ENBRIDGE

Stephanie Allman
Regulatory Coordinator
Regulatory Affairs

tel 416 495 5499
egiregulatoryproceedings@enbridge.com

Enbridge Gas Inc.
500 Consumers Road
North York, Ontario M2J 1P8
Canada

July 17, 2019

VIA EMAIL, RESS, and COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2019-0105 – Enbridge Gas Inc. – 2018 Disposition of Deferral & Variance Account Balances and 2018 Utility Earnings

Effective January 1, 2019, Enbridge Gas Distribution Inc. ("EGD") and Union Gas Limited ("Union") amalgamated to become Enbridge Gas Inc. ("Enbridge Gas"). Enclosed is the application and evidence submitted by Enbridge Gas concerning the disposition and recovery of certain 2018 deferral and variance account balances (the "Application") for all Enbridge Gas rate zones (EGD, Union North and Union South).[1]

The Application has been filed through the Ontario Energy Board's (the "OEB") RESS and will be available on the Enbridge website at: www.enbridgegas.com/ratecase.

The Application is supported by evidence which is outlined below:

Exhibit A: Overview and Introduction

Exhibit B: Enbridge Gas Distribution Rate Zone
- Tab 1 - Deferral and Variance Accounts requested for clearance
- Tab 2 – Utility Results and Earnings Sharing
- Tab 3 – Rate Allocation

Exhibit C: Union Rate Zones
- Tab 1 – Deferral and Variance Accounts requested for clearance
- Tab 2 – Utility Results and Earnings Sharing
- Tab 3 – Rate Allocation

Exhibit D: Reporting and Reference Material

[1] Collectively, the Union North and Union South rate zones are referred to as the "Union rate zones".

Enbridge Gas proposes that the impacts which result from the disposition of 2018 deferral and variance account balances be implemented on January 1, 2020 to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism.

In the event that you have any questions on the above or would like to discuss in more detail, please do not hesitate to contact me.

Yours truly,

[original signed by]

Rakesh Torul
Technical Manager, Regulatory Applications

cc: David Stevens (Aird & Berlis LLP)
Fred Cass (Aird & Berlis LLP)
Mark Kitchen (Enbridge Gas)

EXHIBIT LIST

A - Administrative

Exhibit	Tab	Appendix	Schedule	Contents
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	2			Application
	3			Overview and Approvals Required
	4			Draft Issues List

B – EGD Rate Zone

B – Deferral Account Disposition – EGD Rate Zone

Exhibit	Tab	Appendix	Schedule	Contents
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B – Utility Results and Earnings Sharing – EGD Rate Zone

Exhibit	Tab	Appendix	Schedule	Contents
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		A	1	ESM Calculations and Required Rate of Return 2018 Actuals
			2	2018 Utility Earnings – Contributors to Utility Earnings and Earnings Sharing Amounts

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B – Utility Results and Earnings Sharing – EGD Rate Zone

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			2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2018 Actuals
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B	2	C	1	Utility Operating Revenue 2018 Actuals
			2	Comparison of Gas Sales and Transportation Volume by Rate Class 2018 Actuals to 2018 EB-2017-0086 Board Approved
			3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2018 Actuals to 2018 EB-2017-0086 Board Approved
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B – Utility Results and Earnings Sharing – EGD Rate Zone

Exhibit	Tab	Appendix	Schedule	Contents
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B	2	F		2018 RRR filings re. Service Quality Indicators

B – Rate Class Allocation – EGD Rate Zone

Exhibit	Tab	Appendix	Schedule	Contents
B	3			Clearance of 2018 Deferral Account Balances - EGD Rate zone
		A	1	Derivation of Proposed Unit Rates

C – Union Rate Zones

C – Deferral Account Disposition – Union Rate Zones

Exhibit	Tab	Appendix	Schedule	Contents
C	1			Deferral & Variance Accounts Requested for Clearance January 1, 2020 – Union Rate Zones

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C – Utility Results and Earnings Sharing – Union Rate Zones

EXHIBIT LIST

C – Utility Results and Earnings Sharing – Union Rate Zones

EXHIBIT LIST

C – Rate Class Allocation – Union Rate Zones

Exhibit	Tab	Appendix	Schedule	Contents
C	3			Allocation and Disposition of 2018 Deferral Account Balances - Union Rate Zones
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D – Reporting and Reference Material

Exhibit	Tab	Appendix	Schedule	Contents
D	1			Reporting and Reference Material

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Inc. for an order or orders clearing certain non-commodity related deferral or variance accounts and sharing utility earnings pursuant to a Board-approved earnings sharing mechanism;

APPLICATION

Enbridge Gas Distribution Inc. (referred to in the evidence as "EGD", "Enbridge" or the "Company") and Union Gas Limited (referred to in the evidence as "Union" or the "Company") (together the "Utilities") were Ontario corporations incorporated under the laws of the Province of Ontario carrying on the business of selling, distributing, transmitting and storing natural gas within the meaning assigned in the *Ontario Energy Board Act*, 1998 (the "Act"). Effective January 1, 2019 the Utilities amalgamated to become Enbridge Gas Inc. ("Enbridge Gas"). Following amalgamation, Enbridge Gas has maintained the existing rates zones of EGD and Union (the EGD, Union North West, Union North East and Union South rate zones).[1]

Enbridge Gas, the Applicant, hereby applies to the Ontario Energy Board (the "Board"), pursuant to Section 36 of the *Ontario Energy Board Act*, 1998 (the "Act"), for an Order or Orders approving the clearance or disposition of amounts recorded in certain deferral or variance accounts.

[1] Collectively the Union North West, Union North East and Union South rates zones are referred to as "Union rate zones". Union North West and Union North East are collectively referred to as "Union North".

EGD Rate Zone

Within the Decision with Reasons in the EB-2012-0459 proceeding[2], the Board established a Custom Incentive Regulation Mechanism ("Custom IR") framework to set EGD's rates over the period from 2014-2018. Among other things, this includes an Earnings Sharing Mechanism ("ESM") under which EGD is to share earnings above the Board-approved Return on Equity ("ROE") with ratepayers on a 50/50 basis. The Custom IR framework includes a number of deferral and variance accounts to be maintained or created during the IR term.

Under the Custom IR framework, after the release of its Audited Financial Statements for the prior year EGD is required to file an Application setting out the ESM calculation for that year. Within the Application, EGD is to set out its proposal for the clearance of amounts recorded in the Earnings Sharing Mechanism Deferral Account ("ESMDA") and other deferral and variance accounts.

Pursuant to the EB-2012-0459 Decision with Reasons, EGD is also required to annually report upon the status of a number of initiatives and activities as part of the ESM Application. The relevant updates for 2018 are included at Tab D.

Union Rate Zones

In EB-2017-0087[3], Union applied to the Board for an order approving or fixing just and reasonable rates and other charges for the sale, distribution, storage and transmission of gas by Union effective January 1, 2018. The Board approved Union's request. In doing so, the Board approved the continuation of certain deferral and variance accounts.

[2] EB-2012-0459 – Enbridge Gas Distribution Application seeking approval of rates for 5-year period beginning January 1, 2014, Decision with Reasons dated July 17, 2014

[3] EB-2017-0087 – Union Gas 2018 Rates proceeding

For the purpose of this Application, Union's approved Incentive Regulation Mechanism ("IRM")[4] provides for sharing if in any calendar year, Union's actual utility return on equity ("ROE") is more than 100 basis points over the 2013 Board-approved ROE of 8.93%.

Excess earnings between 100 basis points and 200 basis points would be shared 50/50 between Union and its customers. If, in any calendar year, Union's actual ROE is more than 200 basis points over the 2013 Board-approved ROE of 8.93%, then such earnings in excess of 200 basis points would be shared 90/10 between customers and Union.

Union's 2018 actual utility earnings did not exceed the 100 basis point threshold therefore there is no earnings sharing. There are balances to be cleared from certain other deferral and variance accounts.

Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone and Union rate zones 2018 deferral and variance accounts as listed in Exhibit B, Tab 1, Appendix A, Schedule 1 for EGD rate zone and Exhibit C, Tab 1, Appendix A, Schedule 1 for Union rate zones.

Enbridge Gas therefore applies to the Board for such final, interim order or other orders as may be necessary or appropriate for the clearance or disposition of the 2018 deferral and variance accounts listed in Exhibit B, Tab 1, Appendix A, Schedule 1 for EGD rate zone and Exhibit C, Tab 1, Appendix A, Schedule 1 for Union rate zones. Enbridge Gas proposes to clear the balances in these accounts in conjunction with the January 1, 2020 QRAM application.

Enbridge Gas further applies to the Board pursuant to the provisions in the Act and the Board's *Rules of Practice and Procedure* for such final, interim or other Orders and

[4] EB-2013-0202 – Union Gas Incentive Regulation Mechanism, decision and Order, dated October 7, 2013

directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

This Application is supported by written evidence. This evidence may be amended from time to time as required by the Board, or as circumstances may require.

The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Enbridge Gas, together with those to whom Enbridge Gas sells gas, or on whose behalf Enbridge Gas distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

Enbridge Gas requests that a copy of every document filed with the Board in this proceeding be served on the Applicant and Applicant's counsel, as follows:

The Applicant:

Mr. Rakesh Torul
Technical Manager, Regulatory Applications
Enbridge Gas Inc.

Address for personal service	Enbridge Gas Inc 500 Consumers Road Willowdale, Ontario M2J 1P8
Mailing address:	P.O. Box 650 Scarborough, Ontario M1K 5E3

Telephone:	416-753-7818
Fax:	416-495-6072
Email:	rakesh.torul@enbridge.com

The Applicant's counsel:

Mr. David Stevens
Mr. Fred Cass
Aird & Berlis LLP

Address for personal service and mailing address:	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	416-863-1500
Fax:	416-863-1515
Email:	fcass@airdberlis.com dstevens@airdberlis.com

DATED: July 17, 2019, at Toronto, Ontario

ENBRIDGE GAS INC.

[Original signed by]

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Rakesh Torul
Technical Manager, Regulatory Applications

2018 DEFERRAL ACCOUNT DISPOSITION AND EARNINGS SHARING OVERVIEW AND APPROVALS REQUESTED

Enbridge Gas Inc. ("Enbridge Gas") is applying to the Ontario Energy Board (the "Board" or "OEB") pursuant to Section 36 of the OEB Act for approval to dispose and recover 2018 deferral and variance account final balances as well as any Earnings Sharing Mechanism ("ESM") amounts for the Enbridge Gas Distribution ("EGD") and Union Gas ("Union")[1] rate zones (EGD and Union are jointly referred to as the "Utilities").

Effective January 1, 2019, EGD and Union amalgamated to become Enbridge Gas. Although Enbridge Gas has filed a single Application concerning the disposition and recovery of certain 2018 deferral and variance account balances and ESM amounts in all rate zones, in recognition of EGD's and Union's historical approaches the supporting evidence for this Application has been divided to address the EGD rate zone and Union rate zones separately. This approach will provide the Ontario Energy Board ("the Board") with continuity and ease of reference in its review of Enbridge Gas' newly combined deferral and variance account disposition proceeding.

The evidence in this Application is organized as follows:

- Exhibit A: Overview and Introduction
- Exhibit B: Enbridge Gas Distribution Rate Zone
  - Tab 1 - Deferral and Variance Accounts requested for clearance
  - Tab 2 – Utility Results and Earnings Sharing
  - Tab 3 – Rate Allocation
- Exhibit C: Union Rate Zones
  - Tab 1 – Deferral and Variance Accounts requested for clearance
  - Tab 2 – Utility Results and Earnings Sharing
  - Tab 3 – Rate Allocation

[1] "Union rate zones" collectively refers to Union North and Union South.

Enbridge Gas proposes that the impacts which result from the disposition of 2018 deferral and variance account balances be implemented on January 1, 2020 to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism.

1. RELIEF REQUESTED

Enbridge Gas seeks approval to clear the final balances of certain EGD rate zone and Union rate zones 2018 deferral and variance accounts. The EGD rate zone balances are included at Exhibit B, Tab 1, Appendix A, Schedule 1 and the Union rate zone balances are included at Exhibit C, Tab 1, Appendix A, Schedule 1 of this Application. Enbridge Gas is also seeking approval of the final disposition of the 2017 revenue recorded in the Lobo D/ Bright C/ Dawn H Compressor Project Costs Deferral Account (179-144), which was approved on an interim basis as part of EB-2018-0105 (Union's 2017 Deferral Account Disposition proceeding).

Enbridge Gas further seeks approval of $29.95 million (Exhibit B, Tab 2, Appendix A, Schedule 1) as the customer portion of earnings sharing in 2018 for the EGD rate zone and the proposed disposition of that amount to customers.[2] Union's 2018 actual utility earnings did not exceed the Return on Equity ("ROE") threshold established as part of its 2014-2018 Incentive Regulation Mechanism ("IRM") therefore there is no earnings sharing.[3]

Within the determination of utility results and deferral account balances requested for clearance, Enbridge Gas has reflected the impact of the enactment of accelerated Capital Cost Allowance ("CCA") measures contained in Bill C-97, which received Royal

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2 Board established a Customer IR Framework for EGD in EB-2012-0459. This Framework established EGD's rates over the period of 2014-2018. Also included an ESM under which EGD is to share earnings above the Board-approved ROE with ratepayers on a 50/50 basis.
3 Union's approved IRM for period 2014-2018 in EB-2013-0202 provides for sharing if in any calendar year Union's actual utility ROE is more than 100 basis points over the 2013 Board-approved ROE of 8.93%.

Assent on June 21, 2019. As detailed later in this Application, the impact of such measures has impacted each legacy utility in a different manner. In 2018, for the EGD rate zone, the revised CCA was reflected in the utility income tax calculation, which impacted the amount of earning sharing payable to ratepayers. In the Union rate zones, 50 percent of the CCA impact for 2018 (exclusive of amounts captured in the capital pass-through deferral accounts) was captured in the Tax Variance Deferral Account to be shared with ratepayers.

2. DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

In the 2016 DSM Clearance of Deferral and Variance Accounts Decision (EB-2018-0300/0301), the OEB states that:

> A common approach to the disposition of deferral and variance accounts should be developed by Enbridge Gas for its EGD and Union rates zones. In future proceedings, Enbridge Gas is expected to adopt a common approach to the extent practical, and if not, explain the rationale for continuing a different approach.[4]

As part of this proceeding, Enbridge Gas proposes to dispose of the deferral and variance accounts consistent with the current practices of legacy EGD and Union.

- For the EGD rate zone, Enbridge Gas disposes of deferral balances as a one-time adjustment for both general service and contract rate classes.
- For the Union rate zones, Enbridge Gas disposes of deferral balances prospectively for general service customers and as a one-time adjustment for in-franchise contract and ex-franchise rate classes.

4 EB-2018-0300/EB-2018-0301, Decision and Rate Order, May 23, 2019, p. 4.

The proposed approach to the one-time adjustments is consistent between the EGD and Union rate zones and will be disposed of as part of the January 2020 bills that customers receive in February 2020.

The rationale for the continued use of a one-time adjustment includes:

- Alignment of the cost incurrence of the deferral account balance with cost recovery by customer. The one-time adjustment avoids material mismatches that could occur between cost incurrence and cost recovery due to customer switching between rate classes and changes in customer's consumption volumes from year to year.
- Elimination of the forecast variance which results from disposing of deferral account balances prospectively.

Enbridge Gas is currently not able to administer one-time adjustments for general service customers in the Union rate zones because of limitations in the system used to bill this group of customers. The continued use of a prospective recovery disposition methodology from general service customers is appropriate as it generally provides alignment between cost incurrence and cost recovery because of the consistency of consumption patterns throughout the year by customers in these rate classes.

As Enbridge Gas is in the early stages of integrating internal systems and processes between legacy EGD and Union, Enbridge Gas is not able to introduce any further commonality to the disposition approaches at this time. A common approach could be proposed once integrated systems and processes are implemented.

3. PARKWAY WEST PROJECT COSTS ACCOUNT INTERIM DISPOSITION

Enbridge Gas is seeking interim disposition of the 2018 balance in the Parkway West Project Costs Deferral Account (179-136), consistent with the 2016 Deferrals[5] and 2017 Deferrals[6] proceedings. The OEB noted that "all parties agreed that the 2016 balance in the Parkway West Project Costs Account should be disposed of only on an interim basis to allow the OEB to perform a prudence review of the capital overspend prior to final disposition of the balance in the account."[7] Consistent with this direction, Enbridge Gas will seek approval of the final disposition of this account as part of a subsequent proceeding when all the project costs have been incurred and the prudence of the project costs are assessed.

5 EB-2017-0091
6 EB-2018-0105
7 EB-2017-0091 Updated Settlement Agreement Proposal, p. 12

DRAFT ISSUES LIST

Are the Deferral and Variance Accounts balances proposed for disposition as set out in Exhibit B, Tab 1, Appendix A, Schedule 1 and Exhibit C, Tab 1, Appendix A, Schedule 1 appropriate?

Are the proposed unit rates and timing for implementation of the clearances appropriate?

2018 DEFERRAL AND VARIANCE ACCOUNT BALANCES REQUESTED FOR CLEARANCE JANUARY 1, 2020 EGD RATE ZONE

The Company requests approval for clearance of the Deferral and Variance Account balances in EGD rate zone shown in the Table at Exhibit B, Tab 1, Appendix A, Schedule 1, Columns 3 & 4, commencing January 1, 2020. The balances requested for clearance total approximately ($33.8) million, which is the combination of principal and interest amounts shown in Columns 3 and 4.

Within the remainder of the Exhibit B, Tab 1 evidence, Enbridge has provided explanatory information for each of the accounts for which clearance is sought, with the exception of the ESMDA, for which details are included in the Exhibit B, Tab 2 series of exhibits.

The interest on the principal balances in the Deferral and Variance Accounts has been calculated using the Board's prescribed interest rates for deferral and variance accounts, including the July 1, 2019 prescribed rate. The eventual interest amounts to be cleared will be calculated using any updated Board prescribed quarterly interest rate that becomes effective before the approved date of clearance. Note that the CCCISRSDA interest has been calculated using a fixed rate of 1.47%, as stipulated in the EB-2011-0226 CC/CIS Settlement Agreement[1].

The Company notes that as part of this proceeding it is not requesting clearance of balances recorded within the 2016, 2017, and 2018 Demand Side Management (DSM) related deferral accounts: Demand Side Management V/A "DSMVA", Lost Revenue Adjustment Mechanism "LRAM", and Demand Side Management

[1] Customer Care Settlement Agreement, EB-2011-0226, Exhibit N1, Tab 1, Schedule 1, p.12

Incentive D/A "DSMIDA". The 2016 DSM related deferral account balances were approved for clearance, commencing July 1, 2019, in the EB-2018-0301 proceeding. Any amounts to be cleared in relation to 2017 and 2018 DSM related accounts will be reviewed and approved through separate DSM proceedings.

The Company is also not requesting clearance of the balances recorded within the 2016, 2017 and 2018 Cap and Trade related deferral accounts: Greenhouse Gas Emissions Impact D/A ("GGEIDA"), Greenhouse Gas Emissions Compliance Obligation – Customer Related V/A ("GGECOCRVA"), and Greenhouse Gas Emission Obligation – Facility Related V/A ("GECOFRVA") as part of this proceeding. All Cap and Trade related deferral account balances are being reviewed as part of the ongoing EB-2018-0331 proceeding.

2018 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT AND 2018 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT

2018 Storage and Transportation Deferral Account ("2018 S&TDA")

The purpose of the 2018 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.

The S&TDA also records the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition the S&TDA is used to record amounts received by the Company related to deferral account dispositions of other utilities deferral accounts.

The balance in the 2018 S&TDA that the Company is proposing to collect from customers is $1.8 million plus interest.

The primary driver for the balance in the 2018 S&TDA is due to actual Cap and Trade costs incurred and not forecasted and higher than forecast Third Party Market Based Storage Costs or a detailed breakdown of the variance please see Exhibit B, Tab 1, Appendix A, Schedule 2.

2018 Transactional Services Deferral Account ("2018 TSDA")

The concept of Transactional Services operates under the premise that if circumstances arise where the assets acquired by Enbridge to meet customer demand are not fully required then those assets can be made available to generate third party revenue. Transactional Services are the optimization of these assets.

Transactional services optimization can be grouped into two different categories – storage optimization and transportation optimization. Storage optimization transactions typically rely on storage or the loan of gas between two points in time at the same location (i.e., Dawn). Transportation optimization transactions typically rely on the exchange of gas on the day between two locations.

Any revenues received from transactional services are to be shared 90:10 between the ratepayer and the Company. The rates designed by the Company include an upfront benefit of $12.0 million in Transactional Services revenue that has been applied to reduce the overall costs to be collected from ratepayers. The purpose of the TSDA is to capture the difference between the total ratepayer share of transactional services revenue and the amount already included in rates.

During 2018 the Company was able to generate a total of $14.7 million in net Transactional Services revenue through a combination of Storage and Transportation Optimization. Exhibit B, Tab 1, Appendix A, Schedule 3 provides a breakdown of Transactional Services revenue by type of transaction, and sets out the details of the amount, $1.3 million proposed to be refunded to customers through the disposition of the 2018 TSDA. For comparison purposes the schedule also includes amounts recorded in the applicable TSDA accounts for years 2017, 2016, 2015 and 2014.

The transactions that Enbridge entered into in 2018 contained the three elements of Transactional Services as were described in the Company's evidence in EB-2013-0046 in that they were Unplanned, the result of a Third Party Service Request and were available because of Temporarily Surplus Capacity.

2018 UNACCOUNTED-FOR GAS VARIANCE ACCOUNT

This evidence provides the volumetric variance underpinning the balance in the 2018 Unaccounted-For Gas Variance Account ("UAFVA"). It will describe the 2018 variance relative to historical Unaccounted-For Gas ("UAF") volumes.

UAF is the difference between natural gas delivered into the distribution system as billed by third-party transmission entities (namely, TransCanada Pipelines and Union Gas[1]) and natural gas that is billed as consumption to over two million customers. Owing to its residual nature, UAF cannot be measured directly. UAF can arise from meter differences, operational or external factors such as line leakage, unmetered uses, and third party damages. In addition, because gas volumes are affected by temperature and pressure, measurement is made more difficult.

In the Company's UAF study filed in 2013 rate application (EB-2011-0354, Exhibit D2, Tab 6, Schedule 1), results identified meter uncertainty as the main source of UAF. Custody transfer meters, residential diaphragm meters, rotary meters and other meters are required by Measurement Canada to be within specified limits of error, depending on the type of meter. 2018 UAF is within all tolerance levels, at 1.1% of total 2018 throughput volumes.

The 2018 level of UAF was determined to be 142,086 10^3m^3. The variance of 35,409 10^3m^3, which is the difference between actual UAF volume and the forecast UAF volume [2]of 106,677 10^3m^3, underpins the $5.6M account balance that is

[1] As of January 1, 2019, Union Gas Limited and Enbridge Gas Distribution have merged as Enbridge Gas Inc.
[2] The Board approved a forecast of 106,077 10^3m^3. Due to a clerical error, all subsequent calculations have used an incorrect UAF forecast volume of 106,677 10^3m^3. The gas supply plan and resulting rates were designed based on the higher forecast UAF value and have been used as the benchmark comparator for the UAFVA. As such, it is appropriate that the UAF forecast volumes will remain at the higher value. Using the approved UAF forecast, the variance would be 36,009 10^3m^3 and would increase the receivable balance by approximately $96,000.

captured in the UAFVA.

Although the root causes of UAF are generally known as noted earlier, it continues to be difficult to quantify the individual factors due to their nature. No significant factors are known to have occurred in 2018 that would have contributed to a higher UAF than recently experienced. As part of the MAAD's Decision and Order dated August 30, 2018 on the amalgamation of Enbridge Gas Distribution and Union Gas (EB-2017-0306), Enbridge Gas Inc. was directed to file a report on the issue of Unaccounted for Gas for both the legacy Union Gas and legacy Enbridge Gas Distribution service areas by December 31, 2019. Among the objectives of the UAF study is an analysis of UAF causes to identify possible points of gas losses and to review functional capabilities of the measurement system used to produce UAF values.

As shown in Tables 1 and 2 in the following pages, UAF has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels especially in 2014 and 2016. The 2018 UAF level falls within the 95% confidence interval, bounded by (30,216) 10^3m^3 and 174,675 10^3m^3.

Table 1: Unaccounted-For Gas Volumes (10^3 m^3), 1991-2018

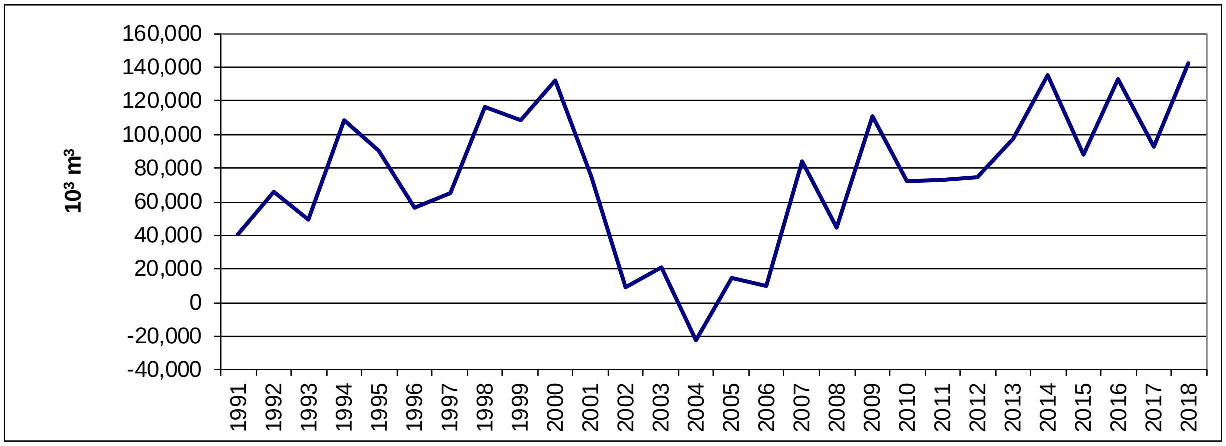

Table 2

Col. 1	*Col. 2*
Calendar Year	**UAF Volumes (10^3 m^3)**
1991	40,662
1992	66,028
1993	49,782
1994	108,765
1995	90,655
1996	56,739
1997	65,228
1998	116,376
1999	108,201
2000	132,021
2001	75,606
2002	9,284
2003	21,412
2004	-22,406
2005	14,815
2006	10,274
2007	83,823
2008	44,424
2009	110,917
2010	72,104
2011	73,355
2012	74,762
2013	97,361
2014	135,380
2015	88,438
2016	133,112
2017	93,077
2018	142,086
	1991-2017
Standard deviation	41,325
Mean	72,229
Lower bound*	-30,216
Upper bound*	174,675

*95% confidence interval with 26 degrees of freedom (number of observations-1)

1

2018 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

The purpose of this evidence is to provide information in support of the 2018 Average Use True-up Variance Account ("AUTUVA") balance.

