Tab 4 exhibits classify the functionalized costs into categories that vary between rate classes by an identifiable factor or allocator. In this step the costs are classified to three general cost groups based on whether they vary with volumetric demands, peak demands, or other customer specific demands. The costs are further sub-classified within these three broad categories of classification when required.

d) Tab 5 exhibits allocate the classified cost to each customer rate class based on allocation factors that are referenced on the exhibits.

e) Tab 6 exhibits provide rate base, working capital and net investment functionalization factors, classify transportation and storage costs and gas costs to operations, and provide cost of service allocation factors and allocation percentages.

f) Tab 7 exhibits provide functionalization and classification of costs for Tecumseh Gas. These costs are then used to charge back storage costs to Enbridge Gas Distribution’s in-franchise customers and to derive ex-franchise storage rates.

REVENUE COMPARISON - CURRENT METHODOLOGY vs PROPOSED METHODOLOGY BY RATE CLASS AND COMPONENT ($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		REVENUE - EB-2015-0163 Q3 RATES					(SUFFICIENCY) / DEFICIENCY					REVENUE - EB-2015-0114 INTERIM RATES				
ITEM NO.	RATE NO.	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL	DISTRIB'TN	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	789,083	288,951	55,093	549,354	1,682,481	33,761	866	13,657	(2,174)	46,110	822,844	289,817	68,750	547,180	1,728,591
2.	6	354,602	229,647	50,026	379,000	1,013,275	14,374	688	13,344	(1,556)	26,851	368,976	230,335	63,370	377,444	1,040,126
3.	9	74	28	0	55	156	0	0	0	(0)	0	74	28	0	54	157
4.	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.	110	15,503	15,395	1,435	9,859	42,192	622	46	409	(31)	1,046	16,125	15,441	1,844	9,828	43,238
6.	115	5,786	1,356	418	0	7,560	238	4	71	0	313	6,025	1,360	489	0	7,874
7.	125	9,849	0	0	0	9,849	976	0	0	0	976	10,825	0	0	0	10,825
8.	135	950	1,929	(499)	457	2,836	83	6	0	(1)	88	1,033	1,934	(499)	456	2,924
9.	145	1,851	1,508	(55)	1,371	4,676	40	5	84	(14)	114	1,891	1,513	29	1,357	4,790
10.	170	2,851	5,611	(3,084)	4,135	9,513	166	17	59	(13)	229	3,017	5,628	(3,026)	4,122	9,742
11.	200	4,217	10,297	1,266	15,657	31,437	(71)	31	501	(49)	412	4,145	10,328	1,766	15,609	31,848
12.	300	172	0	0	0	172	13	0	0	0	13	185	0	0	0	185
13. SUB-TOTAL		1,184,938	554,721	104,600	959,888	2,804,148	50,203	1,663	28,123	(3,837)	76,152	1,235,141	556,384	132,724	956,051	2,880,300
14. STORAGE		1,895	0	0	0	1,895	(95)	0	0	0	(95)	1,800	0	0	0	1,800
15. DPAC		1,486	0	0	0	1,486	0	0	0	0	0	1,486	0	0	0	1,486
16. 332		0	0	0	0	0	4,893	0	0	0	4,893	4,893	0	0	0	4,893
17. TOTAL		1,188,319	554,721	104,600	959,888	2,807,529	55,001	1,663	28,123	(3,837)	80,950	1,243,320	556,384	132,724	956,051	2,888,479

PROPOSED VOLUMES AND REVENUE RECOVERY BY RATE CLASS ($000)

		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
		DISTRIBUTION			GAS SUPPLY TRANSPORTATION			GAS SUPPLY LOAD BALANCING			GAS SUPPLY COMMODITY			TOTAL
ITEM NO.	RATE NO.	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	REVENUES
		10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	$000
1.	1	4,869,333	822,844	16.90	4,633,078	289,817	6.26	4,869,333	68,750	1.41	4,510,521	547,180	12.13	1,728,591
2.	6	4,794,977	368,976	7.70	3,682,184	230,335	6.26	4,794,977	63,370	1.32	3,104,852	377,444	12.16	1,040,126
3.	9	510	74	14.55	450	28	6.26	510	0	0.02	450	54	12.09	157
4.	100	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0
5.	110	703,348	16,125	2.29	246,846	15,441	6.26	703,348	1,844	0.26	81,295	9,828	12.09	43,238
6.	115	517,078	6,025	1.17	21,737	1,360	6.26	517,078	489	0.09	0	0	0.00	7,874
7.	125	0	10,825	0.00	0	0	0.00	0	0	0.00	0	0	0.00	10,825
8.	135	59,278	1,033	1.74	30,925	1,934	6.26	59,278	(499)	(0.84)	3,768	456	12.10	2,924
9.	145	88,566	1,891	2.14	24,187	1,513	6.26	88,566	29	0.03	11,222	1,357	12.09	4,790
10.	170	325,657	3,017	0.93	89,965	5,628	6.26	325,657	(3,026)	(0.93)	34,100	4,122	12.09	9,742
11.	200	170,837	4,145	2.43	165,105	10,328	6.26	170,837	1,766	1.03	129,109	15,609	12.09	31,848
12.	300	34,992	185	0.00	0	0	0.00	0	0	0.00	0	0	0.00	185
13	SUB-TOTAL	11,564,575	1,235,141	10.68	8,894,477	556,384	6.26	11,529,583	132,724	1.15	7,875,316	956,051	12.14	2,880,300
14.	STORAGE	N/A	1,800	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,800
15.	DPAC	N/A	1,486	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,486
16.	332	N/A	4,893	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	4,893
17.	TOTAL	11,564,575	1,243,320	10.68	8,894,477	556,384	6.26	11,529,583	132,724	1.15	7,875,316	956,051	12.14	2,888,479

FISCAL YEAR REVENUE COMPARISON - CURRENT REVENUE vs PROPOSED REVENUE BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		REVENUE - EB-2015-0163 Q3 RATES			REVENUE - EB-2015-0114 INTERIM RATES			
Item No.	Rate No.	Revenue ($000)	Unbilled Revenue ($000)	Total ($000)	Proposed Revenue ($000)	Unbilled Revenue ($000)	Total ($000)	Total Difference ($000)
1.	1	1,682,481	2,840	1,685,321	1,728,591	1,702	1,730,294	44,972
2.	6	1,013,275	1,733	1,015,008	1,040,126	1,257	1,041,383	26,376
3.	9	156	0	156	157	0	157	0
4.	100	0	0	0	0	0	0	0
5.	110	42,192	276	42,468	43,238	236	43,474	1,006
6.	115	7,560	(51)	7,509	7,874	(52)	7,822	312
7.	125	9,849	0	9,849	10,825	0	10,825	976
8.	135	2,836	4	2,840	2,924	4	2,928	88
9.	145	4,676	(156)	4,520	4,790	(135)	4,655	136
10.	170	9,513	(102)	9,411	9,742	(99)	9,643	232
11.	200	31,437	0	31,437	31,848	0	31,848	412
12.	300	172	0	172	185	0	185	13
13.	SUB-TOTAL	2,804,148	4,544	2,808,691	2,880,300	2,914	2,883,214	74,523
14.	STORAGE	1,895	0	1,895	1,800	0	1,800	(95)
15.	DPAC	1,486	0	1,486	1,486	0	1,486	0
16.	332	0	0	0	4,893	0	4,893	4,893
16.	TOTAL	2,807,529	4,544	2,812,073	2,888,479	2,914	2,891,393	79,321

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Item No.	Rate No.		Rate Block m³	EB-2015-0163 cents *	Rate Change cents *	Interim EB-2015-0114 cents *
	RATE 1					
1.01		Customer Charge		$20.00	$0.00	$20.00
1.02		Delivery Charge	first 30	7.3000	0.7756	8.0756
1.03			next 55	6.8296	0.7257	7.5552
1.04			next 85	6.4613	0.6865	7.1479
1.05			over 170	6.1868	0.6574	6.8442
1.06		Gas Supply Load Balancing		1.1314	0.2805	1.4119
1.07		Gas Supply Transportation		6.2367	0.0187	6.2554
1.08		Gas Supply Commodity - System		12.1794	(0.0482)	12.1312
1.09		Gas Supply Commodity - Buy/Sell		12.1566	(0.0464)	12.1102
	RATE 6					
2.01		Customer Charge		$70.00	$0.00	$70.00
2.02		Delivery Charge	First 500	7.3569	0.4911	7.8481
2.03			Next 1050	5.6241	0.3755	5.9996
2.04			Next 4500	4.4107	0.2945	4.7052
2.05			Next 7000	3.6310	0.2424	3.8734
2.06			Next 15250	3.2847	0.2193	3.5039
2.07			Over 28300	3.1977	0.2135	3.4112
2.08		Gas Supply Load Balancing		1.0433	0.2783	1.3216
2.09		Gas Supply Transportation		6.2367	0.0187	6.2554
2.10		Gas Supply Commodity - System		12.2067	(0.0501)	12.1566
2.11		Gas Supply Commodity - Buy/Sell		12.1838	(0.0482)	12.1356
	RATE 9					
3.01		Customer Charge		$235.95	$0.00	$235.95
3.02		Delivery Charge	first 20000	10.5841	0.0914	10.6755
3.03			over 20000	9.9069	0.0856	9.9924
3.04		Gas Supply Load Balancing		0.0135	0.0022	0.0156
3.05		Gas Supply Transportation		6.2367	0.0187	6.2554
3.06		Gas Supply Commodity - System		12.1270	(0.0376)	12.0894
3.07		Gas Supply Commodity - Buy/Sell		12.1041	(0.0357)	12.0684
	RATE 100					
4.01		Customer Charge		$122.01	$0.00	$122.01
4.02		Demand Charge (Cents/Month/m³)		36.0000	0.0000	36.0000
4.03		Delivery Charge	first 14,000	0.1563	0.0097	0.1660
4.04			next 28,000	0.1563	0.0097	0.1660
4.05			over 42,000	0.1563	0.0097	0.1660
4.06		Gas Supply Load Balancing		1.0433	0.2783	1.3216
4.07		Gas Supply Transportation		6.2367	0.0187	6.2554
4.08		Gas Supply Commodity - System		12.2067	(0.0501)	12.1566
		Gas Supply Commodity - Buy/Sell		12.1838	(0.0482)	12.1356
	RATE 110					
5.01		Customer Charge		$587.37	$0.00	$587.37
5.02		Demand Charge (Cents/Month/m³)		22.9100	0.0000	22.9100
5.03		Delivery Charge	first 1,000,000	0.5680	0.0884	0.6564
5.04			over 1,000,000	0.4180	0.0884	0.5064
5.05		Gas Supply Load Balancing		0.2041	0.0581	0.2622
5.06		Gas Supply Transportation		6.2367	0.0187	6.2554
5.07		Gas Supply Commodity - System		12.1270	(0.0376)	12.0894
5.08		Gas Supply Commodity - Buy/Sell		12.1041	(0.0357)	12.0684

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³		Col. 3 EB-2015-0163 cents *	Col. 4 Rate Change cents *	Col. 5 Interim EB-2015-0114 cents *
	RATE 115						
1.01		Customer Charge			$622.62	$0.00	$622.62
1.02		Demand Charge (Cents/Month/m³)			24.3600	0.0000	24.3600
1.03		Delivery Charge	first	1,000,000	0.2168	0.0461	0.2629
1.04			over	1,000,000	0.1168	0.0461	0.1629
1.05		Gas Supply Load Balancing			0.0809	0.0137	0.0946
1.06		Gas Supply Transportation			6.2367	0.0187	6.2554
1.07		Gas Supply Commodity - System			12.1270	(0.0376)	12.0894
1.08		Gas Supply Commodity - Buy/Sell			12.1041	(0.0357)	12.0684
	RATE 125						
2.01		Customer Charge			500.00	$ -	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)			8.2361	0.8184	9.0545
	RATE 135	DEC - MAR					
3.00		Customer Charge			$115.08	$0.00	$115.08
3.01		Delivery Charge	first	14,000	6.7133	0.1405	6.8538
3.02			next	28,000	5.5133	0.1405	5.6538
3.03			over	42,000	5.1133	0.1405	5.2538
3.04		Gas Supply Load Balancing			0.0000	0.0000	0.0000
3.05		Gas Supply Transportation			6.2367	0.0187	6.2554
3.06		Gas Supply Commodity - System			12.1337	(0.0335)	12.1002
3.07		Gas Supply Commodity - Buy/Sell			12.1108	(0.0317)	12.0791
	RATE 135	APR - NOV					
3.08		Customer Charge			$115.08	$0.00	$115.08
3.09		Delivery Charge	first	14,000	2.0133	0.1405	2.1538
3.10			next	28,000	1.3133	0.1405	1.4538
3.11			over	42,000	1.1133	0.1405	1.2538
3.12		Gas Supply Load Balancing			0.0000	0.0000	0.0000
3.13		Gas Supply Transportation			6.2367	0.0187	6.2554
3.14		Gas Supply Commodity - System			12.1337	(0.0335)	12.1002
3.15		Gas Supply Commodity - Buy/Sell			12.1108	(0.0317)	12.0791
	RATE 145						
4.00		Customer Charge			$123.34	$0.00	$123.34
4.01		Demand Charge (Cents/Month/m³)			8.2300	-	8.2300
4.02		Delivery Charge	first	14,000	2.6352	0.0453	2.6806
4.03			next	28,000	1.2762	0.0453	1.3216
4.04			over	42,000	0.7172	0.0453	0.7626
4.05		Gas Supply Load Balancing			0.4859	0.0946	0.5805
4.06		Gas Supply Transportation			6.2367	0.0187	6.2554
4.07		Gas Supply Commodity - System			12.2198	(0.1268)	12.0930
4.08		Gas Supply Commodity - Buy/Sell			12.1970	(0.1250)	12.0720
	RATE 170						
5.00		Customer Charge			$279.31	$0.00	$279.31
5.01		Demand Charge (Cents/Month/m³)			4.0900	0.0000	4.0900
5.02		Delivery Charge	first	1,000,000	0.3954	0.0511	0.4465
5.03			over	1,000,000	0.1954	0.0511	0.2465
5.04		Gas Supply Load Balancing			0.2585	0.0180	0.2764
5.05		Gas Supply Transportation			6.2367	0.0187	6.2554
5.06		Gas Supply Commodity - System			12.1270	(0.0376)	12.0894
5.07		Gas Supply Commodity - Buy/Sell			12.1041	(0.0357)	12.0684

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2015-0163 cents *	Col. 4 Rate Change cents *	Col. 5 Interim EB-2015-0114 cents *
	RATE 200					
1.00		Customer Charge		$0.00	$0.00	$0.00
1.01		Demand Charge (Cents/Month/m³)		14.7000	0.0000	14.7000
1.02		Delivery Charge		1.1932	(0.0416)	1.1516
1.03		Gas Supply Load Balancing		0.8591	0.2931	1.1522
1.04		Gas Supply Transportation		6.2367	0.0187	6.2554
1.05		Gas Supply Commodity - System		12.1270	(0.0376)	12.0894
1.06		Gas Supply Commodity - Buy/Sell		12.1041	(0.0357)	12.0684
	RATE 300	FIRM SERVICE				
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00
2.01		Demand Charge (Cents/Month/m³)		24.9071	0.7472	25.6543
		INTERRUPTIBLE SERVICE				
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3249	0.0094	0.3343
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.9826	0.0295	1.0121
	RATE 315					
		Monthly Customer Charge		$150.00	$0.00	$150.00
3.00		Space Demand Chg (Cents/Month/m³)		0.0493	(0.0014)	0.0479
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		21.3652	1.0652	22.4303
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.3102	0.0060	0.3162
	RATE 316					
		Monthly Customer Charge		$150.00	$0.00	$150.00
4.00		Space Demand Chg (Cents/Month/m³)		0.0493	(0.0015)	0.0479
4.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		5.1917	(0.1260)	5.0657
4.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.1158	(0.0281)	0.0877
	RATE 320					
5.00		Backstop	All Gas Sold	18.8176	0.0501	18.8677

* Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2015-0163 cents *	Col. 4 Change cents *	Col. 5 Interim EB-2015-0114 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.2023	(0.0001)	0.2022
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		22.2530	(0.0023)	22.2507
1.02		Commodity Charge		1.1850	(0.2385)	0.9465
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.1911	(0.0006)	0.1905
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		21.2494	(0.0622)	21.1873
1.05		Commodity Charge		0.2170	(0.0600)	0.1570
		(2) Note: These are UNBUNDLED Rates				
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.00		Minimum		0.3934	(0.0007)	0.3927
2.01		Maximum		1.9671	(0.0034)	1.9637
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.02		Minimum		43.5024	(0.0645)	43.4380
2.03		Maximum		217.5122	(0.3223)	217.1898
		Commodity Charge				
2.04		Minimum		1.4020	(0.2985)	1.1035
2.05		Maximum		7.0100	(1.4923)	5.5177
		Storage Service - Interruptible				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.06		Minimum		0.3934	(0.0007)	0.3927
2.07		Maximum		1.9670	(0.0033)	1.9637
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.08		Minimum		34.8020	(0.0517)	34.7504
2.09		Maximum		174.0097	(0.2578)	173.7519
		Commodity Charge				
2.10		Minimum		1.4020	(0.2985)	1.1035
2.11		Maximum		7.0100	(1.4923)	5.5177
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		0.4984	(0.0921)	0.4063
2.13		Maximum		46.9463	(5.7924)	41.1539
	RATE 331	Tecumseh Transmission Service				
		Firm				
		Demand Charge ($/Month/10³ m³ of				
3.00		Maximum Contracted Daily Delivery)		5.5340	0.1090	5.6430
		Interruptible				
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.2180	0.0050	0.2230

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	948,621	543,315	373,995	54	-	9,792	-	454	1,352	4,108	15,552	G2 T5 S3 1.1
1.2	Bad Debt Commodity	3,972	1,885	2,086	-	-	-	-	0	0	-	-	G2 T5 S3 1.2
1.3	System Gas Fee	1,658	950	654	0	-	17	-	1	2	7	27	G2 T5 S3 1.3
1.4	Return on Rate Base - Working Cash	1,800	1,031	710	0	-	19	-	1	3	8	30	G2 T5 S2 1.1
1	Total Commodity Costs	956,052	547,180	377,445	54	-	9,828	-	456	1,357	4,122	15,609	
	VOLUMES (103 m3)												
2.1	System and Buy/Sell Volumes	7,875,316	4,510,521	3,104,852	450	-	81,295	-	3,768	11,222	34,100	129,109	
2.2	System Volumes	7,875,316	4,510,521	3,104,852	450	-	81,295	-	3,768	11,222	34,100	129,109	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	12.0455	12.0455	12.0455	12.0455	-	12.0455	-	12.0455	12.0455	12.0455	12.0455	1.1 / 2.1
3.2	Bad Debt Commodity	0.0504	0.0418	0.0672	-	-	-	-	0.0108	0.0036	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0211	0.0211	0.0211	0.0211	-	0.0211	-	0.0211	0.0211	0.0211	0.0211	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0229	0.0229	0.0229	0.0229	-	0.0229	-	0.0229	0.0229	0.0229	0.0229	1.4 / 2.1
3	System Gas Supply Charge	12.1399	12.1312	12.1566	12.0894	-	12.0894	12.0894	12.1002	12.0930	12.0894	12.0894	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	12.0455	12.0455	12.0455	12.0455	-	12.0455	-	12.0455	12.0455	12.0455	12.0455	1.1 / 2.1
4.2	Bad Debt Commodity	0.0504	0.0418	0.0672	-	-	-	-	0.0108	0.0036	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0229	0.0229	0.0229	0.0229	-	0.0229	-	0.0229	0.0229	0.0229	0.0229	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	12.1188	12.1102	12.1356	12.0684	-	12.0684	12.0684	12.0791	12.0720	12.0684	12.0684	

CALCULATION OF GAS SUPPLY LOAD BALANCING & TRANSPORTATION CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF LOAD BALANCING CHARGES												
	ANNUAL LOAD BALANCING COSTS ($000)												
5.1	Peak	17,355	9,560	7,465	0	-	140	27	-	-	-	163	G2 T5 S3 2.1
5.2	Seasonal	93,935	46,148	43,587	0	-	1,329	360	-	401	702	1,407	G2 T5 S3 2.2
5.3	Return on Rate Base - Gas in Inventory	26,546	13,042	12,318	0	-	376	102	-	113	198	398	G2 T5 S2 2.2
5	Total Load Balancing	137,836	68,750	63,370	0	-	1,844	489	-	514	900	1,968	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,529,583	4,869,333	4,794,977	510	-	703,348	517,078	59,278	88,566	325,657	170,837	
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)** Load Balancing		1.4119	1.3216	0.0156	-	0.2622	0.0946	-	0.5805	0.2764	1.1522	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
	VOLUMES (10^3 m^3)												
6.1	Annual Transportation Volumes	8,894,477	4,633,078	3,682,184	450	-	246,846	21,737	30,925	24,187	89,965	165,105	
7.1	**Annual Transportation Costs ($000)**	556,384	289,817	230,335	28	-	15,441	1,360	1,934	1,513	5,628	10,328	
7	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		6.2554	6.2554	6.2554	6.2554	6.2554	6.2554	6.2554	6.2554	6.2554	6.2554	

CALCULATION OF SEASONAL CREDIT FOR RATE 135, 145, 170 & 200

			Reference
RATE 135			
Seasonal Credits Applicable to Rate 135	**$**	**(499)**	H2T5S1 P5 line 2.3
Annual Volume (103 m3)		59,278	
Mean Daily Volume (103 m3)		162	
Annual Seasonal Credits	$	(3.08)	
Payable from December to March	$	(0.77)	
RATE 145			
Seasonal Credits Applicable to Rate 145	**$**	**(485)**	H2T5S1 P6 line 2.3
Annual Volume (103 m3)		88,566	
Mean Daily Volume (103 m3)			
16 Hours		243	
Annual Seasonal Credits			
16 Hours	$	(2.00)	
Payable from December to March	$	(0.50)	
Seasonal Credits Applicable to Rate 145			
16 Hours	$	(485)	
RATE 200			
Seasonal Credits Applicable to Rate 200	**$**	**(202)**	H2T5S1 P7 line 2.3
Annual Volume (103 m3)		16,748	
Mean Daily Volume (103 m3)		46	
Annual Seasonal Credits	$	(4.40)	
Payable from December to March	$	(1.10)	

DETAILED REVENUE CALCULATION

EB-2015-0163 vs EB-2015-0114

Item No.		Rate Block m³		Col. 2 Bills & Volumes 10³ m³	Col. 3 EB-2015-0163 Rate cents*	Col. 4 EB-2015-0163 Revenues $000	Col. 5 Rate Change cents*	Col. 6 Interim EB-2015-0114 Rate cents*	Col. 7 Interim EB-2015-0114 Revenues $000
	RATE 1								
1.1	Customer Charge	Bills		23,570,385	$20.00	471,408	$0.00	$20.00	471,408
1.2	Delivery Charge	first	30	671,991	7.3000	49,055	0.7756	8.0756	54,267
1.3		next	55	954,662	6.8296	65,199	0.7257	7.5552	72,127
1.4		next	85	1,056,776	6.4613	68,282	0.6865	7.1479	75,537
1.5		over	170	2,185,905	6.1868	135,238	0.6574	6.8442	149,607
1.	Total Distribution Charge			4,869,333		789,182			822,946
2.1	Gas Supply Load Balancing			4,869,333	1.1314	55,093	0.2805	1.4119	68,750
2.2	Gas Supply Transportation			4,633,078	6.2367	288,951	0.0187	6.2554	289,817
3.1	Gas Supply Commodity - System			4,510,521	12.1794	549,354	(0.0482)	12.1312	547,180
3.2	Gas Supply Commodity - Buy/Sell			0	12.1566	0	(0.0464)	12.1102	0
3.	Total Gas Supply Charge			4,510,521		549,354			547,180
4.1	TOTAL DISTRIBUTION			4,869,333		789,182			822,946
4.2	TOTAL GAS SUPPLY LOAD BALANCING			4,869,333		344,044			358,567
4.3	TOTAL GAS SUPPLY COMMODITY			4,510,521		549,354			547,180
4.	TOTAL RATE 1			**4,869,333**		1,682,580			1,728,693
5.	Adj. Factor		0.9999						
6.	ADJUSTED REVENUE					**1,682,481**			**1,728,591**
7.	REVENUE INC./(DEC.)								**46,110**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION — EB-2015-0163 vs EB-2015-0114