Table 1 of Exhibit B, Tab 1, Appendix A, Schedule 4 details the calculations that result in the amount of $18.79 million that will constitute a refund to ratepayers. The refund is attributable to actual Rate 1 (residential) and Rate 6 average (apartment, small commercial and industrial) uses being higher than 2018 forecast levels.

Higher weather-normalized average use is primarily attributable to lower actual natural gas prices and better economic conditions in 2018 than were forecast. Lower gas prices have led to higher consumption for both Rate 1 and Rate 6 customers. In additions, higher employment levels and stronger GDP support stronger economic conditions which also lead to higher consumption.

The purpose of the AUTUVA is to record ("true-up") the revenue impact (exclusive of gas costs) of the normalized volumetric difference between the forecast of average use per customers in Rate 1 and Rate 6 and the actual weather-normalized average use experienced during the year. The revenue impact is calculated using a unit rate determined in the same manner as the impact used in the derivation of the Lost Revenue Adjustment Mechanism ("LRAM").

As detailed in Table 1 of Exhibit B, Tab 1, Appendix A, Schedule 4, the calculation of the volumetric variance between forecast average use and actual normalized average use subtracts the volumetric impact of Demand Side Management ("DSM") programs in the year. As has been the case in previous applications, since the audited actual volume savings of 2018 DSM activities will not be available until a later date, the 2018 Board Approved Budget DSM volumes are used as an estimate of 2018 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2018 LRAM amounts which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

2018 POST-RETIREMENT TRUE-UP VARIANCE ACCOUNT (“PTUVA”)

In accordance with the EB-2017-0086 Final Accounting Order, page 20, the purpose of PTUVA is to record any allowed revenue impact that results from actual pension and Other post-employment benefit (“OPEB”) related amounts (accrual based expense amounts and cash based funding) which differ compared to what was forecast and included in rates. This also includes any allowed revenue impacts arising as result of proposed changes to Ontario pension legislation and regulations which proceed. The Board-approved forecast for the 2018 PTUVA was $12.1 million.

As of December 31, 2018 the actual allowed revenue impact that resulted from pension and OPEB related amounts was $12.4 million. A breakdown of the $12.4 million can be seen at Exhibit B, Tab 1, Appendix A, Schedule 5.

Please refer to Exhibit B, Tab 1, Appendix A, Schedule 6 for extracts of the 2018 Final Accounting Mercer Report that support the breakdown above.

Therefore, the PTUVA balance that relates to the 2018 year is a $0.3 million recovery, which is the difference between the Board-approved forecast of $12.1 million and the actual revenue impact of $12.4 million.

As was agreed in Enbridge’s 2013 Rate Application (EB-2011-0354) Settlement Agreement (p. 20), the maximum clearance from the PTUVA (credit or debit) in any one year is $5 million. Any remaining balance is to be carried forward to the following year, so that large variances can be cleared over time (smoothed). This treatment for the PTUVA has remained in place since 2013, and is reflected in the EB-2017-0086 approved 2018 PTUVA.

There is no carry-over balance in the PTUVA from 2017. In this proceeding, the Company is requesting to recover $0.3 million from the 2018 PTUVA in accordance with the EB-2017-0086 approved variance account scope.

GAS DISTRIBUTION ACCESS RULE IMPACT DEFERRAL ACCOUNT

Within the EB-2017-0086 Final Accounting Order, included as Schedule A to the Decision and Accounting Order, dated February 22, 2018, the Board approved the 2018 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA") to record impacts associated with the Company maintaining compliance with the Board's Gas Distribution Access Rule ("GDAR") directives.

While there were no amendments to GDAR directives during 2018, the Company has included for recovery within the 2018 GDARIDA, the 2018 revenue requirement impact resulting from the Low Income Customer Service Rule ("LICSR") changes which came into effect on January 1, 2013 through an amendment to GDAR which the Board adopted on September 6, 2012.

Within Enbridge's Clearance of 2013 Deferral and Variance Accounts and 2012 DSM Related Accounts proceeding, EB-2014-0195, the Company requested and received Board approval to credit to ratepayers the 2013 revenue requirement resulting from the capital spending incurred to implement the Low Income Customer Service Rule ("LICSR") changes. As was indicated within that proceeding, at Exhibit B, Tab 3, Schedule 3, Enbridge was not able to include a forecast of the impacts of the change in the GDAR low income customer service rule at the time of forecasting its 2013 revenue requirement within its 2013 Test Year rate proceeding, EB-2011-0354, which also served as the base for the 2014 through 2018 Customized Incentive Regulation plan approved in EB-2012-0459. Within that proceeding, the Company also indicated that there would be 2014 through 2018 revenue requirement impacts resulting from the LICSR capital spending to be recovered through the GDAR deferral account.

Consistent with what was indicated within EB-2014-0195, as part of each of Enbridge's 2014 through 2017 Earnings Sharing Mechanism and Deferral Account Clearance proceedings, EB-2015-0122, EB-2016-0142, EB-2017-0102, and EB-2018-0131, the Company requested and received approval to recover the 2014 through 2017 revenue requirements resulting from the LICSR changes.

As mentioned above, within this proceeding the Company has included for recovery within the 2018 GDARIDA, the 2018 revenue requirement, determined through a cost of service type calculation, which results from the LICSR changes. The Company is proposing to recover from ratepayers $0.117 million (and corresponding interest of $2.5 thousand) as part of the requested one time rate rider adjustment in January 2020, as shown in the proposed clearance balances at Exhibit B, Tab 1, Appendix A, Schedule 1, Columns 3 and 4.

The determination of the 2018 revenue requirement amount is shown at Exhibit B, Tab 1, Appendix A, Schedule 7. Included within the revenue requirement calculation requested for recovery are the typical items included within a cost of service revenue requirement, such as depreciation, taxes, and total return on rate base (including interest and return on equity). The Company has used the 2018 actual required capital structure within the 2018 revenue requirement calculation. The approved 2013, 2014, 2015, 2016, and 2017 revenue requirement amounts credited to and recovered from ratepayers as part of the EB-2014-0195, EB-2015-0122, EB-2016-0142, EB-2017-0102, and EB-2018-0131 proceedings, are also shown for continuity. 2018 is the final year for which the LICSR changes will have a revenue requirement impact, as the capital costs are fully depreciated.

2018 DEFERRED REBATE ACCOUNT

The 2018 Deferred Rebate Account ("DRA") was approved by the Board within the EB-2017-0086 Accounting Order, at page 15. The description and scope of the 2018 account, consistent with prior fiscal years, was to record any amounts payable to, or receivable from, customers as a result of clearing Deferral and Variance Accounts, which remain outstanding due to the inability to locate such customers.

The $1.0 million recorded in the 2018 DRA and requested for clearance (and corresponding interest of $9.3 thousand), reflects the outstanding amount resulting from the clearance of 2015 DSM related deferral and variance accounts which occurred in October 2018, and the inability to locate all the intended customers.

2019 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT

The purpose of the Transition Impact of Accounting Changes Deferral Account ("TIACDA") is to track the un-cleared Other Post Employment Benefit ("OPEB") costs which the Board has approved for recovery. Within EB-2011-0354, the Board approved the recovery of OPEB costs, which were forecast to be $90 million at the end of 2012, evenly 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 amount recorded in the TIACDA as of the end of 2012 was $88.716 million. The first six installments (for each of 2013 through 2018) of $4.436 million each (1/20 of $88.716 million), were approved for recovery within the EB-2013-0046, EB-2014-0195, EB-2015-0122, EB-2016-0142, EB-2017-0102, and EB-2018-0131 proceedings.

Enbridge is now requesting recovery of the seventh, or 2019 installment of the Board-Approved TIACDA amount, in the amount of $4.436 million (1/20 of $88.716 million).

As per the approved description and scope of the account, interest is not applicable to the balances to be cleared from the TIACDA.

2013, 2014, 2015, 2016, 2017, AND 2018 CUSTOMER CARE CIS RATE SMOOTHING DEFERRAL ACCOUNTS

Within the Customer Care and CIS Costs Settlement Agreement and proceeding EB-2011-0226, the Board approved of a Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"), for each of 2013 through 2018. The purpose of the account was to capture the difference between the forecast customer care and CIS costs (as approved in EB-2011-0226) versus the amount to be collected in revenues in each year. The amount to be debited or credited to the Deferral Account in each year was calculated by multiplying the difference in approved cost per customer and smoothed cost per customer for that year, by the updated customer forecast for that year.

The Settlement Agreement also specified that the balances in the account were not to be cleared during the 2013 through 2018 period. The cumulative balance was to build up during the years 2013 to 2015 when the approved cost per customer exceeded the smoothed cost per customer collected in rates, and then was to be drawn down during the years 2016 to 2018 when the approved cost per customer was lower than the smoothed cost per customer collected in rates. After 2018, any remaining balance in the account was to be cleared along with the clearance of other Deferral and Variance Accounts.

The Settlement Agreement also specified that Enbridge would be entitled to collect interest, at a fixed annual rate of 1.47%, on the balances in the CCCISRSDAs, and that interest would be cleared annually at the same time as other Deferral and Variance Account clearings.

In accordance with the EB-2011-0226 Settlement Agreement parameters, within each of the EB-2011-0354, EB-2012-0459, EB-2014-0276, EB-2015-0114, EB-2016-0215, and EB-2017-0086 proceedings (EGD 2013 – 2018 rate proceedings), the Board approved each of the 2013 - 2018 CCCISRSDAs, the updated customer forecast for each year, and the resultant updated approved customer care and CIS cost per year, the updated smoothed cost per year (to be recovered in rates), and variance to be captured in the CCCISRSDA. The annual approved variance reflects the principal balance recorded within each of the 2013 - 2018 accounts ($4.6 million, $2.9 million, $1.1 million, $0.8 million credit, $2.8 million credit, and $4.9 million credit). Table 3 below summarizes the calculation of each of the annual amounts that were approved in the annual rate proceedings, while Table 4 summarizes the original forecast amounts from the EB-2011-0226 Settlement Agreement.

Table 3

Proceeding	Year	Updated Number of Customers	Approved Cost per Customer	Approved Smoothed Cost per Customer	Approved CIS & Customer Care Cost	Approved CIS & Customer Care Smoothed Cost	Variance recorded to CCCISRSDA
					($000's)	($000's)	($000's)
EB-2011-0354	2013	2,059,959	55.75	53.50	114,842.7	110,207.8	4,634.9
EB-2012-0459	2014	2,086,534	56.08	54.68	117,011.3	114,084.3	2,927.0
EB-2014-0276	2015	2,114,261	56.41	55.88	119,266.5	118,142.3	1,124.2
EB-2015-0114	2016	2,143,429	56.74	57.11	121,626.1	122,406.0	(779.9)
EB-2016-0215	2017	2,168,434	57.08	58.36	123,771.7	126,557.0	(2,785.3)
EB-2017-0086	2018	2,197,291	57.42	59.65	126,159.6	131,061.2	(4,901.6)
					722,677.9	722,458.6	219.3

Table 4

Proceeding	Year	Number of Customers	Approved Cost per Customer	Approved Smoothed Cost per Customer	Approved CIS & Customer Care Cost	Approved CIS & Customer Care Smoothed Cost	Variance to CCCISRSDA
					($000's)	($000's)	($000's)
EB-2011-0226	2013	2,059,959	55.75	53.50	114,842.7	110,207.8	4,634.9
EB-2011-0226	2014	2,100,317	56.08	54.68	117,784.3	114,837.9	2,946.4
EB-2011-0226	2015	2,142,191	56.41	55.88	120,842.1	119,703.0	1,139.1
EB-2011-0226	2016	2,185,464	56.74	57.11	124,011.3	124,806.5	(795.2)
EB-2011-0226	2017	2,229,173	57.08	58.36	127,238.6	130,102.0	(2,863.4)
EB-2011-0226	2018	2,269,074	57.42	59.65	130,281.1	135,342.8	(5,061.8)
					735,000.0	735,000.0	0.0

In accordance with the EB-2011-0226 Settlement Agreement methodology (described above), within this proceeding the Company is requesting clearance of the 2013, 2014, 2015, 2016, 2017 and 2018 CCCISRSDAs with a net cumulative principal balance of $0.2 million, as well as corresponding interest balance on each account with a net balance of ($29.7) thousand. The individual principal and interest balances for each account are shown in Exhibit B, Tab 1, Appendix A, Schedule 1, Columns 3 and 4.

2018 ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT

The 2018 Electric Program Earnings Sharing Deferral Account ("EPESDA") was approved by the Board within the EB-2017-0086 Accounting Order. The description and scope of the 2018 account, consistent with prior fiscal years, was 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 the DSM guidelines proceeding EB-2008-0346.

On June 10, 2016, the Minister of Energy provided a direction to the IESO whereby, the IESO shall, in consultation with the Distributors, centrally design, fund and deliver "a province-wide home Conservation and Demand Management (CDM) pilot program for residential consumers." The IESO Whole Home Pilot was launched on May 29, 2017 and leverages the existing Enbridge Gas DSM Home Energy Conservation (HEC) program offering by adding an electric assessment component, and offering prescriptive electric incentives to participants. The aim of this "one stop shop" approach was to increase Enbridge Gas Distribution participant satisfaction, provide additional energy literacy to Ontario residents, and remove the barriers around access to incentives from different parties. The pilot program was extended into 2018, with enrollments of residential homeowners into the Whole Home Pilot continuing to the pilot end date of October 31st, 2018.

The ($1.2) million recorded in the 2018 EPESDA and requested for clearance, reflects the ratepayers' 50% share of the net recovery generated by providing Conservation & Demand Management ("CDM") activities, using fully allocated costs, as determined in the DSM guidelines proceeding EB-2008-0346.

2018 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT

The purpose of the 2018 Ontario Energy Board Cost Assessment Variance Account ("OEBCAVA") was to record any variances between the OEB costs assessed to Enbridge through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the OEB costs which were included in rates, which were determined through application of the prior Cost Assessment Model. The 2018 OEBCAVA was approved as part of the EB-2017-0086 Decision and Accounting Order, dated February 22, 2018. The scope of the account is consistent with prior 2016 and 2017 OEBCAVAs. The OEBCAVA was originally approved for establishment by Board letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model.*

The amount recorded within the 2018 OEBCAVA is $2,702.3 thousand. This amount reflects the variance between OEB costs assessed to Enbridge in each quarter of fiscal 2018, utilizing the revised CAM, and Enbridge's average quarterly OEB cost assessment under the prior CAM. For purposes of calculating amounts to be recovered through the 2018 OEBCAVA, the Company used the OEB's fiscal 2015 / 2016 cost assessment amount of $2.8 million (or an average of $0.7 million per quarter) as the comparator, as it was the most recent amount which the Company was expected to accommodate through its Custom Incentive Regulation Mechanism established rates. This methodology is consistent with the determination of amounts which were approved for recovery through the 2016 and 2017 OEBCAVAs. Table 5 below, shows the calculation of the amount recorded in the 2018 OEBCAVA, while Table 6 shows the calculation of the average 2015 / 2016 OEB costs assessed to the Company under the prior CAM.

Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2018 OEBCAVA, in the amount of $2,702.3 million and $89.7 thousand respectively, as shown in Exhibit B, Tab 1, Appendix A, Schedule 1.

Table 5

OEB assessment	Fiscal 2018 OEB cost assessment amounts under the revised CAM	Average cost assessment based on previous CAM*	Variance recorded in the 2018 OEBCAVA
	($)	($)	($)
Q4 2017/18 - Jan. 1, 2018	1,319,997	699,846	620,151
Q1 2018/19 - Apr. 1, 2018	1,467,963	699,846	768,117
Q2 2018/19 - July 1, 2018	1,356,860	699,846	657,014
Q3 2018/19 - Oct. 1, 2018	1,356,860	699,846	657,014
Total	5,501,680	2,799,383	2,702,297

* Enbridge utilized the average of the OEB's fiscal 2015/2016 quarterly invoiced amounts, determined under the previous CAM, as representative of the OEB costs embedded in 2018 rates.

Table 6

OEB Cost Assessment Based on prior CAM	Qtr. #	Quarterly Assessment	Total for the year	Average/Qtr
		$	$	$
OEB Fiscal 2015/2016	1	656,800		
	2	656,800		
	3	655,137		
	4	830,646	2,799,383	699,846

2018 DAWN ACCESS COSTS DEFERRAL ACCOUNT

Within the EB-2017-0086 Final Accounting Order, included as Schedule A to the Decision and Accounting Order, Dated February 22, 2018, the Board approved the 2018 DACDA. The purpose of the DACDA, as established in the EB-2014-0323 Settlement Agreement, 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. In addition, in accordance with the 2017 Rate Application Settlement Proposal, EB-2016-0215, the revenue requirement related to additional costs incurred to accommodate the heat value conversion modification, implemented in conjunction with the Dawn Transportation Service system development process, are also to be recorded within this account. Under the terms of the EB-2014-0323 Settlement Agreement, 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. Further details explaining the DACDA, including the recovery method, are included within Section 2.7 of the Settlement Agreement filed at Exhibit B, Tab 2, Schedule 1 of the EB-2014-0323 proceeding.

As was indicated in the EB-2018-0131 proceeding (in support of the clearance of the 2017 revenue requirement amount recorded in the 2017 DACDA), all incremental costs incurred by the Company to implement the DTS (and functionality for 2 additional receipt points) and heat value conversion modification were capital in nature. Capital costs of $6.5 million were incurred to develop, test, and integrate enhancements to the functionality of Enbridge's EnTRAC and connected systems. The systems modifications were placed into service effective November 1, 2017, in conjunction with the implementation of

Phase 2 of the Dawn Access Settlement. The annual revenue requirement amounts sought for refund/recovery in association with those capital costs, includes the typical items in a cost of service revenue requirement, such as total return on rate base, including interest and return on equity, depreciation, and income taxes.

Within this proceeding, the Company is requesting clearance of the 2018 revenue requirement, or principal balance, of $1.2 million (and corresponding interest of $26.1 thousand) as part of the requested one time rate rider adjustment in January 2020, as shown in the proposed clearance balances at Exhibit B, Tab 1, Appendix A, Schedule 1. As indicated above, this amount represents the 2018 revenue requirement associated with the capital spending incurred to accommodate the DTS and heat value changes, which were placed into service in 2017. The Company has used the 2018 actual required capital structure within the 2018 revenue requirement calculation (consistent with the use of the 2017 actual capital structure that was utilized in determining the 2017 revenue requirement which was approved for clearance in EB-2018-0131). There will also be revenue requirement amounts to be recorded in relation to this spending within future DACDA’s. Those future amounts will be higher, as the 2018 amount (similar to 2017) benefits from a significant Capital Cost Allowance (“CCA”) tax deduction that does not repeat in subsequent years beyond 2018.

The revenue requirement sought for recovery will be allocated to the various rate classes based on the bundled annual deliveries of each rate class.

The determination of the 2018 DACDA revenue requirement deferral account amount and related costs is shown at Exhibit B, Tab 1, Appendix A, Schedule 8. The approved 2017 revenue requirement amount which was credited to ratepayers as part of the EB-2018-0131 proceeding, is also shown for continuity.

2018 PENSION AND OPEB FORECAST ACCRUAL VERSUS ACTUAL CASH PAYMENT DIFFERENTIAL VARIANCE ACCOUNT (“P&OPEBFAVACPDVA”)

In accordance with the Board's EB-2015-0040 report to all regulated entities, dated September 14, 2017, titled “Regulatory Treatment of Pension and Other Post-employment Benefits (“OPEB”) Costs”, the Board ordered the establishment of the P&OPEBFAVACPDVA, effective January 1, 2018, to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis. The Company recovers its pension and OPEB costs on an accrual basis.

The purpose of the P&OPEBFAVACPDVA is to track the differences between forecast accrual pension and OPEB amounts recovered in rates, and the actual cash payments made for both pension and OPEB, on a go-forward basis from the date the account was established. In 2018, the accrual pension and OPEB amount recovered in rates was $15.4 million and the actual cash payments made for both pension and OPEB were $23.7 million, resulting in an annual $8.3 million debit variance.

During 2018 the accrual based pension and OPEB amount recovered in rates was equivalent to the actual accrual based cost incurred by the Company. This is because the forecast accrual based pension and OPEB amount included in base 2018 rates (of $20.7 million), should be offset by the variance ($5.3 million credit) against the 2018 actual accrual based pension and OPEB amount (of $15.4 million), which has been reflected in the amount recorded in the Post Retirement True-up Variance Account (PTUVA). Recognition of the amount reflected in the PTUVA is appropriate as it results in a comparison against the net amount actually recovered through rates. In addition, failure to recognize the amount reflected in the PTUVA could result in interest payable being calculated on the same amount in both the PTUVA and P&OPEBFAVACPDVA accounts.

In accordance with the Board's report (EB-2015-0040), when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, an asymmetrical carrying charge, to be returned to ratepayers, should be accrued based on the opening monthly difference between amounts recovered in rates and actual cash payments. The balance in the account is an interest credit to ratepayers of $1 thousand to December 31, 2018. Please refer to Table 1 for a detailed calculation of the Company's actual accrual versus actual cash payments for 2018 and associated interest.

Table 1

Details of 2018 Interest Calculated on P&OPEBFAVACPDVA

Particulars ($000's)	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Actual accrual amounts	1,282	1,282	1,282	1,282	1,282	1,283	1,282	1,282	1,282	1,282	1,282	1,282	15,385[1]
Actual cash payments	864	6,753	5,113	5,080	407	704	582	451	219	2,622	436	448	23,679[1]
Monthly variance	(418)	5,471	3,831	3,798	(875)	(579)	(700)	(831)	(1,063)	1,340	(846)	(834)	8,294
Cumulative variance	(418)	5,053	8,884	12,682	11,807	11,228	10,528	9,697	8,634	9,974	9,128	8,294	
OEB prescribed CWIP rate	2.99	2.99	2.99	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	
Asymmetrical interest	-	(1)	-	-	-	-	-	-	-	-	-	-	(1)

1 *Please refer to Exhibit B, Tab 1, Appendix A, Schedule 6, for extracts of the 2018 Final Accounting Mercer Report*

<u>2018 Manufactured Gas Plant Deferral Account ("2018 MGPDA")</u>

The purpose of the 2018 MGPDA is to capture all costs incurred in managing and resolving issues related to the Company's Manufactured Gas Plant ("MGP") legacy operations. 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 is also 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.

Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2018 MGPDA, in the amount of $0.967 million. This balance represents the accumulation of costs incurred since 2006, the year in which the account was first approved, which have been carried forward through to the current account balance.

Most of the amounts recorded within the MGPDA arise from EGD's defense of a lawsuit brought by Cityscape Residential Inc. against the Company in relation to alleged contamination at a site in Toronto. That lawsuit, which was issued in 2003, sought damages of $55 million against the Company. The Cityscape Residential lawsuit was settled and completed in 2018, and that is why the Company is now seeking to clear the current balance in the MGPDA.

As noted, the $0.967 million balance in the 2018 MGPDA represents the accumulation of costs incurred since 2006, the year in which the account was first approved, which have been carried forward through to the current account balance. The costs in the account include legal costs related to defending the Cityscape litigation over 15 years, consultant costs related to environmental and insurance coverage and real estate issues, settlement funds paid to Cityscape and legal costs related to MGP issues other than the Cityscape litigation.

EGD RATE ZONE
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at April 30, 2019 Principal ($000's)	Col. 2 Actual at April 30, 2019 Interest ($000's)	Col. 3 Forecast for clearance at January 1, 2020 Principal ($000's)	Col. 4 Forecast for clearance at January 1, 2020 Interest ($000's)
	Commodity Related Accounts					
1.	Storage and Transportation D/A	2018 S&TDA	1,787.7	83.4	1,787.7	109.0
2.	Transactional Services D/A	2018 TSDA	(1,304.7)	(10.3)	(1,304.7)	(29.5)
3.	Unaccounted for Gas V/A	2018 UAFVA	5,616.0	34.6	5,616.0	116.2
4.	Total commodity related accounts		6,099.0	107.7	6,099.0	195.7
	Non Commodity Related Accounts					
5.	Average Use True-Up V/A	2018 AUTUVA	(18,787.8)	(149.2)	(18,787.8)	(422.0)
6.	Post-Retirement True-Up V/A	2018 PTUVA	256.6	2.0	256.6	6.0
7.	Gas Distribution Access Rule Impact D/A	2018 GDARIDA	117.1	0.9	117.1	2.5
8.	Deferred Rebate Account	2018 DRA	981.7	(5.1)	981.7	9.3
9.	Transition Impact of Accounting Changes D/A	2019 TIACDA	62,101.2	-	4,435.8	-
10.	Customer Care CIS Rate Smoothing D/A	2018 CCCISRSDA	(4,901.6)	(57.2)	(4,901.6)	(105.2)
11.	Customer Care CIS Rate Smoothing D/A	2017 CCCISRSDA	(2,785.3)	(13.6)	(2,785.3)	(40.8)
12.	Customer Care CIS Rate Smoothing D/A	2016 CCCISRSDA	(779.9)	(3.8)	(779.9)	(11.8)
13.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	5.5	1,124.2	16.7
14.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	14.3	2,927.0	43.1
15.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	22.7	4,634.9	68.3
16.	Electric Program Earnings Sharing D/A	2018 EPESDA	(1,210.1)	(13.2)	(1,210.1)	(30.8)
17.	OEB Cost Assessment V/A	2018 OEBCAVA	2,702.3	50.5	2,702.3	89.7
18.	Dawn Access Costs D/A	2018 DACDA	1,173.7	9.3	1,173.7	26.1
19.	Pension and OPEB Forecast Accrual Vs. Actual Cash Payment Differential V/A	2018 P&OPEBFAVACPDVA	-	(2.2)	-	(1.0)
20.	Manufactured Gas Plant D/A	2018 MGPDA	888.0	66.1	888.0	78.9
21.	Earnings Sharing Mechanism Deferral Account	2018 ESMDA	(27,350.0)	(217.2)	(29,950.0)	(643.0)
22.	Total non commodity Related Accounts		21,092.0	(290.2)	(39,173.4)	(914.0)
23.	Total Deferral and Variance Accounts		27,191.0	(182.5)	(33,074.4)	(718.3)

Breakdown of the 2018 Storage and Transportation Deferral Account ("2018 S&TDA)

Item #		Column 1	Column 2		Column 3	Column 4	Column 5
	Contracted Union Capacity	Daily Contract Demand Volume - GJ's	Monthly Demand Toll Assumed in 2018 Budget - $/GJ	Forecasted Annual Cost - $ (millions)	Monthly Demand Toll Effective January 1, 2018 - $/GJ	Annual Cost - $ (millions)	Balance in the 2018 S&TDA
	1.1 Union Gas Dawn to Lisgar	67,929	2.865	2.3	3.154	2.6	
	1.2.1 Union Gas Dawn to Parkway	2,527,173	3.402	103.2	3.716	112.7	
	1.2.1 Union Gas Dawn to Parkway	190,000	3.402	1.3	3.716	8.5	
	1.3 Union Gas Dawn to Parkway - M12X	200,000	4.239	10.2	4.59	11.0	
	1.4 Union Gas Parkway to Dawn - C1	236,586	0.719	2.0	0.874	2.5	
	1.5 Union Gas F24 T	85,000	0.069	0.1	0.07	0.1	
1.	Union Transmission Costs			119.1		137.3	18.2
2.	Dawn T Service Costs			(11.2)		(29.4)	(18.2)
3.	Cap and Trade costs			-		1.1	1.1
4	Third Party Market Based Storage			20.1		20.8	0.7
5.	Total			128.0		129.8	1.8

Item #		2018 Transactional Services Revenue	2017 Transactional Services Revenue	2016 Transactional Services Revenue	2015 Transactional Services Revenue	2014 Transactional Services Revenue
		$ 000's	$ 000's	$ 000's	$ 000's	$ 000's
1.0	Storage Optimization	423.9	1,550.1	7,277.2	517.4	1,703.4
2.0	Transportation Optimization	14,292.4	10,393.3	10,463.5	22,727.1	12,910.3
3.0	Transactional Services Revenue	14,716.2	11,943.5	17,740.6	23,244.6	14,613.7
4.0	Ratepayer Portion of TS	13,244.6	10,749.1	15,966.6	20,920.1	13,152.4
5.0	Less Amount Included in Rates	12,000.0	12,000.0	12,000.0	12,000.0	12,000.0
6.0	TSDA sub-total	1,244.6	(1,250.9)	3,966.6	8,920.1	1,152.4
7.0	ETT Revenue - Rider H	60.1	44.5	69.7	154.7	104.4
8.0	TSDA Total	1,304.7	(1,206.4)	4,036.3	9,074.8	1,256.7

TABLE 1
2018 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
			=Col. 2-1		=Col. 3*4			=Col. 7-6	=Col. 5-8	Unit Rate of the Revenue Impact, exclusive of gas costs	=Col. 9*10
Rate Class	2018 Budget Annual Use (m^3)	2018 Normalized Actual Annual Use (m^3)	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2018 DSM Budget (10^6m^3)	2018 DSM Actual (10^6m^3)	DSM Volumetric Variance (10^6m^3)	Normalized Volumetric Variance Excluding DSM (10^6m^3)	Unit Rate ($/$m^3$)	AUTUVA: Revenue Impact, Exclusive of Gas Costs - ($ millions)
1	2,358	2,456	98	2,015,077	197.6	(6.8)	(6.8)	0.0	197.6	0.0705	13.93
6	28,656	29,377	721	167,564	120.8	(18.1)	(18.1)	0.0	120.8	0.0402	4.86
Total					318.5	(24.9)	(24.9)	0.0	318.5		18.79

2018 PTUVA Revenue Requirement

Line No.	Particulars ($000,000's)	Actual 2018 (a)	Board Approved 2018 (b)	Allowed Revenue Impact 2018 (a) - (b)
	Incremental Rate Base Investment			
1	Capital Expenditures	-	-	-
2	Average Rate Base	-	-	-
	Incremental Revenue Requirement Calculation:			
	Return on Incremental Rate Base:			
3	Long-term Debt Interest	-	-	-
4	Short-term Debt Interest	-	-	-
5	Preference Shares	-	-	-
6	Equity	-	-	-
7	Total Return on Incremental Rate Base	-	-	-
	Incremental Operating Expenses:			
8	Operating and Maintenance Expenses	15.4	20.7	(5.3)
9	Depreciation Expense	-	-	-
10	Property Taxes	-	-	-
11	Total Incremental Operating Expenses	15.4	20.7	(5.3)
	Incremental Income Taxes:			
12	Return on Equity and Preference Shares (line 5 + line 6)	-	-	-
	Utility/Tax Timing Differences			
13	Add: Pension and OPEB Accrual Cost (line 8)	15.4	20.7	(5.3)
14	Less: Pension and OPEB Cash Contribution	(23.7)	(44.6)	20.9
15	Taxable Income (line 12 + line 13 + line 14)	(8.3)	(23.9)	15.6
16	Income Taxes Before Gross Up (line 15 x 26.5%) (1)	(2.2)	(6.3)	4.1
17	Total Incremental Income Taxes After Gross Up (line 16 / (1-26.5%) (1)	(3.0)	(8.6)	5.6
18	Total Incremental Revenue Requirement (line 7 + line 11 + line 17)	12.4	12.1	0.3

Notes:
(1) EGD's current provincial and federal tax rate is equal to 26.5%.

Breakdown of actual pension and post-employment benefit (“OPEB”) expense as of December 31, 2018:

	$ million	Reference
Registered Pension Plan – Enbridge Gas Distribution Inc.	(16.8)	Page 2
Registered Pension Plan – Enbridge Inc.	24.3	Page 2
Supplementary Executive Retirement Plan	0.1	Page 2
Senior Supplementary Executive Retirement Plan	(0.1)	Page 2
Supplementary Pension Plan	1.1	Page 2
Defined contribution	0.3	
Pension credits[1]	1.3	
Total pension expense	10.2	
OPEB expense	5.2	Page 2
Total pension and OPEB expense	15.4	

1) Pension credits are paid outside the pension plans and are not accounted for as part of the pension expense.

Breakdown of actual pension and OPEB cash based funding amounts as of December 31, 2018:

	$ million	Reference
Registered Pension Plan – Enbridge Gas Distribution Inc.	6.3	Page 4
Registered Pension Plan – Enbridge Inc.	12.0	Page 4
Supplementary Executive Retirement Plan	–	Page 4
Senior Supplementary Executive Retirement Plan	–	Page 4
Supplementary Pension Plan	–	Page 4
Defined contribution	0.3	
Pension credits[1]	1.3	
Total pension cash contributions	19.9	
OPEB expense	3.8	Page 4
Total pension and OPEB cash contributions	23.7	

1) Pension credits are paid outside the pension plans and are not accounted for as part of the pension expense.

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Plan ID Number	1	2	3	4	5	6	
Plan - Business Unit	Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates - Enbridge Gas Distribution Inc. (PP)	Supplemental Executive Retirement Plan of Enbridge Gas Distribution and Affiliates	Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc.	Retirement Plan for the Employees of Enbridge Inc. and Affiliates - Enbridge Gas Distribution Inc. (RP)	The Enbridge Supplemental Pension Plan (without CGT Assets) - Enbridge Gas Distribution Inc. (SP)	EGD OPEB - Enbridge Gas Distribution Inc. (OPEB)	All Plans
Participating Company	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.
Country	Canada	Canada	Canada	Canada	Canada	Canada	
Fiscal year ending on	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018
A. Change in benefit obligation							
1. Benefit obligation at beginning of year	1,086,510,100	15,780,100	3,997,000	6,373,200	22,773,300	111,841,000	1,247,274,700
2. Service cost	7,077,300	-	-	25,252,100	1,124,200	1,516,000	34,969,600
3. Interest cost	34,654,100	469,600	109,500	206,800	740,000	3,596,000	39,776,000
4. Employee contributions	-	-	-	5,009,500	-	-	5,009,500
5. Plan amendments	-	-	-	-	-	-	-
6. Plan curtailments	-	-	-	-	-	-	-
7. Plan settlements	-	-	-	-	-	-	-
8. Special termination benefits	-	-	-	-	-	-	-
9. a. Benefits paid from the plan	(46,958,700)	(1,080,200)	(405,100)	(449,900)	(665,800)	-	(49,559,700)
b. Direct benefit payments	-	-	-	-	-	(3,760,000)	(3,760,000)
10. Medicare subsidies received	-	-	-	-	-	-	-
11. Expenses paid	-	-	-	-	-	-	-
12. Taxes paid	-	-	-	-	-	-	-
13. Premiums paid	-	-	-	-	-	-	-
14. Net transfer in/(out) (including the effect of any business combinations/divestitures)	-	-	-	-	-	-	-
15. Plan combinations	-	-	-	-	-	-	-
16. Actuarial loss (gain)	(36,900,200)	(264,400)	35,600	(358,000)	(2,884,300)	(18,683,000)	(59,054,300)
17. Exchange rate changes	-	-	-	-	-	-	-
18. Benefit obligation at end of year	**1,044,382,600**	**14,905,100**	**3,737,000**	**36,033,700**	**21,087,400**	**94,510,000**	**1,214,655,800**
B. Change in plan assets							
1. Fair value of plan assets at beginning of year	1,035,869,600	16,376,700	8,141,100	7,935,800	19,529,100	-	1,087,852,300
2. Actual return on plan assets	5,824,700	(227,700)	(134,300)	1,662,200	(2,361,000)	-	4,763,900
3. a. Employer contributions to plan	6,316,300	-	-	12,025,400	-	-	18,341,700
b. Employer direct benefit payments	-	-	-	-	-	3,760,000	3,760,000
4. Employee contributions	-	-	-	5,009,500	-	-	5,009,500
5. Plan settlements	-	-	-	-	-	-	-
6. a. Benefits paid from the plan	(46,958,700)	(1,080,200)	(405,100)	(449,900)	(665,800)	-	(49,559,700)
b. Direct benefit payments	-	-	-	-	-	(3,760,000)	(3,760,000)
7. Medicare subsidies received	-	-	-	-	-	-	-
8. Expenses paid	-	-	-	-	-	-	-
9. Taxes paid	-	-	-	-	-	-	-
10. Premiums paid	-	-	-	-	-	-	-
11. Acquisitions / divestitures	-	-	-	-	-	-	-
12. Plan combinations	-	-	-	-	-	-	-
13. Adjustments	-	-	-	-	-	-	-
14. Exchange rate changes	-	-	-	-	-	-	-
15. Fair value of plan assets at end of year	**1,001,051,900**	**15,068,800**	**7,601,700**	**26,183,000**	**16,502,300**	**-**	**1,066,407,700**
C. Reconciliation of funded status							
1. Fair value of plan assets	1,001,051,900	15,068,800	7,601,700	26,183,000	16,502,300	-	1,066,407,700
2. Benefit obligations	1,044,382,600	14,905,100	3,737,000	36,033,700	21,087,400	94,510,000	1,214,655,800
3. Funded status (plan assets less benefit obligations)	**(43,330,700)**	**163,700**	**3,864,700**	**(9,850,700)**	**(4,585,100)**	**(94,510,000)**	**(148,248,100)**
4. Contributions and distributions made by company from measurement date to fiscal year end	-	-	-	-	-	-	-
5. Net amount [asset (obligation)] recognized in statement of financial position	**(43,330,700)**	**163,700**	**3,864,700**	**(9,850,700)**	**(4,585,100)**	**(94,510,000)**	**(148,248,100)**
D. Amounts recognized on the consolidated balance sheet position consists of							
1. Noncurrent assets	-	163,700	3,864,700	-	-	-	4,028,400
2. Current liabilities	-	-	-	-	-	(4,393,000)	(4,393,000)
3. Noncurrent liabilities	(43,330,700)	-	-	(9,850,700)	(4,585,100)	(90,117,000)	(147,883,500)
4. Net amount [asset (obligation)] recognized in statement of financial position	**(43,330,700)**	**163,700**	**3,864,700**	**(9,850,700)**	**(4,585,100)**	**(94,510,000)**	**(148,248,100)**
**Results are allocated based on plan status and may not reflect participating employer's status*							
E. Reconciliation of amounts recognized in statement of financial position							
1. Initial net asset(obligation)	-	-	-	-	-	-	-
2. Prior service credit (cost)	-	-	-	-	-	(1,437,000)	(1,437,000)
3. Net gain (loss)	(298,116,100)	(4,382,100)	(274,400)	(1,104,800)	(6,031,900)	7,932,800	(301,976,500)
4. Accumulated other comprehensive income (loss)	**(298,116,100)**	**(4,382,100)**	**(274,400)**	**(1,104,800)**	**(6,031,900)**	**6,495,800**	**(303,413,500)**
5. Accumulated contributions in excess of net periodic benefit cost	254,785,400	4,545,800	4,139,100	(8,745,900)	1,446,800	(101,005,800)	155,165,400
6. Net amount [surplus (deficit)] recognized in statement of financial position	**(43,330,700)**	**163,700**	**3,864,700**	**(9,850,700)**	**(4,585,100)**	**(94,510,000)**	**(148,248,100)**
F. Components of net periodic benefit cost							
1. Service cost	7,077,300	-	-	25,252,100	1,124,200	1,516,000	34,969,600
2. Interest cost	34,654,100	469,600	109,500	206,800	740,000	3,596,000	39,776,000
3. Expected return on plan assets	(71,743,800)	(507,200)	(254,200)	(1,271,500)	(999,800)	-	(74,776,500)
4. Amortization of initial net obligation (asset)	-	-	-	-	-	-	-
5. Amortization of prior service cost	-	-	-	-	-	103,000	103,000
6. Amortization of net (gain) loss	13,216,300	155,900	-	73,400	259,200	30,000	13,734,800
7. Curtailment (gain) / loss recognized	-	-	-	-	-	-	-
8. Settlement (gain) / loss recognized	-	-	-	-	-	-	-
9. Special termination benefit recognized	-	-	-	-	-	-	-
10. Net periodic benefit cost	**(16,796,100)**	**118,300**	**(144,700)**	**24,260,800**	**1,123,600**	**5,245,000**	**13,806,900**
G. Changes recognized in other comprehensive income							
Changes in plan assets and benefit obligations recognized in other comprehensive							
1. New prior service cost	-	-	-	-	-	-	-
2. Net loss (gain) arising during the year (includes curtailment gains not recognized as a component of net period cost)	29,018,900	470,500	424,100	(748,700)	476,500	(18,683,000)	10,958,300
3. Effect of exchange rates on amounts included in AOCI	-	-	-	-	-	-	-

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Participating Company	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.
Country	Canada	Canada	Canada	Canada	Canada	Canada	
Fiscal year ending on	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018
Amounts recognized as a component of net periodic benefit cost							
4. Amortization, settlement or curtailment recognition of net transition asset (obligation)	-	-	-	-	-	-	-
5. Amortization or curtailment recognition of prior service credit (cost)	-	-	-	-	-	(103,000)	(103,000)
6. Amortization or settlement recognition of net gain (loss)	(13,216,300)	(155,900)	-	(73,400)	(259,200)	(30,000)	(13,734,800)
7. Total recognized in other comprehensive loss (income)	**15,802,600**	**314,600**	**424,100**	**(822,100)**	**217,300**	**(18,816,000)**	**(2,879,500)**
8. Total recognized in net periodic benefit and other comprehensive loss (income)	**(993,500)**	**432,900**	**279,400**	**23,438,700**	**1,340,900**	**(13,571,000)**	**10,927,400**
Estimated amounts that will be amortized from accumulated other comprehensive							
9. Initial net asset (obligation)	-	-	-	-	-	-	-
10. Prior service credit (cost)	-	-	-	-	-	(103,000)	(103,000)
11. Net gain (loss)	(15,583,100)	(188,900)	-	(53,000)	(341,900)	-	(16,166,900)
12. Total estimated to be amortized from AOCI over the next fiscal year	**(15,583,100)**	**(188,900)**	**-**	**(53,000)**	**(341,900)**	**(103,000)**	**(16,269,900)**
H. Weighted-average assumptions to determine benefit obligations							
1. Discount rate	3.82%	3.70%	3.49%	3.88%	3.83%	3.82%	3.82%
2. Rate of compensation increase	3.22%	Not applicable	Not applicable	3.46%	3.01%	3.16%	3.22%
3. Measurement date	31-Dec-2018	31-Dec-2018	31-Dec-2018	31-Dec-2018	31-Dec-2018	31-Dec-2018	31-Dec-2018
Additional information for post-retirement medical plans							
4. Assumed health care trend rate							
a. Immediate trend rate	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable	4.00%	4.00%
b. Ultimate trend rate	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable	4.00%	4.00%
c. Year that the rate reaches ultimate trend rate	-	-	-	-	-	-	-
I. Assumptions to determine net cost							
1. a. Effective discount rate for benefit obligations	3.57%	3.43%	3.20%	3.64%	3.59%	3.58%	3.57%
b. Effective rate for interest on benefit obligations	3.26%	3.08%	2.88%	3.39%	3.32%	3.28%	3.26%
c. Effective rate for service cost	3.69%	Not applicable	Not applicable	3.70%	3.67%	3.69%	3.70%
d. Effective rate for interest on service cost	3.52%	Not applicable	Not applicable	3.55%	3.55%	3.57%	3.54%
2. Expected return on assets	7.00%	3.20%	3.20%	7.50%	5.25%	0.00%	6.89%
3. Rate of compensation increase	3.22%	Not applicable	Not applicable	3.32%	2.98%	3.22%	3.22%
Additional information for post-retirement medical plans							
5. Assumed health care trend rate							
a. Immediate trend rate	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable	5.49%	5.49%
b. Ultimate trend rate	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable	4.34%	4.34%
c. Year that the rate reaches ultimate trend rate	-	-	-	-	-	2034	2034
J. Additional year-end information							
Required information for all defined benefit plans							
1. Accumulated benefit obligation	974,695,200	14,905,100	3,737,000	28,826,300	17,928,000	-	1,040,091,600
Required disclosures for post-retirement medical plans							
2. Sensitivity to trend rate assumptions							
a. One percent increase in trend rate							
i. Effect on total service cost and interest cost components	-	-	-	-	-	493,000	493,000
ii. Effect on benefit obligation	-	-	-	-	-	9,472,000	9,472,000
b. One percent decrease in trend rate							
i. Effect on total service cost and interest cost components	-	-	-	-	-	(401,000)	(401,000)
ii. Effect on benefit obligation	-	-	-	-	-	(7,861,000)	(7,861,000)
3. Special Disclosure on the Impact of the Medicare Drug Act of 2003	The Medicare	The Medicare	The Medicare	Not applicable	Not applicable	Not applicable	
a. Reduction in APBO due to the federal subsidy	-	-	-	-	-	-	-
The effect of the federal subsidy by net periodic postretirement benefit cost component							
b. Service Cost	-	-	-	-	-	-	-
c. Interest Cost	-	-	-	-	-	-	-
d. Net amortization and deferral of actuarial (gain)/loss	-	-	-	-	-	-	-
e. Net periodic postretirement benefit cost	-	-	-	-	-	-	-
K. Additional year-end information for plans with accumulated benefit obligations							
1. Projected benefit obligation	-	-	-	-	21,087,400	-	21,087,400
2. Accumulated benefit obligation	-	-	-	-	17,928,000	-	17,928,000
3. Fair value of plan assets	-	-	-	-	16,502,300	-	16,502,300
**Results are allocated based on plan status and may not reflect participating employer's status*							
L. Additional year-end information for plans with projected benefit obligations in							
1. Projected benefit obligation	1,044,382,600	-	-	36,033,700	21,087,400	94,510,000	1,196,013,700
2. Fair value of plan assets	1,001,051,900	-	-	26,183,000	16,502,300	-	1,043,737,200
**Results are allocated based on plan status and may not reflect participating employer's status*							
M. Cash flows							
1. Projected company contributions for following fiscal year	4,545,600	-	-	12,626,900	-	4,393,000	21,565,500
2. Expected benefit payments for FYE							
31-Dec-2019 :	48,974,100	1,068,400	393,600	708,500	698,000	4,393,000	56,235,600
31-Dec-2020 :	50,040,100	1,064,200	385,700	1,104,800	736,400	4,446,000	57,777,200
31-Dec-2021 :	51,128,800	1,058,000	376,200	1,539,800	773,900	4,513,000	59,389,700
31-Dec-2022 :	52,179,100	1,049,700	365,000	2,033,900	818,800	4,549,000	60,995,500
31-Dec-2023 :	53,155,300	1,038,900	351,800	2,581,000	882,400	4,589,000	62,598,400
Next five years	276,678,600	4,933,400	1,490,800	23,133,900	5,469,500	23,648,000	335,354,200
3. Expected Medicare subsidy receipts for FYE							
31-Dec-2019 :	-	-	-	-	-	-	-
31-Dec-2020 :	-	-	-	-	-	-	-
31-Dec-2021 :	-	-	-	-	-	-	-

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Participating Company	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.
Country	Canada	Canada	Canada	Canada	Canada	Canada	
Fiscal year ending on	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018	12/31/2018
31-Dec-2022 :	-	-	-	-	-	-	-
31-Dec-2023 :	-	-	-	-	-	-	-
Next five years	-	-	-	-	-	-	-
N. Accumulated contributions in excess of net periodic benefit cost							
1. Amount as of beginning of year	231,673,000	4,664,100	3,994,400	3,489,500	2,570,400	(99,293,800)	147,097,600
2. Net periodic pension (cost) income for fiscal year	16,796,100	(118,300)	144,700	(24,260,800)	(1,123,600)	(5,245,000)	(13,806,900)
3. Employer contributions made in fiscal year (excludes contributions made between measurement year end and fiscal year end)	6,316,300	-	-	12,025,400	-	-	18,341,700
4. Benefits paid directly by company in the fiscal year (excludes contributions made between measurement year end and fiscal year end)	-	-	-	-	-	3,760,000	3,760,000
5. FAS 88 (expense) income	-	-	-	-	-	-	-
6. Other gain / (loss) recognized	-	-	-	-	-	-	-
7. Plan combinations	-	-	-	-	-	-	-
8. Adjustment to match local books	-	-	-	-	-	(227,000)	(227,000)
9. Exchange rate adjustment	-	-	-	-	-	-	-
10. Preliminary amount as of end of year	**254,785,400**	**4,545,800**	**4,139,100**	**(8,745,900)**	**1,446,800**	**(101,005,800)**	**155,165,400**
11. Contributions and direct benefit payments made between measurement date and fiscal year end	-	-	-	-	-	-	-
12. Amount as of end of year	**254,785,400**	**4,545,800**	**4,139,100**	**(8,745,900)**	**1,446,800**	**(101,005,800)**	**155,165,400**
O. Reconciliation of transition obligation (asset)							
1. Amount as disclosed as of prior year end	-	-	-	-	-	-	-
Amounts recognized as a component of net periodic benefit cost							
2. Amortization	-	-	-	-	-	-	-
3. Effect of curtailment	-	-	-	-	-	-	-
4. Effect of settlement	-	-	-	-	-	-	-
5. Total amount recognized as a component of net periodic benefit cost	-	-	-	-	-	-	-
Other changes (adjustment to accumulated comprehensive income, retained earnings)							
6. Plan combinations	-	-	-	-	-	-	-
7. Difference between prior year end and beginning of current year	-	-	-	-	-	-	-
8. Total amount recognized as other change in accumulated other comprehensive income	-	-	-	-	-	-	-
9. Exchange rate adjustment	-	-	-	-	-	-	-
10. Amount at end of year	-	-	-	-	-	-	-
P. Reconciliation of prior service cost (credit)							
1. Amount as disclosed as of prior year end	-	-	-	-	-	1,540,000	1,540,000
Amounts recognized as a component of net periodic benefit cost							
2. Amortization	-	-	-	-	-	(103,000)	(103,000)
3. Effect of curtailment	-	-	-	-	-	-	-
4. Total amount recognized as a component of net periodic benefit cost	-	-	-	-	-	**(103,000)**	**(103,000)**
Changes in plan assets and benefit obligations recognized in other comprehensive income							
5. Plan amendments	-	-	-	-	-	-	-
Other changes (adjustment to accumulated comprehensive income, retained earnings)							
6. Plan combinations	-	-	-	-	-	-	-
7. Difference between prior year end and beginning of current year	-	-	-	-	-	-	-
8. Total amount recognized as other change in accumulated other comprehensive income	-	-	-	-	-	-	-
9. Exchange rate adjustment	-	-	-	-	-	-	-
10. Amount at end of year	-	-	-	-	-	**1,437,000**	**1,437,000**
Q. Reconciliation of net (gain) loss							
1. Amount as disclosed as of prior year end	282,313,500	4,067,500	(149,700)	1,926,900	5,814,600	11,007,200	304,980,000
Amounts recognized as a component of net periodic benefit cost							
2. Amortization	(13,216,300)	(155,900)	-	(73,400)	(259,200)	(30,000)	(13,734,800)
3. Effect of settlement	-	-	-	-	-	-	-
4. Total amount recognized as a component of net periodic benefit cost	**(13,216,300)**	**(155,900)**	-	**(73,400)**	**(259,200)**	**(30,000)**	**(13,734,800)**
Changes in plan assets and benefit obligations recognized in other comprehensive income							
5. Liability experience	(36,900,200)	(264,400)	35,600	(358,000)	(2,884,300)	(18,683,000)	(59,054,300)
6. Asset experience	65,919,100	734,900	388,500	(390,700)	3,360,800	-	70,012,600
7. Effect of curtailment	-	-	-	-	-	-	-
8. Extraordinary event that adjusts assets	-	-	-	-	-	-	-
9. Total amount recognized as a change in plan assets and benefit obligations	**29,018,900**	**470,500**	**424,100**	**(748,700)**	**476,500**	**(18,683,000)**	**10,958,300**
Other changes (adjustment to accumulated comprehensive income, retained earnings)							
10. Plan combinations	-	-	-	-	-	-	-
11. Adjustment to match local books	-	-	-	-	-	(227,000)	(227,000)
12. Difference between prior year end and beginning of current year	-	-	-	-	-	-	-
13. Difference between calculated year-end gain/loss and amount using events that occurred during the year	-	-	-	-	-	-	-
14. Total amount recognized as other change in accumulated other comprehensive income	-	-	-	-	-	**(227,000)**	**(227,000)**
15. Exchange rate adjustment	-	-	-	-	-	-	-
16. Amount at end of year	**298,116,100**	**4,382,100**	**274,400**	**1,104,800**	**6,031,900**	**(7,932,800)**	**301,976,500**

* Note: All figures shown in this Disclosure have only been rounded once at the final step. Differences that might occur in the summation of figures and the figures displayed in the Disclosure will be as a result of rounding.