Item No.		Rate Block m³	Bills & Volumes 10³ m³	EB-2015-0163 Rate cents*	EB-2015-0163 Revenues $000	Rate Change cents*	Interim EB-2015-0114 Rate cents*	Interim EB-2015-0114 Revenues $000
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
	RATE 6							
1.1	Customer Charge	Bills	1,990,260	$70.00	139,318	$0.00	$70.00	139,318
1.2	Delivery Charge	First 500	608,398	7.3569	44,760	0.4911	7.8481	47,748
1.3		Next 1050	731,014	5.6241	41,113	0.3755	5.9996	43,858
1.4		Next 4500	1,259,521	4.4107	55,554	0.2945	4.7052	59,263
1.5		Next 7000	731,990	3.6310	26,579	0.2424	3.8734	28,353
1.6		Next 15250	600,569	3.2847	19,727	0.2193	3.5039	21,044
1.7		Over 28300	863,484	3.1977	27,612	0.2135	3.4112	29,455
1.	Total Distribution Charge		4,794,977		354,662			369,038
2.1	Gas Supply Load Balancing		4,794,977	1.0433	50,026	0.2783	1.3216	63,370
2.2	Gas Supply Transportation		3,682,184	6.2367	229,647	0.0187	6.2554	230,335
3.1	Gas Supply Commodity - System		3,104,852	12.2067	379,000	(0.0501)	12.1566	377,444
3.2	Gas Supply Commodity - Buy/Sell		0	12.1838	0	(0.0482)	12.1356	0
3.	Total Gas Supply Charge		3,104,852		379,000			377,444
4.1	TOTAL DISTRIBUTION		4,794,977		354,662			369,038
4.2	TOTAL GAS SUPPLY LOAD BALANCING		4,794,977		279,673			293,705
4.3	TOTAL GAS SUPPLY COMMODITY		3,104,852		379,000			377,444
4.	TOTAL RATE 6		**4,794,977**		1,013,335			1,040,187
5.	Adj. Factor	1.000						
6.	ADJUSTED REVENUE				**1,013,275**			**1,040,126**
7.	REVENUE INC./(DEC.)							**26,850**

NOTE * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION   EB-2015-0163 vs EB-2015-0114

Item No.		Rate Block m³ (Col. 1)		Bills & Volumes 10³ m³ (Col. 2)	EB-2015-0163 Rate cents* (Col. 3)	EB-2015-0163 Revenues $000 (Col. 4)	Rate Change cents* (Col. 5)	Interim EB-2015-0114 Rate cents* (Col. 6)	Interim EB-2015-0114 Revenues $000 (Col. 7)
	RATE 9								
1.1	Customer Charge		Bills	84	$235.95	20	$0.00	$235.95	20
1.2	Delivery Charge	first	20000	503	10.5841	53	0.0914	10.6755	54
1.3		over	20000	7	9.9069	1	0.0856	9.9924	1
1.	Total Distribution Charge			510		74			74
2.1	Gas Supply Load Balancing			510	0.0135	0	0.0022	0.0156	0
2.2	Gas Supply Transportation			450	6.2367	28	0.0187	6.2554	28
3.1	Gas Supply Commodity - System			450	12.1270	55	(0.0376)	12.0894	54
3.2	Gas Supply Commodity - Buy/Sell			0	12.1041	0	(0.0357)	12.0684	0
3.	Total Gas Supply Charge			450		55			54
4.1	TOTAL DISTRIBUTION			510		74			74
4.2	TOTAL GAS SUPPLY LOAD BALANCING			510		28			28
4.3	TOTAL GAS SUPPLY COMMODITY			450		55			54
4	TOTAL RATE 9			**510**		**156**			**157**
5.	REVENUE INC./(DEC.)								**0**

Item No.		Rate Block m³		Contracts & Volumes 10³ m³	EB-2015-0163 Rate cents*	EB-2015-0163 Revenues $000	Rate Change cents*	Interim EB-2015-0114 Rate cents*	Interim EB-2015-0114 Revenues $000
	RATE 100								
1.1	Customer Charge		Contracts	0	$122.01	0	$0.00	$122.01	0
1.2	Demand Charge			0	$36.00	0	-	36.00	0
1.3	Delivery Charge	first	14,000	0	0.1563	0	0.0097	0.1660	0
1.4		next	28,000	0	0.1563	0	0.0097	0.1660	0
1.5		over	42,000	0	0.1563	0	0.0097	0.1660	0
1	Total Distribution Charge			0		0			0
2.1	Gas Supply Load Balancing			0	1.0433	0	0.2783	1.3216	0
2.2	Gas Supply Transportation			0	6.2367	0	0.0187	6.2554	0
3.1	Gas Supply Commodity - System			0	12.2067	0	(0.0501)	12.1566	0
3.2	Gas Supply Commodity - Buy/Sell			0	12.1838	0	(0.0482)	12.1356	0
3	Total Gas Supply Charge			0		0			0
4.1	TOTAL DISTRIBUTION			0		0			0
4.2	TOTAL GAS SUPPLY LOAD BALANCING			0		0			0
4.3	TOTAL GAS SUPPLY COMMODITY			0		0			0
4	TOTAL RATE 100			**0**		**0**			**0**
5	REVENUE INC./(DEC.)								**0**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION EB-2015-0163 vs EB-2015-0114

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
							Interim	
Item			Contracts &	EB-2015-0163		Rate	EB-2015-0114	
No.		Rate Block	Volumes	Rate	Revenues	Change	Rate	Revenues
		m³	10³ m³	cents*	$000	cents*	cents*	$000
	RATE 110							
1.1	Customer Charge	Contracts	2,664	$587.37	1,565	$0.00	$587.37	1,565
1.2	Demand Charge		44,373	22.9100	10,166	0.0000	22.9100	10,166
1.3	Delivery Charge	first 1,000,000	554,646	0.5680	3,151	0.0884	0.6564	3,641
1.4		over 1,000,000	148,702	0.4180	622	0.0884	0.5064	753
1.	Total Distribution Charge		703,348		15,503			16,125
2.1	Load Balancing Commodity		703,348	0.2041	1,435	0.0581	0.2622	1,844
2.2	Gas Supply Transportation		246,846	6.2367	15,395	0.0187	6.2554	15,441
2.	Total Gas Supply Load Balancing				16,830			17,285
3.1	Gas Supply Commodity - System		81,295	12.1270	9,859	(0.0376)	12.0894	9,828
3.2	Gas Supply Commodity - Buy/Sell		0	12.1041	0	(0.0357)	12.0684	0
3.	Total Gas Supply Charge		81,295		9,859			9,828
4.1	TOTAL DISTRIBUTION		703,348		15,503			16,125
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		703,348		16,830			17,285
4.3	TOTAL GAS SUPPLY COMMODITY		81,295		9,859			9,828
4.	TOTAL RATE 110		**703,348**		**42,192**			**43,238**
5.	REVENUE INC./(DEC.)							**1,046**

				Interim			Interim	
			Contracts &	EB-2015-0163		Rate	EB-2015-0114	
		Rate Block	Volumes	Rate	Revenues	Change	Rate	Revenues
		m³	10³ m³	cents*	$000	cents*	cents*	$000
	RATE 115							
6.6	Customer Charge	Contracts	300	$622.62	187	$0.00	$622.62	187
6.2	Demand Charge		19,861	24.3600	4,838	0.0000	24.3600	4,838
6.3	Delivery Charge	first 1,000,000	157,328	0.2168	341	0.0461	0.2629	414
6.4		over 1,000,000	359,750	0.1168	420	0.0461	0.1629	586
6	Total Distribution Charge		517,078		5,786			6,025
7.1	Load Balancing Commodity		517,078	0.0809	418	0.0137	0.0946	489
7.2	Gas Supply Transportation		21,737	6.2367	1,356	0.0187	6.2554	1,360
7	Total Gas Supply Load Balancing				1,774			1,849
8.1	Gas Supply Commodity - System		0	12.1270	0	(0.0376)	12.0894	0
8.2	Gas Supply Commodity - Buy/Sell		0	12.1041	0	(0.0357)	12.0684	0
8.	Total Gas Supply Charge		0		0			0
9.1	TOTAL DISTRIBUTION		517,078		5,786			6,025
9.2	TOTAL GAS SUPPLY LOAD BALANCIN		517,078		1,774			1,849
9.3	TOTAL GAS SUPPLY COMMODITY		0		0			0
9.	TOTAL RATE 115		**517,078**		**7,560**			**7,873**
10.	REVENUE INC./(DEC.)							**314**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION   EB-2015-0163 vs EB-2015-0114

Item No.		Col. 1 Rate Block m³	Col. 2 Contracts & Volumes 10³ m³	Col. 3 EB-2015-0163 Rate cents*	Col. 4 EB-2015-0163 Revenues $000	Col. 5 Rate Change cents*	Col. 6 Interim EB-2015-0114 Rate cents*	Col. 7 Interim EB-2015-0114 Revenues $000
	RATE 125							
1.1	Customer Charge		60	$ 500.00	30	$ -	$ 500.00	30
1.2	Demand Charge		119,224	8.2361	9,819	0.8184	9.0545	10,795
1.	Total Distribution Charge		**119,224**		**9,849**			**10,825**
2.	REVENUE INC./(DEC.)							**976**

Item No.		Rate Block m³	Contracts & Volumes 10³ m³	EB-2015-0163 Rate cents*	EB-2015-0163 Revenues $000	Rate Change cents*	Interim EB-2015-0114 Rate cents*	Interim EB-2015-0114 Revenues $000
	RATE 135							
	DEC to MAR							
1.1	Customer Charge	Contracts	176	$115.08	20	$0.00	$115.08	20
1.2	Delivery Charge	first 14,000	596	6.7133	40	0.1405	6.8538	41
1.3		next 28,000	942	5.5133	52	0.1405	5.6538	53
1.4		over 42,000	2,410	5.1133	123	0.1405	5.2538	127
1.	Total Distribution Charge		3,948		235			241
2.1	Gas Supply Load Balancing		3,948	0.0000	0	0.0000	0.0000	0
2.2	Gas Supply Transportation		1,772	6.2367	110	0.0187	6.2554	111
2.3	Seasonal Credit				(499)			(499)
3.1	Gas Supply Commodity - System		213	12.1337	26	(0.0335)	12.1002	26
3.2	Gas Supply Commodity - Buy/Sell		0	12.1108	0	(0.0317)	12.0791	0
3.	Total Gas Supply Charge		213		26			26
4.	SUB-TOTAL WINTER				-128			-122
	APR to NOV							
5.1	Customer Charge	Contracts	352	$115.08	41	$0.00	$115.08	41
5.2	Delivery Charge	first 14,000	4,506	2.0133	91	0.1405	2.1538	97
5.3		next 28,000	8,537	1.3133	112	0.1405	1.4538	124
5.4		over 42,000	42,288	1.1133	471	0.1405	1.2538	530
5.	Total Distribution Charge		55,331		714			792
6.1	Gas Supply Load Balancing		55,331	0.0000	0	0.0000	0.0000	0
6.2	Gas Supply Transportation		29,153	6.2367	1,818	0.0187	6.2554	1,824
7.1	Gas Supply Commodity - System		3,555	12.1337	431	(0.0335)	12.1002	430
7.2	Gas Supply Commodity - Buy/Sell		0	12.1108	0	(0.0317)	12.0791	0
7.	Total Gas Supply Charge		3,555		431			430
8.	SUB-TOTAL SUMMER				2,964			3,046
9.1	TOTAL DISTRIBUTION		59,278		950			1,033
9.2	TOTAL GAS SUPPLY LOAD BALANCIN		59,278		1,429			1,435
9.3	TOTAL GAS SUPPLY COMMODITY		3,768		457			456
9.	TOTAL RATE 135		**59,278**		**2,836**			**2,924**
10.	REVENUE INC./(DEC.)							**88**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION EB-2015-0163 vs EB-2015-0114

Item No.		Rate Block m³	Col. 2 Contracts & Volumes 10³ m³	Col. 3 EB-2015-0163 Rate cents*	Col. 4 EB-2015-0163 Revenues $000	Col. 5 Rate Change cents*	Col. 6 Interim EB-2015-0114 Rate cents*	Col. 7 Interim EB-2015-0114 Revenues $000
	RATE 145							
1.1	Customer Charge	Contracts	624	$123.34	77	$0.00	$123.34	77
1.2	Demand Charge		10,860	8.2300	894	-	8.2300	894
1.2	Delivery Charge	first 14,000	8,311	2.6352	219	0.0453	2.6806	223
1.3		next 28,000	15,323	1.2762	196	0.0453	1.3216	203
1.4		over 42,000	64,931	0.7172	466	0.0453	0.7626	495
1.	Total Distribution Charge		88,566		1,851			1,891
2.1	Gas Supply Load Balancing		88,566	0.4859	430	0.0946	0.5805	514
2.2	Gas Supply Transportation		24,187	6.2367	1,508	0.0187	6.2554	1,513
2.3	Curtailment Credit				(485)			(485)
3.1	Gas Supply Commodity - System		11,222	12.2198	1,371	(0.1268)	12.0930	1,357
3.2	Gas Supply Commodity - Buy/Sell		0	12.1970	0	(0.1250)	12.0720	0
3.	Total Gas Supply Charge		11,222		1,371			1,357
4.1	TOTAL DISTRIBUTION		88,566		1,851			1,891
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		88,566		1,454			1,542
4.3	TOTAL GAS SUPPLY COMMODITY		11,222		1,371			1,357
4.	TOTAL RATE 145		**88,566**		**4,676**			**4,790**
5.	REVENUE INC./(DEC.)							**115**

		Rate Block m³	Contracts & Volumes 10³ m³	EB-2015-0163 Rate cents*	EB-2015-0163 Revenues $000	Rate Change cents*	Interim EB-2015-0114 Rate cents*	Interim EB-2015-0114 Revenues $000
	RATE 170							
6.6	Customer Charge	Contracts	300	$279.31	84	$0.00	$279.31	84
6.2	Demand Charge		42,020	4.0900	1,719	0.0000	4.0900	1,719
6.3	Delivery Charge	first 1,000,000	206,043	0.3954	815	0.0511	0.4465	920
6.4		over 1,000,000	119,614	0.1954	234	0.0511	0.2465	295
6	Total Distribution Charge		325,657		2,851			3,017
7.1	Gas Supply Load Balancing		325,657	0.2585	842	0.0180	0.2764	900
7.7	Gas Supply Transportation		89,965	6.2367	5,611	0.0187	6.2554	5,628
7.3	Curtailment Credit				(3,926)			(3,926)
8.1	Gas Supply Commodity - System		34,100	12.1270	4,135	(0.0376)	12.0894	4,122
8.2	Gas Supply Commodity - Buy/Sell		0	12.1041	0	(0.0357)	12.0684	0
8.	Total Gas Supply Charge		34,100		4,135			4,122
9.1	TOTAL DISTRIBUTION		325,657		2,851			3,017
9.2	TOTAL GAS SUPPLY LOAD BALANCIN		325,657		2,527			2,602
9.3	TOTAL GAS SUPPLY COMMODITY		34,100		4,135			4,122
9.	TOTAL RATE 170		**325,657**		**9,513**			**9,742**
10.	REVENUE INC./(DEC.)							**229**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION   EB-2015-0163 vs EB-2015-0114

Item No.		Col. 1 Rate Block m³	Col. 2 Contracts & Volumes 10³ m³	Col. 3 EB-2015-0163 Rate cents*	Col. 4 EB-2015-0163 Revenues $000	Col. 5 Rate Change cents*	Col. 6 Interim EB-2015-0114 Rate cents*	Col. 7 Interim EB-2015-0114 Revenues $000
	RATE 200							
1.1	Customer Charge	Contracts	12	$0.00	0	$0.00	$0.00	0
1.2	Demand Charge		14,818	14.7000	2,178	0.0000	14.7000	2,178
1.3	Delivery Charge		170,837	1.1932	2,038	(0.0416)	1.1516	1,967
1.	Total Distribution Charge		170,837		4,217			4,145
2.1	Gas Supply Load Balancing		170,837	0.8591	1,468	0.2931	1.1522	1,968
2.2	Gas Supply Transportation		165,105	6.2367	10,297	0.0187	6.2554	10,328
2.3	Curtailment Credit				(202)			(202)
3.1	Gas Supply Commodity - System		129,109	12.1270	15,657	(0.0376)	12.0894	15,609
3.2	Gas Supply Commodity - Buy/Sell		0	12.1041	0	(0.0357)	12.0684	0
3.	Total Gas Supply Charge		129,109		15,657			15,609
4.1	TOTAL DISTRIBUTION		170,837		4,217			4,145
4.2	TOTAL GAS SUPPLY LOAD BALANCIN		170,837		11,563			12,094
4.3	TOTAL GAS SUPPLY COMMODITY		129,109		15,657			15,609
4.	TOTAL RATE 200		**170,837**		**31,437**			**31,848**
5.	REVENUE INC./(DEC.)							**412**

		Rate Block m³	Contracts & Volumes 10³ m³	EB-2015-0163 Rate cents*	EB-2015-0163 Revenues $000	Rate Change cents*	Interim EB-2015-0114 Rate cents*	Interim EB-2015-0114 Revenues $000
	RATE 300							
	Firm							
	Customer Charge		24	$500.00	12	0.0000	$500.00	12
	Demand Charge		187	24.9071	47	0.7472	25.6543	48
	Interruptible							
	Minimum Delivery Charge		34,992	0.3249	114	0.0094	0.3343	125
	Maximum Delivery Charge		0	0.9826	0	0.0295	1.0121	0
8.	TOTAL RATE 300		**0**		**172**			**185**
9.	REVENUE INC./(DEC.)							**13**

NOTE: * Cents unless otherwise noted.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				Heating, Water Htg. & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	240.00	240.00	0.00	0.0%	240.00	240.00	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	220.81	199.48	21.33	10.7%	332.79	300.69	32.10	10.7%
1.4	LOAD BALANCING	§ $	234.91	225.75	9.16	4.1%	359.67	345.65	14.02	4.1%
1.5	SALES COMMDTY	$	371.69	373.18	(1.49)	-0.4%	569.08	571.32	(2.24)	-0.4%
1.6	TOTAL SALES	$	1,067.41	1,038.41	29.00	2.8%	1,501.54	1,457.66	43.88	3.0%
1.7	TOTAL T-SERVICE	$	695.72	665.23	30.49	4.6%	932.46	886.34	46.12	5.2%
1.8	SALES UNIT RATE	$/m³	0.3484	0.3389	0.0095	2.8%	0.3201	0.3107	0.0094	3.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.2271	0.2171	0.0100	4.6%	0.1988	0.1889	0.0098	5.2%
1.10	SALES UNIT RATE	$/GJ	9.243	8.992	0.2511	2.8%	8.493	8.245	0.2482	3.0%
1.11	T-SERVICE UNIT RATE	$/GJ	6.024	5.760	0.2640	4.6%	5.274	5.013	0.2609	5.2%
1.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(37.73)	(43.07)	5.34		(57.77)	(65.95)	8.18	
1.13	TOTAL SALES WITH SRC REFUND	$	1,029.68	995.34	34.34	3.5%	1,443.77	1,391.71	52.06	3.7%
1.14	TOTAL T-SERVICE WITH SRC REFUND	$	657.99	622.16	35.83	5.8%	874.69	820.39	54.30	6.6%

Item No.			Heating Only				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	240.00	240.00	0.00	0.0%	240.00	240.00	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	141.65	127.94	13.71	10.7%	147.45	133.14	14.31	10.7%
2.4	LOAD BALANCING	§ $	149.89	144.04	5.85	4.1%	153.73	147.76	5.97	4.0%
2.5	SALES COMMDTY	$	237.17	238.10	(0.93)	-0.4%	243.23	244.19	(0.96)	-0.4%
2.6	TOTAL SALES	$	768.71	750.08	18.63	2.5%	784.41	765.09	19.32	2.5%
2.7	TOTAL T-SERVICE	$	531.54	511.98	19.56	3.8%	541.18	520.90	20.28	3.9%
2.8	SALES UNIT RATE	$/m³	0.3932	0.3837	0.0095	2.5%	0.3912	0.3816	0.0096	2.5%
2.9	T-SERVICE UNIT RATE	$/m³	0.2719	0.2619	0.0100	3.8%	0.2699	0.2598	0.0101	3.9%
2.10	SALES UNIT RATE	$/GJ	10.433	10.180	0.2528	2.5%	10.380	10.124	0.2557	2.5%
2.11	T-SERVICE UNIT RATE	$/GJ	7.214	6.948	0.2655	3.8%	7.161	6.893	0.2684	3.9%
2.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(24.08)	(27.48)	3.41		(24.69)	(28.19)	3.49	
2.13	TOTAL SALES WITH SRC REFUND	$	744.63	722.60	22.04	3.0%	759.72	736.90	22.81	3.1%
2.14	TOTAL T-SERVICE WITH SRC REFUND	$	507.46	484.50	22.97	4.7%	516.49	492.71	23.77	4.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	240.00	240.00	0.00	0.0%	240.00	240.00	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	357.93	323.35	34.58	10.7%	83.28	75.21	8.07	10.7%
3.4	LOAD BALANCING	§ $	387.05	371.96	15.09	4.1%	82.89	79.64	3.25	4.1%
3.5	SALES COMMDTY	$	612.39	614.81	(2.42)	-0.4%	131.14	131.65	(0.51)	-0.4%
3.6	TOTAL SALES	$	1,597.37	1,550.12	47.25	3.0%	537.31	526.50	10.81	2.1%
3.7	TOTAL T-SERVICE	$	984.98	935.31	49.67	5.3%	406.17	394.85	11.32	2.9%
3.8	SALES UNIT RATE	$/m³	0.3164	0.3071	0.0094	3.0%	0.4970	0.4870	0.0100	2.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1951	0.1853	0.0098	5.3%	0.3757	0.3653	0.0105	2.9%
3.10	SALES UNIT RATE	$/GJ	8.396	8.147	0.2483	3.0%	13.188	12.923	0.2653	2.1%
3.11	T-SERVICE UNIT RATE	$/GJ	5.177	4.916	0.2611	5.3%	9.969	9.691	0.2778	2.9%
3.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(62.17)	(70.96)	8.80		(13.31)	(15.20)	1.88	
3.13	TOTAL SALES WITH SRC REFUND	$	1,535.20	1,479.16	56.05	3.8%	524.00	511.30	12.69	2.5%
3.14	TOTAL T-SERVICE WITH SRC REFUND	$	922.81	864.35	58.47	6.8%	392.86	379.65	13.20	3.5%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				**Heating & Water Htg.**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	2,480	2,480	0	0.0%	2,400	2,400	0	0.0%
3.2	CUSTOMER CHG.	$	240.00	240.00	0.00	0.0%	240.00	240.00	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	180.34	162.89	17.45	10.7%	174.56	157.67	16.89	10.7%
3.4	LOAD BALANCING	§ $	190.17	182.73	7.44	4.1%	184.02	176.82	7.20	4.1%
3.5	SALES COMMDTY	$	300.86	302.05	(1.19)	-0.4%	291.15	292.29	(1.14)	-0.4%
3.6	TOTAL SALES	$	911.37	887.67	23.70	2.7%	889.73	866.78	22.95	2.6%
3.7	TOTAL T-SERVICE	$	610.51	585.62	24.89	4.3%	598.58	574.49	24.09	4.2%
3.8	SALES UNIT RATE	$/m³	0.3675	0.3579	0.0096	2.7%	0.3707	0.3612	0.0096	2.6%
3.9	T-SERVICE UNIT RATE	$/m³	0.2462	0.2361	0.0100	4.3%	0.2494	0.2394	0.0100	4.2%
3.10	SALES UNIT RATE	$/GJ	9.750	9.497	0.2536	2.7%	9.836	9.582	0.2537	2.6%
3.11	T-SERVICE UNIT RATE	$/GJ	6.532	6.265	0.2663	4.3%	6.617	6.351	0.2663	4.2%
3.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(30.54)	(34.86)	4.32		(29.56)	(33.74)	4.18	
3.13	TOTAL SALES WITH SRC REFUND	$	880.83	852.81	28.02	3.3%	860.17	833.04	27.13	3.3%
3.14	TOTAL T-SERVICE WITH SRC REFUND	$	579.97	550.76	29.21	5.3%	569.02	540.75	28.27	5.2%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	840.00	840.00	0.00	0.0%	840.00	840.00	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	1,342.69	1,258.55	84.14	6.7%	1,722.74	1,614.79	107.95	6.7%
1.4	LOAD BALANCING	§ $	1,712.85	1,645.72	67.13	4.1%	2,218.40	2,131.45	86.95	4.1%
1.5	SALES COMMDTY	$	2,748.12	2,759.45	(11.33)	-0.4%	3,559.20	3,573.89	(14.69)	-0.4%
1.6	TOTAL SALES	$	6,643.66	6,503.72	139.94	2.2%	8,340.34	8,160.13	180.21	2.2%
1.7	TOTAL T-SERVICE	$	3,895.54	3,744.27	151.27	4.0%	4,781.14	4,586.24	194.90	4.2%
1.8	SALES UNIT RATE	$/m³	0.2939	0.2877	0.0062	2.2%	0.2849	0.2787	0.0062	2.2%
1.9	T-SERVICE UNIT RATE	$/m³	0.1723	0.1656	0.0067	4.0%	0.1633	0.1566	0.0067	4.2%
1.10	SALES UNIT RATE	$/GJ	7.798	7.633	0.1642	2.2%	7.558	7.395	0.1633	2.2%
1.11	T-SERVICE UNIT RATE	$/GJ	4.572	4.395	0.1775	4.0%	4.333	4.156	0.1766	4.2%
1.12	SITE RESTORATION CLEARANCE REFUND		(98.85)	(107.46)	8.61		(128.03)	(139.18)	11.15	
1.13	TOTAL SALES WITH SRC REFUND		6,544.81	6,396.26	148.55	2.3%	8,212.31	8,020.95	191.36	2.4%
1.14	TOTAL T-SERVICE WITH SRC REFUND		3,796.69	3,636.81	159.88	4.4%	4,653.11	4,447.06	206.05	4.6%