UTILITY CAPITAL STRUCTURE
2018 GDARIDA IMPACTS

Line No.		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. 13	Col. 14	Col. 15
		2013 Actual Capital Structure			2014 Actual Capital Structure			2015 Actual Capital Structure			2016 Actual Capital Structure			2017 Actual Capital Structure			2018 Actual Capital Structure		
		Component %	Indicated Cost Rate %	Return Component %	Component %	Indicated Cost Rate %	Return Component %	Component %	Indicated Cost Rate %	Return Component %	Component %	Indicated Cost Rate %	Return Component %	Component %	Indicated Cost Rate %	Return Component %	Component %	Indicated Cost Rate %	Return Component %
1.	Long-term debt	56.16	5.84	3.28	57.55	5.41	3.11	58.78	5.15	3.03	58.77	4.95	2.91	56.88	4.86	2.76	57.04	4.72	2.69
2.	Short-term debt	5.51	1.11	0.06	4.32	1.38	0.06	3.25	1.32	0.04	3.54	1.33	0.05	5.57	1.05	0.06	5.66	1.81	0.10
3.		61.67		3.34	61.87		3.17	62.03		3.07	62.31		2.96	62.45		2.82	62.70		2.79
4.	Preference shares	2.33	2.40	0.06	2.13	2.40	0.05	1.97	2.24	0.04	1.69	2.16	0.04	1.55	2.32	0.04	1.30	2.98	0.04
5.	Common equity	36.00	8.93	3.21	36.00	9.36	3.37	36.00	9.30	3.35	36.00	9.19	3.31	36.00	8.78	3.16	36.00	9.00	3.24
6.	Required Return on Rate Base	100.00		6.61	100.00		6.59	100.00		6.46	100.00		6.30	100.00		6.02	100.00		6.07

	($000's)	2013	2014	2015	2016	2017	2018
7.	Ontario Utility Income	70.9	(63.7)	(181.5)	(183.1)	(184.7)	(84.9)
8.	Rate base	238.4	736.0	550.0	364.0	178.0	19.6
9.	Indicated rate of return	29.74 %	(8.65)%	(33.00)%	(50.30)%	(103.76)%	(433.16)%
10.	(Def.) / suff. in rate of return	23.13 %	(15.24)%	(39.46)%	(56.60)%	(109.78)%	(439.23)%
11.	Net (def.) / suff.	55.1	(112.2)	(217.0)	(206.0)	(195.4)	(86.1)
12.	Gross (def.) / suff.	75.0	(152.7)	(295.2)	(280.3)	(265.9)	(117.1)

UTILITY RATE BASE
2018 GDARIDA IMPACTS

Line No.	($000's)	2013	2014	2015	2016	2017	2018
	Property, plant, and equipment						
1.	Cost or redetermined value	260.1	876.3	876.3	876.3	876.3	876.3
2.	Accumulated depreciation	(21.7)	(140.3)	(326.3)	(512.3)	(698.3)	(856.7)
3.		238.4	736.0	550.0	364.0	178.0	19.6
	Allowance for working capital						
4.	Accounts receivable merchandise finance plan	-	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-	-
12.		-	-	-	-	-	-
13.	Ontario utility rate base	238.4	736.0	550.0	364.0	178.0	19.6

UTILITY INCOME
2018 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016	2017	2018
	Revenue						
1.	Gas sales	-	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-	-
5.	Other income	-	-	-	-	-	-
6.	Total revenue	-	-	-	-	-	-
	Costs and expenses						
7.	Gas costs	-	-	-	-	-	-
8.	Operation and Maintenance	-	-	-	-	-	-
9.	Depreciation and amortization	47.3	186.0	186.0	186.0	186.0	85.0
10.	Municipal and other taxes	-	-	-	-	-	-
11.	Total costs and expenses	47.3	186.0	186.0	186.0	186.0	85.0
12.	**Utility income before inc. taxes**	(47.3)	(186.0)	(186.0)	(186.0)	(186.0)	(85.0)
	Income taxes						
13.	Excluding interest shield	(116.1)	(116.1)	-	-	-	-
14.	Tax shield on interest expense	(2.1)	(6.2)	(4.5)	(2.9)	(1.3)	(0.1)
15.	Total income taxes	(118.2)	(122.3)	(4.5)	(2.9)	(1.3)	(0.1)
16.	**Ontario utility net income**	70.9	(63.7)	(181.5)	(183.1)	(184.7)	(84.9)

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016	2017	2018
1.	Utility income before income taxes	(47.3)	(186.0)	(186.0)	(186.0)	(186.0)	(85.0)
	Add Backs						
2.	Depreciation and amortization	47.3	186.0	186.0	186.0	186.0	85.0
3.	Large corporation tax	-	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-	-
6.	Total added back	47.3	186.0	186.0	186.0	186.0	85.0
7.	Sub total - pre-tax income plus add backs	-	-	-	-	-	-
	Deductions						
8.	Capital cost allowance - Federal	438.2	438.1	-	-	-	-
9.	Capital cost allowance - Provincial	438.2	438.1	-	-	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-	-
16.	Total Deductions - Federal	438.2	438.1	-	-	-	-
17.	Total Deductions - Provincial	438.2	438.1	-	-	-	-
18.	Taxable income - Federal	(438.2)	(438.1)	-	-	-	-
19.	Taxable income - Provincial	(438.2)	(438.1)	-	-	-	-
20.	Income tax provision - Federal	(65.7)	(65.7)	-	-	-	-
21.	Income tax provision - Provincial	(50.4)	(50.4)	-	-	-	-
22.	Income tax provision - combined	(116.1)	(116.1)	-	-	-	-
23.	Part V1.1 tax	-	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(116.1)	(116.1)	-	-	-	-
	Tax shield on interest expense						
26.	Rate base as adjusted	238.4	736.0	550.0	364.0	178.0	19.6
27.	Return component of debt	3.34%	3.17%	3.07%	2.96%	2.82%	2.79%
28.	Interest expense	8.0	23.3	16.9	10.8	5.0	0.5
29.	Combined tax rate	26.500%	26.500%	26.500%	26.500%	26.500%	26.500%
30.	Income tax credit	(2.1)	(6.2)	(4.5)	(2.9)	(1.3)	(0.1)
31.	**Total income taxes**	(118.2)	(122.3)	(4.5)	(2.9)	(1.3)	(0.1)

UTILITY REVENUE REQUIREMENT
2018 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016	2017	2018
	Cost of capital						
1.	Rate base	238.4	736.0	550.0	364.0	178.0	19.6
2.	Required rate of return	6.61%	6.59%	6.46%	6.30%	6.02%	6.07%
3.	Cost of capital	15.8	48.5	35.5	22.9	10.7	1.2
	Cost of service						
4.	Gas costs	-	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-	-
6.	Depreciation and amortization	47.3	186.0	186.0	186.0	186.0	85.0
7.	Municipal and other taxes	-	-	-	-	-	-
8.	Cost of service	47.3	186.0	186.0	186.0	186.0	85.0
	Misc. & Non-Op. Rev						
9.	Other operating revenue	-	-	-	-	-	-
10.	Other income	-	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-	-
	Income taxes on earnings						
12.	Excluding tax shield	(116.1)	(116.1)	-	-	-	-
13.	Tax shield provided by interest expense	(2.1)	(6.2)	(4.5)	(2.9)	(1.3)	(0.1)
14.	Income taxes on earnings	(118.2)	(122.3)	(4.5)	(2.9)	(1.3)	(0.1)
	Taxes on (def) / suff.						
15.	Gross (def.) / suff.	75.0	(152.7)	(295.2)	(280.3)	(265.9)	(117.1)
16.	Net (def.) / suff.	55.1	(112.2)	(217.0)	(206.0)	(195.4)	(86.1)
17.	Taxes on (def.) / suff.	(19.9)	40.5	78.2	74.3	70.5	31.0
18.	**Revenue requirement**	(75.0)	152.7	295.2	280.3	265.9	117.1
	Revenue at existing Rates						
19.	Gas sales	0.0	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.0	0.0	0.0	0.0	0.0	0.0
23.	Revenue at existing rates	0.0	0.0	0.0	0.0	0.0	0.0
24.	**Gross revenue (def.) / suff.**	75.0	(152.7)	(295.2)	(280.3)	(265.9)	(117.1)

UTILITY CAPITAL STRUCTURE
2018 DACDA IMPACTS

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2017 Actual Capital Structure			2018 Actual Capital Structure		
		Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component
		%	%	%	%	%	%
1.	Long-term debt	56.88	4.86	2.76	57.04	4.72	2.69
2.	Short-term debt	5.57	1.05	0.06	5.66	1.81	0.10
3.		62.45		2.82	62.70		2.79
4.	Preference shares	1.55	2.32	0.04	1.30	2.98	0.04
5.	Common equity	36.00	8.78	3.16	36.00	9.00	3.24
6.		100.00		6.02	100.00		6.07

Line No.	($ 000's)	2017	2018
7.	Ontario Utility Income	685.0	(521.3)
8.	Rate base	259.7	5,623.8
9.	Indicated rate of return	263.76 %	(9.27)%
10.	(Def.) / suff. in rate of return	257.74 %	(15.34)%
11.	Net (def.) / suff.	669.4	(862.7)
12.	Gross (def.) / suff.	910.7	(1,173.7)

UTILITY RATE BASE
2018 DACDA IMPACTS

($ 000's)

Line No.		2017	2018
	Property, plant, and equipment		
1.	Cost or redetermined value	264.4	6,421.6
2.	Accumulated depreciation	(4.7)	(797.8)
3.		259.7	5,623.8
	Allowance for working capital		
4.	Accounts receivable merchandise finance plan	-	-
5.	Accounts receivable rebillable projects	-	-
6.	Materials and supplies	-	-
7.	Mortgages receivable	-	-
8.	Customer security deposits	-	-
9.	Prepaid expenses	-	-
10.	Gas in storage	-	-
11.	Working cash allowance	-	-
12.		-	-
13.	**Ontario utility rate base**	259.7	5,623.8

UTILITY INCOME
2018 DACDA IMPACTS

($ 000's)

Line No.		2017	2018
	Revenue		
1.	Gas sales	-	-
2.	Transportation of gas	-	-
3.	Transmission and compression	-	-
4.	Other operating revenue	-	-
5.	Other income	-	-
6.	Total revenue	-	-
	Costs and expenses		
7.	Gas costs	-	-
8.	Operation and Maintenance	-	-
9.	Depreciation and amortization	112.3	1,372.4
10.	Municipal and other taxes	-	-
11.	Total costs and expenses	112.3	1,372.4
12.	**Utility income before inc. taxes**	(112.3)	(1,372.4)
	Income taxes		
13.	Excluding interest shield	(795.4)	(809.5)
14.	Tax shield on interest expense	(1.9)	(41.6)
15.	Total income taxes	(797.3)	(851.1)
16.	**Ontario utility net income**	685.0	(521.3)

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 DACDA IMPACTS

($ 000's)

Line No.		2017	2018
1.	Utility income before income taxes	(112.3)	(1,372.4)
	Add Backs		
2.	Depreciation and amortization	112.3	1,372.4
3.	Large corporation tax	-	-
4.	Other non-deductible items	-	-
5.	Any other add back(s)	-	-
6.	Total added back	112.3	1,372.4
7.	Sub total - pre-tax income plus add backs	-	-
	Deductions		
8.	Capital cost allowance - Federal	3,001.6	3,054.9
9.	Capital cost allowance - Provincial	3,001.6	3,054.9
10.	Items capitalized for regulatory purposes	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-
12.	Amortization of share and debt issue expense	-	-
13.	Amortization of cumulative eligible capital	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-
15.	Any other deduction(s)	-	-
16.	Total Deductions - Federal	3,001.6	3,054.9
17.	Total Deductions - Provincial	3,001.6	3,054.9
18.	Taxable income - Federal	(3,001.6)	(3,054.9)
19.	Taxable income - Provincial	(3,001.6)	(3,054.9)
20.	Income tax provision - Federal	(450.2)	(458.2)
21.	Income tax provision - Provincial	(345.2)	(351.3)
22.	Income tax provision - combined	(795.4)	(809.5)
23.	Part V1.1 tax	-	-
24.	Investment tax credit	-	-
25.	Total taxes excluding tax shield on interest expense	(795.4)	(809.5)
	Tax shield on interest expense		
26.	Rate base as adjusted	259.7	5,623.8
27.	Return component of debt	2.82%	2.79%
28.	Interest expense	7.3	156.9
29.	Combined tax rate	26.500%	26.500%
30.	Income tax credit	(1.9)	(41.6)
31.	**Total income taxes**	(797.3)	(851.1)

UTILITY REVENUE REQUIREMENT
2018 DACDA IMPACTS

($ 000's)

Line No.		2017	2018
	Cost of capital		
1.	Rate base	259.7	5,623.8
2.	Required rate of return	6.02%	6.07%
3.	Cost of capital	15.6	341.4
	Cost of service		
4.	Gas costs	-	-
5.	Operation and Maintenance	-	-
6.	Depreciation and amortization	112.3	1,372.4
7.	Municipal and other taxes	-	-
8.	Cost of service	112.3	1,372.4
	Misc. & Non-Op. Rev		
9.	Other operating revenue	-	-
10.	Other income	-	-
11.	Misc, & Non-operating Rev.	-	-
	Income taxes on earnings		
12.	Excluding tax shield	(795.4)	(809.5)
13.	Tax shield provided by interest expense	(1.9)	(41.6)
14.	Income taxes on earnings	(797.3)	(851.1)
	Taxes on (def) / suff.		
15.	Gross (def.) / suff.	910.7	(1,173.7)
16.	Net (def.) / suff.	669.4	(862.7)
17.	Taxes on (def.) / suff.	(241.3)	311.0
18.	**Revenue requirement**	(910.7)	1,173.7
	Revenue at existing Rates		
19.	Gas sales	0.0	0.0
20.	Transportation service	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0
22.	Rounding adjustment	0.0	0.0
23.	Revenue at existing rates	0.0	0.0
24.	**Gross revenue (def.) / suff.**	910.7	(1,173.7)

2018 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS EGD RATE ZONE

The 2018 Earnings Sharing amount included within the Fiscal 2018 year-end audited statements, for the EGD rate zone (Enbridge, or the Company), was $27.35 million, which was lower than the amount being requested for approval and clearance within this application of $29.95 million. In order to meet year end timing obligations, estimates for elements impacting the accrual are sometimes required in lieu of complete or detailed analyses along with the rounding of various actual amounts into millions of dollars for regulatory presentation. Following the year end close process, however, completion of analyses are performed for elements where estimates were used along with rounding finalizations, in order to ensure the earnings sharing amount is accurate. If required and appropriate, an adjustment is made to the earnings sharing results, which ultimately is reflected in following year financial statements. In certain other instances, new information becomes available which requires the earnings sharing amount to be recalculated.

The process followed is the same as that which was followed for earnings sharing amounts calculated for 2014 through 2017, and during the 2008 through 2012 incentive regulation term. For 2018, the year-end earnings sharing provision reflected in the financial statements was based on information available at that time. Subsequent to year end, the earnings sharing calculation was updated to reflect to a revised capital cost allowance (“CCA”) tax deduction. The revision was to reflect the impact of the enactment of accelerated CCA measures contained in Bill C-97, which received Royal Assent on June 21, 2019, and to reflect an updated level of 2018 capital additions to asset pools, as compared to the year-end provision. The impact of these changes caused a $5.2 million increase in the gross sufficiency to be shared with rate payers, and a corresponding $2.6 million increase to the earnings sharing amount.

The amounts for each of the cost elements of utility rate base, utility income and taxes, and the utility capital structure components, which were used in the calculation of the earnings sharing amount, are summarized within Exhibit B, Tab 2, Appendix A, Schedule 1.

The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2012-0459 Board Decision, dated July 17, 2014, at pages 13 through 15, and within the pre-filed evidence at Exhibit A2, Tab 7, Schedule 1;

- if in any calendar year during the customized incentive regulation term, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than the allowed ROE included in that year's rates (updated annually by the application of the Board's ROE Formula), then the resultant amount shall be shared equally (ie., 50/50) between Enbridge and its ratepayers;
- for the purposes of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;
- all revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculation.

In addition, the following are examples of shareholder incentives and other amounts which are outside the ambit of the ESM: amounts related to Demand Side Management incentives, amounts related to Transactional Services incentives, and amounts related to Open Bill program incentives.

As shown within the summary of return on equity and earnings sharing determination, Exhibit B, Tab 2, Appendix A, Schedule 1, the Company has calculated earnings for sharing in two ways for confirmation purposes.

In part A) of the summary, a return on rate base method is shown, while in part B), a return on equity from a deemed equity embedded within rate base perspective is shown. Column 2 within the exhibit provides references indicating where additional evidence in support of the determination of the amounts in the summary can be found. Column 3 contains results shown in millions of dollars, or percentages.

Part A)

The level of utility income, $452.7 million (Line 17) divided by the level of utility rate base, $6,729.2 million (Line 22) generates a utility return on rate base of 6.727% (Line 23).

When compared to the Company's required rate of return of 6.073% (Line 24), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.654% (Line 25) on total rate base.

As shown in Lines 26 through 28, the sufficiency of 0.654% multiplied by the rate base of $6,729.2 million, produces a net over earnings or sufficiency of $44.01 million which from a pre-tax perspective, ($44.01 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%) shows a $59.88 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Part B) (Confirming the Calculated Earnings Sharing)

Net utility income applicable to common equity is first determined.

The $491.5 million (Line 31) of utility income before income tax, less utility taxes of $38.8 million (Line 36), produces the $452.7 million of utility income used in part A) above (at Line 17).

In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $452.7 million utility income.

These reductions are shown at Lines 32, 33 and 34 which along with the utility income tax reduction already mentioned and shown at Line 36, results in a net income applicable to common equity of $262.0 million, shown at Line 37.

The $262.0 million, divided by the deemed common equity level of $2,422.5 million (Line 38, calculated as 36% of the $6,729.2 million rate base) produces a return on equity of 10.817% (Line 40). When comparing the 10.817% achieved return on equity to the threshold ROE percentage of 9.000% (Line 39), which is the Board approved formula return on equity for 2018, there is a sufficiency in ROE of 1.817% (Line 41).

The 1.817% multiplied by the common equity level of $2,422.5 million (Line 38) produces a net over earnings or sufficiency of $44.01 million which from a pre-tax perspective ($44.01 million divided by the reciprocal, 73.5%, of the corporate tax rate), shows a $59.88 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Process Description

The calculation of utility earnings and any sharing requirement starts with financial results contained within the Enbridge Ontario corporate trial balance.

From there, in order to calculate the Ontario utility rate base, income, and capital structure results, and supporting evidence exhibits, various adjustments, regroupings or eliminations are required. This is accomplished by following and applying regulatory rules as prescribed by the Board and the standards associated with cost of service rate related accounting processes. Examples are:

- determination of rate base amounts using the average of monthly averages value concept,
- elimination of corporate interest expense due to the treatment of interest expense as embedded in the capital structure balanced to rate base, and
- elimination of corporate income taxes due to the determination of income taxes specific to utility results,

In addition, Enbridge has made the appropriate adjustments in relation to non-standard rate regulated items which the Board has either decided in the past, or are required in order to determine an appropriate utility return on equity. Examples are:

- rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
- rate base disallowance from RP-2002-0133 (shared assets),
- exclusion of non-utility or unregulated activities,
- elimination of approved shareholder incentives.

As shown in the Column 2 references in the summary exhibit, supporting rate base information is found in Exhibit B, Tab 2, Appendix B, supporting revenue, volumes, customers and cost information is found in Exhibit B, Tab 2, Appendixes C & D, and supporting capital structure, required rate of return, utility income, and cost of capital information is found in Exhibit B, Tab 2, Appendix E.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
EGD RATE ZONE

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2018

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales	(Ex.B,T2,App.E,S2,P1,Col.1,line 1)	2,498.8
3.	Transportation Revenue	(Ex.B,T2,App.E,S2,P1,Col.1,line 2)	276.3
4.	Transmission, Compr. and Storage Revenue	(Ex.B,T2,App.E,S2,P1,Col.1,line 3)	19.2
5.	Less Cost of Gas	(Ex.B,T2,App.E,S2,P1,Col.1,line 8)	1,566.0
6.	Gas Distribution Margin		1,228.3
7.	Other Revenue	(Ex.B,T2,App.E,S2,P1,Col.1,line 4)	42.3
8.	Other Income	(Ex.B,T2,App.E,S2,P1,Col.1,line 6)	0.2
9.	Total - Other Revenue & Income		42.5
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)	(Ex.B,T2,App.E,S2,P1,Col.1,line 9)	437.5
11.	Depreciation & amortization	(Ex.B,T2,App.E,S2,P1,Col.1,line 10)	294.7
12.	Fixed financing costs	(Ex.B,T2,App.E,S2,P1,Col.1,line 11)	2.2
13.	Municipal & capital taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 12)	44.9
14.	Total O&M, Depr., & other		779.3
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	491.5
16.	Less: Income Taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 17)	38.8
17.	**Utility Income**		**452.7**
18.	Gross plant	(Ex.B,T2,App.B,S1,P1,Col.1,line 1)	9,594.5
19.	Accumulated depreciation	(Ex.B,T2,App.B,S1,P1,Col.1,line 2)	(3,277.9)
20.	Net plant		6,316.6
21.	Working capital	(Ex.B,T2,App.B,S1,P1,Col.1,line 11)	412.6
22.	**Utility Rate Base**		**6,729.2**
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.727%
24.	Less: Required Rate of Return %	(Ex.B,T2,App.E,S1,P1,Col.4,line 6)	6.073%
25.	(Deficiency) / Sufficiency %		0.654%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	44.01
27.	Provision for Income Taxes		15.87
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	59.88
29.	**50% Earnings sharing to ratepayers**	(line 28 x 50%)	**29.94**
30.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
31.	Utility Income before Income Tax	(Ex.B,T2,App.E,S2,P1,Col.1,line 16)	491.5
32.	Less: Long Term Debt Costs	(Ex.B,T2,App.E,S1,P1,Col.5,line 1)	181.2
33.	Less: Short Term Debt Costs	(Ex.B,T2,App.E,S1,P1,Col.5,line 2)	6.9
34.	Less: Cost of Preferred Capital	(Ex.B,T2,App.E,S1,P1,Col.5,line 4)	2.6
35.	Net Income before Income Taxes		300.8
36.	Less: Income Taxes	(Ex.B,T2,App.E,S2,P1,Col.1,line 17)	38.8
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	262.0
38.	Common Equity	(Ex.B,T2,App.E,S1,P1,Col.1,line 5)	2,422.5
39.	Approved ROE %		9.000%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	10.817%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.817%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	44.01
43.	Provision for Income Taxes		15.87
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	59.88
45.	**50% Earnings sharing to ratepayers**	(line 44 x 50%)	**29.94**

CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS (INCLUDING CUSTOMER CARE & CIS)
EGD RATE ZONE
2018 ACTUAL

Line No.		Col. 1 2018 Actual Normalized $Millions	Col. 2 2018 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,498.8	2,684.8		
2.	Transportation revenue	276.3	263.0		
3.	Transmission, compression & storage (incl. Rate 332)	19.2	19.2		
4.	Gas costs	1,566.0	1,753.0		
5.	Distribution margin	1,228.3	1,214.0	14.3	a)
6.	Other revenue	42.3	42.7	(0.4)	b)
7.	Other income	0.2	0.1	0.1	b)
8.	O&M (incl. CC/CIS rate smoothing adj.)	437.5	472.3	34.8	c)
9.	Depreciation expense	294.7	305.5	10.8	d)
10.	Other expense	47.1	52.3	5.2	e)
11.	Income taxes	38.8	39.5	0.7	f)
12.	Utility Income	452.7	387.2	65.5	
13.	LTD & STD costs	188.1	182.1	(6.0)	g)
14.	Preference share costs	2.6	2.7	0.1	
15.	Return on Equity @ 9.00% in 2018 Board Approved	218.0	202.4	(15.6)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	44.0	(0.0)	44.0	
17.	Provision for taxes on Earnings Over / (Under)	15.9	(0.0)	15.9	
18.	Gross Earnings Over / (Under)	59.9	(0.0)	59.9	
19.	EGD Equity Level @ 36% (B-2-E-1, Col.1. line 5)	2,422.5			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	262.0			
21.	EGD normalized Return on Equity	10.82%			

2018 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

The following are explanations of the Utility Normalized Earnings results as compared to the 2018 Board approved amounts. The reference letters are in relation to those identified on page 1 of this Schedule.

a) The distribution margin increase of $14.3 million was driven primarily due to higher large volume customer contract demand revenues resulting from higher than expected customer migration from the general service rate class, higher actual delivery revenue than forecast resulting from a higher proportion of actual volumes consumed in the lower delivery blocks, and lower fuel costs required to manage storage operations and the transmission of volumes on Union's system. The favourable variances were partially offset by lower than forecast gas in storage carrying charges reflected in rates, resulting from lower than forecast PGVA reference prices which were approved through the 2018 Quarterly Rate Adjustment Mechanism ("QRAM") proceedings.

b) The net decrease in other revenue and other income of $0.3 million resulted in a negative earnings impact. Details of other revenue and other income are presented in Exhibit B, Tab 2, Appendix C, Schedule 5.

c) Utility O&M was $34.8 million lower than the 2018 Board approved level which resulted in a positive earnings impact. Explanations of the major changes between actual and Board approved O&M are presented in Exhibit B, Tab 2, Appendix D, Schedule 2.

d) The decrease in depreciation expense of $10.8 million was predominantly due to lower than approved depreciation on IT related assets, which resulted from ceasing depreciation on asset pools at times when they were fully depreciated (i.e., NBV was equal to $0) in accordance with the OEB's Uniform System of Accounts, partially offset by higher depreciation on other asset categories as a result of the cumulative impact of capital variances (level and mix of capital spending and level of retirements) from prior years (2012 to 2017) which were not reflected in the 2018 depreciable balances approved by the OEB for rate setting as part of the Custom IR proceeding. The decrease in depreciation resulted in a positive earnings impact.

e) The decrease in other expenses of $5.2 million was due to lower municipal taxes of $5.5 million, partially offset by higher fixed financing charges of $0.3 million. The favourable municipal tax variance was attributable to lower than forecast municipal tax rate increases. The unfavourable variance in fixed financing charges was attributable to the unforecast increase in the Company's credit facility which occurred in 2014. The net decrease resulted in a positive earnings impact.

f) The decrease in income taxes of $0.7 million was primarily attributable to higher than forecast actual 2018 tax deductible amounts, predominantly due to higher CCA (including the impact of Bill C-97) and cost of retirements, partially offset by higher utility income before taxes. The decrease resulted in a positive earnings impact.

g) The interest cost of utility long and short term debt increased by $6.0 million primarily as a result of a higher outstanding principal balance required to fund the higher than forecast actual rate base value. The impact of the higher principal balance was largely offset by a lower weighted average cost of debt rate, which was attributable to the change in the component percentages of long (decrease) and short term (increase) debt. The lower long term debt component percentage, was partially attributable to the lower than forecast average of monthly average long-term debt balance outstanding that resulted from issuing $300 million later in the year, September 2018 as compared to August 2018, than forecast. The net increase has a negative earnings impact.

UTILITY RATE BASE (INCLUDING CUSTOMER CARE & CIS)
COMPARISON OF 2018 ACTUAL TO 2018 BOARD APPROVED

Line No.		Col. 1 2018 Actual	Col. 2 EB-2017-0086 2018 Board Approved	Col. 3 Variance
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	9,594.5	9,269.3	325.2
2.	Accumulated depreciation	(3,277.9)	(3,369.4)	91.5
3.	Net property, plant, and equipment	6,316.6	5,899.9	416.7
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	1.4	-
5.	Materials and supplies	38.3	34.6	3.7
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(44.8)	(64.6)	19.8
8.	Prepaid expenses	0.6	1.0	(0.4)
9.	Gas in storage	415.4	370.9	44.5
10.	Working cash allowance	1.7	2.9	(1.2)
11.	Total Working Capital	412.6	346.2	66.4
12.	Utility Rate Base	6,729.2	6,246.1	483.1

UTILITY PROPERTY, PLANT, AND EQUIPMENT (INCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Gross Property, Plant, and Equipment	Col. 2 Accumulated Depreciation	Col. 3 Net Property, Plant, and Equipment
		($Millions)	($Millions)	($Millions)
1.	Underground storage plant	425.1	(142.0)	283.1
2.	Distribution plant	8,585.5	(2,734.5)	5,851.0
3.	General plant	594.1	(402.9)	191.2
4.	Other plant	-	-	-
5.	Total plant in service	9,604.7	(3,279.4)	6,325.3
6.	Plant held for future use	1.7	(1.3)	0.4
7.	Sub- total	9,606.4	(3,280.7)	6,325.7
8.	Affiliate Shared Assets Value	(11.9)	2.8	(9.1)
9.	Total property, plant, and equipment	9,594.5	(3,277.9)	6,316.6

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	4.2	-	-	4.2	-	4.2	4.2
2.	Land and gas storage rights (450/451)	46.0	0.3	-	46.3	(1.0)	45.3	45.1
3.	Structures and improvements (452.00)	30.9	0.3	(0.0)	31.3	(0.1)	31.2	31.0
4.	Wells (453.00)	52.9	4.6	-	57.5	-	57.5	56.5
5.	Well equipment (454.00)	10.9	0.9	-	11.8	-	11.8	11.5
6.	Field Lines (455.00)	99.7	2.7	-	102.3	-	102.3	101.0
7.	Compressor equipment (456.00)	129.1	6.8	-	135.9	(0.5)	135.4	131.2
8.	Measuring and regulating equipment (457.00)	11.2	-	-	11.2	-	11.2	11.2
9.	Base pressure gas (458.00)	33.4	-	-	33.4	-	33.4	33.4
10.	Total	418.3	15.5	(0.0)	433.8	(1.5)	432.2	425.1

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2018	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2018	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.6)	(0.1)	-	-	1.4	(1.3)	-	(1.3)	(2.5)
2.	Land and gas storage rights (451.00)	(24.3)	(0.5)	-	-	-	(24.7)	-	(24.7)	(24.5)
3.	Structures and improvements (452.00)	(3.3)	(0.6)	-	0.0	1.1	(2.8)	0.1	(2.8)	(3.4)
4.	Wells (453.00)	(20.3)	(0.9)	(0.0)	-	6.4	(14.7)	-	(14.7)	(19.9)
5.	Well equipment (454.00)	(6.8)	(0.6)	-	-	0.0	(7.4)	-	(7.4)	(7.1)
6.	Field Lines (455.00)	(28.7)	(1.5)	(0.0)	-	0.5	(29.8)	-	(29.8)	(29.4)
7.	Compressor equipment (456.00)	(46.4)	(3.7)	(0.0)	-	0.1	(50.1)	0.2	(49.8)	(47.9)
8.	Measuring and regulating equipment (457.00)	(7.1)	(0.3)	-	-	0.2	(7.3)	-	(7.3)	(7.2)
9.	Total	(139.5)	(8.2)	(0.0)	0.0	9.7	(138.0)	0.3	(137.7)	(142.0)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	23.2	-	-	23.2	-	23.2	23.2
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	63.7	0.1	-	63.8	-	63.8	63.7
4.	Structures and improvements (472.00)	142.0	3.5	(1.7)	143.7	(0.3)	143.4	142.6
5.	Services, house reg & meter install. (473/474)	2,848.6	114.7	(8.4)	2,954.9	-	2,954.9	2,897.4
6.	NGV station compressors (476)	3.6	0.2	(0.1)	3.7	-	3.7	3.8
7.	Meters (478)	421.1	16.4	(8.2)	429.4	-	429.4	423.3
8.	Sub-total	3,502.2	134.9	(18.4)	3,618.7	(0.3)	3,618.4	3,554.0
9.	Mains (475)	4,362.1	175.5	(6.6)	4,530.9	(2.2)	4,528.7	4,432.0
10.	Measuring and regulating equip. (477)	591.1	18.2	(1.1)	608.2	(0.5)	607.7	599.5
11.	Sub-total	4,953.1	193.7	(7.8)	5,139.1	(2.7)	5,136.4	5,031.5
12.	Total	8,455.3	328.6	(26.2)	8,757.8	(3.1)	8,754.7	8,585.5

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2018	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2018	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(3.5)	(0.8)	-	-	-	(4.2)	-	(4.2)	(3.9)
2.	Structures and improvements (472.00)	(18.8)	(9.1)	-	1.7	1.0	(25.1)	0.3	(24.9)	(22.3)
3.	Services, house reg & meter install. (473/474)	(1,045.1)	(65.6)	10.6	8.4	64.4	(1,027.4)	-	(1,027.4)	(1,053.6)
4.	NGV station compressors (476)	(2.6)	(0.2)	-	0.1	-	(2.7)	-	(2.7)	(2.7)
5.	Meters (478)	(196.0)	(39.3)	-	8.2	(4.9)	(232.0)	-	(232.0)	(212.0)
6.	Mains (475)	(1,182.1)	(99.7)	20.5	6.6	(27.1)	(1,281.7)	2.0	(1,279.7)	(1,209.2)
7.	Measuring and regulating equip. (477)	(226.4)	(12.4)	0.1	1.1	6.5	(231.0)	0.5	(230.5)	(230.8)
8.	Total	(2,674.4)	(226.9)	31.2	26.2	39.9	(2,804.1)	2.8	(2,801.3)	(2,734.5)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	0.1	-	-	0.1	(0.2)	(0.1)	(0.1)
2.	Office furniture and equipment (483.00)	20.0	0.5	-	20.5	-	20.5	20.2
3.	Transportation equipment (484.00)	51.7	1.9	(2.1)	51.5	(0.1)	51.4	51.4
4.	NGV conversion kits (484.01)	2.3	-	(0.1)	2.2	-	2.2	2.2
5.	Heavy work equipment (485.00)	15.6	2.4	(0.2)	17.9	-	17.9	16.2
6.	Tools and work equipment (486.00)	49.5	1.2	-	50.7	-	50.7	50.0
7.	Rental equipment (487.70)	1.6	-	-	1.6	-	1.6	1.6
8.	NGV rental compressors (487.80)	8.0	(0.1)	(0.8)	7.1	-	7.1	7.8
9.	NGV cylinders (484.02 and 487.90)	0.6	-	-	0.6	-	0.6	0.6
10.	Communication structures & equip. (488)	3.9	0.2	-	4.1	-	4.1	4.0
11.	Computer equipment (490.00)	24.8	3.8	(2.2)	26.4	-	26.4	25.5
12.	Software Aquired/Developed (491.00)	190.7	38.1	(13.6)	215.2	-	215.2	195.6
13.	CIS (491.00)	127.1	-	-	127.1	-	127.1	127.1
14.	WAMS (489.00)	92.0	-	-	92.1	-	92.1	92.1
15.	Total	588.0	48.0	(19.0)	617.0	(0.3)	616.8	594.1

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2018	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2018	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	(0.0)	(0.0)	-	(0.0)	(0.1)	0.2	0.1	0.1
2.	Office furniture and equipment (483.00)	(6.0)	(2.2)	-	-	(8.2)	-	(8.2)	(7.1)
3.	Transportation equipment (484.00)	(19.6)	(5.5)	2.1	(0.2)	(23.2)	0.1	(23.1)	(21.3)
4.	NGV conversion kits (484.01)	1.0	(0.2)	0.1	-	0.9	-	0.9	1.0
5.	Heavy work equipment (485.00)	(4.6)	(0.6)	0.2	(0.0)	(5.1)	-	(5.1)	(4.9)
6.	Tools and work equipment (486.00)	(15.9)	(2.0)	-	-	(17.9)	-	(17.9)	(16.9)
7.	Rental equipment (487.70)	(1.1)	(0.0)	-	-	(1.1)	-	(1.1)	(1.1)
8.	NGV rental compressors (487.80)	(0.8)	(0.6)	0.8	(0.0)	(0.6)	-	(0.6)	(0.9)
9.	NGV cylinders (484.02 and 487.90)	(0.5)	(0.0)	-	(0.0)	(0.5)	-	(0.5)	(0.5)
10.	Communication structures & equip. (488)	(0.9)	(0.4)	-	0.2	(1.1)	-	(1.1)	(1.0)
11.	Computer equipment (490.00)	(24.9)	(2.3)	2.2	(0.7)	(25.7)	-	(25.7)	(28.5)
12.	Software Aquired/Developed (491.00)	(177.9)	(24.5)	13.6	-	(188.8)	-	(188.8)	(195.4)
13.	CIS (491.00)	(104.9)	(12.7)	-	-	(117.6)	-	(117.6)	(111.2)
14.	WAMS (489.00)	(10.7)	(9.2)	-	-	(19.9)	-	(20.0)	(15.3)
15.	Total	(366.6)	(60.3)	19.0	(0.9)	(408.9)	0.3	(408.6)	(402.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	-	-	-	-	-	-	-
2.	Total	-	-	-	-	-	-	-

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2018	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2018	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	-	-	-	-	-	-	-	-
2.	Total	-	-	-	-	-	-	-	-

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2018	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2018	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2017	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2018	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2018	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)
2.	Total	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.		Account Receivable Rebillable Projects	Materials and Supplies	Mortgages Receivable	Customer Security Deposits	Prepaid Expenses	Gas in Storage	Working Cash Allowance	Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.4	37.4	-	(46.7)	1.8	475.9	1.7	471.5
2.	January 31	1.4	37.9	-	(46.7)	1.5	424.3	1.7	420.1
3.	February	1.4	38.3	-	(46.6)	1.8	370.5	1.7	367.1
4.	March	1.4	38.3	-	(46.5)	0.3	280.8	1.7	276.0
5.	April	1.4	38.5	-	(46.1)	0.3	233.8	1.7	229.6
6.	May	1.4	38.1	-	(45.6)	0.3	269.1	1.7	265.0
7.	June	1.4	37.7	-	(45.1)	0.3	329.8	1.7	325.8
8.	July	1.3	39.0	-	(44.6)	0.3	404.9	1.7	402.6
9.	August	1.3	38.0	-	(43.9)	0.5	474.9	1.7	472.5
10.	September	1.3	38.8	-	(43.2)	0.5	538.7	1.7	537.8
11.	October	1.3	39.4	-	(43.0)	0.5	594.7	1.7	594.6
12.	November	1.3	38.2	-	(42.4)	0.5	564.1	1.7	563.4
13.	December	1.3	37.1	-	(41.9)	-	523.2	1.7	521.4
14.	Avg. of monthly avgs.	1.4	38.3	-	(44.8)	0.6	415.4	1.7	412.6

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2018 ACTUAL

Line No.		Col. 1 Disbursements	Col. 2 Net Lag-Days	Col. 3 Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,567.0	2.2	9.4
2.	Items not subject to working cash allowance (Note 1)	(1.0)		
3.	Gas costs charged to operations	1,566.0		
4.	Operation and Maintenance	437.5		
5.	Less: Storage costs	(8.4)		
6.	Operation and maintenance costs subject to working cash	429.1		
7.	Ancillary customer services	-		
8.		429.1	(10.9)	(12.8)
9.	Sub-total			(3.4)
10.	Storage costs	8.4	58.4	1.3
11.	Storage municipal and capital taxes	1.4	22.9	0.1
12.	Sub-total			1.4
13.	Harmonized Sales Tax			3.7
14.	Total working cash allowance			1.7

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

COMPARISON OF UTILITY CAPITAL EXPENDITURES
2018 ACTUALS VS. 2018 BOARD APPROVED BUDGET

Table 1
Summary of Capital Expenditures 2018 Actual and 2018 Board Approved Budget
($millions)

	Col 1	Col 2	Col 3
	Actual	Board Approved Budget	Actual Over/(Under)
	2018	2018	2018
Customer Related Distribution Plant	150.3	140.8	9.5
System Improvements and Upgrades	198.2	242.2	(44.0)
General and Other Plant	49.2	48.4	0.8
Underground Storage Plant	15.6	10.5	5.1
Total Core Capital Expenditures	**413.3**	**441.9**	**(28.7)**

The 2018 Actual core capital expenditures were $413.3 million, which was $28.6 million less than the 2018 Budget of $441.9 million. Core capital amounts also include overheads (i.e., departmental labour costs, capitalized administrative and general, and interest during construction). Excluding overheads, the 2018 Actual core capital spend was $299.6 million or $ 22.6 million less than the 2018 Budget of $322.2 million.

Table 2 below shows the major drivers of the $28.6 million underspend vs. Board approved budget and includes high-level commentary. Further details are provided below Table 2.

Table 2
Summary of Capital Expenditures 2018 Actual and 2018 Board Approved Budget
($millions)

		Actual Over/(Under)	% Change	Commentary
	Total 2018 Variance	(28.6)	-6%	
A	Customer Growth	7.8	8%	Overspent due to changes in the customer and geographic mix
B	Storage	4.3	49%	Remediation of degrading compressor equipment, foundations and storage pipeline integrity
C	Facilities and Genl Plant	(2.8)	-16%	Lower spend in building improvements and workspace alterations
D	Reinforcements	(1.7)	-19%	Due to project deferrals associated growth
E	Overheads - DLC, A&G and IDC	(6.1)	-5%	Lower IDC, A&G and DLC
F	Relocations	(14.0)	-111%	Incremental cost recovery from non-municipal infrastructure parties
G	Information Technology	5.3	19%	Customer Experience Program offset by lower spend in multi IT projects
H	Business Development	3.6	97%	Additional refueling station
I	System Integrity and Reliability	(25.0)	-18%	Lower spend in Service Replacements and Distribution Records
		(28.6)	**-6%**	

A. Customer Growth - Overspent by $7.8 Million

The cost of adding new customers increased due to higher direct costs related to customer mix and higher unit costs. The cost pressure challenges include increased municipal fees, full year construction and managing geographic sectors. Rising municipal and permitting fees are costs that are beyond the Company's control. Geographic challenges have a direct impact on the unit cost of adding new customers. The mix of more expensive replacement customers vs. new construction (subdivision) customers also factor heavily into the cost equation.

B. Storage – Overspent by $4.3 Million

The overage is due to increased spend on remediation of degrading compressor equipment and foundations and storage pipeline integrity, offset by lower spend in Well Integrity.

C. Facilities and General Plant – Underspent by $2.8 Million

Facilities and General Plant was lower than budget by ($2.8M) due to lower spending on building improvements and workspace alterations ($2.5M) and lower Fleet costs ($0.3M).

D. Reinforcements – Underspent by $1.7 Million

Reinforcements are primarily driven by customer growth and system reliability considerations to meet the anticipated peak hourly demand. The 2018 spend on reinforcements was lower due to project deferrals associated with growth.

E. Departmental Labour Costs, A&G and IDC – Underspent by $6.1 Million

From an overall perspective, these three cost categories were ($6.1M) less than budget. Interest during construction ("IDC") was lower by ($4.0M) due to lower interest rates and lower Work In Progress ("WIP") balances from lower capital spend along with lower capitalized administrative and general ("A&G") of ($1.3M). Departmental labour costs were also lower by ($0.8M) due to organizational restructuring and productivity.

F. Relocations - Underspent by $14.0 Million

Enbridge is required to relocate its infrastructure to accommodate 3rd party construction. The 2018 variance is primarily due to the incremental cost recovery from non-municipal infrastructure parties.

G. Information Technology – Overspent by $5.3 Million

The increased spend in Information Technology was primarily due to the implementation cost of EGD's Customer Experience Program of $14.4M. The Program aims to make interaction with customers easier, provide seamless customer service experiences that meets or exceeds our customers' expectations, and lower O&M costs.

The increased spend was offset by lower spend for IT Infrastructure of $5.9M, which includes Network Services, Data Centre Operations and IT Risk Management, which is now contained within IT Shared Services. Also offset by delayed CIS SAP Software Upgrade of ($3M). Project was delayed to accommodate the implementation of the EGD's Customer Experience Program.

H. Business Development – Overspent by $3.6 Million

The overspend was due to the result of an additional NGV refueling station project that occurred in 2018.

I. System Integrity and Reliability (SIR) – Underspent by $25.0 Million

The underspend was due to reduced Service Replacements ($21M) and Distribution Records ($3M).

UTILITY OPERATING REVENUE (INCLUDING CUSTOMER CARE & CIS)
2018 ACTUAL

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	2,565.4	(66.6)	2,498.8
2.	Transportation of gas	281.9	(5.6)	276.3
3.	Transmission, compression & storage	19.2	-	19.2
4.	Other operating revenue	42.3	-	42.3
5.	Interest and property rental	-	-	-
6.	Other income	0.2	-	0.2
7.	Total operating revenue	2,909.0	(72.2)	2,836.8

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2018 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	(66.6)	Gas sales
		Adjustment to gas sales revenue required to reflect normal weather.
2.	(5.6)	Transportation of gas
		Adjustment to gas sales revenue required to reflect normal weather.

UTILITY REVENUE (INCLUDING CUSTOMER CARE & CIS)
2018 ACTUAL

Line No.		Col. 1 EGDI Ont. Corporate Revenue	Col. 2 Adjustment	Col. 3 Utility Revenue
		($Millions)	($Millions)	($Millions)
1.	Residential	1,869.1	(182.6)	1,686.5
2.	Commercial	768.4	-	768.4
3.	Industrial	80.3	-	80.3
4.	Wholesale	30.2	-	30.2
5.	Gas sales	2,748.0	(182.6)	2,565.4
6.	Transportation of gas	339.9	(58.0)	281.9
7.	Transmission, compression & storage	19.2	-	19.2
8.	Service charges & DPAC	11.2	-	11.2
9.	Rent from NGV rentals	1.5	-	1.5
10.	Late payment penalties	11.9	-	11.9
11.	Transactional services	13.5	(1.5)	12.0
12.	Open bill revenue	7.4	(2.0)	5.4
13.	Dow Moore recovery	0.3	-	0.3
14.	Affiliate asset use revenue	-	-	-
15.	ABC T-service (net)	1.5	(1.5)	-
16.	Other operating revenue	47.3	(5.0)	42.3
17.	Income from investments	0.5	(0.5)	-
18.	Interest during construction	3.3	(3.3)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	1.7	(1.7)	-
21.	Property/asset use revenue 3rd party	1.0	(1.0)	-
22.	Interest and property rental	6.5	(6.5)	-
23.	Miscellaneous	18.1	(17.9)	0.2
24.	Dividend income	59.6	(59.6)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	77.7	(77.5)	0.2
28.	Total revenue	3,238.6	(329.6)	2,909.0

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2018 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	(182.6)	Residential gas sales	
		US GAAP adjustment elimination for deferral & variance clearance recognition.	(43.7)
		Removal of Cap and Trade revenues.	(166.1)
		To eliminate earnings sharing in the financial statements	27.2
			(182.6)
6.	(58.0)	Transportation of Gas	
		Removal of Cap and Trade revenues.	
11.	(1.5)	Transactional services	
		To eliminate transactional services revenues above the base amount included in rates. Ratepayer and shareholder amounts above the base are treated outside of utility results and returns.	
12.	(2.0)	Open bill revenue	
		To adjust OBA costs to reflect the EB-2013-0099 approved unit costs agreed to be used for determining net revenues.	(1.8)
		To eliminate the Open Bill shareholder incentive.	(0.2)
			(2.0)
15.	(1.5)	ABC T-Service (net)	
		To eliminate the net revenue from ABC T-Service considered to be non-utility. (RP-1999-0001)	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2018 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(0.5)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(3.3)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
20.	(1.7)	Interest on (net) deferral accounts	
		To eliminate interest income form assets not included in Utility rate base.	
21.	(1.0)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(17.9)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(10.6)
		To eliminate the revenue indemnification received from Enbridge Inc. related to a non-utility Corporate tax planning Part VI.1 tax transfer to EGD.	(1.2)
		To eliminate the shareholders' incentive income recorded as a result of calculating the 2016 DSMIDA amount.	(6.1)
			(17.9)
24.	(59.6)	Dividend income	
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2018 ACTUAL AND 2018 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2018 Actual		Col. 2 2018 Board Approved Budget		Col. 3 2018 Actual Over (Under) 2018 Budget (1-2)
General Service						
1.1.1	Rate 1 - Sales	5 114.2		4 583.6		530.6
1.1.2	Rate 1 - T-Service	182.1		166.6		15.5
1.1	Total Rate 1	5 296.3		4 750.2		546.1
1.2.1	Rate 6 - Sales	3 209.6		3 121.4		88.2
1.2.2	Rate 6 - T-Service	2 074.3		1 708.4		365.9
1.2	Total Rate 6	5 283.9		4 829.8		454.1
1.3.1	Rate 9 - Sales	0.0	**	0.0		0.0
1.3.2	Rate 9 - T-Service	0.0		0.0		0.0
1.3	Total Rate 9	0.0		0.0		0.0
1.	Total General Service Sales & T-Service	10 580.2		9 580.0		1 000.2
Contract Sales						
2.1	Rate 100	1.5		0.0		1.5
2.2	Rate 110	56.5		56.3		0.2
2.3	Rate 115	0.3		0.0		0.3
2.4	Rate 135	2.0		4.5		(2.5)
2.5	Rate 145	6.2		8.6		(2.4)
2.6	Rate 170	28.6		34.5		(5.9)
2.7	Rate 200	184.4		169.8		14.6
2.	Total Contract Sales	279.5		273.7		5.8
Contract T-Service						
3.1	Rate 100	0.6		0.0		0.6
3.2	Rate 110	789.4		732.7		56.7
3.3	Rate 115	499.1		542.8		(43.7)
3.4	Rate 125	0.0	*	0.0	*	0.0
3.5	Rate 135	60.6		60.0		0.6
3.6	Rate 145	37.1		41.6		(4.5)
3.7	Rate 170	299.5		256.7		42.8
3.8	Rate 300	0.0		0.0		0.0
3.9	Rate 315	0.0		0.0		0.0
3.	Total Contract T-Service	1 686.3		1 633.8		52.5
4.	Total Contract Sales & T-Service	1 965.8		1 907.5		58.3
5.	Total	12 546.0		11 487.5		1 058.5

* There is no distribution volume for Rate 125 customers.

** Less than 50,000 m^3

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2018 ACTUAL AND 2018 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2018 Actual		Col. 2 2018 Board Approved Budget	Col. 3 2018 Actual Over (Under) 2018 Budget (1-2)	Col. 4 2018* Adjustments	Col. 5 2018 Actual Over (Under) 2018 Budget with Adjustments (3+4)
General Service							
1.1.1	Rate 1 - Sales	5 114.2		4 583.6	530.6	(332.7)	197.9
1.1.2	Rate 1 - T-Service	182.1		166.6	15.5	(11.5)	4.0
1.1	Total Rate 1	5 296.3		4 750.2	546.1	(344.2)	201.9
1.2.1	Rate 6 - Sales	3 209.6		3 121.4	88.2	(216.4)	(128.2)
1.2.2	Rate 6 - T-Service	2 074.3		1 708.4	365.9	(135.6)	230.3
1.2	Total Rate 6	5 283.9		4 829.8	454.1	(352.0)	102.1
1.3.1	Rate 9 - Sales	0.0	**	0.0	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.0		0.0	0.0	0.0	0.0
1.3	Total Rate 9	0.0		0.0	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	10 580.2		9 580.0	1 000.2	(696.2)	304.0
Contract Sales							
2.1	Rate 100	1.5		0.0	1.5	0.0	1.5
2.2	Rate 110	56.5		56.3	0.2	0.0	0.2
2.3	Rate 115	0.3		0.0	0.3	0.0	0.3
2.4	Rate 135	2.0		4.5	(2.5)	0.0	(2.5)
2.5	Rate 145	6.2		8.6	(2.4)	0.1	(2.3)
2.6	Rate 170	28.6		34.5	(5.9)	0.1	(5.8)
2.7	Rate 200	184.4		169.8	14.6	1.7	16.3
2.	Total Contract Sales	279.5		273.7	5.8	1.9	7.7
Contract T-Service							
3.1	Rate 100	0.6		0.0	0.6	0.0	0.6
3.2	Rate 110	789.4		732.7	56.7	(1.0)	55.7
3.3	Rate 115	499.1		542.8	(43.7)	(0.1)	(43.8)
3.4	Rate 125	0.0		0.0	0.0	0.0	0.0
3.5	Rate 135	60.6		60.0	0.6	0.0	0.6
3.6	Rate 145	37.1		41.6	(4.5)	0.4	(4.1)
3.7	Rate 170	299.5		256.7	42.8	4.3	47.1
3.8	Rate 300	0.0		0.0	0.0	0.0	0.0
3.9	Rate 315	0.0		0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 686.3		1 633.8	52.5	3.6	56.1
4.	Total Contract Sales & T-Service	1 965.8		1 907.5	58.3	5.5	63.8
5.	Total	12 546.0		11 487.5	1 058.5	(690.7)	367.8

*Note: Weather normalization adjustments have been made to the 2018 Actual utilizing the 2018 Board Approved Budget Degree Days .

** Less than 50,000 m^3

The principal reasons for the variances contributing to the weather normalized increase of 367.8 10^6m^3 in the 2018 Actual over the 2018 Board Approved Budget are as follows:

1. The volumetric increase of 201.9 10^6m^3 in Rate 1 was due to a higher average use per customer totalling 197.6 10^6m^3 and favourable customer variance of 4.3 10^6m^3;

2. The volumetric increase of 102.1 10^6m^3 in Rate 6 was primarily due to a higher average use per customer totaling 120.8 10^6m^3, and partially offset by unfavourable customer variance of 18.7 10^6m^3;

3. The volumetric increase for Contract Sales and T-Service of 63.8 10^6m^3 was due to increases in the apartment sector of 1.2 10^6m^3, commercial sector of 3.9 10^6m^3 , industrial sector of 42.4 10^6m^3 and and rate 200 of 16.3 10^6m^3 .