			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	**(B)**	**CHANGE**		**(A)**	**(B)**	**CHANGE**	
					(A) - (B)	%			(A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	840.00	840.00	0.00	0.0%	840.00	840.00	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	7,230.42	6,777.80	452.62	6.7%	13,238.41	12,409.81	828.60	6.7%
2.4	LOAD BALANCING	§ $	12,847.78	12,344.17	503.61	4.1%	25,695.46	24,688.29	1,007.17	4.1%
2.5	SALES COMMDTY	$	20,613.10	20,698.04	(84.94)	-0.4%	41,226.06	41,395.97	(169.91)	-0.4%
2.6	TOTAL SALES	$	41,531.30	40,660.01	871.29	2.1%	80,999.93	79,334.07	1,665.86	2.1%
2.7	TOTAL T-SERVICE	$	20,918.20	19,961.97	956.23	4.8%	39,773.87	37,938.10	1,835.77	4.8%
2.8	SALES UNIT RATE	$/m³	0.2449	0.2398	0.0051	2.1%	0.2388	0.2339	0.0049	2.1%
2.9	T-SERVICE UNIT RATE	$/m³	0.1234	0.1177	0.0056	4.8%	0.1173	0.1119	0.0054	4.8%
2.10	SALES UNIT RATE	$/GJ	6.499	6.362	0.1363	2.1%	6.337	6.207	0.1303	2.1%
2.11	T-SERVICE UNIT RATE	$/GJ	3.273	3.124	0.1496	4.8%	3.112	2.968	0.1436	4.8%
2.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(741.47)	(806.04)	64.57		(1,482.94)	(1,612.08)	129.14	
2.13	TOTAL SALES WITH SRC REFUND	$	40,789.83	39,853.97	935.86	2.3%	79,516.99	77,721.99	1,795.00	2.3%
2.14	TOTAL T-SERVICE WITH SRC REFUND	$	20,176.73	19,155.93	1,020.80	5.3%	38,290.93	36,326.02	1,964.91	5.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				Industrial Heating & Other Uses			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	840.00	840.00	0.00	0.0%	840.00	840.00	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	2,380.35	2,231.25	149.10	6.7%	3,192.47	2,992.59	199.88	6.7%
3.4	LOAD BALANCING	§ $	3,279.70	3,151.14	128.56	4.1%	4,841.90	4,652.14	189.76	4.1%
3.5	SALES COMMDTY	$	5,262.00	5,283.67	(21.67)	-0.4%	7,768.42	7,800.46	(32.04)	-0.4%
3.6	TOTAL SALES	$	11,762.05	11,506.06	255.99	2.2%	16,642.79	16,285.19	357.60	2.2%
3.7	TOTAL T-SERVICE	$	6,500.05	6,222.39	277.66	4.5%	8,874.37	8,484.73	389.64	4.6%
3.8	SALES UNIT RATE	$/m³	0.2717	0.2658	0.0059	2.2%	0.2604	0.2548	0.0056	2.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.1502	0.1438	0.0064	4.5%	0.1389	0.1328	0.0061	4.6%
3.10	SALES UNIT RATE	$/GJ	7.210	7.053	0.1569	2.2%	6.910	6.762	0.1485	2.2%
3.11	T-SERVICE UNIT RATE	$/GJ	3.984	3.814	0.1702	4.5%	3.685	3.523	0.1618	4.6%
3.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(189.28)	(205.76)	16.48		(279.44)	(303.77)	24.33	
3.13	TOTAL SALES WITH SRC REFUND	$	11,572.77	11,300.30	272.47	2.4%	16,363.35	15,981.42	381.93	2.4%
3.14	TOTAL T-SERVICE WITH SRC REFUND	$	6,310.77	6,016.63	294.14	4.9%	8,594.93	8,180.96	413.97	5.1%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Medium Industrial Customer				Large Industrial Customer			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	840.00	840.00	0.00	0.0%	840.00	840.00	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	7,404.29	6,940.77	463.52	6.7%	13,367.75	12,531.06	836.69	6.7%
4.4	LOAD BALANCING	§ $	12,847.75	12,344.17	503.58	4.1%	25,695.35	24,688.24	1,007.11	4.1%
4.5	SALES COMMDTY	$	20,613.11	20,698.06	(84.95)	-0.4%	41,225.93	41,395.85	(169.92)	-0.4%
4.6	TOTAL SALES	$	41,705.15	40,823.00	882.15	2.2%	81,129.03	79,455.15	1,673.88	2.1%
4.7	TOTAL T-SERVICE	$	21,092.04	20,124.94	967.10	4.8%	39,903.10	38,059.30	1,843.80	4.8%
4.8	SALES UNIT RATE	$/m³	0.2460	0.2408	0.0052	2.2%	0.2392	0.2343	0.0049	2.1%
4.9	T-SERVICE UNIT RATE	$/m³	0.1244	0.1187	0.0057	4.8%	0.1177	0.1122	0.0054	4.8%
4.10	SALES UNIT RATE	$/GJ	6.526	6.388	0.1380	2.2%	6.347	6.216	0.1310	2.1%
4.11	T-SERVICE UNIT RATE	$/GJ	3.300	3.149	0.1513	4.8%	3.122	2.978	0.1443	4.8%
4.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(741.47)	(806.04)	64.57		(1,482.93)	(1,612.07)	129.14	
4.13	TOTAL SALES WITH SRC REFUND	$	40,963.68	40,016.96	946.72	2.4%	79,646.10	77,843.08	1,803.02	2.3%
4.14	TOTAL T-SERVICE WITH SRC REFUND	$	20,350.57	19,318.90	1,031.67	5.3%	38,420.17	36,447.23	1,972.94	5.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				Rate 100 - Average Commercial Firm			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
1.2	CUSTOMER CHG.	$	1,464.12	1,464.12	0.00	0.0%	1,464.12	1,464.12	0.00	0.0%
1.3	DISTRIBUTION CHG.	$	13,492.96	13,459.86	33.10	0.2%	65,793.89	65,735.51	58.38	0.1%
1.4	LOAD BALANCING	$	25,700.23	24,692.90	1,007.33	4.1%	45,353.32	43,575.70	1,777.62	4.1%
1.5	SALES COMMDTY	$	41,233.74	41,403.66	(169.92)	-0.4%	72,765.37	73,065.28	(299.91)	-0.4%
1.6	TOTAL SALES	$	81,891.05	81,020.54	870.51	1.1%	185,376.70	183,840.61	1,536.09	0.8%
1.7	TOTAL T-SERVICE	$	40,657.31	39,616.88	1,040.43	2.6%	112,611.33	110,775.33	1,836.00	1.7%
1.8	SALES UNIT RATE	$/m³	0.2414	0.2389	0.0026	1.1%	0.3097	0.3071	0.0026	0.8%
1.9	T-SERVICE UNIT RATE	$/m³	0.1199	0.1168	0.0031	2.6%	0.1881	0.1851	0.0031	1.7%
1.10	SALES UNIT RATE	$/GJ	6.406	6.338	0.0681	1.1%	8.217	8.149	0.0681	0.8%
1.11	T-SERVICE UNIT RATE	$/GJ	3.180	3.099	0.0814	2.6%	4.992	4.910	0.0814	1.7%
1.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(1,483.21)	(1,612.38)	129.16		(2,617.44)	(2,845.37)	227.93	
1.13	TOTAL SALES WITH SRC REFUND	$	80,407.83	79,408.16	999.67	1.3%	182,759.27	180,995.24	1,764.03	1.0%
1.14	TOTAL T-SERVICE WITH SRC REFUND	$	39,174.09	38,004.50	1,169.59	3.1%	109,993.90	107,929.96	2,063.94	1.9%

Rate 100 - Large Industrial Firm

			(A)	(B)	CHANGE	
					(A) - (B)	%
2.1	VOLUME	m³	1,500,000	1,500,000	0	0.0%
2.2	CUSTOMER CHG.	$	1,464.12	1,464.12	0.00	0.0%
2.3	DISTRIBUTION CHG.	$	132,090.60	131,944.38	146.22	0.1%
2.4	LOAD BALANCING	$	113,654.77	109,200.02	4,454.75	4.1%
2.5	SALES COMMDTY	$	182,349.01	183,100.50	(751.49)	-0.4%
2.6	TOTAL SALES	$	429,558.50	425,709.02	3,849.48	0.9%
2.7	TOTAL T-SERVICE	$	247,209.49	242,608.52	4,600.97	1.9%
2.8	SALES UNIT RATE	$/m³	0.2864	0.2838	0.0026	0.9%
2.9	T-SERVICE UNIT RATE	$/m³	0.1648	0.1617	0.0031	1.9%
2.10	SALES UNIT RATE	$/GJ	7.598	7.530	0.0681	0.9%
2.11	T-SERVICE UNIT RATE	$/GJ	4.373	4.291	0.0814	1.9%
2.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(6,559.25)	(7,130.45)	571.20	
2.13	TOTAL SALES WITH SRC REFUND	$	422,999.24	418,578.57	4,420.68	1.1%
2.14	TOTAL T-SERVICE WITH SRC REFUND	$	240,650.23	235,478.07	5,172.17	2.2%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				**Rate 145 - Average Commercial Interr.**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,480.08	1,480.08	0.00	0.0%	1,480.08	1,480.08	0.00	0.0%
3.3	DISTRIBUTION CHG.	$	9,358.66	9,204.90	153.76	1.7%	13,454.12	13,182.79	271.33	2.1%
3.4	LOAD BALANCING	$	21,326.07	20,941.78	384.29	1.8%	37,634.67	36,956.56	678.11	1.8%
3.5	SALES COMMDTY	$	41,018.01	41,448.12	(430.11)	-1.0%	72,384.82	73,143.81	(758.99)	-1.0%
3.6	TOTAL SALES	$	73,182.82	73,074.88	107.94	0.1%	124,953.69	124,763.24	190.45	0.2%
3.7	TOTAL T-SERVICE	$	32,164.81	31,626.76	538.05	1.7%	52,568.87	51,619.43	949.44	1.8%
3.8	SALES UNIT RATE	$/m³	0.2158	0.2154	0.0003	0.1%	0.2088	0.2084	0.0003	0.2%
3.9	T-SERVICE UNIT RATE	$/m³	0.0948	0.0932	0.0016	1.7%	0.0878	0.0862	0.0016	1.8%
3.10	SALES UNIT RATE	$/GJ	5.725	5.716	0.0084	0.1%	5.539	5.530	0.0084	0.2%
3.11	T-SERVICE UNIT RATE	$/GJ	2.516	2.474	0.0421	1.7%	2.330	2.288	0.0421	1.8%
3.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(281.32)	(361.77)	80.45		(496.45)	(638.42)	141.97	
3.13	TOTAL SALES WITH SRC REFUND	$	72,901.50	72,713.10	188.39	0.3%	124,457.24	124,124.81	332.42	0.3%
3.14	TOTAL T-SERVICE WITH SRC REFUND	$	31,883.49	31,264.98	618.50	2.0%	52,072.42	50,981.00	1,091.41	2.1%
			Rate 145 - Small Industrial Interr.				**Rate 145 - Average Industrial Interr.**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,480.08	1,480.08	0.00	0.0%	1,480.08	1,480.08	0.00	0.0%
4.3	DISTRIBUTION CHG.	$	9,631.43	9,477.66	153.77	1.6%	13,695.57	13,424.25	271.32	2.0%
4.4	LOAD BALANCING	$	21,326.08	20,941.80	384.28	1.8%	37,634.62	36,956.49	678.13	1.8%
4.5	SALES COMMDTY	$	41,017.98	41,448.11	(430.13)	-1.0%	72,384.72	73,143.68	(758.96)	-1.0%
4.6	TOTAL SALES	$	73,455.57	73,347.65	107.92	0.1%	125,194.99	125,004.50	190.49	0.2%
4.7	TOTAL T-SERVICE	$	32,437.59	31,899.54	538.05	1.7%	52,810.27	51,860.82	949.45	1.8%
4.8	SALES UNIT RATE	$/m³	0.2166	0.2162	0.0003	0.1%	0.2092	0.2088	0.0003	0.2%
4.9	T-SERVICE UNIT RATE	$/m³	0.0956	0.0940	0.0016	1.7%	0.0882	0.0866	0.0016	1.8%
4.10	SALES UNIT RATE	$/GJ	5.746	5.737	0.0084	0.1%	5.549	5.541	0.0084	0.2%
4.11	T-SERVICE UNIT RATE	$/GJ	2.537	2.495	0.0421	1.7%	2.341	2.299	0.0421	1.8%
4.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(281.32)	(361.77)	80.45		(496.45)	(638.42)	141.97	
4.13	TOTAL SALES WITH SRC REFUND	$	73,174.25	72,985.87	188.37	0.3%	124,698.54	124,366.07	332.46	0.3%
4.14	TOTAL T-SERVICE WITH SRC REFUND	$	32,156.27	31,537.76	618.50	2.0%	52,313.82	51,222.39	1,091.42	2.1%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				Rate 110 - Average Ind. Firm - 50% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,048.44	7,048.44	0.00	0.0%	7,048.44	7,048.44	0.00	0.0%
5.3	DISTRIBUTION CHG.	$	12,979.57	12,450.52	529.05	4.2%	212,550.79	203,732.89	8,817.90	4.3%
5.4	LOAD BALANCING	$	39,012.08	38,552.38	459.70	1.2%	650,200.52	642,538.78	7,661.74	1.2%
5.5	SALES COMMDTY	$	72,363.27	72,588.31	(225.04)	-0.3%	1,206,053.17	1,209,804.19	(3,751.02)	-0.3%
5.6	TOTAL SALES	$	131,403.36	130,639.65	763.71	0.6%	2,075,852.92	2,063,124.30	12,728.62	0.6%
5.7	TOTAL T-SERVICE	$	59,040.09	58,051.34	988.75	1.7%	869,799.75	853,320.11	16,479.64	1.9%
5.8	SALES UNIT RATE	$/m³	0.2195	0.2183	0.0013	0.6%	0.2081	0.2068	0.0013	0.6%
5.9	T-SERVICE UNIT RATE	$/m³	0.0986	0.0970	0.0017	1.7%	0.0872	0.0855	0.0017	1.9%
5.10	SALES UNIT RATE	$/GJ	5.825	5.791	0.0339	0.6%	5.521	5.487	0.0339	0.6%
5.11	T-SERVICE UNIT RATE	$/GJ	2.617	2.573	0.0438	1.7%	2.313	2.269	0.0438	1.9%
5.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(835.62)	(858.45)	22.82		(13,927.01)	(14,307.42)	380.40	
5.13	TOTAL SALES WITH SRC REFUND	$	130,567.74	129,781.20	786.53	0.6%	2,061,925.91	2,048,816.88	13,109.02	0.6%
5.14	TOTAL T-SERVICE WITH SRC REFUND	$	58,204.47	57,192.89	1,011.57	1.8%	855,872.74	839,012.69	16,860.04	2.0%
			Rate 110 - Average Ind. Firm - 75% LF				Rate 115 - Large Ind. Firm - 80% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,048.44	7,048.44	0.00	0.0%	7,471.44	7,471.44	0.00	0.0%
6.3	DISTRIBUTION CHG.	$	165,592.84	156,774.98	8,817.86	5.6%	824,188.81	792,007.00	32,181.81	4.1%
6.4	LOAD BALANCING	$	650,200.45	642,538.73	7,661.72	1.2%	4,434,381.03	4,411,758.95	22,622.08	0.5%
6.5	SALES COMMDTY	$	1,206,053.05	1,209,804.08	(3,751.03)	-0.3%	8,442,372.56	8,468,629.71	(26,257.15)	-0.3%
6.6	TOTAL SALES	$	2,028,894.78	2,016,166.23	12,728.55	0.6%	13,708,413.84	13,679,867.10	28,546.74	0.2%
6.7	TOTAL T-SERVICE	$	822,841.73	806,362.15	16,479.58	2.0%	5,266,041.28	5,211,237.39	54,803.89	1.1%
6.8	SALES UNIT RATE	$/m³	0.2034	0.2021	0.0013	0.6%	0.1963	0.1959	0.0004	0.2%
6.9	T-SERVICE UNIT RATE	$/m³	0.0825	0.0808	0.0017	2.0%	0.0754	0.0746	0.0008	1.1%
6.10	SALES UNIT RATE	$/GJ	5.396	5.362	0.0339	0.6%	5.208	5.198	0.0108	0.2%
6.11	T-SERVICE UNIT RATE	$/GJ	2.188	2.145	0.0438	2.0%	2.001	1.980	0.0208	1.1%
6.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(13,927.01)	(14,307.42)	380.40		(75,248.89)	(56,903.74)	(18,345.15)	
6.13	TOTAL SALES WITH SRC REFUND	$	2,014,967.77	2,001,858.81	13,108.95	0.7%	13,633,164.95	13,622,963.36	10,201.59	0.1%
6.14	TOTAL T-SERVICE WITH SRC REFUND	$	808,914.72	792,054.73	16,859.98	2.1%	5,190,792.39	5,154,333.65	36,458.74	0.7%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2015-0114 Interim Rates @ 37.69 MJ/m³ vs (B) EB-2015-0163 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				**Rate 170 - Average Ind. Interr. - 50% LF**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,380.96	1,380.96	0.00	0.0%	3,351.72	3,351.72	0.00	0.0%
7.3	DISTRIBUTION CHG.	$	8,929.4	8,088.22	841.13	10.4%	69,600.3	64,506.08	5,094.23	7.9%
7.4	LOAD BALANCING	$	32,399.86	32,287.96	111.90	0.3%	531,362.16	527,703.75	3,658.41	0.7%
7.5	SALES COMMDTY	$	72,427.81	72,628.32	(200.51)	-0.3%	1,206,053.17	1,209,804.19	(3,751.02)	-0.3%
7.6	TOTAL SALES	$	115,137.98	114,385.46	752.52	0.7%	1,810,367.36	1,805,365.74	5,001.62	0.3%
7.7	TOTAL T-SERVICE	$	42,710.17	41,757.14	953.03	2.3%	604,314.19	595,561.55	8,752.64	1.5%
7.8	SALES UNIT RATE	$/m³	0.1924	0.1911	0.0013	0.7%	0.1815	0.1810	0.0005	0.3%
7.9	T-SERVICE UNIT RATE	$/m³	0.0714	0.0698	0.0016	2.3%	0.0606	0.0597	0.0009	1.5%
7.10	SALES UNIT RATE	$/GJ	5.104	5.070	0.0334	0.7%	4.815	4.802	0.0133	0.3%
7.11	T-SERVICE UNIT RATE	$/GJ	1.893	1.851	0.0422	2.3%	1.607	1.584	0.0233	1.5%
7.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(75.47)	(82.36)	6.89		(2,795.33)	(3,348.02)	552.69	
7.13	TOTAL SALES WITH SRC REFUND	$	115,062.51	114,303.10	759.41	0.7%	1,807,572.03	1,802,017.72	5,554.31	0.3%
7.14	TOTAL T-SERVICE WITH SRC REFUND	$	42,634.70	41,674.78	959.92	2.3%	601,518.86	592,213.53	9,305.33	1.6%

			Rate 170 - Average Ind. Interr. - 75% LF				**Rate 170 - Large Ind. Interr. - 75% LF**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,351.72	3,351.72	0.00	0.0%	3,351.72	3,351.72	0.00	0.0%
8.3	DISTRIBUTION CHG.	$	62,415.5	57,321.25	5,094.22	8.9%	321,340.0	285,680.32	35,659.63	12.5%
8.4	LOAD BALANCING	$	531,362.09	527,703.69	3,658.40	0.7%	3,719,535.19	3,693,926.39	25,608.80	0.7%
8.5	SALES COMMDTY	$	1,206,053.05	1,209,804.08	(3,751.03)	-0.3%	8,442,372.56	8,468,629.71	(26,257.15)	-0.3%
8.6	TOTAL SALES	$	1,803,182.33	1,798,180.74	5,001.59	0.3%	12,486,599.42	12,451,588.14	35,011.28	0.3%
8.7	TOTAL T-SERVICE	$	597,129.28	588,376.66	8,752.62	1.5%	4,044,226.86	3,982,958.43	61,268.43	1.5%
8.8	SALES UNIT RATE	$/m³	0.1807	0.1802	0.0005	0.3%	0.1788	0.1783	0.0005	0.3%
8.9	T-SERVICE UNIT RATE	$/m³	0.0599	0.0590	0.0009	1.5%	0.0579	0.0570	0.0009	1.5%
8.10	SALES UNIT RATE	$/GJ	4.796	4.782	0.0133	0.3%	4.744	4.731	0.0133	0.3%
8.11	T-SERVICE UNIT RATE	$/GJ	1.588	1.565	0.0233	1.5%	1.537	1.513	0.0233	1.5%
8.12	SITE RESTORATION CLEARANCE REFUND	$/m³	(2,795.33)	(3,348.02)	552.69		(19,567.29)	(23,436.13)	3,868.84	
8.13	TOTAL SALES WITH SRC REFUND	$	1,800,387.01	1,794,832.73	5,554.28	0.3%	12,467,032.13	12,428,152.01	38,880.12	0.3%
8.14	TOTAL T-SERVICE WITH SRC REFUND	$	594,333.96	585,028.65	9,305.31	1.6%	4,024,659.57	3,959,522.30	65,137.27	1.6%

REVENUE TO COST/
RATE OF RETURN COMPARISONS
Year Ended December 31, 2016
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	Total	Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 325 & 330	Direct Purchase	Rate 332
1.	Sales and Transportation Revenue	2,883.59	1,728.59	1,040.13	0.16	0.00	43.24	7.87	10.83	2.92	4.79	9.74	31.85	0.19	1.80	1.49	0.00
2.	Unbilled Revenues	2.91	1.70	1.26	0.00	0.00	0.24	(0.05)	0.00	0.00	(0.13)	(0.10)	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,891.40	1,730.29	1,041.38	0.16	0.00	43.47	7.82	10.83	2.93	4.66	9.64	31.85	0.19	1.80	1.49	4.89
4.	Cost of Service	2,891.40	1,719.48	1,045.43	0.99	0.00	45.06	9.50	12.22	3.45	5.50	9.44	31.79	0.36	1.80	1.49	4.89
5.	Over / Under Contribution	(0.00)	10.82	(4.05)	(0.83)	(0.00)	(1.59)	(1.68)	(1.39)	(0.53)	(0.85)	0.20	0.06	(0.18)	(0.00)	0.01	0.00
6.	Revenue to Cost Ratio	1.00	1.01	1.00	0.16	0.00	0.96	0.82	0.89	0.85	0.85	1.02	1.00	0.51	1.00	1.00	1.00
7.	Revenue to Cost Ratio (2015 Final Rate Order)	1.00	1.01	1.00	0.16	0.00	0.92	0.95	1.00	0.79	0.73	0.82	1.02	1.84	1.00	1.00	1.00

REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
Year Ended December 31, 2016

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	Total	Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 325 & 330	Direct Purchase	Rate 332
1.	Sales and Transportation Revenue	1,925.73	1,181.41	662.68	0.10	0.00	33.41	7.87	10.83	2.47	3.43	5.62	16.24	0.19	0.00	1.49	0.00
2.	Unbilled Revenues	2.91	1.70	1.26	0.00	0.00	0.24	(0.05)	0.00	0.00	(0.13)	(0.10)	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,933.54	1,183.11	663.94	0.10	0.00	33.65	7.82	10.83	2.47	3.30	5.52	16.24	0.19	0.00	1.49	4.89
4.	Cost of Service	1,933.54	1,172.29	667.99	0.94	0.00	35.23	9.50	12.22	3.00	4.15	5.32	16.18	0.36	0.00	1.49	4.89
5.	Over / Under Contribution	(0.00)	10.82	(4.05)	(0.83)	(0.00)	(1.59)	(1.68)	(1.39)	(0.53)	(0.85)	0.20	0.06	(0.18)	0.00	0.01	0.00
6.	Revenue to Cost Ratio	1.00	1.01	0.99	0.11	0.00	0.95	0.82	0.89	0.82	0.80	1.04	1.00	0.51	0.00	1.00	1.00
7.	Revenue to Cost Ratio (2015 Final Rate Order)	1.00	1.01	1.00	0.10	0.00	0.88	0.95	1.00	0.75	0.62	0.65	1.06	1.84	0.00	1.00	1.00