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2018 ACTUAL AND 2018 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2018 Actual	Col. 2 2018 Board Approved Budget	Col. 3 2018 Actual Over (Under) 2018 Budget (1-2)	Col. 4 2018* Adjustments	Col. 5 2018 Actual Over (Under) 2018 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 878.3	1 739.0	139.3	(81.3)	58.0
1.1.2	Rate 1 - T-Service	54.5	38.3	16.2	(1.4)	14.8
1.1	Total Rate 1	1 932.8	1 777.3	155.5	(82.7)	72.8
1.2.1	Rate 6 - Sales	913.1	892.6	20.5	(45.3)	(24.8)
1.2.2	Rate 6 - T-Service	238.7	163.8	74.9	(10.3)	64.6
1.2	Total Rate 6	1 151.8	1 056.4	95.4	(55.6)	39.8
1.3.1	Rate 9 - Sales	0.0 **	0.0	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0	0.0	0.0
1.3	Total Rate 9	0.0	0.0	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	3 084.6	2 833.7	250.9	(138.3)	112.6
Contract Sales						
2.1	Rate 100	0.5	0.0	0.5	0.0	0.5
2.2	Rate 110	11.0	11.6	(0.6)	0.0 **	(0.6)
2.3	Rate 115	0.2	0.0	0.2	0.0	0.2
2.4	Rate 135	0.3	0.8	(0.5)	0.0	(0.5)
2.5	Rate 145	1.3	1.7	(0.4)	0.0 **	(0.4)
2.6	Rate 170	5.2	6.0	(0.8)	0.0	(0.8)
2.7	Rate 200	30.2	29.7	0.5	0.3	0.8
2.	Total Contract Sales	48.7	49.8	(1.1)	0.3	(0.8)
Contract T-Service						
3.1	Rate 100	0.1	0.0	0.1	0.0	0.1
3.2	Rate 110	40.9	34.6	6.3	0.0 **	6.3
3.3	Rate 115	12.5	12.7	(0.2)	0.0 **	(0.2)
3.4	Rate 125	11.1	11.0	0.1	0.0	0.1
3.5	Rate 135	2.9	2.0	0.9	0.0	0.9
3.6	Rate 145	2.7	1.8	0.9	0.0 **	0.9
3.7	Rate 170	6.1	2.7	3.4	0.0 **	3.4
3.8	Rate 300	0.1	0.1	0.0	0.0	0.0
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	76.4	64.9	11.5	0.0	11.5
4.	Total Contract Sales & T-Service	125.1	114.7	10.4	0.3	10.7
5.	Total	3 209.7	2 948.4	261.3	(138.0)	123.3

* Note: Weather normalization adjustments have been made to the 2018 Actuals utilizing the 2018 Board Approved Budget degree days. Please refer to Exhibit B, Tab 2, Appendix C, Schedule 2, Page 2, for the corresponding volumetric adjustments.

** Less than $50,000

1. Gas sales and transportation of gas revenues for the 2018 Test Year Budget were developed on the basis of EB-2017-0086 rates.

2. The principal reasons for the variance contributing to the increase of $261.3 million in the 2018 Actual compared to the 2018 Budget are as follows:

3. Gas Sales - increase of $158.7 Million

   The increase in gas sales revenue was mainly due to higher volume than budgeted.

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

4. Transportation of Gas - Increase of $102.6 Million

   The increase in T-service revenue was mainly due to higher T-service volumein rate 6.

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2018 ACTUAL

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)		Col. 3 Revenues ($Millions)	
General Service						
1.1.1	Rate 1 - Sales	1 948 130	5 114.2		1 878.3	
1.1.2	Rate 1 - T-Service	68 998	182.1		54.5	
1.1	Total Rate 1	2 017 128	5 296.3		1 932.8	
1.2.1	Rate 6 - Sales	144 285	3 209.6		913.1	
1.2.2	Rate 6 - T-Service	22 930	2 074.3		238.7	
1.2	Total Rate 6	167 215	5 283.9		1 151.8	
1.3.1	Rate 9 - Sales	2	0.0	**	0.0	***
1.3.2	Rate 9 - T-Service	0	0.0		0.0	
1.3	Total Rate 9	2	0.0		0.0	
1.	Total General Service Sales & T-Service	2 184 345	10 580.2		3 084.6	
Contract Sales						
2.1	Rate 100	2	1.5		0.5	
2.2	Rate 110	43	56.5		11.0	
2.3	Rate 115	1	0.3		0.2	
2.4	Rate 135	3	2.0		0.3	
2.5	Rate 145	4	6.2		1.3	
2.6	Rate 170	6	28.6		5.2	
2.7	Rate 200	1	184.4		30.2	
2.	Total Contract Sales	60	279.5		48.7	
Contract T-Service						
3.1	Rate 100	1	0.6		0.1	
3.2	Rate 110	231	789.4		40.9	
3.3	Rate 115	25	499.1		12.5	
3.4	Rate 125	4	0.0	*	11.1	
3.5	Rate 135	40	60.6		2.9	
3.6	Rate 145	29	37.1		2.7	
3.7	Rate 170	21	299.5		6.1	
3.8	Rate 300	2	0.0		0.1	
3.9	Rate 315	1	0.0		0.0	
3.	Total Contract T-Service	354	1 686.3		76.4	
4.	Total Contract Sales & T-Service	414	1 965.8		125.1	
5.	Total	2 184 759	12 546.0		3 209.7	

* There is no distribution volume for Rate 125 customers.

** Less than 50,000 m^3

*** Less than $50,000

DETAILS OF OTHER REVENUE AND OTHER INCOME
2018 ACTUAL AND 2018 BOARD APPROVED

		Col. 1	Col. 2	Col. 3
Item No.		2018 Actual ($Millions)	2018 Board Approved Budget ($Millions)	2018 Actual Over/(Under) 2018 Board Approved ($Millions)
1.1	Service Charges & DPAC	11.2	12.3	(1.1)
1.2	Rental Revenue - NGV Program	1.5	1.1	0.4
1.3	Late Payment Penalties	11.9	10.1	1.8
1.4	Dow Moore Recovery	0.3	0.3	-
1.5	Transactional Services (net)	12.0	12.0	-
1.6	Miscellaneous and Other Income	0.2	1.6	(1.4)
1.7	Open Bill Revenue	5.4	5.4	-
1.8	Total Other Revenue	42.5	42.8	(0.3)

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2018 ACTUAL

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,612.7	(46.7)	1,566.0
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	437.5	-	437.5
3.	Depreciation and amortization expense	294.7	-	294.7
4.	Fixed financing costs	2.2	-	2.2
5.	Municipal and other taxes	44.9	-	44.9
6.	Operating costs	2,392.0	(46.7)	2,345.3
7.	Income tax expense			38.8
8.	Cost of service			2,384.1

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2018 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(46.7)	Gas costs Adjustment required to gas costs to reflect normal weather.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2018 ACTUAL

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	491.5	491.5	
	Add			
2.	Depreciation and amortization	294.7	294.7	
3.	Accrual based pension and OPEB costs	15.4	15.4	
4.	Other non-deductible items	2.5	2.5	
5.	Total Add Back	312.6	312.6	
6.	Sub-total	804.1	804.1	
	Deduct			
7.	Capital cost allowance	334.6	334.6	
8.	Items capitalized for regulatory purposes	75.8	75.8	
9.	Deduction for "grossed up" Part VI.1 tax	3.7	3.7	
10.	Amortization of share/debenture issue expense	4.3	4.3	
11.	Amortization of cumulative eligible capital	-	-	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site Restoration Costs adjustment	31.1	31.1	
14.	Cash based pension and OPEB costs	23.7	23.7	
15.	Total Deduction	473.3	473.3	
16.	Taxable income	330.8	330.8	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	49.6	38.0	87.6
19.	Part VI.1 tax			1.0
20.	Total taxes excluding interest shield			88.6
	Tax shield on interest expense			
21.	Rate base	6,729.2		
22.	Return component of debt	2.79%		
23.	Interest expense	188.0		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(49.8)
26.	Total utility income taxes			38.8

COST OF SERVICE
2018 ACTUAL

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,880.5	(267.8)	1,612.7
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	437.0	0.5	437.5
3.	Depreciation	295.5	(0.8)	294.7
4.	Amortization	22.5	(22.5)	-
5.	Depreciation and amortization	318.0	(23.3)	294.7
6.	Fixed financing costs	2.2	-	2.2
7.	Municipal and other taxes	45.1	(0.2)	44.9
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	45.1	(0.2)	44.9
10.	Interest on long-term debt	173.6	(173.6)	-
11.	Amortization of preference share issue costs and debt discount and expense	4.0	(4.0)	-
				-
12.	Interest and financing amortization	177.6	(177.6)	-
13.	Interest on short-term debt	17.4	(17.4)	-
14.	Interest due affiliates	28.7	(28.7)	-
				-
15.	Other interest expense	46.1	(46.1)	-
16.	Total operating costs	2,906.5	(514.5)	2,392.0
17.	Current taxes	43.9	(43.9)	-
18.	Deferred taxes	(7.0)	7.0	-
19.	Income tax expense	36.9	(36.9)	-
20.	Cost of service	2,943.4	(551.4)	2,392.0

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2018 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation	
	($Millions)		
1	(267.8)	Gas costs	
		US GAAP adjustment elimination for deferral & variance clearance recognition.	(43.7)
		Removal of Cap and Trade costs.	(224.1)
			(267.8)
2.	0.5	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	0.8
		To eliminate donations (EBRO 490).	(1.0)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(0.4)
		To eliminate Electric CDM net benefit. Ratepayer amount was transferred to the 2018 EPESDA and shareholder amount is eliminated from utility results.	1.2
		To eliminate EGD/Union Amalgamation transaction costs	(0.1)
			0.5
3.	(0.8)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
			(0.8)
4.	(22.5)	Amortization expense	
		To eliminate the amortization of PPD.	
7.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2018 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
10.	(173.6)	Interest on long-term debt	
		Expense of capital.	
11.	(4.0)	Amortization of preference share issue costs and debt discount and expense	
		Expense of capital.	
13.	(17.4)	Interest on short-term debt	
		Expense of capital.	
14.	(28.7)	Interest due affiliates	
		To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).	(25.5)
		To eliminate inter-company interest expense on note from Enbridge Inc..	(3.2)
			(28.7)
17.	(43.9)	Income taxes - current	
		Income tax expense related to corporate earnings.	
18.	7.0	Income taxes - deferred	
		Income tax expense related to corporate earnings.	

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2018 ACTUAL

Capital Cost Allowance

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
Class No.	UCC At Beginning of year	Cost of Additions Subject to 1/2 Year Rule	Cost of Additions Subject to Bill C-97 Accel. CCA	Less: Lessor of Costs or Proceeds	Eligible CCA Additions	Depreciable UCC Balance	Rate %	CCA F2018	UCC Carry Forward
1	1,518,665,810	-	-	-	-	1,518,665,810	4.00%	60,746,632	1,457,919,178
51	3,172,822,162	272,659,041	32,106,174	(159,640)	184,408,962	3,357,231,124	6.00%	201,433,867	3,275,993,870
2	87,026,933	-	-	-	-	87,026,933	6.00%	5,221,616	81,805,317
6	8,059	-	-	-	-	8,059	10.00%	806	7,253
8	17,701,283	348,080	-	-	174,040	17,875,323	20.00%	3,575,065	14,474,298
10	21,553,540	2,414,130	1,840,127	(303,475)	3,815,518	25,369,058	30.00%	7,610,717	17,893,605
12	12,813,435	24,452,093	10,859,635	-	23,085,682	35,899,117	100.00%	35,899,117	12,226,047
17	21,344	-	-	-	-	21,344	8.00%	1,708	19,636
38	2,811,783	1,250,678	-	(79,315)	585,682	3,397,465	30.00%	1,019,239	2,963,907
41	38,593,224	10,903,776	191,958	-	5,739,825	44,333,049	25.00%	11,083,262	38,605,696
13	13,754	-	-	-	-	13,754	-	13,754	-
3	183,169	-	-	-	-	183,169	5.00%	9,158	174,010
45	24,648	-	-	-	-	24,648	45.00%	11,092	13,557
50	8,316,426	3,023,995	862,692	-	2,806,036	11,122,462	55.00%	6,117,354	6,085,759
14.1	37,564,019	-	-	-	-	37,564,019	7.00%	2,629,481	34,934,538
14.1	-	21,449	2,736	-	14,829	14,829	5.00%	741	23,444
Total	4,918,119,589	315,073,242	45,863,322	(542,430)	220,630,572	5,138,750,160		335,373,610	4,943,140,113

Non-utility and shared asset eliminations	(756,512)
Utility CCA	334,617,098

2018 UTILITY O&M

Line No.	Particulars (in millions)	Actuals 2018	IR 2018	Actual Under/(Over)
1	Total Compensation	230.4	242.5	12.1
2	Employee Training and Development	3.3	5.1	1.8
3	Materials and Supplies	6.0	5.7	(0.3)
4	Outside Services	95.3	97.0	1.6
5	Consulting	3.2	5.5	2.3
6	Repairs and Maintenance	1.8	2.6	0.8
7	Fleet	3.6	11.4	7.7
8	Rents and Leases	4.5	8.3	3.8
9	Telecommunications	0.0	4.2	4.1
10	Travel and Other Business Expenses	2.1	5.5	3.4
11	Memberships	6.4	5.6	(0.8)
12	Claims, Damages and Legal Fees	0.3	1.0	0.7
13	Interest on Security Deposits	0.8	2.7	1.9
14	Provision for Uncollectibles	5.6	10.1	4.5
15	Natural Gas Vehicles (NGV)	0.5	-	(0.5)
16	Legal Fees	0.8	3.1	2.3
17	Audit Fees	2.1	1.8	(0.3)
18	Other	(2.3)	(13.7)	(11.4)
19	Internal Allocations and Recoveries	(14.8)	(32.1)	(17.2)
20	Capitalization (A&G)	(37.1)	(39.5)	(2.4)
21	Capitalization	(87.6)	(85.8)	1.8
22	Regulatory Eliminations	(1.0)	(3.5)	(2.5)
23	Other O&M Subtotal	224.0	237.3	13.3
24	Customer Care/CIS Service Charges	88.4	110.8	22.4
25	Pensions and OPEB	15.4	20.7	5.3
26	RCAM	43.2	35.9	(7.3)
27	Demand Side Management Programs (DSM)	67.6	67.6	0.0
28	Conservation Services	(1.2)	-	1.2
29	Total Net Utility O&M Expense before Eliminations	437.4	472.3	34.9

EXPLANATION OF MAJOR CHANGES
ACTUAL 2018 O&M EXPENSES COMPARED TO OEB APPROVED 2018 O&M EXPENSES

1 Decrease in Total Compensation due to reduction in headcount.

7 Decrease in Fleet is mainly due to capital allocations which is budgeted in Internal Allocations and Recoveries while actuals are recognized in the Fleet category.

9 Decrease in Telecommunications due to the centralization of telecommunication costs under Enbridge Inc.

14 Decrease in Provision for Uncollectibles due to continued improvements in collections.

18 Increase in Other mainly due to reduction in IR budget of $19.0M based on OEB decision partially offset by other smaller favourable items.

19 Decrease in Internal Allocations and Recoveries mainly due Fleet and Outside Service. Actual allocations and recoveries are recognized in the respective cost categories while the budget resides in Internal Allocations and Recoveries.

24 Decrease in Customer Care/CIS Service Charges due to reduced CIS support costs, improved collections, postage savings from higher number of customers on e-bill, and system improvements reducing manual work.

26 Increase in RCAM is due to the centralization of IT and HR services to Enbridge Inc.

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN (INCLUDING CUSTOMER CARE & CIS)
2018 ACTUAL

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (col 1x col 3) Interest & pref share Expense
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	3,838.2	57.04	4.72	2.692	181.2
2.	Short-Term Debt	381.0	5.66	1.81	0.102	6.9
3.		4,219.2	62.70		2.794	
4.	Preference Shares	87.5	1.30	2.99	0.039	2.6
						190.7
5.	Common Equity	2,422.5	36.00	9.00	3.240	
6.		6,729.2	100.00		6.073	
7.	Rate Base	($Millions)			6,729.2	
8.	Utility Income	($Millions)			452.7	
9.	Indicated Rate of Return				6.727	
10.	Sufficiency in Rate of Return				0.654	
11.	Net Sufficiency	($Millions)			44.0	
12.	Gross Sufficiency	($Millions)			59.9	
13.	Revenue at Existing Rates	($Millions)			2,794.3	
14.	Allowed Revenue	($Millions)			2,734.4	
15.	Gross Revenue Sufficiency	($Millions)			59.9	
	Common Equity					
16.	Allowed Rate of Return				9.00	
17.	Earnings on Common Equity				10.82	
18.	Sufficiency in Common Equity Return				1.82	

UTILITY INCOME (INCLUDING CIS & CUSTOMER CARE)
2018 ACTUAL

Line No.		Col. 1 Utility Income Incl. CIS & Customer Care ($Millions)
1.	Gas sales	2,498.8
2.	Transportation of gas	276.3
3.	Transmission, compression and storage revenue	19.2
4.	Other operating revenue	42.3
5.	Interest and property rental	-
6.	Other income	0.2
7.	Total operating revenue (Ex. B-2-C-1-pg.1)	2,836.8
8.	Gas costs	1,566.0
9.	Operation and maintenance	437.5
10.	Depreciation and amortization expense	294.7
11.	Fixed financing costs	2.2
12.	Municipal and other taxes	44.9
13.	Interest and financing amortization expense	-
14.	Other interest expense	-
15.	Cost of service (Ex. B-2-D-1-pg.1)	2,345.3
16.	Utility income before income taxes	491.5
17.	Income tax expense (Ex. B-2-D-1-pg.3)	38.8
18.	Utility income	452.7

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2018 ACTUAL

Line No.		Col. 1 Average of Monthly Averages	Col. 2	Col. 3 Carrying Cost
		($Millions)		($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	3,867.5		182.4
2.	Unamortized Finance Costs	(29.3)		-
3.	(Profit)/Loss on Redemption	-		-
4.		3,838.2		182.4
5.	Calculated Cost Rate		4.72%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.81%	
	Preference Shares			
7.	Preference Share Summary	87.5		2.6
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		87.5		2.6
11.	Calculated Cost Rate		2.99%	
	Common Equity			
12.	Board Formula ROE		9.00%	

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2018 ACTUAL

			Col. 1	Col. 2	Col. 3
Line No.	Coupon Rate	Maturity Date	Average of Monthly Averages Principal	Effective Cost Rate	Carrying Cost
			($Millions)		($Millions)
Medium Term Notes					
1.	8.85%	October 2, 2025	20.0	8.970%	1.8
2.	7.60%	October 29, 2026	100.0	8.086%	8.1
3.	6.65%	November 3, 2027	100.0	6.711%	6.7
4.	6.10%	May 19, 2028	100.0	6.161%	6.2
5.	6.05%	July 5, 2023	100.0	6.383%	6.4
6.	6.90%	November 15, 2032	150.0	6.950%	10.4
7.	6.16%	December 16, 2033	150.0	6.180%	9.3
8.	5.21%	February 25, 2036	300.0	5.183%	15.5
9.	4.77%	December 17, 2021	175.0	5.310%	9.3
10.	4.04%	November 23, 2020	200.0	5.209%	10.4
11.	4.95%	November 22, 2050	200.0	4.990%	10.0
12.	4.95%	November 22, 2050	100.0	4.731%	4.7
13.	4.04%	November 23, 2020	200.0	2.801%	5.6
14.	4.50%	November 23, 2043	200.0	4.198%	8.4
15.	3.15%	August 22, 2024	215.0	3.241%	7.0
16.	4.00%	August 22, 2044	215.0	3.889%	8.4
17.	4.00%	August 22, 2044	170.0	4.436%	7.5
18.	3.31%	September 11, 2025	400.0	3.619%	14.5
19.	2.50%	August 5, 2026	300.0	3.423%	10.3
20.	3.51%	November 29, 2047	300.0	3.527%	10.6
21.	3.32%	September 6, 2028	87.5	3.370%	2.9
22.			3,782.5		174.0
Long-Term Debentures					
23.	9.85%	December 2, 2024	85.0	9.910%	8.4
24.			85.0		8.4
25.	Total Term Debt		3,867.5		182.4

UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2018 ACTUAL

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	31.2
2.	January 31	30.9
3.	February	30.6
4.	March	30.3
5.	April	29.9
6.	May	29.6
7.	June	29.3
8.	July	28.9
9.	August	28.6
10.	September	28.3
11.	October	27.9
12.	November	27.6
13.	December	27.2
14.	Average of Monthly Averages	29.3

2018 RRR FILINGS – SERVICE QUALITY INDICATORS

1. Please find the Service Quality Indicator results in the tables below.

G.2.1.9.A - TELEPHONE ANSWERING PERFORMANCE

G.2.1.9.A.1 - Call Answering Service Level (CASL)
Measure Calculations: CASL = Number of calls reaching a distributor's general inquiry number answered within 30 seconds divided by the number of calls received by a distributor's general inquiry number.
OEB Approved Standard: Yearly performance shall be 75% with minimum monthly standard of 40%.

Month	Number of Calls Reaching a Distributor's General Inquiry Number Answered Within 30 Seconds (1)	Number of Calls Received by a Distributor's General Inquiry Number (2)	Call Answer Service Level (%) (3=1/2*100)
Jan.	185,694	222,121	83.6%
Feb.	158,952	178,510	89.0%
Mar.	160,938	195,724	82.2%
Apr.	175,064	210,108	83.3%
May	188,289	228,108	82.5%
Jun.	170,248	206,101	82.6%
Jul.	178,938	232,309	77.0%
Aug.	167,398	207,775	80.6%
Sept.	151,954	191,595	79.3%
Oct.	184,987	234,783	78.8%
Nov.	175,977	215,149	81.8%
Dec.	132,773	155,879	85.2%
TOTAL	2,031,212	2,478,162	82.0%

G.2.1.9.A.2 - Abandon Rate (AR)
Measure Calculations: AR = Number of calls abandoned while waiting for a live agent divided by a total number of calls requesting to speak to a live agent.
OEB Approved Standard: Performance shall not exceed 10% on a yearly basis.

Month	Number of Calls Abandoned While Waiting for a Live Agent (1)	Total Number of Calls Requesting to Speak to a Live Agent (2)	Abandon Rate (%) (3=1/2*100)
Jan.	2,119	126,529	1.7%
Feb.	1,130	100,600	1.1%
Mar.	2,143	111,537	1.9%
Apr.	2,036	122026	1.7%
May	2,154	135288	1.6%
Jun.	1,851	120484	1.5%
Jul.	3,376	131960	2.6%
Aug.	2,752	120434	2.3%
Sept.	2,496	112968	2.2%
Oct.	3,474	141551	2.5%
Nov.	2,151	124777	1.7%
Dec.	1,357	87781	1.5%
TOTAL	27,039	1,435,935	1.9%

G.2.1.9.B - BILL PERFORMANCE

Measure Calculations: The utility is required to have a verifiable Quality Assurance Program ("QAP") in place. Manual checks must be done to validate billing data when meter reads fall outside criteria (as set by the QAP) for excessively high or low usage.

OEB Approved Standard: No specific metric is attached to this requirement.

Month	Total Number of Billings	Total Number of Manual Checks Done as per QAP	Total Number of Manual Checks Done When Meter Reads Show Excessively High Usage Vs. QAP Criteria	Total Number of Manual Checks Done When Meter Reads Show Excessively Low Usage Vs. QAP Criteria
	(1)	(2)	(3)**	(5)**
January	2,209,904	19,616	4,034	
February	2,200,796	13,494	4,466	
March	2,208,547	14,108	7,205	
April	2,208,356	15,194	8,608	
May	2,273,723	13,678	9,134	
June	2,367,499	18,388	13,199	
July	2,221,688	18,961	14,615	
August	2,259,982	28,245	21,529	
September	2,221,754	24,336	15,981	
October	2,192,062	20,540	13,245	
November	2,224,233	18,234	8,342	
December	2,222,922	13,522	7,015	
Total	26,811,466	218,316	127,373	

**volume in Column 3 includes both high & low checks

Brief Explanation for Excessively High Usage (In 100 Words or less) (4)	

1. Bills that exceed our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly (e.g. backwards or digits like and 8 or 6 may have been visually misread).
3. An actual read could be higher following a number of estimates.
4. The historical usage on the account might that suggest that the customer’s usage increases at a particular times each year. (eg. Pool heaters)
5. The customer has installed additional and/or upgraded gas appliances.

Brief Explanation for Excessively Low Usage (in 100 Words or less) (6)	

1. Bills that are below our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly e.g. backwards or digits like and 8 or 6 may have been visually misread.
3. An actual read could be lower following a number of estimates.
4. The historical usage on the account might that suggest that the customer’s usage is reduced or stops altogether for certain periods each year.
5. The customer has removed or discontinued use of gas appliances.

G.2.1.9.C - METER READING PERFORMANCE

G.2.1.9.C.1 - Meter Reading Performance Measurement (MRPM)

Measure Calculations: MRPM = Number of meters with no read for 4 consecutive months or more divided by the total number of active meters to be read.

OEB Approved Standard: Measurement shall not exceed 0.5% on a yearly basis.

Month	Number of Meters with No Read for 4 Consecutive Months or More (1)	Total Number of Active Meters to be Read (2)	Meter Performance Measurement (%) (3=1/2*100)
Jan	15,399	2,194,403	0.7%
Feb	21,066	2,196,125	1.0%
Mar	16,091	2,198,653	0.7%
Apr	12,711	2,200,511	0.6%
May	8,588	2,202,928	0.4%
Jun	8,498	2,205,493	0.4%
Jul	8,169	2,207,608	0.4%
Aug	9,922	2,209,686	0.4%
Sep	10,847	2,211,818	0.5%
Oct	9,735	2,214,221	0.4%
Nov	9,473	2,216,864	0.4%
Dec	9,611	2,219,285	0.4%
Total	140,110	26,477,595	0.5%

G.2.1.9.D - SERVICE APPOINTMENTS RESPONSE TIME

G.2.1.9.D.1 - Appointments Met Within the Designated Time Period (AMWDTP)

Measure Calculations: AMWDTP = Number of appointments met within the 4 hour time on the scheduled date divided by the total number of appointments scheduled in the reporting month.

OEB Approved Standard: Minimum Performance Standard shall be 85% average over a year.

Month	Number of Appointments Met Within the 4-Hour Time on the Scheduled Date (1)	Total Number of Appointments Scheduled in the Reporting Month (2)	Appointments Met Within the Designated Time Period (%) (3=1/2*100)
Jan	2,916	3,104	93.9%
Feb	2,034	2,117	96.1%
Mar	2,300	2,384	96.5%
Apr	2,437	2,554	95.4%
May	3,342	3,514	95.1%
Jun	3,487	3,640	95.8%
Jul	3,451	3,631	95.0%
Aug	3,701	3,867	95.7%
Sep	4,126	4,341	95.0%
Oct	6,001	6,532	91.9%
Nov	4,471	4,748	94.2%
Dec	3,401	3,577	95.1%
Total	41,667	44,009	94.7%

G.2.1.9.D.2 - Time to Reschedule a Missed Appointment (TRMA)
Measure Calculations: TRMA = this measurement tracks the time taken by the utility to contact the consumer to offer to reschedule a missed appointment. This includes appointments for meter-related customer requests or other customer requested work such as installations, meter reads, and reconnections appointments not due to non-payment. At minimum the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment.
OEB Approved Standard: Minimum Performance Standard shall be 100% of affected customers will receive a call from the utility offering to reschedule work within 2 hours of the end of the original appointment time.

Month	Total Number of Customers Appointments Missed (1)	Total Number of Customers Who Did Receive a Call Offering to Reschedule Within 2 Hours of the End of the Original Appointment Time Missed (2)	Brief Explanation of the Reasons Customers Did Not Receive a Call Within the Time Limit (In 50 Words) (3)	Percentage of Customers who Did Receive a Call Divided by the Total Number of Customer Appointments Missed (%) (4=2/1*100)
Jan	165	160	5 calls missed: 5 rescheduled after 2 hour limit without notifying customer	97%
Feb	70	67	3 calls missed: 3 rescheduled after 2 hour limit without notifying customer	95.7%
Mar	59	57	2 calls missed; 2 rescheduled after 2 hour limit without notifying customer	96.6%
Apr	96	95	1 call missed; 1 rescheduled after 2 hour limit without notifying customer	99%

Month	Total Number of Customers Appointments Missed (1)	Total Number of Customers Who Did Receive a Call Offering to Reschedule Within 2 Hours of the End of the Original Appointment Time Missed (2)	Brief Explanation of the Reasons Customers Did Not Receive a Call Within the Time Limit (In 50 Words) (3)	Percentage of Customers who Did Receive a Call Divided by the Total Number of Customer Appointments Missed (%) (4=2/1*100)
May	139	135	4 calls missed; 1 calls arrived later than 2 hours, 3 rescheduled after 2 hour limit without notifying customer	97.1%
Jun	124	123	1 call missed; 1 rescheduled after 2 hour limit without notifying customer	99.2%
Jul	142	141	1 call missed; 1 rescheduled after 2 hour limit without notifying customer	99.3%
Aug	131	130	1 call missed; 1 call arrived later than 2 hours	99.2%
Sep	173	172	1 call missed; 1 rescheduled after 2 hour limit without notifying customer	99.4%
Oct	476	473	3 calls missed: 3 rescheduled after 2 hour limit without notifying customer	99.4%
Nov	254	251	3 calls missed: 1 call arrived later than 2 hours, 2 rescheduled after 2 hour limit without notifying customer	98.8%
Dec	157	156	1 call missed; 1 rescheduled after 2 hour limit without notifying customer	99.4%
Total	1,986	1,960	As noted above.	98.7%

G.2.1.9.E - GAS EMERGENCY RESPONSE

G.2.1.9.E.1 - Percentage of Emergency Calls Responded Within One Hour (ECRWOH)

Measure Calculations: ECRWOH = Number of emergency calls responded to within 60 minutes divided by the total number of emergency calls received.

OEB Approved Standard: Measurement shall be that 90% of customers have received responses within 60 minutes of their call reaching a live person calculated on an annual basis.

Month	Number of Emergency Calls Responded to Within 60 Minutes (1)	Total Number of Emergency Calls Received (2)	Percentage of Emergency Calls Responded Within One Hour (%) (3=1/2*100)
Jan	4,350	4,556	95.5%
Feb	3,258	3,386	96.2%
Mar	3,030	3,106	97.6%
Apr	3,379	3,497	96.6%
May	3,544	3,672	96.5%
Jun	3,139	3,222	97.4%
Jul	3,063	3,160	96.9%
Aug	2,785	2,871	97.0%
Sep	3,289	3,413	96.4%
Oct	4,345	4,476	97.1%
Nov	4,094	4,258	96.1%
Dec	3.393	3,537	95.9%
Total	41,669	43,154	96.6%

G.2.1.9.F - CUSTOMER COMPLAINT WRITTEN RESPONSE

G.2.1.9.F.1 - Number of Days to Provide a Written Response (NDPAWR)

Measure Calculations: NDPAWR = Number of complaints requiring a written response responded to within 10 days divided by the total number of complaints requiring a written response.

OEB Approved Standard: Measurement shall be that 80% of customers have received written responses in 10 days of the distributor receiving the complaint.

Month	Number of Complaints Requiring a Written Response Responded to Within 10 Days (1)	Total Number of Complaints Requiring a Written Response (2)	NDPAWR Percentage (%) (3=1/2*100)
Jan.	0	0	0%
Feb.	0	0	0%
Mar.	3	3	100%
Apr.	2	2	100%
May	0	0	0%
Jun.	1	1	100%
Jul.	2	2	100%
Aug.	1	1	100%
Sept.	1	1	100%
Oct.	0	0	0%
Nov.	0	0	0%
Dec.	0	0	0%
TOTAL	10	10	100%

G.2.1.9.G - RECONNECTION RESPONSE TIME

G.2.1.9.G.1 - Number of Days to Reconnect A Customer (NDTRAC)

Measure Calculations: NDTRAC = Number of reconnections completed within 2 business days divided by the total number of reconnections completed.

OEB Approved Standard: Measurement shall be that 85% of customers are reconnected within 2 business days of bringing their accounts into good standing and will be tracked on a monthly basis.

Month	Number of Reconnections Completed Within 2 Business Days (1)	Total Number of Reconnections Completed (2)	Number of Days to Reconnect a Customer Percentage (%) (3=1/2*100)
Jan	591	639	92.5%
Feb	299	328	91.2%
Mar	367	392	93.6%
Apr	1,607	1,636	98.2%
May	5,803	5,850	99.2%
Jun	3,442	3,500	98.3%
Jul	3,228	3,274	98.6%
Aug	3,521	3,580	98.4%
Sep	3,250	3,333	97.5%
Oct	4,517	4,748	95.1%
Nov	1,791	1,910	93.8%
Dec	621	666	93.2%
Total	29,037	29,856	97.3%

CLEARANCE OF 2018 DEFERRAL AND VARIANCE ACCOUNT BALANCES
EGD RATE ZONE

The Company is proposing to clear 2018 Deferral and Variance Account balances (as well as other balances set out at Appendix A to the Application as shown at Exhibit B, Tab 1, Appendix A, Schedule 1) to customers during the January 2020 billing cycle.

The unit rates for each type of service are shown at Exhibit B, Tab 3, Appendix A, Schedule 1, page 1. For the EGD rate zone these unit rates will be applied to each customer's actual 2018 consumption volume for the period January 1, 2018 to December 31, 2018, and will be recovered or refunded as a one-time billing adjustment during the of January 2020 billing cycle.

Exhibit B, Tab 3, Appendix A, Schedule 1 shows the derivation of the proposed unit rates:

- page 2 determines the balance (principal and interest) to be cleared for each Board-approved 2018 Deferral and Variance Account;
- page 3 allocates account balances to the rate classes based on cost drivers for each type of account;
- page 4 summarizes the allocation of account balances by rate class and type of service; and
- page 5 derives the unit rates for the clearance / disposition by rate class and type of service. The unit rates are derived using actual 2018 consumption volumes for each rate class and each type of service.

The table on page 6 displays the one-time bill adjustment in January 2020 for typical customers resulting from the clearance of the 2018 Deferral and Variance Account balances.[1] These bill adjustments will be shown as a separate line item on customers' bills.

Although, the 2018 Deferral and Variance Accounts balances are allocated to the customer classes using the same methodology that the Board approved for the EGD rate zone in previous years, the Company would like to highlight the proposed clearance methodology for the following two account balances which will be cleared to EGD rate zone customers for the first time as part of this application: 1) Pension & OPEB Forecast Accrual Vs. Actual Cash Payment Differential Variance Account (P&OPEBFAVA), and, 2) Manufactured Gas Plant Deferral Account (MGPDA).

P&OPEBFAVA

In accordance with the Board's EB-2015-0040 report, the purpose of the P&OPEBFAVA is to track the difference between the Company's forecast accrual pension and OPEB amounts recovered in rates versus the actual cash payments made. Interest charges need to be calculated on the account balance when the amount collected in rates exceeds the actual amount paid out by the Company.

For the EGD rate zone, the Company proposes to clear this account balance to all customer classes using / according to the allocated rate base (i.e. the rate base allocator) underpinning the 2018 Fully Allocated Cost Study (EB-2017-0086). While the EGD rate zone does not have a labour (or an O&M) allocator, the proposed clearing methodology recognizes that labour costs (inclusive of labour benefits) are supporting all facets / aspects of the Company's assets in the provision of the gas distribution service to customers. In other words, the three step cost allocation methodology (functionalization, classification and allocation) of labour costs follow the same three

[1] The impacts exclude the proposed clearance of the 2018 Union South Storage and Transportation account to the EGD Rate Zone customers. This balance will be cleared to the EGD Rate Zone customers as part of the 2019 Deferral and Variance Accounts.

step methodology used for allocation of rate base (i.e. the Company's assets). Consequently, the rate base allocator is the most comprehensive representation of how distribution costs, including labour costs, are allocated and recovered from each customer class.

MGPDA

The purpose of the MGPDA is to record all costs incurred in managing and resolving issues related to the EGD rate zone's manufactured gas plant legacy operations.

The Company proposes to clear this account balance to the customer classes using / according to the allocated rate base (i.e., the rate base allocator) underpinning the 2018 Fully Allocated Cost Study (EB-2017-0086).

The proposed clearing methodology recognizes that legacy manufactured gas plants supported the provision of the gas distribution service to customers when they were in operation. The rate base allocator encompasses all facets / aspects of the Company's assets and is the most comprehensive representation of how the costs of providing gas distribution service are allocated and recovered from each customer class.

UNIT RATE AND TYPE OF SERVICE: CLEARING IN JANUARY 2020

		COL.1
		Unit Rate (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	(0.4854)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.4722)
	- DAWN T-SERVICE	(0.4722)
	- WESTERN T-SERVICE	(0.4854)
RATE 6	- SYSTEM SALES	(0.1524)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.1391)
	- DAWN T-SERVICE	(0.1391)
	- WESTERN T-SERVICE	(0.1524)
RATE 9	- SYSTEM SALES	0.0425
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0000
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	(0.0660)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	(0.0527)
	- WESTERN T-SERVICE	(0.0660)
RATE 110	- SYSTEM SALES	0.0189
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0322
	- DAWN T-SERVICE	0.0322
	- WESTERN T-SERVICE	0.0189
RATE 115	- SYSTEM SALES	0.0313
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0445
	- DAWN T-SERVICE	0.0445
	- WESTERN T-SERVICE	0.0313
RATE 135	- SYSTEM SALES	0.0305
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0438
	- DAWN T-SERVICE	0.0438
	- WESTERN T-SERVICE	0.0305
RATE 145	- SYSTEM SALES	0.0023
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0156
	- DAWN T-SERVICE	0.0156
	- WESTERN T-SERVICE	0.0023
RATE 170	- SYSTEM SALES	0.0410
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0543
	- DAWN T-SERVICE	0.0543
	- WESTERN T-SERVICE	0.0410
RATE 200	- SYSTEM SALES	0.0290
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0423
	- DAWN T-SERVICE	0.0423
	- WESTERN T-SERVICE	0.0290
Unbundled Services (Billing based on CD):		
RATE 125	- All	(2.4335)
RATE 300	- All	(11.4952)
RATE 332	- All	(2.3820)

DETERMINATION OF BALANCES TO BE CLEARED
FROM THE 2018 DEFERRAL AND VARIANCE ACCOUNTS

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
1.	TRANSACTIONAL SERVICES D/A	(1,304.7)	(29.5)	(1,334.2)
2.	UNACCOUNTED FOR GAS V/A	5,616.0	116.2	5,732.2
3.	STORAGE AND TRANSPORTATION D/A	1,787.7	109.0	1,896.7
4.	DEFERRED REBATE ACCOUNT	981.7	9.3	991.0
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	2,702.3	89.7	2,792.0
6.	GAS DISTRIBUTION ACCESS RULE D/A 2018	117.1	2.5	119.6
7.	MANUFACTURED GAS PLANT	888.0	78.9	966.9
8.	PENSION & OPEB FORECAST ACCRUAL Vs. ACTUAL CASH PYMP DIFF. V/A		(1.0)	(1.0)
9.	AVERAGE USE TRUE-UP V/A	(18,787.8)	(422.0)	(19,209.8)
10.	POST-RETIREMENT TRUE-UP V/A	256.6	6.0	262.6
11.	2018 CUSTOMER CARE CIS RATE SMOOTHING D/A	(4,901.6)	(105.2)	(5,006.8)
12.	2017 CUSTOMER CARE CIS RATE SMOOTHING D/A	(2,785.3)	(40.8)	(2,826.1)
13.	2016 CUSTOMER CARE CIS RATE SMOOTHING D/A	(779.9)	(11.8)	(791.7)
14.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A	1,124.2	16.7	1,140.9
15.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A	2,927.0	43.1	2,970.1
16.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A	4,634.9	68.3	4,703.2
17.	ELECTRIC PROGRAM EARNINGS SHARING D/A	(1,210.1)	(30.8)	(1,240.9)
18.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8	-	4,435.8
19.	DAWN ACCESS COSTS D/A	1,173.7	26.1	1,199.8
20.	EARNINGS SHARING MECHANISM	(29,950.0)	(643.0)	(30,593.0)
	TOTAL	(33,074.4)	(718.3)	(33,792.7)

Classification and Allocation of Deferral and Variance Account Balances

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)	COL. 11 BUNDLED ANNUAL DELIVERIES ($000)
	CLASSIFICATION											
1.	TRANSACTIONAL SERVICES D/A	(1,334.2)	(1,236.1)			(33.4)	(64.7)					
2.	UNACCOUNTED FOR GAS V/A	5,732.2			5,732.2							
3.	STORAGE AND TRANSPORTATION D/A	1,896.7				645.7	1,251.0					
4.	DEFERRED REBATE ACCOUNT	991.0			991.0							
5.	OEB COST ASSESSMENT VARIANCE ACCOUNT	2,792.0									2,792.0	
6.	GAS DISTRIBUTION ACCESS RULE D/A 2018	119.6								119.6		
7.	PENSION & OPEB FORECAST ACCRUAL Vs. ACTUAL CASH PYMP DIFF. V/A	(1.0)									(1.0)	
8.	MANUFACTURED GAS PLANT	966.9									966.9	
9.	AVERAGE USE TRUE-UP V/A	(19,209.8)							(19,209.8)			
10.	POST-RETIREMENT TRUE-UP V/A	262.6									262.6	
11.	2018 CUSTOMER CARE CIS RATE SMOOTHING D/A	(5,006.8)								(5,006.8)		
12.	2017 CUSTOMER CARE CIS RATE SMOOTHING D/A	(2,826.1)								(2,826.1)		
13.	2016 CUSTOMER CARE CIS RATE SMOOTHING D/A	(791.7)								(791.7)		
14.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A	1,140.9								1,140.9		
15.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A	2,970.1								2,970.1		
16.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A	4,703.2								4,703.2		
17.	GREEN HOUSE GAS EMISSIONS IMPACT D/A	0.0			0.0					0.0		
18.	UNABSORBED DEMAND COST D/A	0.0					0.0					
19.	ELECTRIC PROGRAM EARNINGS SHARING D/A	(1,240.9)									(1,240.9)	
20.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8									4,435.8	
21.	DAWN ACCESS COSTS D/A	1,199.8										1,199.8
22.	CONSTANT DOLLAR NET SALVAGE ADJ. D/A	0.0										
23.	EARNINGS SHARING MECHANISM	(30,593.0)									(30,593.0)	
	TOTAL	(33,792.7)	(1,236.1)	0.0	6,723.2	612.3	1,186.3	0.0	(19,209.8)	309.2	(23,377.6)	1,199.8
	ALLOCATION											
1.1	RATE 1	(25,697.5)	(690.8)	0.0	2,838.2	297.0	651.6	0.0	(14,239.6)	285.5	(15,335.4)	496.1
1.2	RATE 6	(7,844.7)	(496.0)	0.0	2,831.6	285.7	519.6	0.0	(4,970.2)	23.7	(6,543.6)	504.4
1.3	RATE 9	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	RATE 100	(1.3)	(0.2)	0.0	1.1	0.2	0.2	0.0	0.0	0.0	(2.6)	0.0
1.5	RATE 110	252.8	(19.6)	0.0	453.3	14.6	2.8	0.0	0.0	0.0	(280.6)	82.4
1.6	RATE 115	222.3	(0.1)	0.0	267.6	0.0	1.1	0.0	0.0	0.0	(103.0)	56.7
1.7	RATE 125	(225.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(225.4)	0.0
1.8	RATE 135	25.2	(2.3)	0.0	33.6	0.0	0.0	0.0	0.0	0.0	(12.9)	6.7
1.9	RATE 145	5.7	(1.0)	0.0	23.2	1.4	0.0	0.0	0.0	0.0	(23.1)	5.2
1.10	RATE 170	174.4	(3.8)	0.0	175.8	4.4	0.0	0.0	0.0	0.0	(32.3)	30.4
1.11	RATE 200	55.8	(22.2)	0.0	98.8	9.0	11.0	0.0	0.0	0.0	(58.6)	17.7
1.12	RATE 300	(1.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.8)	0.0
1.13	RATE 332	(758.4)							0.0		(758.4)	
1.		(33,792.7)	(1,236.1)	0.0	6,723.2	612.3	1,186.3	0.0	(19,209.8)	309.2	(23,377.6)	1,199.8

ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:												
RATE 1	- SYSTEM SALES	(24,826.6)	(679.9)	0.0	2,740.6	286.8	629.2	0.0	(13,750.0)	275.7	(14,808.1)	479.1
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(148.2)			16.8	1.8	3.9	0.0	(84.4)	1.7	(90.9)	2.9
	- DAWN T-SERVICE	(325.3)			36.9	3.9	8.5	0.0	(185.2)	3.7	(199.5)	6.5
	- WBT	(397.3)	(10.9)		43.9	4.6	10.1	0.0	(220.0)	4.4	(237.0)	7.7
RATE 6	- SYSTEM SALES	(4,890.5)	(426.7)	0.0	1,720.0	173.6	315.6	0.0	(3,019.0)	14.4	(3,974.8)	306.4
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(417.8)			161.0	16.2	29.5	0.0	(282.6)	1.3	(372.0)	28.7
	- DAWN T-SERVICE	(1,742.6)			671.4	67.8	123.2	0.0	(1,178.6)	5.6	(1,551.7)	119.6
	- WBT	(793.8)	(69.3)		279.2	28.2	51.2	0.0	(490.0)	2.3	(645.1)	49.7
RATE 9	- SYSTEM SALES	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	-			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- DAWN T-SERVICE	-			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	-	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	(1.0)	(0.2)	0.0	0.8	0.1	0.1	0.0	0.0	0.0	(1.9)	0.0
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	-			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- DAWN T-SERVICE	(0.3)			0.3	0.0	0.1	0.0	0.0	0.0	(0.7)	0.0
	- WBT	(0.0)	(0.0)		0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0
RATE 110	- SYSTEM SALES	10.7	(7.5)	0.0	30.3	1.0	0.2	0.0	0.0	0.0	(18.7)	5.5
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	25.2			41.9	1.3	0.3	0.0	0.0	0.0	(25.9)	7.6
	- DAWN T-SERVICE	199.7			332.3	10.7	2.0	0.0	0.0	0.0	(205.7)	60.4
	- WBT	17.3	(12.1)		48.9	1.6	0.3	0.0	0.0	0.0	(30.3)	8.9
RATE 115	- SYSTEM SALES	0.1	(0.0)	0.0	0.2	0.0	0.0	0.0	0.0	0.0	(0.1)	0.0
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	107.9			129.8	0.0	0.5	0.0	0.0	0.0	(49.9)	27.5
	- DAWN T-SERVICE	114.1			137.2	0.0	0.6	0.0	0.0	0.0	(52.8)	29.1
	- WBT	0.3	(0.1)		0.4	0.0	0.0	0.0	0.0	0.0	(0.2)	0.1
RATE 135	- SYSTEM SALES	0.6	(0.3)	0.0	1.1	0.0	0.0	0.0	0.0	0.0	(0.4)	0.2
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	2.3			2.9	0.0	0.0	0.0	0.0	0.0	(1.1)	0.6
	- DAWN T-SERVICE	17.6			21.6	0.0	0.0	0.0	0.0	0.0	(8.3)	4.3
	- WBT	4.6	(2.0)		8.0	0.0	0.0	0.0	0.0	0.0	(3.1)	1.6
RATE 145	- SYSTEM SALES	0.1	(0.8)	0.0	3.3	0.2	0.0	0.0	0.0	0.0	(3.3)	0.7
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.6			2.1	0.1	0.0	0.0	0.0	0.0	(2.1)	0.5
	- DAWN T-SERVICE	4.9			16.9	1.0	0.0	0.0	0.0	0.0	(16.8)	3.8
	- WBT	0.0	(0.2)		0.9	0.1	0.0	0.0	0.0	0.0	(0.9)	0.2
RATE 170	- SYSTEM SALES	11.7	(3.8)	0.0	15.3	0.4	0.0	0.0	0.0	0.0	(2.8)	2.6
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	89.0			87.7	2.2	0.0	0.0	0.0	0.0	(16.1)	15.2
	- DAWN T-SERVICE	73.7			72.7	1.8	0.0	0.0	0.0	0.0	(13.4)	12.6
	- WBT	0.1	(0.0)		0.1	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0
RATE 200	- SYSTEM SALES	40.6	(18.6)	0.0	75.0	6.8	8.3	0.0	0.0	(0.0)	(44.4)	13.5
	- BUY/SELL	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	2.6			3.3	0.3	0.4	0.0	0.0	0.0	(1.9)	0.6
	- DAWN T-SERVICE	4.7			6.0	0.5	0.7	0.0	0.0	0.0	(3.6)	1.1
	- WBT	7.9	(3.6)		14.6	1.3	1.6	0.0	0.0	0.0	(8.6)	2.6
Unbundled Services: (Billing based on CD)												
RATE 125		(225.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(225.4)	
RATE 300		(1.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.8)	
RATE 332		(758.4)							0.0		(758.4)	
		(33,792.6)	(1,236.1)	0.0	6,723.2	612.3	1,186.3	0.0	(19,209.7)	309.2	(23,377.6)	1,199.8

UNIT RATE AND TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)
Bundled Services:												
RATE 1	- SYSTEM SALES	(0.4854)	(0.0133)	0.0000	0.0536	0.0056	0.0123	0.0000	(0.2689)	0.0054	(0.2896)	0.0094
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.4722)	0.0000	0.0000	0.0536	0.0056	0.0123	0.0000	(0.2689)	0.0054	(0.2896)	0.0094
	- DAWN T-SERVICE	(0.4722)	0.0000	0.0000	0.0536	0.0056	0.0123	0.0000	(0.2689)	0.0054	(0.2896)	0.0094
	- WESTERN T-SERVICE	(0.4854)	(0.0133)	0.0000	0.0536	0.0056	0.0123	0.0000	(0.2689)	0.0054	(0.2896)	0.0094
RATE 6	- SYSTEM SALES	(0.1524)	(0.0133)	0.0000	0.0536	0.0054	0.0098	0.0000	(0.0941)	0.0004	(0.1238)	0.0095
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.1391)	0.0000	0.0000	0.0536	0.0054	0.0098	0.0000	(0.0941)	0.0004	(0.1238)	0.0095
	- DAWN T-SERVICE	(0.1391)	0.0000	0.0000	0.0536	0.0054	0.0098	0.0000	(0.0941)	0.0004	(0.1238)	0.0095
	- WESTERN T-SERVICE	(0.1524)	(0.0133)	0.0000	0.0536	0.0054	0.0098	0.0000	(0.0941)	0.0004	(0.1238)	0.0095
RATE 9	- SYSTEM SALES	0.0425	(0.0133)	0.0000	0.0536	0.0000	0.0000	0.0000	0.0000	0.0022	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	(0.0660)	(0.0133)	0.0000	0.0536	0.0077	0.0098	0.0000	0.0000	0.0000	(0.1238)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- DAWN T-SERVICE	(0.0527)	0.0000	0.0000	0.0536	0.0077	0.0098	0.0000	0.0000	0.0000	(0.1238)	0.0000
	- WESTERN T-SERVICE	(0.0660)	(0.0133)	0.0000	0.0536	0.0077	0.0098	0.0000	0.0000	0.0000	(0.1238)	0.0000
RATE 110	- SYSTEM SALES	0.0189	(0.0133)	0.0000	0.0536	0.0017	0.0003	0.0000	0.0000	0.0000	(0.0332)	0.0097
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0322	0.0000	0.0000	0.0536	0.0017	0.0003	0.0000	0.0000	0.0000	(0.0332)	0.0097
	- DAWN T-SERVICE	0.0322	0.0000	0.0000	0.0536	0.0017	0.0003	0.0000	0.0000	0.0000	(0.0332)	0.0097
	- WESTERN T-SERVICE	0.0189	(0.0133)	0.0000	0.0536	0.0017	0.0003	0.0000	0.0000	0.0000	(0.0332)	0.0097
RATE 115	- SYSTEM SALES	0.0313	(0.0133)	0.0000	0.0536	0.0000	0.0002	0.0000	0.0000	0.0000	(0.0206)	0.0114
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0445	0.0000	0.0000	0.0536	0.0000	0.0002	0.0000	0.0000	0.0000	(0.0206)	0.0114
	- DAWN T-SERVICE	0.0445	0.0000	0.0000	0.0536	0.0000	0.0002	0.0000	0.0000	0.0000	(0.0206)	0.0114
	- WESTERN T-SERVICE	0.0313	(0.0133)	0.0000	0.0536	0.0000	0.0002	0.0000	0.0000	0.0000	(0.0206)	0.0114
RATE 135	- SYSTEM SALES	0.0305	(0.0133)	0.0000	0.0536	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0206)	0.0108
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0438	0.0000	0.0000	0.0536	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0206)	0.0108
	- DAWN T-SERVICE	0.0438	0.0000	0.0000	0.0536	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0206)	0.0108
	- WESTERN T-SERVICE	0.0305	(0.0133)	0.0000	0.0536	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0206)	0.0108
RATE 145	- SYSTEM SALES	0.0023	(0.0133)	0.0000	0.0536	0.0032	0.0000	0.0000	0.0000	0.0000	(0.0533)	0.0121
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0156	0.0000	0.0000	0.0536	0.0032	0.0000	0.0000	0.0000	0.0000	(0.0533)	0.0121
	- DAWN T-SERVICE	0.0156	0.0000	0.0000	0.0536	0.0032	0.0000	0.0000	0.0000	0.0000	(0.0533)	0.0121
	- WESTERN T-SERVICE	0.0023	(0.0133)	0.0000	0.0536	0.0032	0.0000	0.0000	0.0000	0.0000	(0.0533)	0.0121
RATE 170	- SYSTEM SALES	0.0410	(0.0133)	0.0000	0.0536	0.0013	0.0000	0.0000	0.0000	0.0000	(0.0099)	0.0093
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0543	0.0000	0.0000	0.0536	0.0013	0.0000	0.0000	0.0000	0.0000	(0.0099)	0.0093
	- DAWN T-SERVICE	0.0543	0.0000	0.0000	0.0536	0.0013	0.0000	0.0000	0.0000	0.0000	(0.0099)	0.0093
	- WESTERN T-SERVICE	0.0410	(0.0133)	0.0000	0.0536	0.0013	0.0000	0.0000	0.0000	0.0000	(0.0099)	0.0093
RATE 200	- SYSTEM SALES	0.0290	(0.0133)	0.0000	0.0536	0.0049	0.0060	0.0000	0.0000	(0.0000)	(0.0318)	0.0096
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0423	0.0000	0.0000	0.0536	0.0049	0.0060	0.0000	0.0000	0.0000	(0.0318)	0.0096
	- DAWN T-SERVICE	0.0423	0.0000	0.0000	0.0536	0.0049	0.0060	0.0000	0.0000	0.0000	(0.0318)	0.0096
	- WESTERN T-SERVICE	0.0290	(0.0133)	0.0000	0.0536	0.0049	0.0060	0.0000	0.0000	0.0000	(0.0318)	0.0096
Unbundled Services (Billing based on CD, ¢/m3):												
RATE 125	- All	(2.4335)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(2.4335)	0.0000
	- Customer-specific **											
RATE 300	- All	(11.4952)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(11.4952)	0.0000
	- Customer-specific **											
RATE 332	- All	(2.3820)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(2.3820)	0.0000