Functionalization of
Ontario Utility Rate Base
Year Ended December 31, 2016
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(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
		Net Rate Base	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Meters	Rental Equipment	Sales/ Marketing	Customer Accounting	Unidenti-fiable	CIS	HST Revenue
1.	**Gas Supply**	1.56	0.00	1.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Distribution Plant														
2.1	Land (incl offers to buy)	133.17	1.30	0.00	0.63	0.31	15.79	52.75	0.31	0.00	8.14	30.15	23.79	0.00	0.00
2.2	Structures & Improvements	101.43	0.99	0.00	0.48	0.23	12.03	9.75	0.23	0.00	16.34	43.25	18.12	0.00	0.00
2.3	Mains	2,312.79	0.00	0.00	0.00	0.00	0.00	2,312.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Meas. Reg. & Telemetering	314.60	0.00	0.00	153.56	161.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.5	Services	1,491.93	0.00	0.00	0.00	0.00	1,491.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Meters	245.09	0.00	0.00	0.00	0.00	0.00	0.00	245.09	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Distribution Plant	4,599.00	2.29	0.00	154.67	161.58	1,519.75	2,375.28	245.63	0.00	24.48	73.40	41.91	0.00	0.00
	General Plant														
3.1	Land (incl offers to buy)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Structures & Improvements	9.27	0.00	0.00	0.00	0.00	3.11	0.42	0.00	0.00	1.17	3.28	1.30	0.00	0.00
3.3	Office Furniture & Equip.	16.17	0.02	0.02	0.02	1.99	2.61	3.24	0.75	0.27	0.39	0.51	6.36	0.00	0.00
3.4	Transportation Equipment	28.23	0.00	0.00	0.00	0.07	8.37	18.87	0.00	0.00	0.92	0.00	0.00	0.00	0.00
3.5	Heavy Work Equipment	13.84	0.00	0.00	0.00	0.03	4.10	9.25	0.00	0.00	0.45	0.00	0.00	0.00	0.00
3.6	Tools & Work Equip.	22.24	0.00	0.00	0.00	0.00	11.12	11.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.7	Rental Equip.	10.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.21	0.00	0.00	0.00	0.00	0.00
3.8	Communication Equip.	1.87	0.03	0.00	0.01	0.53	0.16	0.23	0.00	0.00	0.18	0.32	0.41	0.00	0.00
3.9	Compressors	0.58	0.00	0.00	0.00	0.00	0.17	0.39	0.00	0.00	0.02	0.00	0.00	0.00	0.00
3.10	Computer Equipment	2.20	0.05	0.01	0.05	0.19	0.35	0.57	0.19	0.00	0.02	0.51	0.25	0.00	0.00
3.11	Software Acquired/Developed	59.24	1.43	0.20	1.38	5.03	9.56	15.47	5.03	0.09	0.53	13.68	6.85	0.00	0.00
3.12	WAMS	61.06	1.47	0.21	1.42	5.18	9.85	15.94	5.18	0.09	0.54	14.10	7.06	0.00	0.00
3.13	CIS	32.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.40	0.00
3.	Total General Plant	257.31	3.00	0.44	2.89	13.02	49.41	75.51	11.15	10.66	4.21	32.39	22.24	32.40	0.00
4.	**Plant Held for Future Use**	0.44	0.00	0.00	0.00	0.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Other Items														
5.1	Working Capital Allowance	359.00	412.63	1.58	(0.14)	(0.44)	15.07	22.79	0.00	0.00	(0.73)	(67.01)	0.72	0.00	(25.47)
5.	Total Other Items	359.00	412.63	1.58	(0.14)	(0.44)	15.07	22.79	0.00	0.00	(0.73)	(67.01)	0.72	0.00	(25.47)
6.	**Total Rate Base**	5,217.30	417.92	3.58	157.41	174.16	1,584.68	2,473.58	256.78	10.66	27.95	38.77	64.88	32.40	(25.47)

Functionalization of
Ontario Utility Working Capital
Year Ended December 31, 2016
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		Total Requirement	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Sales/ Marketing	Customer Accounting	Unidenti- fiable	HST Revenue
	Working Capital Allowance											
1.	Prepaid Expenses	1.00	0.00	0.00	0.00	0.00	0.12	0.12	0.01	0.00	0.75	0.00
	Materials & Supplies											
2.1	NGV Inventory	0.64	0.00	0.00	0.00	0.00	0.00	0.00	0.64	0.00	0.00	0.00
2.2	Pipe	6.27	0.00	0.00	0.00	0.00	1.43	4.84	0.00	0.00	0.00	0.00
2.3	Warehouse Inventory	5.77	0.00	0.00	0.00	0.00	2.89	2.89	0.00	0.00	0.00	0.00
2.4	Holding Account	18.84	0.00	0.00	0.00	0.00	9.42	9.42	0.00	0.00	0.00	0.00
3.	Mortgages Receivable	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Rebilled Construction Work	1.40	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	0.00	0.00
5.	Gas in Inventory	391.10	391.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Customer Security Deposits	(64.60)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(64.60)	0.00	0.00
	Working Cash Allowance											
7.1	Gas Costs/O&M	(0.23)	9.40	0.69	(0.21)	(0.64)	(0.90)	(3.03)	(2.00)	(3.51)	(0.03)	0.00
7.2	HST	(1.19)	12.13	0.89	0.07	0.20	2.12	7.15	0.63	1.09	0.01	(25.47)
8.	**Total Working Capital**	359.00	412.63	1.58	(0.14)	(0.44)	15.07	22.79	(0.73)	(67.01)	0.72	(25.47)

Functionalization of
Ontario Utility Net Investments
Year Ended December 31, 2016

(millions of dollars)

		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
		Investment and Revenues	Gas Supply	Storage	Sales Stations	Distribution Measurement	Services	Mains	Meters	Rental Equipment	Sales/ Marketing	Customer Accounting	Unidenti- fiable	CIS
	Investment Costs													
1.1	Depreciation	273.70	1.24	0.17	6.50	10.13	69.36	101.08	44.73	1.90	2.23	15.17	8.52	12.68
1.2	Municipal Taxes	43.24	0.02	0.00	0.20	0.20	11.91	29.28	0.00	0.00	0.34	0.90	0.38	0.00
1.3	Capital Taxes	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Investments	316.94	1.26	0.17	6.70	10.33	81.26	130.36	44.73	1.90	2.57	16.07	8.90	12.68
	Miscellaneous Revenues													
2.1	Rentals	(0.90)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.90)	0.00	0.00	0.00	0.00
2.2	Transactional Services	(6.00)	(6.12)	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	Miscellaneous Income	(1.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(1.00)	0.00
2.4	Late Payment Penalties	(10.10)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(10.10)	0.00	0.00
2.5	Open Bill Revenue	(5.40)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(5.40)	0.00	0.00
2.6	Customer Accounting Charge	(8.92)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8.92)	0.00	0.00
2.7	Meter Charge	(1.03)	0.00	0.00	0.00	0.00	0.00	0.00	(1.03)	0.00	0.00	0.00	0.00	0.00
2.8	Service Alteration Charge	(1.36)	0.00	0.00	0.00	0.00	(1.36)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Revenues	(34.71)	(6.12)	0.12	0.00	0.00	(1.36)	0.00	(1.03)	(0.90)	0.00	(24.42)	(1.00)	0.00
3.	**Net Investments Total**	282.23	(4.85)	0.28	6.70	10.33	79.90	130.36	43.70	1.00	2.57	(8.35)	7.90	12.68

Functionalization of
Ontario Utility O&M
Year Ended December 31, 2016

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Gas Supply							
1.1	Gas Purchased	1,609.92	0.00	1,609.92	0.00	1,609.92	0.00	1,609.92
1.2	Gas Storage	184.58	2.87	187.45	0.00	187.45	0.00	187.45
1.3	A&G	0.00	0.00	0.00	0.00	0.00	11.91	11.91
1.4	System Gas Management	0.97	0.69	1.66	0.00	1.66	0.00	1.66
1.5	Direct Purchase Management	1.07	0.43	1.49	0.00	1.49	0.00	1.49
1.	Total Gas Supply	1,796.51	3.99	1,800.50	0.00	1,800.50	11.91	1,812.41
	Distribution Costs							
	Operating Costs							
2.1.1	Chart Processing	0.04	0.00	0.04	0.02	0.07	0.01	0.08
2.1.2	Distribution Sta.	1.26	0.83	2.09	1.21	3.30	0.73	4.03
2.1.3	Sub-total	1.30	0.83	2.13	1.24	3.37	0.74	4.11
2.1.4	Supervision M&R	0.46	0.37	0.83	(0.83)	0.00	0.00	0.00
2.1.5	System Operation	45.41	12.33	57.74	11.12	68.86	15.18	84.03
2.1.6	Sub-total	47.18	13.52	60.70	11.53	72.22	15.92	88.15
2.1.7	Supervision Dist Op	7.07	4.45	11.53	(11.53)	0.00	0.00	0.00
2.1.8	Gas Dispatched	4.84	2.44	7.28	0.00	7.28	1.61	8.89
2.1	Total Operating Costs	59.09	20.42	79.51	0.00	79.51	17.53	97.03
	Maintenance Costs							
2.2.1	Distribution Sys Reg	1.16	0.08	1.25	3.15	4.40	0.97	5.37
2.2.2	Sales Meters	0.81	0.40	1.21	3.07	4.29	0.95	5.23
2.2.3	Other Meters	1.82	1.10	2.92	7.39	10.32	2.27	12.59
2.2.4	Instruments	0.85	0.44	1.29	3.27	4.56	1.01	5.56
2.2.5	Sub-total M&R	4.64	2.03	6.67	16.89	23.57	5.19	28.76
2.2.6	Supervision M&R	6.04	3.02	9.06	(9.06)	0.00	0.00	0.00
2.2.7	Mains	9.03	3.18	12.21	14.33	26.54	5.85	32.38
2.2.8	Structures	0.30	0.20	0.50	0.58	1.08	0.24	1.31
2.2.9	Sub-total Mntce	20.02	8.42	28.43	22.74	51.18	11.28	62.46
2.2.10	Supervision Dist Mntce	14.72	8.02	22.74	(22.74)	0.00	0.00	0.00
2.2	Total Maintenance Costs	34.74	16.44	51.18	0.00	51.18	11.28	62.46
2.	Total Distribution Costs	93.82	36.86	130.68	0.00	130.68	28.81	159.49

Functionalization of
Ontario Utility O&M
Year Ended December 31, 2016
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Customer Service Costs							
	Operating Costs							
3.1.1	Heating Equipment Service	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.1	Other Service Work	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.2	Inspect Appl Inst.	2.23	0.63	2.85	1.16	4.01	0.88	4.90
3.1.3	Sub-total Service Work	2.23	0.63	2.85	1.16	4.01	0.88	4.90
3.1.4	Mtr Locks,Unlks,Exchanges	9.63	0.99	10.63	4.32	14.95	3.29	18.24
3.1.5	Jobbing Contracts Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.1.6	Sub-total	11.86	1.62	13.48	5.48	18.96	4.18	23.14
3.1.7	Training & Supervision	5.13	3.04	8.17	(8.17)	0.00	0.00	0.00
3.1	Total Operating Costs	16.99	4.66	21.65	(2.69)	18.96	4.18	23.14
	Maintenance Costs							
3.2.1	Co Equip on Cust. Premises	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2.2	Service Lines	4.58	2.03	6.61	2.69	9.30	2.05	11.35
3.2	Total Maintenance Costs	4.58	2.03	6.61	2.69	9.30	2.05	11.35
3.	Total Customer Service Costs	21.58	6.69	28.26	0.00	28.26	6.23	34.50
	Sales/Marketing Costs							
4.1	Residential Promotion	2.67	0.77	3.44	1.20	4.64	1.02	5.67
4.2	Commercial Promotion	1.08	1.38	2.46	0.86	3.32	0.73	4.05
4.3	Industrial Promotion	0.79	0.97	1.76	0.62	2.37	0.52	2.89
4.4	General Sales Promotion	2.70	1.88	4.58	1.60	6.18	1.36	7.55
4.5	Merchandising Expenses	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.75	0.45	1.19	0.42	1.61	0.36	1.97
4.7	Contract Administration Costs	2.32	1.69	4.01	1.40	5.41	1.19	6.61
4.8	Sub-total	10.31	7.13	17.44	6.11	23.55	5.19	28.74
4.9	General Supervision	3.86	2.25	6.11	(6.11)	0.00	0.00	0.00
4.10	DSM - Program	28.42	0.00	28.42	0.00	28.42	6.26	34.68
4.11	DSM - General	6.62	4.59	11.21	0.00	11.21	2.47	13.68
4.	Total Sales	49.20	13.97	63.17	0.00	63.17	13.93	77.09

Functionalization of
Ontario Utility O&M
Year Ended December 31, 2016
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(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		Cost of Service	Fringe Benefits	Sub-Total	Supervision	Sub-Total	A&G Overhead	Total
	Customer Accounting Costs							
5.1	Billing	43.72	1.40	45.12	9.01	54.13	11.93	66.07
5.2	Service & Billing Enquiry	10.04	0.00	10.04	2.00	12.04	2.65	14.70
5.3	Meter Reading	10.64	0.00	10.64	2.12	12.76	2.81	15.58
5.4	Credit & Collection	16.21	0.00	16.21	3.24	19.45	4.29	23.74
5.5	Sub-total	80.61	1.40	82.01	16.37	98.38	21.69	120.07
5.6	Supervision	16.09	0.28	16.37	(16.37)	0.00	0.00	0.00
5.7	Large Volume Customer Care	2.58	0.05	2.63	0.00	2.63	0.58	3.21
5.8	Uncollectible Accounts	9.50	0.00	9.50	0.00	9.50	2.09	11.59
5.	Total Customer Accounting	108.78	1.73	110.51	0.00	110.51	24.36	134.87
6.	**Fringe Benefits**	86.13	(86.13)	0.00	0.00	0.00	0.00	0.00
7.	**Admin & Gen Overhead**	62.33	22.90	85.23	0.00	85.23	(85.23)	0.00
8.	Sub-total A&G and F/B	148.47	(63.23)	85.23	0.00	85.23	(85.23)	0.00
9.	**Total Operating & Maintenance**	2,218.36	(0.00)	2,218.36	0.00	2,218.36	0.00	2,218.36
10.	Fixed Financing Costs	1.90	0.00	1.90	0.00	1.90	0.00	1.90
11.	**TOTAL O&M EXPENSE**	2,220.26	(0.00)	2,220.26	0.00	2,220.26	0.00	2,220.26

CLASSIFICATION OF RATE BASE
Year Ended December 31, 2016

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
				GAS SUPPLY												
				PRODUCT COSTS		LOAD BALANCING			STORAGE COSTS			DISTRIBUTION COSTS				
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	Peak	Seasonal	Annual	Deliverability	Space	Winter	TP Capacity <=4"	TP Capacity >4"	HP Capacity	LP Capacity	Commodity
	GAS SUPPLY															
1.	Gas Supply	417.92	0.00	0.00	26.53	0.00	391.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30
2.	Storage	3.58	0.00	0.00	0.00	0.00	0.00	0.00	2.45	1.13	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION															
3.	Mains	2,473.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.25	565.64	177.01	922.31	0.00
4.	Distribution Reg.	174.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.98	57.13	17.88	93.16	0.00
	CUSTOMER															
5.	Sales Station	157.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	256.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	1,584.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	10.66	4.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	27.95	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.48	4.59	1.43	7.48	0.00
10.	Customer Accounting	38.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11.	HST Revenue	(25.47)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12.	**Sub-total**	5,120.03	4.99	0.00	26.53	0.00	391.10	0.00	2.45	1.13	0.00	65.71	627.36	196.33	1,022.95	0.30
13.	Unidentifiable	64.88	0.06	0.00	0.33	0.00	4.93	0.00	0.03	0.01	0.00	0.83	7.91	2.48	12.90	0.00
14	CIS	32.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16.	**Total Classified**	5,217.30	5.06	0.00	26.86	0.00	396.03	0.00	2.48	1.14	0.00	66.54	635.27	198.80	1,035.85	0.30

CLASSIFICATION OF RATE BASE
Year Ended December 31, 2016

(millions of dollars)

		Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26	Col. 27
		CUSTOMER RELATED INVESTMENTS					NUMBER OF CUSTOMERS						
Item No.	Description	Meters	Sales Stations	Services	Customer Plant	Rentals	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	CIS	HST Revenue
	GAS SUPPLY												
1.	Gas Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION												
3.	Mains	0.00	0.00	0.00	749.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Distribution Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER												
5.	Sales Station	0.00	157.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	256.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	0.00	0.00	1,584.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	0.00	0.00	0.00	0.00	6.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.61	0.00	0.00	0.00
10.	Customer Accounting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.77	0.00	0.00	0.00
11.	HST Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(25.47)
12.	**Sub-total**	256.78	157.41	1,584.68	749.37	6.04	0.00	0.00	0.00	52.38	0.00	0.00	(25.47)
13.	Unidentifiable	3.24	1.98	19.98	9.45	0.08	0.00	0.00	0.00	0.66	0.00	0.00	0.00
14	CIS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.40	0.00
15.	**Total Classified**	260.02	159.40	1,604.66	758.82	6.11	0.00	0.00	0.00	53.04	0.00	32.40	(25.47)

CLASSIFICATION OF NET INVESTMENT
Year Ended December 31, 2016

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
				GAS SUPPLY														
				PRODUCT COSTS		LOAD BALANCING					STORAGE COSTS			DISTRIBUTION COSTS				
Item No.	Description	Total	Specific Classes	Winter Commodity	Annual Commodity	Peak	Seasonal	Annual	DSM Peak	DSM Annual	Deliverability	Space	Winter	TP Capacity <=4"	TP Capacity >4"	HP Capacity	LP Capacity	Commodity
	GAS SUPPLY																	
1.	Gas Supply	(4.85)	0.00	0.00	0.08	0.00	1.23	(6.12)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.05)
2.	Storage	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.19	0.09	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION																	
3.	Mains	130.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.12	29.81	9.33	48.61	0.00
4.	Distribution Reg.	10.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.36	3.39	1.06	5.53	0.00
	CUSTOMER																	
5.	Sales Station	6.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	43.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	79.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	1.00	(0.31)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	2.57	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.42	0.13	0.69	0.00
10.	Customer Accounting	(8.35)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11.	**Sub-total**	261.65	(0.27)	0.00	0.08	0.00	1.23	(6.12)	0.00	0.00	0.19	0.09	0.00	3.52	33.62	10.52	54.82	(0.05)
12.	Unidentifiable	7.90	0.01	0.00	0.04	0.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.96	0.30	1.57	0.00
13	CIS	12.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14.	**Total Classified**	282.23	(0.27)	0.00	0.12	0.00	1.84	(6.12)	0.00	0.00	0.20	0.09	0.00	3.62	34.59	10.82	56.39	(0.05)

CLASSIFICATION OF NET INVESTMENT
Year Ended December 31, 2016
(millions of dollars)

		Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24	Col. 25	Col. 26	Col. 27	Col. 28
		CUSTOMER RELATED INVESTMENTS					NUMBER OF CUSTOMERS					
Item No.	Description	Meters	Sales Stations	Services	Customer Plant	Rentals	Commercial/ Industrial	Contracts	Direct Purchase	Total	Readings Processed	CIS
	GAS SUPPLY											
1.	Gas Supply	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION											
3.	Mains	0.00	0.00	0.00	39.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Distribution Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER											
5.	Sales Station	0.00	6.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6.	Meters	43.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7.	Services	0.00	0.00	79.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	Rental Equipment	0.00	0.00	0.00	0.00	1.30	0.00	0.00	0.00	0.00	0.00	0.00
9.	Sales/Marketing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.25	0.00	0.00
10.	Customer Accounting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8.35)	0.00	0.00
11.	**Sub-total**	43.70	6.70	79.90	39.49	1.30	0.00	0.00	0.00	(7.10)	0.00	0.00
12.	Unidentifiable	0.39	0.24	2.43	1.15	0.01	0.00	0.00	0.00	0.08	0.00	0.00
13	CIS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.68
14.	**Total Classified**	44.09	6.94	82.33	40.64	1.31	0.00	0.00	0.00	(7.02)	0.00	12.68

CLASSIFICATION OF O&M COSTS
Year Ended December 31, 2014

(millions of dollars)

Item No.	Description	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
				GAS SUPPLY									
				PRODUCT COSTS				LOAD BALANCING			STORAGE COSTS		
		Total	Specific Classes	Winter Commodity	Annual Commodity	System Gas	Bad Debt Commodity	Peak	Seasonal	Transportation Annual	Deliverability	Space	Winter
	GAS SUPPLY												
1.1	Gas Purchased	1,609.92	0.00	0.00	948.50	0.00	0.00	9.96	69.82	562.50	0.00	0.00	0.00
1.2	Stored Gas	187.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	128.34	59.11	0.00
1.3	A&G	11.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	1.66	0.00	0.00	0.00	1.66	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	1.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Gas Supply	1,812.41	0.00	0.00	948.50	1.66	0.00	9.96	69.82	562.50	128.34	59.11	0.00
	DISTRIBUTION												
	OPERATING COSTS												
2.1	Chart Processing	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	District Stations	4.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	84.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Gas Dispatched	8.89	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
2.5	Dist. System Reg.	5.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	5.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.7	Other Meters	12.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.8	Instruments	5.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	32.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.10	Structures	1.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.	Total Distribution Costs	159.49	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER SERVICE												
	OPERATING COSTS												
3.1	Appliance Inspection	4.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Locks/Unlocks/Exchanges	18.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
3.3	Service Lines	11.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Customer Service	34.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SALES/MARKETING												
4.1	Residential	5.67	5.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	4.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	2.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	General Promotion	7.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	Merchandising Ex.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	1.97	1.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	6.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	34.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	13.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	77.09	7.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING												
5.1	Billing	66.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.2	Enquiry	14.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.3	Readings	15.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.4	Credit	23.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Large Volume Customer Care	3.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.6	Uncollectibles	11.59	0.00	0.00	0.00	0.00	3.97	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	134.87	0.00	0.00	0.00	0.00	3.97	0.00	0.00	0.00	0.00	0.00	0.00
6.	**Total O&M**	2,218.36	7.72	0.00	948.50	1.66	3.97	9.96	69.82	562.50	128.34	59.11	0.00
7.	Fixed Financing Costs	1.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	**Total O&M Expense**	2,220.26	7.72	0.00	948.50	1.66	3.97	9.96	69.82	562.50	128.34	59.11	0.00

CLASSIFICATION OF O&M COSTS
Year Ended December 31, 2016

(millions of dollars)

		Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18	Col. 19	Col. 20	Col. 21	Col. 22	Col. 23	Col. 24
		DISTRIBUTION COSTS						CUSTOMER RELATED INVESTMENTS					
Item No.	Description	TP Capacity <=4"	TP Capacity >4"	HP Capacity	LP Capacity	Commodity	Bad Debt Distribution	DSM	Meters	Sales Stations	Services	Customer Plant	Rentals
	GAS SUPPLY												
1.1	Gas Purchased	0.00	0.00	0.00	0.00	19.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.2	Stored Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.3	A&G	1.13	10.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.	Total Gas Supply	1.13	10.78	0.00	0.00	19.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION												
	OPERATING COSTS												
2.1	Chart Processing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	District Stations	0.14	1.32	0.41	2.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	2.01	19.22	6.01	31.33	0.00	0.00	0.00	0.00	0.00	0.00	25.46	0.00
2.4	Gas Dispatched	0.83	7.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
2.5	Dist. System Reg.	0.18	1.76	0.55	2.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.23	0.00	0.00	0.00
2.7	Other Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.59	0.00	0.00	0.00	0.00
2.8	Instruments	0.53	5.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	0.49	4.64	1.45	14.23	0.00	0.00	0.00	0.00	0.00	0.00	11.57	0.00
2.10	Structures	0.26	0.04	0.01	0.06	0.02	0.00	0.00	0.01	0.00	0.19	0.05	0.00
2.	Total Distribution Costs	4.45	39.98	8.44	50.66	0.02	0.00	0.00	12.60	5.23	0.19	37.07	0.00
	CUSTOMER SERVICE												
	OPERATING COSTS												
3.1	Appliance Inspection	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Locks/Unlocks/Exchanges	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS												
3.4	Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.35	0.00	0.00
3.	Total Customer Service	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.35	0.00	0.00
	SALES/MARKETING												
4.1	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.4	General Promotion	0.72	6.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	Merchandising Ex.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	0.00	0.00	0.00	0.00	0.00	0.00	34.68	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	0.00	0.00	0.00	0.00	0.00	0.00	13.68	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	0.72	6.83	0.00	0.00	0.00	0.00	48.36	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING												
5.1	Billing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.2	Enquiry	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.3	Readings	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.4	Credit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Large Volume Customer Care	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.6	Uncollectibles	0.00	0.00	0.00	0.00	0.00	7.62	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	0.00	0.00	0.00	0.00	0.00	7.62	0.00	0.00	0.00	0.00	0.00	0.00
6.	**Total O&M**	6.29	57.59	8.44	50.66	19.16	7.62	48.36	12.60	5.23	11.54	37.07	0.00
7.	Fixed Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8.	**Total O&M Expense**	6.29	57.59	8.44	50.66	19.16	7.62	48.36	12.60	5.23	11.54	37.07	0.00

CLASSIFICATION OF O&M COSTS
Year Ended December 31, 2016
(millions of dollars)

Item No.	Description	Col. 25 Commercial/ Industrial	Col. 26 Contracts	Col. 27 Direct Purchase	Col. 28 Total	Col. 29 Readings Processed	Col. 30 LV CC	Col. 31 Fixed Financing
		NUMBER OF CUSTOMERS						
	GAS SUPPLY							
1.1	Gas Purchased	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.2	Stored Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.3	A&G	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.4	System Gas Management	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1.5	Direct Purchase Management	0.00	0.00	1.49	0.00	0.00	0.00	0.00
1.	Total Gas Supply	0.00	0.00	1.49	0.00	0.00	0.00	0.00
	DISTRIBUTION							
	OPERATING COSTS							
2.1	Chart Processing	0.00	0.00	0.00	0.00	0.08	0.00	0.00
2.2	District Stations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.3	System Operations	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.4	Gas Dispatched	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MAINTENANCE COSTS							
2.5	Dist. System Reg.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.6	Sales Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.7	Other Meters	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.8	Instruments	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.9	Mains	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.10	Structures	0.00	0.00	0.00	0.68	0.00	0.00	0.00
2.	Total Distribution Costs	0.00	0.00	0.00	0.68	0.08	0.00	0.00
	CUSTOMER SERVICE							
	OPERATING COSTS							
3.1	Appliance Inspection	0.00	0.00	0.00	4.90	0.00	0.00	0.00
3.2	Locks/Unlocks/Exchanges	0.00	0.00	0.00	18.24	0.00	0.00	0.00
	MAINTENANCE COSTS							
3.3	Service Lines	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Customer Service	0.00	0.00	0.00	23.14	0.00	0.00	0.00
	SALES/MARKETING							
4.1	Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.2	Commercial	4.05	0.00	0.00	0.00	0.00	0.00	0.00
4.3	Industrial	2.89	0.00	0.00	0.00	0.00	0.00	0.00
4.4	General Promotion	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.5	Merchandising Ex.	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	NGV Operation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.7	Contract Administration	0.00	6.61	0.00	0.00	0.00	0.00	0.00
4.8	DSM - Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.9	DSM - General	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.	Total Promotions	6.95	6.61	0.00	0.00	0.00	0.00	0.00
	CUSTOMER ACCOUNTING							
5.1	Billing	0.00	0.00	0.00	66.07	0.00	0.00	0.00
5.2	Enquiry	0.00	0.00	0.00	14.70	0.00	0.00	0.00
5.3	Readings	0.00	0.00	0.00	0.00	15.58	0.00	0.00
5.4	Credit	0.00	0.00	0.00	23.74	0.00	0.00	0.00
5.5	Large Volume Customer Care	3.21	0.00	0.00	0.00	0.00	0.00	0.00
5.6	Uncollectibles	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.	Total Customer Accounting	3.21	0.00	0.00	104.50	15.58	0.00	0.00
6.	**Total O&M**	10.15	6.61	1.49	128.32	15.66	0.00	0.00
7.	Fixed Financing Costs	0.00	0.00	0.00	0.00	0.00	0.00	1.90
8.	**Total O&M Expense**	10.15	6.61	1.49	128.32	15.66	0.00	1.90

ALLOCATION OF RATE BASE
Year Ended December 31, 2016
(millions of dollars)

ITEM NO	DESCRIPTION	Col. 1 Rate Base	Col. 2 Rate 1	Col. 3 Rate 6	Col. 4 Rate 9	Col. 5 Rate 100	Col. 6 Rate 110	Col. 7 Rate 115	Col. 8 Rate 125	Col. 9 Rate 135	Col. 10 Rate 145	Col. 11 Rate 170	Col. 12 Rate 200	Col. 13 Rate 300	Col. 14 Rate 300 Int	Col. 15 Allocation Factors G2.6.3.1
	SUPPLY COST															
	PRODUCT COST															
1.1	Annual Commodity	26.86	15.38	10.59	0.00	0.00	0.28	0.00	0.00	0.01	0.04	0.12	0.44	0.00	0.00	1.1
1	Total Gas Cost	26.86	15.38	10.59	0.00	0.00	0.28	0.00	0.00	0.01	0.04	0.12	0.44	0.00	0.00	
	PIPELINE TRANSPORTATION															
2.1	Peak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.4
2.2	Seasonal	396.03	194.56	183.76	0.00	0.00	5.60	1.52	0.00	0.00	1.69	2.96	5.93	0.00	0.00	3.2
2.3	Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.2
2	Total Pipeline Trans. Cost	396.03	194.56	183.76	0.00	0.00	5.60	1.52	0.00	0.00	1.69	2.96	5.93	0.00	0.00	
	FACILITIES' COST															
	STORAGE FACILITIES															
3.1	Deliverability	2.48	1.37	1.07	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	3.1
3.2	Space	1.14	0.56	0.53	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.00	3.2
3	Total Storage	3.62	1.93	1.60	0.00	0.00	0.04	0.01	0.00	0.00	0.00	0.01	0.04	0.00	0.00	
	DISTRIBUTION FACILITIES															
4.1	Capacity TP > 4"	635.27	295.35	253.49	0.01	0.00	14.47	8.61	54.27	0.03	1.02	0.91	7.01	0.09	0.00	2.1
4.2	Capacity TP <= 4"	66.54	33.83	29.03	0.00	0.00	1.66	0.99	0.00	0.00	0.12	0.10	0.80	0.01	0.00	2.2
4.3	Capacity HP	198.80	102.19	87.71	0.00	0.00	5.01	2.98	0.00	0.01	0.35	0.32	0.00	0.03	0.21	2.3
4.4	Capacity LP	1,035.85	532.67	457.18	0.01	0.00	26.10	15.08	0.00	0.05	1.85	1.65	0.00	0.15	1.11	2.4
4.5	Commodity	0.30	0.13	0.13	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	1.3
4.6	Customer Plant	758.82	699.61	59.07	0.00	0.00	0.08	0.01	0.00	0.02	0.02	0.01	0.00	0.00	0.00	2.5
4	Total Distribution	2,695.58	1,663.76	886.61	0.03	0.00	47.32	27.68	54.28	0.10	3.36	3.00	7.82	0.28	1.32	
	CUSTOMER RELATED															
5.1	Meters	260.02	143.59	111.90	0.04	0.00	1.90	0.22	1.36	0.37	0.38	0.23	0.00	0.01	0.01	4.1
5.2	Sales Stations	159.40	11.86	135.56	0.13	0.00	5.46	0.93	0.00	2.28	1.35	1.61	0.00	0.11	0.11	4.2
5.3	Services	1,604.66	1,422.28	177.16	0.01	0.00	2.13	0.30	0.28	0.30	0.35	1.76	0.00	0.01	0.07	4.3
5.4	Rentals	6.11	1.22	4.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4
5.5	Comm / Ind. Customers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.6
5.6	Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.7
5.7	Direct Purchase	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.12
5.8	Total Customers	53.04	48.90	4.13	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.5
5.9	Specific Classes	5.06	0.72	1.05	3.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
5.10	Readings Processed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8 & 4.9
5.11	HST Revenue	(25.47)	(14.59)	(10.04)	(0.00)	0.00	(0.26)	0.00	0.00	(0.01)	(0.04)	(0.11)	(0.42)	0.00	0.00	1.2
5	Total Customer Related	2,062.81	1,614.01	424.66	3.46	0.00	9.24	1.45	1.64	2.93	2.05	3.49	(0.42)	0.13	0.19	
6	**Total Rate Base**	5,184.90	3,489.64	1,507.22	3.49	0.00	62.48	30.66	55.92	3.05	7.14	9.58	13.82	0.41	1.51	
7	CIS	32.40	29.87	2.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
8	**Total Rate Base + CIS**	5,217.30	3,519.51	1,509.74	3.49	0.00	62.48	30.66	55.92	3.05	7.14	9.58	13.82	0.41	1.51	

* G2.6.3 refers to Exhibit G2, Tab 6, Schedule 3.

ALLOCATION OF RETURN & TAXES
Year Ended December 31, 2016

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 RATE BASE	Col. 2 RETURN & TAXES	Col. 3 RATE 1	Col. 4 RATE 6	Col. 5 RATE 9	Col. 6 RATE 100	Col. 7 RATE 110	Col. 8 RATE 115	Col. 9 RATE 125	Col. 10 RATE 135	Col. 11 RATE 145	Col. 12 RATE 170	Col. 13 RATE 200	Col. 14 RATE 300	Col. 15 RATE 300 Int
	SUPPLY COST															
	PRODUCT COST															
1.1	Annual Commodity	26.86	1.80	1.03	0.71	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00
1	Total Gas Cost	26.86	1.80	1.03	0.71	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00
	PIPELINE TRANSPORTATION															
2.1	Peak	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2	Seasonal	396.03	26.55	13.04	12.32	0.00	0.00	0.38	0.10	0.00	0.00	0.11	0.20	0.40	0.00	0.00
2.3	Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	Total Pipeline Trans. Cost	396.03	26.55	13.04	12.32	0.00	0.00	0.38	0.10	0.00	0.00	0.11	0.20	0.40	0.00	0.00
	FACILITIES' COST															
	STORAGE FACILITIES															
3.1	Deliverability	2.48	0.17	0.09	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.2	Space	1.14	0.08	0.04	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	Total Storage	3.62	0.24	0.13	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DISTRIBUTION FACILITIES															
4.1	Capacity TP > 4"	635.27	42.58	19.80	16.99	0.00	0.00	0.97	0.58	3.64	0.00	0.07	0.06	0.47	0.01	0.00
4.2	Capacity TP <= 4"	66.54	4.46	2.27	1.95	0.00	0.00	0.11	0.07	0.00	0.00	0.01	0.01	0.05	0.00	0.00
4.3	Capacity HP	198.80	13.33	6.85	5.88	0.00	0.00	0.34	0.20	0.00	0.00	0.02	0.02	0.00	0.00	0.01
4.4	Capacity LP	1,035.85	69.43	35.71	30.65	0.00	0.00	1.75	1.01	0.00	0.00	0.12	0.11	0.00	0.01	0.07
4.5	Commodity	0.30	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.6	Customer Plant	758.82	50.86	46.90	3.96	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	Total Distribution	2,695.58	180.69	111.52	59.43	0.00	0.00	3.17	1.86	3.64	0.01	0.23	0.20	0.52	0.02	0.09
	CUSTOMER RELATED															
5.1	Meters	260.02	17.43	9.63	7.50	0.00	0.00	0.13	0.01	0.09	0.02	0.03	0.02	0.00	0.00	0.00
5.2	Sales Stations	159.40	10.68	0.80	9.09	0.01	0.00	0.37	0.06	0.00	0.15	0.09	0.11	0.00	0.01	0.01
5.3	Services	1,604.66	107.56	95.34	11.88	0.00	0.00	0.14	0.02	0.02	0.02	0.02	0.12	0.00	0.00	0.00
5.4	Rentals	6.11	0.41	0.08	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.5	Comm / Ind. Customers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.6	Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.7	Direct Purchase	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.8	Total Customers	53.04	3.56	3.28	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.9	Specific Classes	5.06	0.34	0.05	0.07	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.10	Readings Processed	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5.11	HST Revenue	(25.47)	(1.71)	(0.98)	(0.67)	(0.00)	0.00	(0.02)	0.00	0.00	(0.00)	(0.00)	(0.01)	(0.03)	0.00	0.00
5	Total Customer Related	2,062.81	138.27	108.19	28.47	0.23	0.00	0.62	0.10	0.11	0.20	0.14	0.23	(0.03)	0.01	0.01
6	**Total Rate Base**	5,184.90	347.55	233.91	101.03	0.23	0.00	4.19	2.06	3.75	0.20	0.48	0.64	0.93	0.03	0.10
	CIS	32.40	9.60	8.85	0.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	**Total Rate Base**	5,217.30	357.15	242.77	101.78	0.23	0.00	4.19	2.06	3.75	0.20	0.48	0.64	0.93	0.03	0.10

* G2.6.3 refers to Exhibit G2, Tab 6, Schedule 3.

ALLOCATION OF TOTAL COST TO SERVE
Year Ended December 31, 2016

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 O&M Costs	Col. 2 Net Investment Costs	Col. 3 Total	Col. 4 Rate 1	Col. 5 Rate 6	Col. 6 Rate 9	Col. 7 Rate 100	Col. 8 Rate 110	Col. 9 Rate 115	Col. 10 Rate 125	Col. 11 Rate 135	Col. 12 Rate 145	Col. 13 Rate 170	Col. 14 Rate 200	Col. 15 Rate 300 Firm	Col. 16 Rate 300 Int	Col. 17 Direct Purchase	Col. 18 Rate 332	Col. 19 Allocation Factors G2.6.3.1
	SUPPLY COST																			
	PRODUCT COST																			
1.1	Annual Commodity	948.50	0.12	948.62	543.31	373.99	0.05	0.00	9.79	0.00	0.00	0.45	1.35	4.11	15.55	0.00	0.00	0.00	0.00	1.1
1.2	Bad Debt Commodity	3.97	0.00	3.97	1.89	2.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.5
1.3	System Gas Fee	1.66	0.00	1.66	0.95	0.65	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.01	0.03	0.00	0.00	0.00	0.00	
1	Total Gas Cost	954.13	0.12	954.25	546.15	376.73	0.05	0.00	9.81	0.00	0.00	0.46	1.35	4.11	15.58	0.00	0.00	0.00	0.00	
	PIPELINE TRANSPORTATION																			
2.1	Peak	9.96	0.00	14.57	8.03	6.27	0.00	0.00	0.12	0.02	0.00	0.00	0.00	0.00	0.14	0.00	0.00	0.00	0.00	3.1
2.2	Seasonal	69.82	1.84	71.66	35.20	33.25	0.00	0.00	1.01	0.27	0.00	0.00	0.31	0.54	1.07	0.00	0.00	0.00	0.00	3.2
2.3	Annual - Transportation	562.50	0.00	562.50	293.00	232.87	0.03	0.00	15.61	1.37	0.00	1.96	1.53	5.69	10.44	0.00	0.00	0.00	0.00	1.6
2.4	Interruptible Credit	0.00	0.00	(4.61)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.49)	(3.93)	(0.20)	0.00	0.00	0.00	0.00	
2.5	TS Revenue	0.00	(6.12)	(6.12)	(2.58)	(2.54)	(0.00)	0.00	(0.37)	(0.27)	0.00	(0.03)	(0.05)	(0.17)	(0.09)	0.00	0.00	0.00	0.00	1.2
2	Total Pipeline Trans. Cost	642.28	(4.28)	638.00	333.65	269.84	0.03	0.00	16.37	1.40	0.00	1.92	1.30	2.13	11.36	0.00	0.00	0.00	0.00	
	FACILITIES' COST																			
	STORAGE FACILITIES																			
3.1	Deliverability	128.34	0.20	129.04	71.08	55.50	0.00	0.00	1.04	0.20	0.00	0.00	0.00	0.00	1.21	0.00	0.00	0.00	0.00	3.1
3.2	Space	59.11	0.09	59.20	29.08	27.47	0.00	0.00	0.84	0.23	0.00	0.00	0.25	0.44	0.89	0.00	0.00	0.00	0.00	3.2
3.3	Seasonal Credit	0.00	0.00	(0.50)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.50)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
3	Total Storage	187.45	0.29	187.74	100.16	82.97	0.00	0.00	1.87	0.43	0.00	(0.50)	0.25	0.44	2.10	0.00	0.00	0.00	0.00	
	DISTRIBUTION FACILITIES																			
4.1	Capacity TP > 4"	57.59	34.59	92.17	42.85	36.78	0.00	0.00	2.10	1.25	7.88	0.00	0.15	0.13	1.02	0.01	0.00	0.00	0.00	2.1
4.2	Capacity TP <= 4"	6.29	3.62	9.91	5.04	4.33	0.00	0.00	0.25	0.15	0.00	0.00	0.02	0.02	0.12	0.00	0.00	0.00	0.00	2.2
4.3	Capacity HP	8.44	10.82	19.27	9.90	8.50	0.00	0.00	0.49	0.29	0.00	0.00	0.03	0.03	0.00	0.00	0.02	0.00	0.00	2.3
4.4	Capacity LP	50.66	56.39	107.05	55.05	47.25	0.00	0.00	2.70	1.56	0.00	0.00	0.19	0.17	0.00	0.02	0.11	0.00	0.00	2.4
4.5	Commodity	19.16	(0.05)	19.11	8.07	7.95	0.00	0.00	1.17	0.86	0.00	0.10	0.15	0.54	0.28	0.00	0.00	0.00	0.00	1.2
4.6	Bad Debt Distribution	7.62	0.00	7.62	3.99	3.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
4.7	Customer Plant	37.07	40.64	77.72	71.65	6.05	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.5
4.8	DSM - Program	34.68	0.00	34.68	19.38	13.36	0.00	0.00	0.62	0.60	0.06	0.15	0.25	0.24	0.02	0.00	0.00	0.00	0.00	
4.9	DSM - General	13.68	0.00	13.68	7.64	5.27	0.00	0.00	0.24	0.24	0.02	0.06	0.10	0.10	0.01	0.00	0.00	0.00	0.00	
4	Total Distribution	235.19	146.01	381.21	223.57	133.11	0.01	0.00	7.57	4.94	7.96	0.32	0.89	1.23	1.45	0.04	0.14	0.00	0.00	
	CUSTOMER RELATED																			
5.1	Meters	12.60	44.09	56.69	31.31	24.40	0.01	0.00	0.42	0.05	0.30	0.08	0.08	0.05	0.00	0.00	0.00	0.00	0.00	4.1
5.2	Sales Stations	5.23	6.94	12.18	0.91	10.36	0.01	0.00	0.42	0.07	0.00	0.17	0.10	0.12	0.00	0.01	0.01	0.00	0.00	4.2
5.3	Services	11.54	82.33	93.88	83.21	10.36	0.00	0.00	0.12	0.02	0.02	0.02	0.02	0.10	0.00	0.00	0.00	0.00	0.00	4.3
5.4	Rentals	0.00	1.31	1.31	0.26	1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4
5.5	Comm / Ind. Customers	6.95	0.00	6.95	0.00	6.93	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.6
5.6	Contracts	6.61	0.00	6.61	0.00	0.00	0.00	0.00	3.90	0.44	0.09	0.77	0.91	0.44	0.02	0.02	0.02	0.00	0.00	4.7
5.7	Direct Purchase	1.49	0.00	1.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.49	0.00	4.1
5.8	Total Customers	128.32	(7.02)	121.30	111.84	9.44	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.5
5.9	Specific Classes	7.72	(0.27)	7.46	5.79	0.93	0.65	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
5.10	Readings Processed	15.66	0.00	15.66	14.41	1.24	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8 &4.9
5.11	Large Volume Customer Care	3.21	0.00	3.21	0.00	3.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.6
5.12	Financing Costs	1.90	0.00	1.90	1.28	0.55	0.00	0.00	0.02	0.01	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	
5.13	CIS Depreciation	0.00	12.68	12.68	11.69	0.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.5
5	Total Customer Related	201.22	140.08	341.30	260.69	69.46	0.67	0.00	4.92	0.59	0.51	1.05	1.13	0.72	0.02	0.03	0.03	1.49	0.00	
6.1	Return	333.42	0.00	333.42	224.40	96.92	0.22	0.00	4.02	1.97	3.60	0.20	0.46	0.62	0.89	0.03	0.10	0.00	0.00	5.
6.2	Taxes	14.13	0.00	14.13	9.51	4.11	0.01	0.00	0.17	0.08	0.15	0.01	0.02	0.03	0.04	0.00	0.00	0.00	0.00	5.
6.3	CIS Return	2.10	0.00	2.10	1.94	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.5
6.4	CIS Tax	7.50	0.00	7.50	6.91	0.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.5
6	Return and Taxes	357.15	0.00	357.15	242.77	101.78	0.23	0.00	4.19	2.06	3.75	0.20	0.48	0.64	0.93	0.03	0.10	0.00	0.00	
7	Total Facilities	981.01	286.38	1,267.39	827.20	387.32	0.91	0.00	18.55	8.01	12.22	1.07	2.75	3.04	4.49	0.09	0.27	1.49	0.00	
8	**Total Cost of Service**	2,577.41	282.23	2,859.64	1,707.00	1,033.90	0.99	0.00	44.72	9.41	12.22	3.45	5.41	9.28	31.43	0.09	0.27	1.49	0.00	
9	**GTA Revenue Requirement**			29.95	12.48	11.53	0.00	0.00	0.34	0.09	0.00	0.00	0.10	0.17	0.36	0.00	0.00	0.00	4.89	
10	**Total 2016 Cost of Service**			2,889.60	1,719.48	1,045.43	0.99	0.00	45.06	9.50	12.22	3.45	5.50	9.44	31.79	0.09	0.27	1.49	4.89	

REVENUE REQUIREMENT FOR SHARED PORTION OF SEGMENT A
DECEMBER 31, 2016

($ Million)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
ITEM NO.	DESCRIPTION	REVENUE REQUIREMENT	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 300 Int	Allocation Factors G2.6.3.1
1.1	*Pipeline Transportation - Seasonal*	22.28	10.94	10.34	0.00	0.00	0.32	0.09	0.00	0.00	0.10	0.17	0.33	0.00	0.00	3.2
1.2	*Pipeline Transportation - Peak*	2.78	1.53	1.20	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	3.1
1.	*Enbridge Revenue Requirement from Segment A*	*25.06*	*12.48*	*11.53*	*0.00*	*0.00*	*0.34*	*0.09*	*0.00*	*0.00*	*0.10*	*0.17*	*0.36*	*0.00*	*0.00*	
2.	*Rate 332 Revenue Requirement from Segment A*	*4.89*														
3.	***Total Revenue Requirement for Segment A***	***29.95***														

RATE BASE
FUNCTIONALIZATION FACTORS
Year Ended December 31, 2016

Item No.		Col. 1 Total	Col. 2 Gas Supply	Col. 3 Storage	Col. 4 Sales Stations	Col. 5 Distribution Measurement	Col. 6 Services	Col. 7 Mains	Col. 8 Meters	Col. 9 Rental Equipment	Col. 10 Sales Promotion	Col. 11 Customer Accounting	Col. 12 Unidenti-fiable	Col. 13 CIS
	Gas Supply													
1.1	Gas Supply	1.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Distribution Plant													
2.1	Land (incl offers to buy)	1.000	0.010	0.000	0.005	0.002	0.119	0.396	0.002	0.000	0.061	0.226	0.179	0.000
2.2	Structures & Improvements	1.000	0.010	0.000	0.005	0.002	0.119	0.096	0.002	0.000	0.161	0.426	0.179	0.000
2.3	Mains	1.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000
2.4	Meas. Reg. & Telemtrng	1.000	0.000	0.000	0.488	0.512	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.5	Services	1.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.6	Meters	1.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000
	General Plant													
3.1	Land (incl offers to buy)	1.000	0.000	0.000	0.000	0.000	0.336	0.045	0.000	0.000	0.126	0.353	0.140	0.000
3.2	Structures & Improvements	1.000	0.000	0.000	0.000	0.000	0.336	0.045	0.000	0.000	0.126	0.353	0.140	0.000
3.3	Office Furniture & Equip.	1.000	0.001	0.001	0.001	0.123	0.161	0.200	0.046	0.017	0.024	0.031	0.394	0.000
3.4	Transportation Equipment	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.5	Heavy Work Equipment	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.6	Tools & Work Equip.	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
3.7	Rental Equip.	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000
3.8	Communication Equip.	1.000	0.014	0.000	0.008	0.283	0.086	0.125	0.000	0.001	0.094	0.171	0.218	0.000
3.9	Compressors	1.000	0.000	0.000	0.000	0.002	0.297	0.669	0.000	0.000	0.033	0.000	0.000	0.000
3.10	Computer Equip.	1.000	0.024	0.003	0.023	0.085	0.161	0.261	0.085	0.002	0.009	0.231	0.116	0.000
3.11	Software Acquired/Developed	1.000	0.024	0.003	0.023	0.085	0.161	0.261	0.085	0.002	0.009	0.231	0.116	0.000
3.12	CIS	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1.000
4.	Other Plant	1.000	0.000	0.000	0.000	0.000	0.436	0.564	0.000	0.000	0.000	0.000	0.000	0.000

WORKING CAPITAL AND
NET INVESTMENT
FUNCTIONALIZATION FACTORS
Year Ended December 31, 2016

Item No.		Col. 1 Total	Col. 2 Gas Supply	Col. 3 Storage	Col. 4 Sales Stations	Col. 5 Distribution Measurement	Col. 6 Services	Col. 7 Mains	Col. 8 Meters	Col. 9 Rental Equipment	Col. 10 Sales/ Marketing	Col. 11 Customer Accounting	Col. 12 Unidenti-fiable	Col. 13 CIS
1.	**Prepaid Expenses**	1.000	0.000	0.000	0.000	0.000	0.123	0.123	0.000	0.000	0.009	0.000	0.746	0.000
	Materials & Supplies													
2.1	Pipe	1.000	0.000	0.000	0.000	0.000	0.227	0.773	0.000	0.000	0.000	0.000	0.000	0.000
2.2	Tools	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
2.3	Construction Supplies	1.000	0.000	0.000	0.000	0.000	0.500	0.500	0.000	0.000	0.000	0.000	0.000	0.000
	Net Investments													
3.	Municipal Taxes	1.000	0.000	0.000	0.005	0.005	0.275	0.677	0.000	0.000	0.008	0.021	0.009	0.000
4.	Capital Taxes	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

CLASSIFICATION OF GAS COSTS TO OPERATIONS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
		System Commodity			Load Balancing							
					Storage			Pipeline				
Item No.	Description	Annual Volumes (10³m³)	Variable Unit Rate $/(10³m³)	Variable Cost $(000)	Deliver-ability $(000)	Seasonal Space $(000)	Winter $(000)	Peak $(000)	Seasonal $(000)	Annual $(000)	Dist'n. Commodity $(000)	Total $(000)
	Purchases and Receipts											
1.1	Long-Term	366.0	118.4	43.3	0.0	0.0	0.0	0.0	0.0	23.3	0.0	66.6
1.2	Western Buy/Sell	48.6	118.4	5.7	0.0	0.0	0.0	0.0	0.0	(0.3)	0.0	5.4
1.3	Ontario Buy.Sell	0.0	118.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	Short-Term Annual	0.0	118.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.5	Short-Term Peak	2,154.4	118.4	255.0	0.0	0.0	0.0	1,270.6	0.0	0.0	0.0	1,525.7
1.6	Discretionary Western & US	5,186,333.6	118.4	613,948.3	0.0	0.0	0.0	0.0	0.0	21,469.6	0.0	635,417.9
1.7	Discretionary - Ontario	1,052,334.6	118.4	124,573.4	0.0	0.0	0.0	6,395.1	51,160.8	0.0	0.0	182,129.2
1.8	Niagara Supplies	1,942,159.7	118.4	229,909.2	0.0	0.0	0.0	0.0	0.0	18,197.2	0.0	248,106.4
1.	Total Purchases & Receipts	8,183,396.8	118.4	968,735.0	0.0	0.0	0.0	7,665.7	51,160.8	39,689.7	0.0	1,067,251.2
	Transportation											
2.1	TCPL FT-Demand System	0.0	0.0	0.0	0.0	0.0	0.0	1,549.4	12,394.9	409,192.6	0.0	423,136.8
2.2	Unutilized Transport Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.3	Alliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.4	Vector	0.0	0.0	0.0	0.0	0.0	0.0	1,074.2	8,593.2	92,464.1	0.0	102,131.5
2.5	Nova	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14,203.9	0.0	14,203.9
2.6	Niagara Falls to Enbridge Parkway DDA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26,113.9	0.0	26,113.9
2.	Total Transportation	0.0	0.0	0.0	0.0	0.0	0.0	2,623.5	20,988.1	541,974.5	0.0	565,586.2
	Other Costs											
3.1	Fuel	0.0	0.0	16,328.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16,328.9
3.	Total Other Variable Costs	0.0	0.0	16,328.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16,328.9
4.	**Total Delivered Supply**	8,183,396.8	0.0	985,063.8	0.0	0.0	0.0	10,289.2	72,148.9	581,664.3	0.0	1,649,166.3
5.	**Storage Fluctuation**	(179,312.3)	118.4	(21,058.2)	0.0	0.0	0.0	(219.9)	(1,541.7)	(12,429.3)	0.0	(35,249.1)
6.	**Gas Costs to Operations**	8,004,084.5	0.0	964,005.6	0.0	0.0	0.0	10,069.4	70,607.2	569,235.0	0.0	1,613,917.1
7.	**Storage and Transportation**	0.0	0.0	0.0	126,687.5	58,345.9	0.0	0.0	0.0	0.0	0.0	185,033.4
8.	**Gas Costs-Storage & Trans.**	8,004,084.5	0.0	964,005.6	126,687.5	58,345.9	0.0	10,069.4	70,607.2	569,235.0	0.0	1,798,950.5
9.1	UUF Adjustment	0.0	0.0	(13,056.0)	0.0	0.0	0.0	(94.3)	(661.3)	(5,331.6)	19,143.2	0.0
9.2	LUFAdjustment	0.0	0.0	(2,452.8)	0.0	0.0	0.0	(17.6)	(123.2)	(1,403.2)	0.0	(3,996.8)
9.	**Total Classified Costs**			948,496.8	126,687.5	58,345.9	0.0	9,957.5	69,822.7	562,500.1	19,143.2	1,794,953.8
	GAS COSTS											
10.1	Classification Factors			948,496.8	0.0	0.0	0.0	9,957.5	69,822.7	562,500.1	19,143.2	1,609,920.3
10.2	Classification Percentages			58.92%	0.00%	0.00%	0.00%	0.62%	4.34%	34.94%	1.19%	100.00%
	STORAGE											
11.1	Classification Factors				126,687.5	58,345.9	0.0	0.0	0.0	0.0	0.0	185,033.4
11.2	Classification Percentages				68.47%	31.53%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

CLASSIFICATION OF TRANSPORTATION COSTS

($000)

Item No.	Description	Col. 1 Total	Col. 2 Peak	Col. 3 Seasonal	Col. 4 Annual Delivery	Col. 5 Annual Commodity
	FT TCPL					
1.1	Demand	415,058.2	651.7	5,213.9	409,192.6	0.0
1.2	FTSN (Parkway to CDA)	8,078.6	897.6	7,181.0	0.0	0.0
1.3	Unutilized Transport. Cost	0.0	0.0	0.0	0.0	0.0
	Alliance					
2.1	Demand	0.0	0.0	0.0	0.0	0.0
2.2	Commodity	0.0	0.0	0.0	0.0	0.0
3.	**Vector Demand & Dawn to Franchise**	102,131.5	1,074.2	8,593.2	92,464.1	0.0
4.	**NOVA Demand**	14,203.9	0.0	0.0	14,203.9	0.0
	Niagara Falls to Enbridge Parkway DDA	26,113.9	0.0	0.0	26,113.9	0.0
	OTHER					
5.1	Fuel	16,328.9	0.0	0.0	0.0	16,328.9
6	**Total**	581,915.1	2,623.5	20,988.1	541,974.5	16,328.9

CLASSIFICATION OF
STORAGE AND TRANSPORTATION

($000)

Item No.	Description	Col. 1 Tecumseh O&M	Col. 2 Annual Cost	Col. 3 Deliver-ability	Col. 4 Seasonal Space	Col. 5 Winter	Col. 6 Annual Commodity
	TECUMSEH						
	TRANSMISSION						
1.1	Annual Demand	6,330.9	6,330.9	0.0	6,330.9	0.0	0.0
1.2	Daily Demand	11,568.9	11,568.9	11,568.9	0.0	0.0	0.0
1.3	In/out	4,611.5	4,611.5	0.0	4,611.5	0.0	0.0
1.4	Fuel	3,393.6	3,393.6	0.0	3,393.6	0.0	0.0
1.5	Transactional Services Revenues	(3,419.6)	(3,419.6)	(2,051.8)	(1,367.9)	0.0	0.0
1.	Total Transmission	22,485.3	22,485.3	9,517.1	12,968.2	0.0	0.0
	STORAGE						
2.1	Annual Demand	5,964.2	5,964.2	0.0	5,964.2	0.0	0.0
2.2	Daily Demand	11,016.0	11,016.0	11,016.0	0.0	0.0	0.0
2.3	In/out	764.9	764.9	0.0	764.9	0.0	0.0
2.4	Transactional Services Revenues	(2,580.4)	(2,580.4)	(1,548.2)	(1,032.1)	0.0	0.0
2.	Total Storage	15,164.7	15,164.7	9,467.7	5,697.0	0.0	0.0
3.	Total Tecumseh	37,650.0	37,650.0	18,984.9	18,665.1	0.0	0.0
	UNION GAS						
	STORAGE						
4.1	Space		7,495.9	0.0	7,495.9	0.0	0.0
4.2	Peak		9,161.6	9,161.6	0.0	0.0	0.0
4.3	Injection		67.6	0.0	67.6	0.0	0.0
4.4	Withdrawal		78.3	0.0	78.3	0.0	0.0
	Chatham D		151.1	0.0	151.1	0.0	0.0
4.	Total Storage		16,954.5	9,161.6	7,792.9	0.0	0.0
	TRANSMISSION						
5.1	Demand with comp.		66,707.7	41,217.8	25,489.8	0.0	0.0
5.4	Fuel		16,242.8	10,036.2	6,206.6	0.0	0.0
5.	Total Transmission		82,950.4	51,254.0	31,696.4	0.0	0.0
	DEHYDRATION						
6.1	Demand		1,019.5	1,019.5	0.0	0.0	0.0
6.2	Commodity		191.5	0.0	191.5	0.0	0.0
6.	Total Dehydration		1,210.9	1,019.5	191.5	0.0	0.0
7.	Total Union		101,115.9	61,435.1	39,680.8	0.0	0.0
	TRANSCANADA						
8.1	STS and Other		46,267.5	46,267.5	0.0	0.0	0.0
8.	Total TransCanada		46,267.5	46,267.5	0.0	0.0	0.0
9.	**TOTAL STORAGE & TRANSP.**		185,033.4	126,687.5	58,345.9	0.0	0.0
10.	**COST TO OPERATIONS**		185,033.4	126,687.5	58,345.9	0.0	0.0

ALLOCATION FACTORS
Year Ended December 31, 2016

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	Direct Purchase
	Commodity Responsibility															
1.1	Annual Sales	7,875.3	4,510.5	3,104.9	0.5	0.0	81.3	0.0	0.0	3.8	11.2	34.1	129.1	0.0	0.0	0.0
1.2	Bundled Annual Deliveries	11,529.6	4,869.3	4,795.0	0.5	0.0	703.3	517.1	0.0	59.3	88.6	325.7	170.8	0.0	0.0	0.0
1.3	Total Annual Deliveries	11,564.6	4,869.3	4,795.0	0.5	0.0	703.3	517.1	0.0	59.3	88.6	325.7	170.8	0.0	35.0	0.0
1.4	Bundled Peak Delivery	106,338.9	54,065.6	46,403.7	1.5	0.0	2,648.6	1,576.3	0.0	4.8	187.5	167.5	1,283.5	0.0	0.0	0.0
1.5	System Gas Sales	7,875.3	4,510.5	3,104.9	0.5	0.0	81.3	0.0	0.0	3.8	11.2	34.1	129.1	0.0	0.0	0.0
	Distribution Capacity Responsibility															
2.1	Delivery Demand TP > 4"	116,289.8	54,065.6	46,403.7	1.5	0.0	2,648.6	1,576.3	9,935.4	4.8	187.5	167.5	1,283.5	15.6	0.0	0.0
2.2	Delivery Demand TP <= 4"	106,354.5	54,065.6	46,403.7	1.5	0.0	2,648.6	1,576.3	0.0	4.8	187.5	167.5	1,283.5	15.6	0.0	0.0
2.3	Delivery Demand HP	105,183.4	54,065.6	46,403.7	1.5	0.0	2,648.6	1,576.3	0.0	4.8	187.5	167.5	0.0	15.6	112.4	0.0
2.4	Delivery Demand LP	105,138.2	54,065.6	46,403.7	1.5	0.0	2,648.6	1,531.0	0.0	4.8	187.5	167.5	0.0	15.6	112.4	0.0
2.5	Cust. Rel Plant	2,130,437.0	1,964,199.0	165,855.0	7.0	0.0	222.0	25.0	5.0	44.0	52.0	25.0	1.0	1.0	1.0	0.0
	Storage Responsibility															
3.1	Deliverability	57.7	31.8	24.8	0.0	0.0	0.5	0.1	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
3.2	Space	2,754.6	1,353.3	1,278.2	0.0	0.0	39.0	10.6	0.0	0.0	11.8	20.6	41.3	0.0	0.0	0.0
	Customer Responsibility															
4.1	Meters	441,090.0	243,592.3	189,834.3	60.7	0.0	3,231.6	364.8	2,307.1	629.5	651.0	389.6	0.0	14.6	14.6	0.0
4.2	Sales Stations	240,073.8	17,869.8	204,178.1	190.0	0.0	8,225.5	1,406.5	0.0	3,428.3	2,028.4	2,420.3	0.0	164.5	162.4	0.0
4.3	Services	2,498,110.0	2,214,194.5	275,806.4	17.7	0.0	3,313.8	464.8	436.3	463.8	545.7	2,741.9	0.0	15.4	109.7	0.0
4.4	Rental Equipment	0.3	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4.5	Total Customer Count	2,130,437.0	1,964,199.0	165,855.0	7.0	0.0	222.0	25.0	5.0	44.0	52.0	25.0	1.0	1.0	1.0	0.0
4.6	Comm / Ind. Customer Count	166,238.0	0.0	165,855.0	7.0	0.0	222.0	25.0	5.0	44.0	52.0	25.0	1.0	1.0	1.0	0.0
4.7	Contracts	376.0	0.0	0.0	0.0	0.0	222.0	25.0	5.0	44.0	52.0	25.0	1.0	1.0	1.0	0.0
4.8	Chart Readings non AMR per year	61,184.0	0.0	60,298.0	24.0	12.0	120.0	0.0	0.0	0.0	0.0	0.0	0.0	365.0	365.0	0.0
4.9	Chart Readings AMR per year	2,483.0	0.0	2,125.0	4.0	0.0	203.0	29.0	5.0	37.0	50.0	30.0	0.0	0.0	0.0	0.0
4.10	Meter Readings per year	12,739,896.0	11,785,194.0	954,702.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4.11	Direct Purchase Customers	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
5.	Rate Base	5,184.9	3,489.6	1,507.2	3.5	0.0	62.5	30.7	55.9	3.0	7.1	9.6	13.8	0.4	1.5	0.0

ALLOCATION PERCENTAGES
Year Ended December 31, 2016

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 300 Int	Direct Purchase
	Commodity Responsibility															
1.1	Annual Sales	1.0000	0.5727	0.3943	0.0001	0.0000	0.0103	0.0000	0.0000	0.0005	0.0014	0.0043	0.0164	0.0000	0.0000	0.0000
1.2	Bundled Annual Deliveries	1.0000	0.4223	0.4159	0.0000	0.0000	0.0610	0.0448	0.0000	0.0051	0.0077	0.0282	0.0148	0.0000	0.0000	0.0000
1.3	Total Annual Deliveries	1.0000	0.4211	0.4146	0.0000	0.0000	0.0608	0.0447	0.0000	0.0051	0.0077	0.0282	0.0148	0.0000	0.0030	0.0000
1.4	Bundled Peak Delivery	1.0000	0.5084	0.4364	0.0000	0.0000	0.0249	0.0148	0.0000	0.0000	0.0018	0.0016	0.0121	0.0000	0.0000	0.0000
1.5	System Gas Sales	1.0000	0.5727	0.3943	0.0001	0.0000	0.0103	0.0000	0.0000	0.0005	0.0014	0.0043	0.0164	0.0000	0.0000	0.0000
1.6	Bundled Transportation Deliveries	1.0000	0.5209	0.4140	0.0001	0.0000	0.0278	0.0024	0.0000	0.0035	0.0027	0.0101	0.0186	0.0000	0.0000	0.0000
	Distribution Capacity Responsibility															
2.1	Delivery Demand TP > 4"	1.0000	0.4649	0.3990	0.0000	0.0000	0.0228	0.0136	0.0854	0.0000	0.0016	0.0014	0.0110	0.0001	0.0000	0.0000
2.2	Delivery Demand TP <= 4"	1.0000	0.5084	0.4363	0.0000	0.0000	0.0249	0.0148	0.0000	0.0000	0.0018	0.0016	0.0121	0.0001	0.0000	0.0000
2.3	Delivery Demand HP	1.0000	0.5140	0.4412	0.0000	0.0000	0.0252	0.0150	0.0000	0.0000	0.0018	0.0016	0.0000	0.0001	0.0011	0.0000
2.4	Delivery Demand LP	1.0000	0.5142	0.4414	0.0000	0.0000	0.0252	0.0146	0.0000	0.0000	0.0018	0.0016	0.0000	0.0001	0.0011	0.0000
2.5	Cust. Rel Plant	1.0000	0.9220	0.0779	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Storage Responsibility															
3.1	Deliverability	1.0000	0.5509	0.4301	0.0000	0.0000	0.0080	0.0016	0.0000	0.0000	0.0000	0.0000	0.0094	0.0000	0.0000	0.0000
3.2	Space	1.0000	0.4913	0.4640	0.0000	0.0000	0.0141	0.0038	0.0000	0.0000	0.0043	0.0075	0.0150	0.0000	0.0000	0.0000
	Customer Responsibility															
4.1	Meters	1.0000	0.5523	0.4304	0.0001	0.0000	0.0073	0.0008	0.0052	0.0014	0.0015	0.0009	0.0000	0.0000	0.0000	0.0000
4.2	Sales Stations	1.0000	0.0744	0.8505	0.0008	0.0000	0.0343	0.0059	0.0000	0.0143	0.0084	0.0101	0.0000	0.0007	0.0007	0.0000
4.3	Services	1.0000	0.8863	0.1104	0.0000	0.0000	0.0013	0.0002	0.0002	0.0002	0.0002	0.0011	0.0000	0.0000	0.0000	0.0000
4.4	Rental Equipment	1.0000	0.2000	0.8000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.5	Total Customer Count	1.0000	0.9220	0.0779	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.6	Comm / Ind. Customer Count	1.0000	0.0000	0.9977	0.0000	0.0000	0.0013	0.0002	0.0000	0.0003	0.0003	0.0002	0.0000	0.0000	0.0000	0.0000
4.7	Contracts	1.0000	0.0000	0.0000	0.0000	0.0000	0.5904	0.0665	0.0133	0.1170	0.1383	0.0665	0.0027	0.0027	0.0027	0.0000
4.8	Chart Readings non AMR per year	1.0000	0.0000	0.9855	0.0004	0.0002	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0060	0.0060	0.0000
4.9	Chart Readings AMR per year	1.0000	0.0000	0.8558	0.0016	0.0000	0.0818	0.0117	0.0020	0.0149	0.0201	0.0121	0.0000	0.0000	0.0000	0.0000
4.10	Meter Readings per year	1.0000	0.9251	0.0749	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.11	Separation Expense Allocator	1.0000	0.7750	0.2250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4.12	Direct Purchase Customers	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000
5.	Rate Base	1.0000	0.6730	0.2907	0.0007	0.0000	0.0121	0.0059	0.0108	0.0006	0.0014	0.0018	0.0027	0.0001	0.0003	0.0000

Allocation of DSM Program and General Costs Including Fringe Benefits and A&G
Year Ended December 31, 2016

(millions of dollars)

	Total	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300
Total DSM Program & Allocated costs	35.04	19.58	13.50	0.00	0.00	0.63	0.61	0.06	0.15	0.25	0.25	0.02	0.00

TECUMSEH GAS
FUNCTIONALIZATION AND CLASSIFICATION OF RATE BASE
2016 TEST YEAR

($000)

Item No.	Description	Functional Allocation T/C	Functional Allocation Pool	Col. 1 FUNCTIONALIZATION Net Investment Avg. of Mnthly Avg.	Col. 2 FUNCTIONALIZATION Transmission & Compression	Col. 3 FUNCTIONALIZATION Pool Storage Space	Col. 4 CLASSIFICATION Transmission & Compression Net Investment Avg. of Mnthly Avg.	Col. 5	Col. 6	Col. 7 Annual Demand	Col. 8 Daily Demand	Col. 9 CLASSIFICATION Pool Storage Space Net Investment Avg. of Mnthly Avg.	Col. 10	Col. 11	Col. 12 Annual Demand	Col. 13 Daily Demand
1.1	Transmission Lines	100%	0%	5,959.4	5,959.4		5,959.4	40%	60%	2,383.8	3,575.6		40%	60%	0.0	0.0
1.2	Compressor Equipment	100%	0% `		68,889.6		68,889.6	40%	60%	27,555.8	41,333.8		40%	60%	0.0	0.0
1.3	Structures & Improvements	100%	0%	32,119.6	32,119.6		32,119.6	40%	60%	12,847.8	19,271.8		40%	60%	0.0	0.0
1.4	Office and Plant Equipment	100%	0%	1,281.5	1,281.5		1,281.5	40%	60%	512.6	768.9		40%	60%	0.0	0.0
1.5	Land	100%	0%	3,733.0	3,733.0		3,733.0	40%	60%	1,493.2	2,239.8		40%	60%	0.0	0.0
1.6.1	Allowance for - Mat'ls & Supplies	100%	0%	3,087.0	3,087.0		3,087.0	40%	60%	1,234.8	1,852.2		40%	60%	0.0	0.0
1.6.2	Working Capital - Working Cash Allow.	100%	0%	1,600.0	1,600.0		1,600.0	40%	60%	640.0	960.0		40%	60%	0.0	0.0
1.7	Provision for LUF	69%	31%		0.0	0.0	0.0	40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
1.				116,670.1	116,670.1		116,670.1			46,668.0	70,002.1					
2.1	Field Lines	0%	100%	35,558.0		35,558.0		40%	60%	0.0	0.0	35,558.0	40%	60%	14,223.2	21,334.8
2.2	Wells	0%	100%	43,593.7		43,593.7		40%	60%	0.0	0.0	43,593.7	40%	60%	17,437.5	26,156.2
2.3	Well Equipment	0%	100%	2,593.2		2,593.2		40%	60%	0.0	0.0	2,593.2	40%	60%	1,037.3	1,555.9
2.4	Measuring & Regulating	0%	100%	7,820.4		7,820.4		40%	60%	0.0	0.0	7,820.4	40%	60%	3,128.2	4,692.2
2.5	Gas Storage Rights	0%	100%	15,953.8		15,953.8		40%	60%	0.0	0.0	15,953.8	40%	60%	6,381.5	9,572.3
2.6	Petroleum and Natural Gas Leases	0%	100%			0.0		40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
2.7	Base Pressure Gas	0%	100%	35,069.5		35,069.5		40%	60%	0.0	0.0	35,069.5	40%	60%	14,027.8	21,041.7
2.8	Other	0%	100%			0.0	0.0	40%	60%	0.0	0.0	0.0	40%	60%	0.0	0.0
2.				140,588.6		140,588.6						140,588.6			56,235.4	84,353.1
3.	Total			257,258.7	116,670.1	140,588.6	116,670.1			46,668.0	70,002.1	140,588.6			56,235.4	84,353.1
4.	Percentage Allocation			1,465.4	45.351%	54.649%				40.000%	60.000%				40.000%	60.000%

TECUMSEH GAS
FUNCTIONAL ALLOCATION OF COST OF SERVICE
2016 TEST YEAR

Item No.		Col.1 Functional Allocation T/C	Col.2 Pool	Col.3 Utility Return & Expenses	Col.4 Transmission & Compression	Col.5 Pool Storage
RATE BASE RETURN AMOUNT				($000)	($000)	($000)
1.1	Utility Return	45%	55%	17,194.8	7,737.7	9,457.2
1.	Total Return	0%	0%	17,194.8	7,737.7	9,457.2
EXPENSES - OPERATION						
2.1.1	Labour	75%	25%	1,472.7	1,104.5	368.2
2.1.2	Supplies & Other		10%	584.9	526.4	58.5
2.1.3	Hydro	100%	0%	370.3	370.3	
2.1.4	Lease Rentals	0%	100%	1,630.0		1,630.0
2.1.5	Surface Rentals	0%	100%	349.6		349.6
2.1.6	Provision for LUF	87%	13%	3,996.8	3,477.2	519.6
2.1	Subtotal			8,404.3	5,478.4	2,925.9
MAINTENANCE						
2.2.1	Company	80%	20%	1,521.1	1,216.8	304.2
2.2.2	Contractor	55%	45%	1,592.4	875.8	716.6
2.2	Subtotal			3,113.4	2,092.6	1,020.8
ADMINISTRATIVE & GENERAL						
2.3.1	General Office	75%	25%	3,331.6	2,498.7	832.9
2.3.2	Service Fees	75%	25%	2,490.1	1,867.6	622.5
2.3.3	Overhead Capitalized	75%	25%	(1,035.3)	(776.5)	(258.8)
2.3	Subtotal			4,786.5	3,589.8	1,196.6
DEPRECIATION AND AMORTIZATION						
2.4.1	Depreciation	59%	41%	6,891.1	4,036.9	2,854.2
2.4.2	Amortization	0%	100%	472.8		472.8
2.4	Subtotal			7,363.9	4,036.9	3,327.0
TAXES - OTHER THAN INCOME						
2.5.1	Municipal	80%	20%	1,538.3	1,230.7	307.7
2.5.2	Capital	45%	55%			
2.5	Subtotal			1,538.3	1,230.7	307.7
2. TOTAL EXPENSES				25,206.4	16,428.4	8,778.0
3. REVENUE REQUIREMENT BEFORE TAXES				42,401.2	24,166.1	18,235.2

TECUMSEH GAS
CLASSIFICATION OF COST OF SERVICE
2016 TEST YEAR

($000)

							Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
		Functional Allocation		Utility	Transmission		Transmission & Compression						Pool Storage							
Item No.		T/C	Pool	Return & Expenses	& Compression	Storage Space	Total	Alloc'tn Ann	Dly	Annual Demand	Daily Demand	Commodity	Storage Total	Union Transfer	Net Tecumseh	Alloc'tn Ann	Dly	Annual Demand	Daily Demand	Commodity
	RATE BASE RETURN AMOUNT																			
1.1	Utility Return	45%	55%	17,194.8	7,737.7	9,457.2	7,737.7	35%	65%	2,708.2	5,029.5		9,457.2	0.0	9,457.2	35%	65%	3,310.0	6,147.2	
1.	Total Return			17,194.8	7,737.7	9,457.2	7,737.7			2,708.2	5,029.5		9,457.2	0.0	9,457.2			3,310.0	6,147.2	
	EXPENSES - OPERATION																			
2.1.1	Labour	75%	25%	1,472.7	1,104.5	368.2	1,104.5	35%	65%	386.6	717.9		368.2	21.3	346.9	35%	65%	121.4	225.5	
2.1.2	Supplies & Other	90%	10%	584.9	526.4	58.5	526.4	20%	30%	105.3	157.9	263.2	58.5	3.4	55.1	30%	45%	16.5	24.8	13.8
2.1.3	Hydro	100%	0%	370.3	370.3		370.3	20%	30%	74.1	111.1	185.1				0%	0%			
2.1.4	Lease Rentals	0%	100%	1,630.0		1,630.0		35%	65%				1,630.0		1,630.0	35%	65%	570.5	1,059.5	
2.1.5	Surface Rentals	0%	100%	349.6		349.6		35%	65%				349.6	20.2	329.4	35%	65%	115.3	214.1	
2.1.6	Provision for LUF	87%	13%	3,996.8	3,477.2	519.6	3,477.2	0%	0%			3,477.2	519.6	0.0	519.6	0%	0%			519.6
2.1	Subtotal			8,404.3	5,478.4	2,925.9	5,478.4			566.0	986.9	3,925.5	2,925.9	44.9	2,881.0			823.7	1,523.9	533.4
	MAINTENANCE																			
2.2.1	Company	80%	20%	1,521.1	1,216.8	304.2	1,216.8	20%	30%	243.4	365.0	608.4	304.2	17.6	286.6	30%	45%	86.0	129.0	71.6
2.2.2	Contractor	55%	45%	1,592.4	875.8	716.6	875.8	20%	30%	175.2	262.7	437.9	716.6	41.5	675.1	30%	45%	202.5	303.8	168.8
2.2	Subtotal			3,113.4	2,092.6	1,020.8	2,092.6			418.6	627.7	1,046.3	1,020.8	59.1	961.7			288.5	432.8	240.4
	ADMINISTRATIVE & GENERAL																			
2.3.1	General Office	75%	25%	3,331.6	2,498.7	832.9	2,498.7	35%	65%	874.5	1,624.2		832.9	48.2	784.7	35%	65%	274.6	510.1	
2.3.2	Service Fees	75%	25%	2,490.1	1,867.6	622.5	1,867.6	35%	65%	653.7	1,213.9		622.5	36.0	586.5	35%	65%	205.3	381.2	
2.3.3	Overhead Capitalized	75%	25%	(1,035.3)	(776.5)	(258.8)	(776.5)	35%	65%	(271.8)	(504.7)		(258.8)	0.0	(258.8)	35%	65%	(90.6)	(168.2)	
2.3	Subtotal			4,786.5	3,589.8	1,196.6	3,589.8			1,256.4	2,333.4		1,196.6	84.2	1,112.4			389.3	723.1	0.0
	DEPRECIATION AND AMORTIZATION																			
2.4.1	Depreciation	59%	41%	6,891.1	4,036.9	2,854.2	4,036.9	35%	65%	1,412.9	2,624.0		2,854.2	138.4	2,715.8	35%	65%	950.5	1,765.3	0.0
2.4.2	Amortization	0%	100%	472.8		472.8		35%	65%				472.8	0.0	472.8	35%	65%	165.5	307.3	0.0
2.4	Subtotal			7,363.9	4,036.9	3,327.0	4,036.9			1,412.9	2,624.0		3,327.0	138.4	3,188.6			1,116.0	2,072.6	
	TAXES - OTHER THAN INCOME																			
2.5.1	Municipal	80%	20%	1,538.3	1,230.7	307.7	1,230.7	35%	65%	430.7	800.0		307.7	17.8	289.9	35%	65%	101.5	188.4	
2.5.2	Capital Rate Base Ratio	45%	55%	0.0	0.0	0.0	0.0	35%	65%				0.0			35%	65%			
2.5	Subtotal			1,538.3	1,230.7	307.7	1,230.7			430.7	800.0		307.7	17.8	289.9			101.5	188.4	
2.	**TOTAL EXPENSES**			25,206.4	16,428.4	8,778.0	16,428.4			4,084.6	7,372.0	4,971.8	8,778.0	344.5	8,433.5			2,719.0	4,940.8	773.8
3.	**REVENUE REQUIREMENT**			42,401.2	24,166.1	18,235.2	24,166.1			6,792.8	12,401.5	4,971.8	18,235.2	344.5	17,890.7			6,029.0	11,088.0	773.8
4.1	**GROSS REVENUE REQUIREMENT (incl. fuel)**			42,401.2	24,166.1	18,235.2	24,166.1			6,792.8	12,401.5	4,971.8	18,235.2	344.5	17,890.7			6,029.0	11,088.0	773.8
4.2	**GROSS REVENUE REQUIREMENT (excl. fuel)**			42,401.2	24,166.1	18,235.2	24,166.1			6,792.8	12,401.5	4,971.8	18,235.2	344.5	17,890.7			6,029.0	11,088.0	773.8
3.1.1	Less: UNION GAS									393.1	757.0	306.7						0.0	0.0	0.0
3.1.2	Less: CENTRA GAS									68.7	75.6	53.6						64.8	72.0	8.9
3.1.3	Less: ST. LAWRENCE									0.0	0.0	0.0						0.0	0.0	0.0
3.1	**Net: CONSUMERS GAS**									6,330.9	11,568.9	4,611.5						5,964.2	11,016.0	764.9

TECUMSEH GAS
RATE DERIVATION
2016 TEST YEAR

Item No.	Transmission and Compression		Col.1 Annual Demand	Col.2 Daily Demand	Col.3 Commodity
1.1	Cost of service		6,792.8	12,401.5	4,971.8
1.2	Forecasted Gas Volumes		2,799,103.7	46,446.1	5,252,601.3
1.3.1	Unit Cost - Annual ($/10³m³)		2.427	267.008	0.947
1.3.2	Unit Cost - Monthly ($/10³m³/month)		0.202	22.251	0.000
1.3.3	Unit Cost - Rounded ($/10³m³)		0.202	22.251	0.947
0	($/10³m³/month)	(excl. fuel gas)	0.202	22.251	0.947
1.4	Fuel Ratio (%)				0.35
	Pool Storage		**Annual Demand**	**Daily Demand**	**Commodity**
2.1	Cost of Service Analysis ($000's)		6,029.0	11,088.0	773.8
2.2	Forecasted Gas Volumes (10³m³)		2,637,103.7	43,611.1	4,928,601.3
2.3.1	Unit Cost - Annual ($/10³m³)		2.2862	254.2472	0.1570
2.3.2	Unit Cost - Monthly ($/10³m³/month)		0.1905	21.1873	0.0000
2.3.3	Unit Cost - Rounded ($/10³m³)		0.1905	21.1873	0.1570

TECUMSEH GAS
ISOLATION OF TRANSMISSION RELATED RATE BASE
2016 TEST YEAR

($000)

				Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		FUNCTIONALIZATION TOTAL COSTS					**ELIMINATION OF COMPRESSION COSTS**		**TRANSMISSION COSTS**	
Item No.	Description	Functional Allocation T/C	Pool	Net Investment Avg. of Mnthly Avg.	Transmission & Compression	Pool Storage Space	Compression	Pool Storage Space	Transmission	Pool Storage Space
1.1	Transmission Lines	100%	0%	5,959.4	5,959.4	0.0	0.0	0.0	5,959.4	0.0
1.2	Compressor Equipment	100%	0%	68,889.6	68,889.6	0.0	(58,039.6)	0.0	10,850.0	0.0
1.3	Structures & Improvements	100%	0%	32,119.6	32,119.6	0.0	(10,399.2)	0.0	21,720.4	0.0
1.4	Office and Plant Equipment	100%	0%	1,281.5	1,281.5	0.0	(1,136.6)	0.0	144.9	0.0
1.5	Land	100%	0%	3,733.0	3,733.0	0.0	(188.7)	0.0	3,544.3	0.0
1.6.1	Allowance for - Mat'ls & Supplies	100%	0%	3,087.0	3,087.0	0.0	(2,465.0)	0.0	622.0	0.0
1.6.2	- Working Cash Allow.	100%	0%	1.6	1.6	0.0	(1,372.3)	0.0	(1,370.7)	0.0
1.7	Provision for LUF	69%	31%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.				115,071.7	115,071.7	0.0	(73,601.4)	0.0	41,470.3	0.0
2.1	Field Lines	0%	100%	35,558.0	0.0	35,558.0	0.0	(35,558.0)	0.0	0.0
2.2	Wells	0%	100%	43,593.7	0.0	43,593.7	0.0	(43,593.7)	0.0	0.0
2.3	Well Equipment	0%	100%	2,593.2	0.0	2,593.2	0.0	(2,593.2)	0.0	0.0
2.4	Measuring & Regulating	0%	100%	7,820.4	0.0	7,820.4	0.0	(7,820.4)	0.0	0.0
2.5	Gas Storage Rights	0%	100%	15,953.8	0.0	15,953.8	0.0	(15,953.8)	0.0	0.0
2.6	Petroleum and Natural Gas Leases	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.7	Base Pressure Gas	0%	100%	40,921.2	0.0	40,921.2	0.0	(40,921.2)	0.0	0.0
2.8	Other	0%	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.				146,440.3	0.0	146,440.3	0.0	(146,440.3)	0.0	0.0
3.	Total			261,512.0	115,071.7	146,440.3	(73,601.4)	(146,440.3)	41,470.3	0.0

TECUMSEH GAS
ISOLATION OF TRANSMISSION RELATED COST OF SERVICE
2016 TEST YEAR

		Col.1	Col.2	Col.3	Col.4	Col.5	Col.6	Col.7	Col.8	Col.9
				TOTAL COST OF SERVICE			**ELIMINATION OF COMPRESSION COSTS**		**TRANSMISSION COSTS**	
Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Pool Storage	Compression	Pool Storage	Transmission	Pool Storage
	RATE BASE RETURN AMOUNT			($000)	($000)	($000)				
1.1	Utility Return (net of fuel)	40%	60%	17,387.7	6,955.1	10,432.6	(4,197.8)	(10,432.6)	2,757.3	0.0
1.	Total Return	0%	0%	17,387.7	6,955.1	10,432.6	(4,197.8)	(10,432.6)	2,757.3	0.0
	EXPENSES - OPERATION									
2.1.1	Labour	80%	20%	1,472.7	1,178.2	294.5	(1,178.2)	(294.5)	0.0	0.0
2.1.2	Supplies & Other	90%	10%	584.9	526.4	58.5	(526.4)	(58.5)	0.0	0.0
2.1.3	Compressor Station Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.4	Compressor Station Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.5	Other Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.6	Other Fuel	100%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.1.7	Hydro	100%	0%	370.3	370.3	0.0	(370.3)	0.0	0.0	0.0
2.1.8	Lease Rentals	0%	100%	1,630.0	0.0	1,630.0	0.0	(1,630.0)	0.0	0.0
2.1.9	Surface Rentals	0%	100%	349.6	0.0	349.6	0.0	(349.6)	0.0	0.0
2.1.10	Provision for LUF	69%	31%	4,663.7	3,217.9	1,445.7	(3,217.9)	(1,445.7)	0.0	0.0
2.1	Subtotal			9,071.2	5,292.8	3,778.4	(5,292.8)	(3,778.4)	0.0	0.0
	MAINTENANCE									
2.2.1	Company	90%	10%	1,521.1	1,368.9	152.1	(1,353.2)	(152.1)	15.8	0.0
2.2.2	Contractor	80%	20%	1,592.4	1,273.9	318.5	(1,241.9)	(318.5)	32.0	0.0
2.2	Subtotal			3,113.4	2,642.8	470.6	(2,595.1)	(470.6)	47.8	0.0
	ADMINISTRATIVE & GENERAL									
2.3.1	General Office	80%	20%	3,331.6	2,665.3	666.3	(2,641.9)	(666.3)	23.4	0.0
2.3.2	Service Fees	80%	20%	2,490.1	1,992.1	498.0	(1,988.8)	(498.0)	3.3	0.0
2.3.3	Overhead Capitalized	80%	20%	(1,035.3)	(828.2)	(207.1)		207.1	(164.2)	0.0
2.3	Subtotal			4,786.5	3,829.2	957.3	(4,630.8)	(957.3)	(137.5)	0.0
	DEPRECIATION AND AMORTIZATION									
2.4.1	Depreciation	59%	41%	6,891.1	4,036.9	2,854.2	(3,859.2)	(2,854.2)	177.7	0.0
2.4.2	Amortization	0%	100%	472.8	0.0	472.8	0.0	(472.8)	0.0	0.0
2.4	Subtotal			7,363.9	4,036.9	3,327.0	(3,859.2)	(3,327.0)	177.7	0.0
	TAXES - OTHER THAN INCOME									
2.5.1	Municipal	80%	20%	1,538.3	1,230.7	307.7	(930.7)	(307.7)	300.0	0.0
2.5.2	Capital	40%	60%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.5	Subtotal			1,538.3	1,230.7	307.7	(930.7)	(307.7)	300.0	0.0
2.	**TOTAL EXPENSES**			25,873.3	17,032.4	8,840.9	(17,308.5)	(8,840.9)	387.9	0.0
3.	**REVENUE REQUIREMENT BEFORE TAXES**			43,261.0	23,987.4	19,273.5	(21,506.2)	(19,273.5)	3,145.3	0.0

FUNCTIONALIZATION OF SHORT CYCLE
NET REVENUES TO IN/EX FRANCHISE CUSTOMERS
2016 TEST YEAR
($000)

		Col. 1	Col. 2	Col. 3 (Col. 1*Col. 2)	Col. 4	Col. 5	Col. 6 (Col. 3*Col. 4)	Col. 7 (Col. 3*Col. 5)
Item No.	Description	Net Revenues ($000)	Sharing	Net Revenues Shared ($000)	T/C	Storage	T/C ($000)	Storage ($000)
1.	Short Cycle	6,000.0	100%	6,000.0	57%	43%	3,419.6	2,580.4

CLASSIFICATION AND ALLOCATION OF NET REVENUES TO IN/EX FRANCHISE CUSTOMERS

		Col. 1	Col. 2 (Col. 1*60%)	Col. 3 (Col 1*40%)	Col. 4	Col. 5	Col. 6 (Col. 4*Col. 2)	Col. 7 (Col. 5*Col. 3)	Col. 8 (Col. 6+Col. 7)
			NET REVENUES		VOLUMES		ALLOCATION		
Item No.	Description	Total ($000)	Daily ($000)	Annual ($000)	Daily	Annual	Daily ($000)	Annual ($000)	Total ($000)
	T/C								
1.1	In Franchise				100%	100%	2,051.8	1,367.9	3,419.6
1.2	Rate 325				0%	0%	0.0	0.0	0.0
1.3	Rate 330				0%	0%	0.0	0.0	0.0
1.4	Rate 331				0%	0%	0.0	0.0	0.0
1.	TOTAL	3,419.6	2,051.8	1,367.9	100%	100%	2,051.8	1,367.9	3,419.6
	Storage								
2.1	In Franchise				100%	100%	1,548.2	1,032.1	2,580.4
2.2	Rate 325				0%	0%	0.0	0.0	0.0
2.3	Rate 330				0%	0%	0.0	0.0	0.0
2.4	Rate 331				0%	0%	0.0	0.0	0.0
2.	TOTAL	2,580.4	1,548.2	1,032.1	100%	100%	1,548.2	1,032.1	2,580.4
	Total T/C and Storage								
3.1	In Franchise						3,600.0	2,400.0	6,000.0
3.2	Rate 325						0.0	0.0	0.0
3.3	Rate 330						0.0	0.0	0.0
3.4	Rate 331						0.0	0.0	0.0
3.	TOTAL	6,000.0	3,600.0	2,400.0			3,600.0	2,400.0	6,000.0

APPENDIX D: DRAFT ACCOUNTING ORDER

ACCOUNTING TREATMENT FOR A PURCHASED GAS VARIANCE ACCOUNT (“2016 PGVA”)

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 PGVA is to record the effect of price variances between actual 2016 gas purchase prices and the forecast prices that underpin the revenue rates to be charged in 2016. Without this deferral account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This deferral account ensures that such effects are eliminated.

Methodology

The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded in the PGVA monthly.

The fixed cost component of the TransCanada firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA.

Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TransCanada tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized capacity will not be recorded in the PGVA and therefore, requires separate adjustment. The inclusion of changes in TransCanada tolls in the PGVA is consistent with past practice.

Since the transportation tolls for the Alliance and Vector pipelines that were used in the determination of the PGVA reference price were based upon an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TransCanada tolls will be recorded in the PGVA as a separate adjustment.

For the period January 1, 2016 to December 31, 2016 expenditures related to TransCanada's Storage Transportation Services, including balancing fees related to TransCanada's Limited Balancing Agreement, will be recorded in the 2016 PGVA. The 2016 PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

The PGVA will record adjustments related to transactional services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2016 PGVA and 2016 TSDA for purposes of deferral account dispositions.

In addition, the 2016 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

The 2016 PGVA will also record an inventory valuation adjustment every time a recalculated "Utility Price" or PGVA Reference Price comes into effect at the beginning of a quarter. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

The 2016 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA.

Simple interest is to be calculated on the opening monthly balance of the 2016 PGVA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2016 PGVA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the monthly gas purchase variance:

Debit:	2016 PGVA	(Account 179.706)
Credit:	Gas in Storage	(Account 152.000)
	or	
Debit:	Gas in Storage	(Account 152.000)
Credit:	2016 PGVA	(Account 179.706)

To record the total rate variance on the current month’s gas purchases.

2. TransCanada Toll changes related to forecast unutilized transportation capacity:

Debit:	2016 PGVA	(Account 179. 706)
Credit:	Accounts Payable	(Account 259. 000)
	or	
Debit:	Gas in Storage	(Account 152. 000)
Credit:	2016 PGVA	(Account 179. 706)

To record the amounts related to TransCanada toll changes on forecast unutilized transportation capacity.

3. TransCanada Toll changes related to Western Canada Bundled T-Service transportation capacity:

Debit:	2016 PGVA	(Account 179. 706)
Credit:	Accounts Payable	(Account 259. 000)
	or	
Debit:	Gas in Storage	(Account 152. 000)
Credit:	2016 PGVA	(Account 179. 706)

To record the amounts related to TransCanada toll changes on Western Canada Bundled T-Service transportation capacity.

4. Transactional services activities:

Debit/Credit:	2016 TSDA	(Account 179. 806)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2016 PGVA	(Account 179. 706)

To record adjustments for direct and avoided costs related to Transactional Services activities between the 2016 PGVA and 2016 TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

5. Electronic bulletin boards:

Debit:	2016 PGVA	(Account 179. 706)
Credit:	Accounts Payable	(Account 259. 000)

To record the amounts related to the Company's use of electronic bulletin boards.

6. Unforecast penalty revenues:

Debit:	Accounts Receivable	(Account 140. 010)
Credit:	2016 PGVA	(Account 179. 706)

To record unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements.

7. Voluntary UDC:

Debit:	2016 PGVA	(Account 179. 706)
Credit:	Accounts Payable	(Account 259. 000)

To record voluntary UDC as a result of purchasing lower priced unforecast discretionary delivered supplies.

8. Inventory valuation adjustment:

Credit/Debit:	Gas In Storage	(Account 152. 000)
Debit/Credit:	2016 PGVA	(Account 179. 706)

To record the adjustment necessary to value actual inventory volumes at a rate equal to the 2016 PGVA reference price.

9. Refund or collection of the Gas Cost Adjustment Rider:

Debit/Credit:	2016 PGVA	(Account 179. 706)
Credit/Debit:	Accounts Receivable	(Account 140. 010)

To record the amounts refunded or collected from customers through the Gas Cost Adjustment Rider.

10. Purchase of banked gas account balance:

Debit:	Gas In Storage	(Account 152. 000)
Credit:	2016 PGVA	(Account 179. 706)

To record the purchase of the Banked Gas Account Balance less the Transportation Service Rider A.

11. Unforecast UDC:

Debit:	2016 PGVA	(Account 179. 706)
Credit:	Accounts Payable	(Account 259. 000)

To record unforecast UDC costs resulting from the purchase of Banked Gas Account Balances from T-Service customers.

12. Sales in excess of 100% of the applicable gas supply charge:

Debit:	Other Income	(Account 319. 010)
Credit:	2016 PGVA	(Account 179. 706)

To record the amount of sales in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt amount.

13. Interest accrual:

Debit:	2016 PGVA - Interest Receivable	(Account 179. 716)
Credit:	Interest Expense	(Account 323. 000)
	or	
Debit:	Interest Expense	(Account 323. 000)
Credit:	2016 PGVA - Interest Payable	(Account 179. 716)

To record simple interest on the opening monthly balance of the 2016 PGVA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
TRANSACTIONAL SERVICES DEFERRAL ACCOUNT
("2016 TSDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 TSDA is to record the incremental ratepayer share of net revenue from transportation and storage related transactional services, to be shared 90/10 between EGD's ratepayers and shareholders.

In the event that the ratepayer share of 2016 TS net revenues exceeds $12 million, then such amounts over $12 million will be credited to the TSDA. In the event that the ratepayer share of 2016 TS net revenues is less than $12 million, then Enbridge will be credited with the difference between the actual ratepayer share of 2016 TS net revenues and $12 million, which would be reflected as a debit in the TSDA.

Net revenue is defined as gross revenues for providing these services less any direct incremental costs incurred, plus, any avoided costs. Direct incremental costs represent those direct costs incurred as a result of a transactional service activity and avoided costs are those costs that have been avoided as a result of a transactional service activity. Typical direct incremental costs and avoided costs would include transportation costs, fuel costs, charges for name changes, re-direct charges, etc.

Simple interest is to be calculated on the opening monthly balance of the 2016 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2016 TSDA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental Transactional Services revenues and costs:

Debit:	Other Income	(Account 319. 010)
Credit:	Operating Revenue	(Account 300. 000)
Debit/Credit:	2016 TSDA	(Account 179. 806)

To record either the incremental ratepayer portion of net revenues generated from transactional services activities in excess of the $12 million included in rates or the recognition of amounts recoverable by EGD where net TS revenue is less than $12 million.

2. Allocation of costs and benefits to Transactional Services activities:

Debit/Credit:	2016 TSDA	(Account 179. 806)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2016 PGVA	(Account 179. 706)

To record adjustments for direct and avoided costs related to transactional services activities between the 2016 PGVA and 2016 TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

3. Interest accrual:

Debit/Credit:	Interest Expense	(Account 323. 000)
Credit/Debit:	2016 TSDA - Interest Payable	(Account 179. 816)

To record simple interest on the opening monthly balance of the 2016 TSDA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
UNACCOUNTED FOR GAS VARIANCE ACCOUNT
("2016 UAFVA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of unaccounted for gas ("UAF") and the 2016 Board approved UAF volumetric forecast.

The gas costs associated with the UAF variance account will be calculated at the end of calendar 2016 based on the estimated volumetric variance between the 2016 Board approved level and the estimate of the 2016 actual UAF. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF and actual UAF.

The UAF annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price.

Where there are recoveries of gas loss amounts invoiced as part of 3rd party damages, the gas loss amounts will be removed from the UAFVA balance.

Carrying costs for the UAFVA will be calculated using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the estimated volumetric variance between the December 31, 2016 actual UAF and the Board Approved level:

Debit/Credit:	2016 UAFVA	(Account 179. 866)
Credit/Debit:	Gas Costs	(Account 623. 010)

To record the costs associated with the volumetric variance related to unaccounted for gas.

2. To record the recovery of gas loss amounts:

Debit:	Accounts Receivable	(Account 142. 010)
Credit:	2016 UAFVA	(Account 179. 866)

To record the recovery of gas loss amounts invoiced as part of 3rd party damages.

3. Interest accrual:

Debit/Credit:	Interest on 2016 UAFVA	(Account 179. 876)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 UAFVA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT
("2016 S&TDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the company. The accounting treatment for the S&TDA is in line with that established for the 2008 S&TDA, which recognized that storage and transportation services may be provided to the Company by suppliers other than Union Gas and at market based rates.

The 2016 S&TDA will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

The 2016 S&TDA will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

Simple interest is to be calculated on the opening monthly balance of the 2016 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. Storage and Transportation rate variance:

[(Final Storage and Transportation rates) – (Storage and Transportation rates underpinning the Company's 2016 rates)] X Actual storage and/or transportation volumes

Debit/Credit:	2016 S&TDA	(Account 179. 886)
Credit/Debit:	Gas in Storage	(Account 152. 000)
	or	
Credit/Debit:	Gas Costs	(Account 623. 010)

To record the difference between the Storage and Transportation rates included in the Company's 2016 rates and the final Storage and Transportation rates.

2. To record variances in the Storage and Transportation rebate programs:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2016 S&TDA	(Account 179. 886)
	or	
Debit:	2016 S&TDA	(Account 179. 886)
Credit:	Accounts Payable	(Account 259. 000)

To record the difference between the Storage and Transportation rebate programs included in the Company's 2016 rates and the final rebates received by the Company.

3. To record Storage and Transportation deferral account dispositions:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2016 S&TDA	(Account 179. 886)
	or	
Debit:	2016 S&TDA	(Account 179. 886)
Credit:	Accounts Payable	(Account 259. 000)

To record amounts related to deferral account dispositions received or invoiced from Storage and Transportation.

4. Inventory valuation adjustment:

Debit/Credit:	2016 S&TDA	(Account 179. 886)
Credit/Debit:	Gas In Storage	(Account 152. 000)

To record adjustments to storage and transmission fuel costs associated with quarterly price changes.

5. Interest accrual:

Debit/Credit:	Interest on 2016 S&TDA	(Account 179. 896)
Credit/Debit:	Interest Expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 S&TDA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN UNABSORBED DEMAND COST DEFERRAL ACCOUNT ("2016 UDCDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 UDCDA is to record the actual cost consequences of unutilized transportation capacity contracted by the Company to meet its Peak Day requirements in 2016. A consequence of contracting for incremental long haul capacity is the possibility of unabsorbed demand charges. The Company estimates that the cost consequences of unutilized transportation capacity will be approximately $15.7 million in the 2016 UDCDA. That is the maximum amount that may be recorded within the 2016 UDCDA.

To address concerns with the amount of potential UDC that could be borne by ratepayers, Enbridge will apply the principles and basis of the 2016 UDC Management Plan that was filed at Exhibit D1, Tab 2, Schedule 1, Appendix A within EB-2015-0114 and agreed to as part of the 2016 Settlement Agreement. The UDC Management Plan was developed as a means to mitigate potential UDC. Any revenues associated with that mitigation will be recorded in the UDCDA, and offset the cost of UDC.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record unabsorbed demand charges:

Debit:	2016 UDCDA	(Account 179. 766)
Credit:	Accounts Payable	(Account 251. 010)

To record the unabsorbed demand charges incurred as a result of not being able to utilize 100% of incremental long haul TCPL FT capacity contracted to meet 2016 peak day requirements.

2. To record revenue from mitigation of Unutilized Transportation costs:

Debit:	Accounts receivable	(Account 142. 010)
Credit:	2016 UDCDA	(Account 179. 766)

To record the revenue received through the mitigation of unutilized transportation costs.

3. Interest accrual:

Debit:	Interest on 2016 UDCDA	(Account 179. 776)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 UDCDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
GREENHOUSE GAS EMISSIONS IMPACT DEFERRAL ACCOUNT
("2016 GGEIDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 GGEIDA is to record any impacts to EGD resulting from federal and or provincial regulations related to greenhouse gas emission requirements, along with the impacts resulting from the sale of, or other dealings in earned carbon dioxide offset credits.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the impact of any greenhouse gas emission requirements, and or from the sale or other dealings in earned carbon dioxide offset credits:

Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2016 GGEIDA	(Account 179. 326)

Costs/proceeds arising from greenhouse gas emission requirements, or carbon dioxide offset credits dealings.

2. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on 2016 GGEIDA	(Account 179. 336)

To record simple interest on the opening monthly balance of the 2016 GGEIDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
CUSTOMER CARE CIS RATE SMOOTHING DEFERRAL ACCOUNT
("2016 CCCISRSDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 CCCISRSDA is to capture the difference between the forecast customer care and CIS costs versus the amount to be collected in revenues as approved by the Board in the EB-2011-0226 CIS Customer Care Settlement Agreement and proceeding. The amount to be debited or credited to the deferral account, for each of 2013 through 2018 years, will be calculated by multiplying the difference in cost per customer and smoothed cost per customer by the updated customer forecast for that year. The balances in the account will not be cleared during the 2013 through 2018 period. The cumulative balance will build up during the years 2013 to 2015 when the cost per customer exceeds the smoothed cost per customer being collected in rates, and then will be drawn down during the years 2016 to 2018 when the cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account it is to be cleared along with the clearance of other deferral and variance accounts.

Interest is to be calculated on the opening monthly balance of this account at a fixed annual rate of 1.47%, and will not change during the period the deferral account is allowed to continue through 2018. The interest carrying charges will be disposed of annually at the same time of clearance of all other deferral and variance accounts.

Accounting Entries

1. To record the approved 2016 treatment of revenue and costs associated with customer care and CIS costs:

Debit:	2016 CCCISRSDA	(Account 179. 166)
Credit:	Various accounts	(Account ___. ___)

To record the variance between customer care and CIS costs versus the amount to be collected in revenues as approved by the Board in the EB-2011-0226 for CCCISRSDA.

2. Interest accrual:

Debit:	Interest on 2016 CCCISRSDA	(Account 179. 176)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 CCCISRSDA using a fixed annual rate of 1.47%, as approved by the Board in the EB-2011-0226.

ACCOUNTING TREATMENT FOR A DEFERRED REBATE ACCOUNT ("2016 DRA")

For the 2016 Fiscal Year (January 1, 2016 to December 31, 2016)

The purpose of the 2016 DRA is to record any amounts payable to, or receivable from, customers of Enbridge Gas Distribution as a result of the clearing of deferral and variance accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. Disposition of deferral and variance accounts:

Debit/Credit:	D/VA's approved for clearance	(Account 179. ___)
Debit/Credit:	Interest on D/VA's – various	(Account 179. ___)
Credit/Debit:	2016 DRA	(Account 179. 006)

2. Refund or collection:

Debit/Credit:	2016 DRA	(Account 179. 006)
Credit/Debit:	Accounts Receivable	(Account 140. 010)

To record the actual amounts refunded to / recovered from customers.

3. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on the 2016 DRA	(Account 179. 016)

To record simple interest on the opening monthly balance of the 2016 DRA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
GAS DISTRIBUTION ACCESS RULE IMPACT DEFERRAL ACCOUNT
("2016 GDARIDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 GDARIDA is to record all incremental unbudgeted capital and operating impacts associated with the development, implementation, and operation of the Gas Distribution Access Rule and any ongoing amendments to the rule. Such costs would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating cost or revenue changes in relation to the establishment of contractual agreements, and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs related to Gas Distribution Access Rule requirements:

Debit:	2016 GDARIDA	(Account 179. 206)
Credit:	Accounts payable	(Account 251. 010)

To record the unbudgeted costs associated with GDAR development, implementation, and operation.

2. Interest accrual:

Debit:	Interest on 2016 GDARIDA	(Account 179. 216)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 GDARIDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
MANUFACTURED GAS PLANT DEFERRAL ACCOUNT
("2016 MGPDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 MGPDA is to capture all costs incurred in managing and resolving issues related to the Company's manufactured gas plant ("MGP") legacy operations. Amounts recorded in the 2015 MGPDA will also be transferred to the 2016 MGPDA. Costs charged to the account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company's responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company's existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs:

Debit:	2016 MGPDA	(Account 179. 306)
Credit:	Accounts Payable	(Account 251. 010)
Credit:	2015 MGPDA	(Account 179. 305)

To record the unbudgeted costs incurred in managing and resolving manufactured gas plants legal proceedings and litigation and to roll forward any un-cleared 2015 MGPDA amounts.

2. Interest accrual:

Debit:	Interest on 2016 MGPDA	(Account 179. 316)
Credit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2015 MGPDA	(Account 179. 315)

To record simple interest on the opening monthly balance of the 2016 MGPDA using the Board approved EB-2006-0117 interest rate methodology and to roll forward any un-cleared interest amounts on the 2015 MGPDA.

ACCOUNTING TREATMENT FOR A
CUSTOMER CARE SERVICES PROCUREMENT DEFERRAL ACCOUNT
("2016 CCSPDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 CCSPDA is to capture the costs associated with the benchmarking, tendering and potential transition of customer care services to a new service provider(s). The majority of EGD's 2013 through 2018 customer care costs were established and approved for recovery in the EB-2011-0226 proceeding, including services provided by two major outsourced customer care agreements which expire on December 31, 2017, subject to extension rights available to the Company. However, the costs related to the process of benchmarking and tendering for services provided by these agreements, to confirm the validity of pricing and quality for such services, and where appropriate identify new service provider(s), were not included, nor were any potential transition costs to new providers. The Ontario Energy Board's EB-2012-0459 Decision approves the continuation of this account through 2016, but limits the total amount recordable in the account to $5 million.

Simple interest is to be calculated on the opening monthly balance of the 2016 CCSPDA using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the customer care services procurement costs:

Debit:	2016 CCSPDA	(Account 179. 186)
Credit:	Accounts payable	(Account 251. 010)

To record benchmarking, tendering and transition costs in relation to customer care service providers.

2. Interest accrual:

Debit:	Interest on 2016 CCSPDA	(Account 179. 196)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 CCSPDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
AVERAGE USE TRUE-UP VARIANCE ACCOUNT
("2016 AUTUVA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism (LRAM), extended by the average use volume variance per customer and the number of customers.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the revenue impact of forecast versus actual normalized average use:

Debit/Credit:	2016 AUTUVA	(Account 179. 666)
Credit/Debit:	Operating revenue	(Account 300. 000)

To record the revenue impact associated with the variance in forecast average use per customer versus actual normalized average use per customer.

2. Interest accrual:

Debit/Credit:	Interest on 2016 AUTUVA	(Account 179. 676)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 AUTUVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
POST-RETIREMENT TRUE-UP VARIANCE ACCOUNT
("2016 PTUVA")

For the 2016 Fiscal Year
January 1, 2016 to December 31, 2016)

The purpose of the Post-Retirement True-Up Variance Account (PTUVA) is to record the differences between the 2016 forecast pension and post-employment benefit expenses of $34.6 million and the actual pension and post-employment benefit expenses (both determined on an accrual basis). The 2016 PTUVA will be cleared in a manner that will allow for all variances between $34.6 million and actual pension and OPEBs expenses to be recorded and cleared, subject to the condition that any amounts in excess of $5 million (credit or debit) will be transferred into a next year's account, so that large variances can be cleared over time (smoothed). Under this approach, the maximum amount (debit or credit) that will be cleared from the 2016 PTUVA will be $5 million, and any remaining amounts will be transferred to the 2017 PTUVA for future clearance.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the pension and post-employment benefit true-up amounts:

Debit:	2016 PTUVA	(Account 179. 246)
Credit:	Accounts payable	(Account 251. 010)
	Or	
Debit:	Operating revenue	(Account 300.000)
Credit:	2016 PTUVA	(Account 179.246)

To record variances between actual pension and post-employment benefits, on an accrual basis, and amounts embedded in rates.

2. To transfer amounts from the 2015 PTUVA to the 2016 PTUVA:

Debit/Credit:	2016 PTUVA	(Account 179. 246)
Credit/Debit:	2015 PTUVA	(Account 179. 245)

To transfer any amount in excess of $5 million (debit or credit) recorded in the 2015 PTUVA to the 2016 PTUVA.

3. Interest accrual:

Debit/Credit:	Interest on 2016 PTUVA	(Account 179. 256)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 PTUVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A TRANSITION IMPACT OF ACCOUNTING CHANGE DEFERRAL ACCOUNT ("2016 TIACDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 Transition Impact Accounting Change Deferral Account (TIACDA) is to track and roll forward un-cleared amounts recorded in the 2015 TIACDA. In EB-2011-0354, the Board approved the recovery of Other Post Employment Benefit (OPEB) costs, forecast to be $90 million at the end of 2012, over a 20 year period, commencing in 2013. The OPEB costs needed to be recognized as a result of Enbridge having to account for post-employment expenses on an accrual basis, upon transition to USGAAP for corporate reporting purposes in 2012. The use of USGAAP for regulatory purposes was approved within the 2013 rate proceeding, EB-2011-0354. The final estimate of OPEB costs to be recovered over 20 years, which was recorded in the TIACDA at the end of 2012, was $88.7 million. The first, second, and third installments of $4.4 million each (1/20 of $88.7 million), were approved for recovery in EB-2013-0046, EB-2014-0195, and EB-2015-0122. The balance in the account will continue to be drawn down and cleared to ratepayers by $4.4 million annually, with the un-cleared balance to be rolled forward to the subsequent year's TIACDA until clearance is complete.

Interest is not applicable to the balance of this account.

Accounting Entries

1. To track and record the accounting changes transition amounts as approved:

Debit:	2016 TIACDA	(Account 179. 026)
Credit:	2015 TIACDA	(Account 179. 025)

To roll forward un-cleared amounts recorded in the 2015 TIACDA.

ACCOUNTING TREATMENT FOR AN
OPEN BILL REVENUE VARIANCE ACCOUNT
("2016 OBRVA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 OBRVA is to track and record the ratepayer portion of net revenue for Open Bill Services. The account allows for net annual revenue amounts in excess of $7.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track and record Open Bill services net revenue:

Debit:	Other income	(Account 319. 010)
Credit:	2016 OBRVA	(Account 179. 486)
	Or	
Debit:	2016 OBRVA	(Account 179. 486)
Credit:	Operating revenue	(Account 300. 000)

To record the variance in the ratepayer porting of net revenue associated with Open Bill Service programs in excess of $7.389 million or below $4.889 million.

2. Interest accrual:

Debit/Credit:	Interest on 2016 OBRVA	(Account 179. 496)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 OBRVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
EX-FRANCHISE THIRD PARTY BILLING SERVICES DEFERRAL ACCOUNT
("2016 EFTPBSDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 EFTPBSDA is to record and track the ratepayer portion of revenues net of incremental costs generated from third party billing services provided to ex-franchise parties. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track and record the ratepayer portion of net revenue:

Debit/Credit:	2016 EFTPBSDA	(Account 179. 086)
Credit/Debit:	Various accounts	(Account ___. ___)

To record net revenue associated with Ex-Franchise third party Billing Services.

2. Interest accrual:

Debit/Credit:	Interest on 2016 EFTPBSDA	(Account 179. 096)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 EFTPBSDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
EARNINGS SHARING MECHANISM DEFERRAL ACCOUNT
("2016 ESMDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 ESMDA is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. If the 2016 actual utility return on equity, calculated on a weather normalized basis, exceeds the Board's approved formula ROE, which was utilized in determining 2016 allowed revenues, the resultant amount will be shared equally (i.e., 50/50) between the Company's ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application. In addition, the following are examples of shareholder incentives and other amounts which are outside of the ambit of the earnings sharing mechanism: amounts related to Demand Side Management incentives ("DSMIDA") and Lost Revenue Adjustment Mechanism ("LRAM"), amounts related to Transactional Services incentives, amounts related to Open Bill program incentives, and amounts related to Electric Program Earnings Sharing incentives ("EPESDA").

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the ratepayers' share of earnings as a result of the earning sharing mechanism:

Debit:	Operating revenue	(Account 300. 000)
Credit:	2016 ESMDA	(Account 179. 586)

To record the ratepayers' 50% share of utility earnings when the actual weather normalized ROE is greater than the Board approved formula ROE.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2016 ESMDA	(Account 179. 596)

To record simple interest on the opening monthly balance of the 2016 ESMDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A CONSTANT DOLLAR NET SALVAGE ADJUSTMENT DEFERRAL ACCOUNT ("2016 CDNSADA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 CDNSADA is to record and clear the 2016 credit to ratepayers that results from the adoption of the Constant Dollar Net Salvage (CDNS) approach for determining the net salvage percentages to be included within EGD's depreciation rates. As a result of the adoption of the CDNS approach, the Company has an estimated excess net salvage reserve when compared to the reserve which accumulated while the Company employed the Traditional Method for determining net salvage percentages. The net salvage reserve is recorded within a liability account which, for utility rate base determination purposes, is accounted for as an offset against specific property, plant and equipment asset category accumulated depreciation balances. Within EGD's EB-2012-0459 decision (2014 – 2018 Rate Application), the Board ordered the refund to ratepayers of $379.8 million in net salvage reserve over the 2014 – 2018 period, through rate rider D. The annual refund amounts are: 2014 - $96.8 million, 2015 - $90.4 million, 2016 - $83.9 million, 2017 - $77.5 million, and 2018 - $31.1 million.

On a monthly basis each year, the net salvage liability (or accumulated depreciation for utility rate base purposes) will be debited by the forecast monthly rider amount, with a corresponding credit recorded in the CDNSADA. Within the same month, the CDNSADA will be debited, with a corresponding credit to accounts receivable, for the actual amount refunded to customers through rate rider D.

In each year, the final balance in the account will be the cumulative variance between the amounts proposed for clearance and the actual amounts cleared. The balance will be transferred to the following year's CDNSADA, and at the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring the actual amount cleared is equivalent to the required $379.8 million.

No interest is to be calculated on the balance in this account.

Accounting Entries

1. To record the forecast monthly net salvage refund:

Debit:	Other LT Liabilities (Accum. Dep.)	(Account 279. 000)
Credit:	2016 CDNSADA	(Account 179. 346)

To record the forecast monthly net salvage refund amount to be returned to ratepayers through rate rider D.

2. To record the actual monthly net salvage refund:

Debit:	2016 CDNSADA	(Account 179. 346)
Credit:	Accounts Receivable	(Account 140. 010)

To record the actual monthly net salvage refund amount returned to ratepayers through rate rider D.

3. To transfer the 2015 CDNSADA balance to the 2016 CDNSADA:

Debit/Credit:	2016 CDNSADA	(Account 179. 346)
Credit/Debit:	2015 CDNSADA	(Account 179. 345)

To transfer the closing 2015 CDNSADA balance to the 2016 CDNSADA.

ACCOUNTING TREATMENT FOR AN
ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT
("2016 EPESDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 EPESDA is to track and account for the ratepayer share of all net revenues generated by DSM services provided for electric CDM activities. The ratepayer share is 50% of net revenues, using fully allocated costs, as was determined in DSM guidelines proceeding EB-2008-0346.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the ratepayer share of net revenues from electric DSM/CDM:

Debit:	Other income	(Account 319. 010)
Credit:	Operating & Maintenance	(Various accounts)
Credit:	2016 EPESDA	(Account 179. 606)

To record the ratepayer share of net revenues generated by providing DSM/CDM services.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2016 EPESDA	(Account 179. 616)

To record simple interest on the opening monthly balance of the 2016 EPESDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
DEMAND SIDE MANAGEMENT VARIANCE ACCOUNT
("2016 DSMVA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 DSMVA is to record the difference between the actual 2016 DSM spending and the eventual 2016 Board approved budget to be included within 2016 rates, as will be determined as part of the Board's decision in Enbridge's 2015-2020 DSM Plan proceeding, EB-2015-0049. Amounts determined to be over or under the budget included within rates will be incorporated into the DSMVA.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record variances in relation to appropriate DSM program costs only:

Debit/Credit:	2016 DSMVA	(Account 179. 066)
Credit/Debit:	Operating & Maintenance	(Various accounts)

To record the difference between actual and approved Demand Side Management operating expenditures.

2. Interest accrual:

Debit/Credit:	Interest on 2016 DSMVA	(Account 179. 076)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 DSMVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A LOST REVENUE ADJUSTMENT MECHANISM (“2016 LRAM”)

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 LRAM is to record the amount of distribution margin gained or lost when the Company's DSM programs are less or more successful than budgeted, for the period January 1, 2016 to December 31, 2016.

When the utility's DSM programs are less successful in the Test Year than budgeted, the utility gains distribution margin. Similarly, the utility loses distribution margin in the Test Year when its DSM programs are more successful than budgeted.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record LRAM amounts:

Debit/Credit:	Operating revenue	(Account 623. 010)
Credit/Debit:	2016 LRAM	(Account 179. 106)

To record in the LRAM, the distribution margin impact of differences between actual and budgeted gas savings forecast in the Company's DSM programs.

2. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on 2016 LRAM	(Account 179. 116)

To record simple interest on the opening monthly balance of the 2016 LRAM using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
DEMAND SIDE MANAGEMENT INCENTIVE DEFERRAL ACCOUNT
("2016 DSMIDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 DSMIDA is to record the actual amount of the shareholder incentive earned by the Company as a result of its DSM programs. The criteria and formula used to determine the amount of any shareholder incentive, to be recorded in the DSMIDA, will be in accordance with the methodology established in the current DSM Framework and Guidelines proceeding, EB-2014-0134, and Enbridge's 2015-2020 DSM Plan proceeding, EB-2015-0049.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. Shareholder incentive earned by the Company related to DSM programs:

Debit:	2016 DSMIDA	(Account 179. 266)
Credit:	Other income	(Account 319. 010)

To record the shareholder incentive earned by the Company related to its DSM programs.

2. Interest accrual:

Debit:	Interest on 2016 DSMIDA	(Account 179. 276)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 DSMIDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
DAWN ACCESS COSTS DEFERRAL ACCOUNT
("2016 DACDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 DACDA is to record for recovery the revenue requirement impact of the incremental costs incurred to implement the Dawn Transportation Service ("DTS"), including the costs for required system changes. Recovery of amounts recorded in the DACDA will be from all bundled customers, regardless of whether they are system or direct purchase and regardless of the service to which they currently subscribe, because all have the option of taking DTS if they so choose.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. Dawn Access Costs Deferral Account:

Debit:	2016 DACDA	(Account 179. 406)
Credit:	Operating revenue	(Account 300. 000)

To record the revenue requirement impact of costs associated with the implementation of the DTS.

2. Interest accrual:

Debit:	Interest on 2016 DACDA	(Account 179. 416)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 DACDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
CREDIT FINAL BILL DEFERRAL ACCOUNT
("2016 CFBDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

As was approved within EB-2014-0276, the purpose of the CFBDA is to address a billing related issue which the Company had identified as resulting from the 2009 CIS implementation, specifically final bills with credit balances. The account is to be used to track un-refunded customer final bill credit amounts, aged two years or more, while continuing efforts are made to return as much of the amounts as possible to the former account holders. Therefore, final bill credit balances aged two years or more will be credited to the account. As the affected customers will always be entitled and able to receive refunds, any future refund amounts paid relating to amounts already credited to the CFBDA will be debited to the account.

As per the terms of the EB-2014-0276 Settlement Agreement, the clearance of the 2015 CFBDA (which included all relevant outstanding credit balances) was requested and approved for clearance within the 2014 Earnings Sharing and Deferral Account Clearance Application, and was effected in October 2015.

Therefore, any amount to be recorded in the 2016 CFBDA will be comprised of any additional un-refunded customer final bill credit amounts resulting from the 2009 CIS implementation, aged two years or more, net of any refund amounts paid relating to amounts which have already been credited to the CFBDA. The Company does not foresee recording any additional credit amounts into the CFBDA.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To transfer un-refunded customer final bill credit amounts:

Debit:	Accounts Receivable	(Account 140. 010)
Credit:	2016 CFBDA	(Account 179. 626)

To transfer un-refunded customer final bill credit amounts, aged two years or more, to the CFBDA.

2. To recognize amounts refunded to affected customers:

Debit:	2016 CFBDA	(Account 179. 626)
Credit:	Accounts Receivable	(Account 140. 010)

To recognize refunds made to affected customers which have already been credited to the CFBDA.

3. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on 2016 CFBDA	(Account 179. 636)

To record simple interest on the opening monthly balance of the 2016 CFBDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
GREATER TORONTO AREA INCREMENTAL TRANSMISSION CAPITAL REVENUE
REQUIREMENT DEFERRAL ACCOUNT
("2016 GTAITCRRDA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 GTAITCRRDA is to record the revenue requirement related to an incremental $55 million of forecast capital costs which resulted from the upsizing of Segment A of the GTA project to an NPS 42 pipeline from an NPS 36 pipeline. The account will only be required in the event that at the time Segment A is put into service there are no transportation customers, or there is no ability for transportation customers to utilize Segment A. The revenue requirement will represent revenue to be collected from appropriate (likely transportation service) customers once they are able to take service under Rate 332. The rationale for calculating the revenue requirement associated with the incremental $55 million is to determine the annual impact of the incremental costs to be paid by transportation customers as a result of upsizing the pipeline for transportation purposes.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the revenue requirement related to incremental capital costs:

Debit:	2016 GTAITCRRDA	(Account 179. 146)
Credit:	Transportation revenue	(Account 570. 000)

To record the revenue requirement impact of $55 million of incremental capital associated with the transmission customer use of the GTA Segment A pipeline.

2. Interest accrual:

Debit:	Interest on 2016 GTAITCRRDA	(Account 179. 156)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2016 GTAITCRRDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
RATE 332 DEFERRAL ACCOUNT
("2016 R332DA")

For the 2016 Fiscal Year
(January 1, 2016 to December 31, 2016)

The purpose of the 2016 R332DA is to record for refund to the Company's bundled customers, any Rate 332 revenues collected from Rate 332 transportation customers, net of any reduction in the amount forecast to be recovered through the 2016 GTAITCRRDA, should Rate 332 transportation service on Segment A of the GTA project become available at some point during 2016 as a result of the completion of all associated interconnected third party facilities. The R332DA will ensure that the Company's bundled customers only pay for the revenue requirement for the transportation component of Segment A, net of the revenue requirement on the incremental $55 million, until such time as Rate 332 transportation service is available. The R332DA will also ensure the Company does not over recover the forecast revenue requirement for Segment A of the GTA Project.

Should Rate 332 transportation service become available at some point during 2016, then Rate 332 customers will be charged the monthly proportion of 60% of the Segment A revenue requirement from that point onward. However, at the same time, the monthly allocation of the $4.9 million forecast to be recovered through the 2016 GTAITCRRDA will stop. As such, the amount actually recovered through Rate 332 customers from the time transportation service becomes available, net of the amount forecast to be recorded in the 2016 GTAITCRRDA for that same time period, will be credited to the Company's bundled customers through the R332DA.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record for refund to bundled customers, a portion of 2016 Rate 332 revenues collected:

Debit:	Transportation revenue	(Account 570. 000)
Credit:	2016 R332DA	(Account 179. 926)

To record for refund to bundled customers, any 2016 Rate 332 revenues collected, net of any reduction in the 2016 amount forecast to be recovered through the 2016 GTAITCRRDA, in the event that Rate 332 transportation service on Segment A of the GTA project become available during 2016.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2016 R332DA	(Account 179. 936)

To record simple interest on the opening monthly balance of the 2016 R332DA using the Board approved EB-2006-0117 interest rate methodology.