Notes:

* Unit Rates derived based on 2018 actual volumes

EGD Rate Zone
2018 Deferral and Variance Account Clearing
Bill Adjustment in January 2020 for Typical Customers

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
			Unit Rates				Bill Adjustment			
		Annual Volume	Sales	Ontario TS	Dawn TS	Western TS	Sales Customers	Ontario TS Customers	Dawn TS Customers	Western TS Customers
	GENERAL SERVICE	m3	cents/m3	cents/m3	cents/m4	cents/m3	$	$	$	$
1.1	**RATE 1 RESIDENTIAL**									
1.2	Heating & Water Heating	2,400	(0.4854)	(0.4722)	(0.4722)	(0.4854)	(11.7)	(11.3)	(11.3)	(11.7)
2.1	**RATE 6 COMMERCIAL**									
2.2	General Use	43,285	(0.1524)	(0.1391)	(0.1391)	(0.1524)	(66.0)	(60.2)	(60.2)	(66.0)
	CONTRACT SERVICE									
3.1	**RATE 100**									
3.2	Industrial - small size	339,188	(0.0660)	0.0000	(0.0527)	(0.0660)	(223.9)	-	(178.8)	(223.9)
4.1	**RATE 110**									
4.2	Industrial - small size, 50% LF	598,568	0.0189	0.0322	0.0322	0.0189	113.2	192.8	192.8	113.2
4.3	Industrial - avg. size, 75% LF	9,976,121	0.0189	0.0322	0.0322	0.0189	1,887.3	3,213.6	3,213.6	1,887.3
5.1	**RATE 115**									
5.2	Industrial - small size, 80% LF	4,471,609	0.0313	0.0445	0.0445	0.0313	1,397.5	1,992.0	1,992.0	1,397.5
6.1	**RATE 135**									
6.2	Industrial - Seasonal Firm	598,567	0.0305	0.0438	0.0438	0.0305	182.5	262.0	262.0	182.5
7.1	**RATE 145**									
7.2	Commercial - avg. size	598,568	0.0023	0.0156	0.0156	0.0023	14.0	93.6	93.6	14.0
8.1	**RATE 170**									
8.2	Industrial - avg. size, 75% LF	9,976,121	0.0410	0.0543	0.0543	0.0410	4,094.4	5,421.7	5,421.7	4,094.4

Notes:
Col. 7 = Col. 2 x Col. 3
Col. 8 = Col. 2 x Col. 4
Col. 9 = Col. 2 x Col. 5
Col. 10 = Col. 2 x Col. 6

2018 DEFERRAL AND VARIANCE ACCOUNT BALANCES
REQUESTED FOR CLEARANCE JANUARY 1, 2020
UNION RATE ZONES

Enbridge Gas has classified the Union rate zone deferral and variance accounts approved by the Ontario Energy Board ("OEB" or "Board") for use in 2018 into three groups:

a) Gas Supply accounts;
b) Storage accounts; and,
c) Other accounts.

The net balance in the above deferral and variance accounts results in a $38.335 million credit to ratepayers. This total includes account balances and interest calculated in accordance with Board-approved accounting orders as at December 31, 2018 and includes interest accrued to December 31, 2019. Interest on account balances has been calculated using the Board's prescribed interest rates for deferral and variance accounts as follows[1]:

Time Period	Interest Rate
January - March 2018	1.50%
April - June 2018	1.89%
July - September 2018	1.89%
October - December 2018	2.17%
January - March 2019	2.45%
April - June 2019	2.18%
July - September 2019	2.18%
October - December 2019 (forecast)	2.18%

Exhibit C, Tab 1, Appendix A, Schedule 1 provides a summary of the deferral account balances.

[1] https://www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates

ACCOUNT NO. 179-107 SPOT GAS VARIANCE ACCOUNT

There is no balance in the Spot Gas Variance Account at December 31, 2018. The account was created in accordance with the Board's Decision in the RP-2003-0063 proceeding to record the difference between the unit cost of spot gas purchased each month and the unit cost of gas included in the gas sales rates as approved by the Board on the spot volumes purchased in excess of planned purchases.

ACCOUNT NO. 179-108 UNABSORBED DEMAND COSTS ("UDC") VARIANCE ACCOUNT

The balance in the UDC Variance Account is a credit to ratepayers of $9.712 million plus interest of $0.321 million, for a total of $10.033 million. The $9.712 million account balance is the difference between the actual UDC incurred by Union rate zones and the amount of UDC collected in rates. The balance in the UDC Variance Account is not prospectively recovered or refunded as part of the approved QRAM. It has therefore been included in this submission.

UDC Recovery in Rates

To meet customer demands of the Union rate zones and to meet the planned storage inventory levels at October 31, approved rates for the Union rate zones in 2018 included planned unutilized pipeline capacity of 11.3 PJ in Union North West, 3.1 PJ in Union North East and 0.0 PJ in Union South. The UDC volumes included in rates are based on the Gas Supply Plan filed in Union's Dawn Reference Price proceeding[2] and included in Union's 2018 Rates proceeding.[3]

As discussed in the 2017/18 Gas Supply Plan Memorandum in Union's 2018 Rates proceeding[4], the upstream transportation capacity for Union North (long-haul, short-haul and STS) is first sized to meet the design day requirements. The amount of transportation capacity needed to meet average annual demand requirements is less than the capacity required to meet design day requirements. Therefore, a portion of contracted capacity for Union North is planned to be unutilized. In a warmer than normal year, UDC may be incurred in Union South, and additional UDC in Union North, to balance supply with lower demands. Union North and Union South transportation

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[2] EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.
[3] EB-2017-0087, Rate Order, Working Papers, Schedule 23, pp. 3 and 4.
[4] EB-2017-0087, Exhibit A, Tab 3.

portfolios are managed on an integrated basis and the decision as to which pipeline to leave unutilized, if necessary, is determined based on the least cost option.

Union collected $13.721 million in rates for UDC during 2018 and recorded an associated interest credit of $0.321 million (see Table 1). Actual UDC costs in 2018 were $7.748 million offset by $3.739 million in released capacity value, resulting in a net cost of $4.009 million (see Table 2).

The variance between the amounts collected in rates and the actual UDC costs, including the interest credit of $0.321 million, results in a net credit to ratepayers in the UDC Variance Account of $10.033 million.

The balance of $10.033 million is allocated to Union North West, Union North East and Union South in proportion to the actual excess supply and UDC costs incurred for each respective area. The balance applicable to sales service and bundled Direct Purchase ("DP") customers in Union North West is a credit of $8.132 million and in Union North East, a credit of $1.901 million. There is a $0 balance applicable to sales service customers in Union South.

Table 1 provides the derivation of the UDC variance account balances by operations area.

Table 1
UDC Variance Account by Rate Zone

Line No.	Particulars ($000's)	Union North West	Union North East	Union South	Total Union Rate Zones
1	UDC Collected in Rates	(11,573)	(2,148)	-	(13,721)
2	UDC Costs Incurred (Table 2)	3,701	308	-	4,009
3	Variance (line 1 + line 2)	(7,872)	(1,840)	-	(9,712)
4	Interest	(260)	(61)	-	(321)
5	(Credit)/Debit to Operations Area	(8,132)	(1,901)	-	(10,033)

A description of each item follows:

UDC Collected in Rates

2018 Board-approved rates include $12.967 million of UDC associated with 14.4 PJ of planned unutilized pipeline capacity in Union North West and Union North East and no planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TransCanada final tolls effective January 1, 2018. On an actual basis in 2018, Union recovered $13.721 million in Union North West and Union North East (due to higher throughput than forecast primarily in March, April and November of 2018) and $0.0 million in Union South.

UDC Costs Incurred

The actual unutilized capacity in 2018 was 7.3 PJ. The level of unutilized capacity experienced in 2018 was due to planned unutilized capacity (and resulting UDC), offset, in part, by higher consumption relative to plan resulting in a reduction in planned UDC.

The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $7.748 million, offset, in part, by the value of $3.739 million generated from releasing the pipeline transportation capacity to the market. Unutilized upstream transportation capacity is released and sold on the secondary market to minimize UDC. The value generated from the transportation releases is credited to the UDC Variance Account mitigating the overall UDC impact as shown in Table 2 below.

Table 2
UDC Costs Incurred

Line No.	Particulars ($000's)	Union North West	Union North East	Union South	Total Union Rate Zones
1	UDC Costs Incurred	7,152	596	-	7,748
2	Released Capacity Revenue	(3,451)	(288)	-	(3,739)
3	Net UDC Costs (Credit)/Debit	3,701	308	-	4,009

ACCOUNT NO. 179-131 UPSTREAM TRANSPORTATION OPTIMIZATION

The Upstream Transportation Optimization Deferral Account was approved by the Board in its EB-2011-0210 Decision to capture the variance between 90% of the net revenues from optimization activities and the amount refunded to ratepayers in rates. The balance in this deferral account is a debit from ratepayers of $10.273 million plus interest of $0.231 million for a total debit from ratepayers of $10.503 million.

In setting rates for 2018, the Board approved a forecast of optimization revenue of $14.918 million.[5] Of that amount, 90% or $13.426 million, was credited to ratepayers in the Board-approved 2018 rates.[6] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $16.839 million in rates to ratepayers during 2018, $3.413 million greater than the Board-approved amount of $13.426 million. The credit is due to actual sales service volumes exceeding the forecast sales service volumes in rates.[7] The main driver of actual sales service volumes exceeding the forecasted amount is customer growth since 2013.

The Company earned $7.296 million in net revenues from upstream transportation optimization during 2018 in the Union rate zones. In accordance with the Board-approved sharing methodology, 90% of this net revenue, or $6.567 million, is to be credited to customers. As stated above, $16.839 million has already been credited through rates; therefore, the deferral balance is a debit from ratepayers of $10.273 million ($16.839 million less $6.567 million).

[5] EB-2018-0087, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[6] EB-2018-0087, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[7] EB-2011-0210, Decision and Rate Order, January 17, 2013, p. 16.

Exhibit C, Tab 1, Appendix A, Schedule 2, provides a summary of the calculation of the balance in this deferral account. 2018 actual Upstream Transportation Optimization revenue in the Union rate zones is lower than 2013 Board-approved revenue due to:

1) The elimination of the TransCanada FT-RAM program ($5.800 million);
2) Changing market dynamics as evidenced by an increase in firm contracting on the TransCanada Mainline to major export points such as East Hereford and Iroquois, and the reversal of Niagara from an export point to an import point; and,
3) 2018 weather in traditional delivery areas was between 2 - 4% warmer compared to what was experienced in 2013 when the Board-approved revenue was determined, resulting in less demand and lower prices for exchange transactions compared to 2013 Board-approved levels.

ACCOUNT NO. 179-70 SHORT-TERM STORAGE AND OTHER BALANCING SERVICES

The Short-Term Storage and Other Balancing Services Deferral Account includes revenues from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services and C1 Short-Term Firm Peak Storage. The net revenue for Short-Term Storage and Other Balancing Services is determined by deducting the costs incurred to provide service from the gross revenue. The balance in this deferral account is a debit from ratepayers of $1.413 million, plus interest of $0.032 million for a total debit from ratepayers of $1.445 million.

As shown in Table 3, the balance is calculated by comparing $3.138 million (90% of the actual 2018 Short-Term Storage and Other Balancing Services net revenue of $3.487 million) to the net revenue included in rates of $4.551 million.[8] The details of the balance are found at Exhibit C, Tab 1, Appendix A, Schedule 3.

Table 3

Deferral Summary: Short-term Storage and Other Storage Services

Line No.	Particulars ($000's)	Actual 2018
1	Net Revenue	3,487
2	Ratepayer Portion (90%)	3,138
3	Approved in Rates	4,551
4	Deferral Balance Payable to/(Collectable from) Ratepayers	(1,413)

Actual 2018 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $1.739 million were $0.761 million lower than the 2013 Board-approved forecast of $2.500 million.

[8] EB-2011-0210, Decision and Rate Order, January 17, 2013, p. 16.

The C1 Short-Term Firm Peak Storage revenues of $5.011 million were $2.872 million lower than the 2013 Board-approved forecast of $7.883 million. Actual utility storage requirements for 2018 were 3.7 PJ higher than the 2013 Board-approved forecast, resulting in a decrease in the C1 Short-Term Firm Peak Storage available for sale (from 11.3 PJ in 2013 Board-approved to 7.6 PJ in 2018). Union's customers received the value of storage directly through the use of the storage space, rather than through the sale of short-term storage.

Year-over-year, actual utility storage requirements for 2018 were 0.8 PJ lower than the requirement in 2017, resulting in an increase in the C1 Short-Term Peak Storage available for sale (from 6.8 PJ in 2017 to 7.6 PJ in 2018). This is a result of a decrease in the storage requirement for the contract market. The storage requirement for the general service market was calculated using the Board-approved aggregate excess methodology. The storage requirement for the contract market was calculated specifically for each customer using either the Board-approved aggregate excess methodology, the 15 times obligated Daily Contracted Quantity ("DCQ") storage methodology, or the 10 times Firm Contract Demand ("CD") storage methodology (for those customers who have elected the Customer Managed Service).[9]

The 2013 Board-approved forecast implied an annual average value for C1 Short-Term Firm Peak Storage of $0.70/GJ ($7.883 million/11.3 PJ), and the actual average annual C1 Short-Term Firm Peak Storage value in 2018 was $0.66/GJ ($5.011 million/7.6 PJ). Please see Figure 1 for Short-Term Peak Storage values in US dollars.

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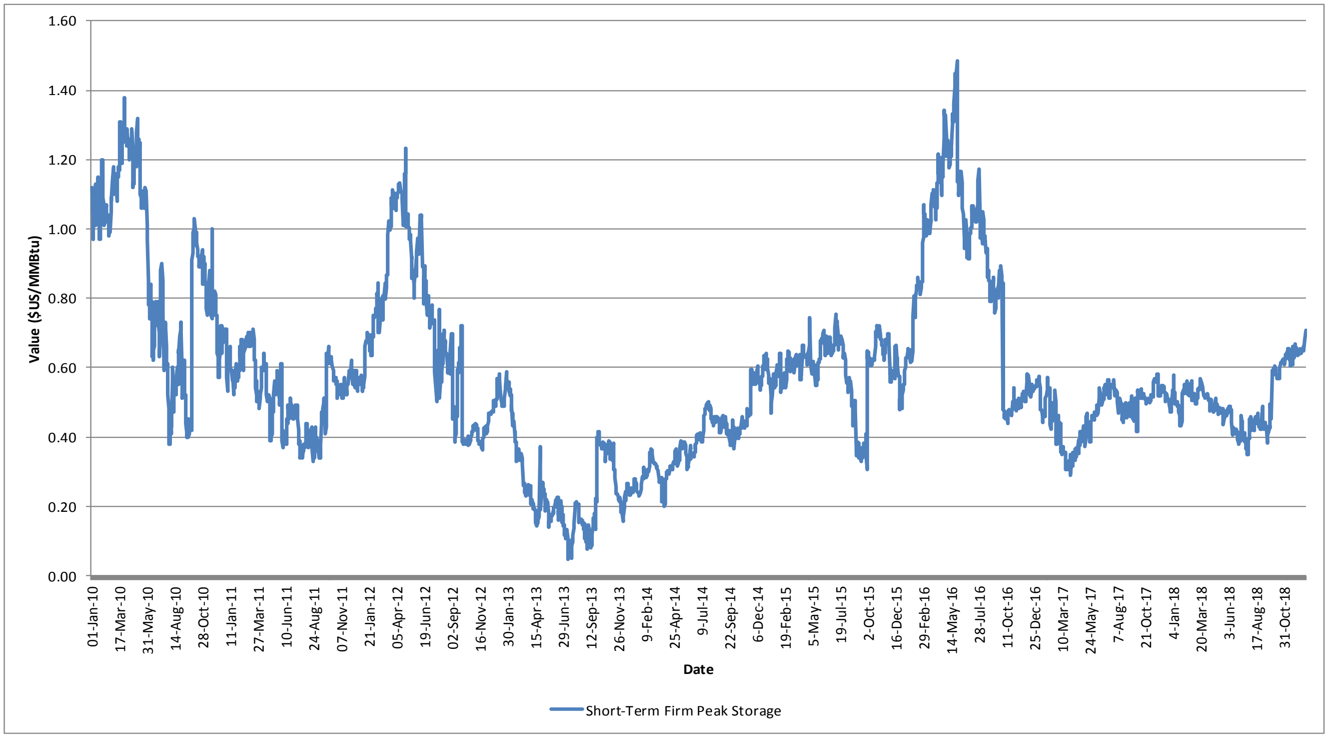
[9] EB-2016-0245, Decision and Rate Order, Schedule 1, Settlement Proposal, p.7.

Figure 1
Historical Short-Term Firm Peak Storage Values at Dawn 2010-2018



Non-Utility Storage Balances for 2018

In its EB-2011-0210 Decision, the Board directed Union to file a report similar to that ordered in EB-2011-0038 to monitor the inventory related to non-utility storage operations. Exhibit C, Tab 1, Appendix A, Schedule 4 shows the non-utility inventory balances for October and November of 2018.

During the 2018 injection season, the non-utility storage balance peaked on October 16, 2018 at 88% full with a balance of 98.1 PJ compared to available space of 111.8 PJ. At October 31, 2018, the date to which Union manages its storage balance, the non-utility balance was 86% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2018.

In EB-2011-0210, the Board further ordered Union to file a calculation for a storage encroachment payment from Union's non-utility business to Union's utility business, if Union's non-utility business encroached on Union's utility space. There was no encroachment of utility space in 2018 and therefore no calculation applies.

Sale of Non-Utility Storage Space

Union prioritizes the sale of its utility storage ahead of the sale of its short-term non-utility storage and allocates short-term peak storage margins between utility and non-utility as directed by the Board in EB-2011-0210.[10] Margins from short-term peak storage services are proportionately split between the utility and non-utility customers based on the utility and non-utility share of the total quantity of short-term peak storage sold each calendar year. Short-term peak sales include any sale of storage space for a term of less than two years.

In 2018, Union sold a total of 7.6 PJ of short-term peak storage. The total 7.6 PJ was excess utility space, calculated by deducting 92.4 PJ of in-franchise utility requirement (as per Union's Gas Supply Plan) from the total 100 PJ of in-franchise utility storage. There was no sale of short-term peak storage from non-utility space.

Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2018 was $5.011 million.

Details of the above sales are reflected in Exhibit C, Tab 1, Appendix A, Schedule 5.

[10] EB-2011-0210, Decision and Order, pp. 116-117.

ACCOUNT NO. 179-103 UNBUNDLED SERVICES UNAUTHORIZED STORAGE OVERRUN

There is no balance in the Unbundled Services Unauthorized Storage Overrun Deferral Account at December 31, 2018. The account was created in accordance with the Board's Decision in the RP-1999-0017 proceeding to record any unauthorized storage overrun charges incurred by customers electing unbundled service. No unauthorized storage overrun charges were incurred by customers electing unbundled service.

ACCOUNT NO. 179-112 GAS DISTRIBUTION ACCESS RULE (“GDAR”) COSTS

There is no balance in the Gas Distribution Access Rules (“GDAR”) Costs Deferral Account at December 31, 2018. The account was created to record the difference between the actual costs required to implement the appropriate process and system changes to achieve compliance with GDAR and the costs included in rates as approved by the Board. There were no system changes as a result of GDAR in 2018.

ACCOUNT NO. 179-120 INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS") CONVERSION COSTS

There is no balance in the International Financial Reporting Standards ("IFRS") Conversion Cost Deferral Account at December 31, 2018. The account was created in accordance with the Board's Decision in the EB-2010-0039 proceeding to record the costs associated with upgrading Union's accounting system in order to report results under IFRS. There were no costs associated with IFRS in 2018. Additionally, the Board approved the closure of this account in its MAADs Decision, effective December 31, 2018[11].

[11] EB-2017-0306/EB-2017-0307, Decision and Order, August 30, 2018, p. 57.

ACCOUNT NO. 179-123 CONSERVATION DEMAND MANAGEMENT (“CDM”)

In its EB-2010-0055 Decision and Order, which granted approval for Union’s 2011 Demand Side Management (“DSM”) Plan, the Board ordered a deferral account be established to track revenues associated with CDM activities, to be shared 50/50 between the Company and ratepayers. The Board approved the accounting order for the CDM Deferral Account in Union’s 2011 Rates application (EB-2010-0148). The balance in this deferral account is a credit to ratepayers of $1.054 million plus interest of $0.031 million for a total credit to ratepayers of $1.085 million.

This balance represents 50% of the net revenue from the “Whole Home Pilot Delivery” between Union and the Independent Electric Systems Operators (“IESO”) for 2018. The Minister of Energy issued a direction to the IESO dated June 10, 2016 clarifying the direction to the IESO in its Conservation First Framework Directive to coordinate and integrate the CDM Programs with that of the Gas Distributors by requiring the IESO to: (a) design and fund a province-wide whole home pilot program for residential consumers (“Pilot”); (b) deliver the Pilot in coordination with the Gas Distributors; and (c) commence implementation of the Pilot by the end of the Fall of 2016. Union and the IESO entered into an agreement in May 2017 to be responsive to the June 2016 Direction, to further the province’s conservation objectives, and provide a mechanism for electrically heated homes to participate in home energy conservation initiatives. The Whole Home Pilot enrollment ended on September 30, 2018. Participants who completed a pre-assessment by this date were eligible for the rebates available through the Pilot upon completion of the home retrofit offering process.

ACCOUNT NO. 179-132 DEFERRAL CLEARING VARIANCE ACCOUNT

In its EB-2014-0145 Decision, the Board approved the Deferral Clearing Variance Account to capture the differences between the forecast and actual volumes associated with the disposition of deferral account balances. The intent of the deferral account is to minimize or eliminate the gains or losses to ratepayers and the Company as a result of volume variances associated with the disposition of deferral account balances.

The balance in this deferral account is a credit to ratepayers of $1.736 million plus interest of $0.060 million, for a total credit to ratepayers of $1.795 million. The $1.736 million balance represents an over-recovery of $1.675 million for the Board-approved deferral account balances in EB-2017-0091 (Union's 2016 Deferral Account Disposition). Also included in the balance is a credit to ratepayers of $0.061 million due to rebills related to the above disposition. Please see Exhibit C, Tab 1, Appendix A, Schedule 6, Page 1 for a summary of the deferral account balance.

Union's 2016 Deferral Account Disposition (EB-2017-0091)

In its EB-2017-0091 Decision, the Board approved the prospective disposition of the total balances in the approved deferral accounts to rate classes through a temporary rate adjustment from October 1, 2017 to March 31, 2018. The total amount approved for prospective recovery from rate classes was $41.449 million. Please see Exhibit C, Tab 1, Appendix A, Schedule 6, page 2, Column (e), for the forecast amount to be recovered by rate class, based on the forecasted volumes as noted at Exhibit C, Tab 1, Appendix A, Schedule 6, Page 2, Column (a).

Actual volumes for the period October 1, 2017 to March 31, 2018 averaged approximately 5% greater than forecast due to colder weather in the same period. As a result of the actual volumes being greater than the forecasted volumes, the Company recovered $43.124 million, which is $1.675 million more than the final deferral account balances approved for disposition in EB-2017-0091. Please see Exhibit C, Tab 1, Appendix A, Schedule 6, Page 2, Column (f) for the actual disposition of deferral accounts and Exhibit C, Tab 1, Appendix A, Schedule 6, Page 2, Column (g) for the variance between forecast and actual disposition.

ACCOUNT NO. 179-133 NORMALIZED AVERAGE CONSUMPTION ("NAC")

The purpose of the NAC deferral account is to record the variance in delivery revenue and storage revenue and costs resulting from the difference between the target NAC included in Board-approved rates and the actual NAC for general service rate classes Rate M1, Rate M2, Rate 01 and Rate 10. As described in Union's 2014 Deferral Account Disposition proceeding (EB-2015-0010), including the revenue from storage rates in the NAC deferral account requires storage-related costs associated with the difference in target and actual NAC to also be included in the deferral account balance.

For 2018, the balance in the NAC deferral account is a credit to ratepayers of $20.322 million plus interest of $0.660 million for a total credit to ratepayers of $20.983 million.

The NAC Deferral Account follows the same methodology agreed to by parties in Union's 2014-2018 Incentive Regulation ("IR") Settlement Agreement (EB-2013-0202) and as subsequently modified in Union's 2015 Rates proceeding (EB-2014-0271).

Target and Actual NAC

The 2018 target NAC for each rate class was approved by the Board in Union's 2018 Rates proceeding (EB-2017-0087). The 2016 actual NAC, weather normalized using the 2018 weather normal, was used to determine the 2018 target NAC. Setting the 2018 target NAC based on the 2016 actual NAC recognizes that over the two year span to the current year, any volumes saved and lost revenues due to DSM activities will be captured by the variance between the target and actual consumption. This is due to the inclusion of the DSM saved volumes within the actual reported consumption.

The 2018 actual NAC for each rate class is weather normalized using the 2018 weather normal, which is based on the Board-approved 50:50 blended weather methodology that incorporates both the 30-year average and 20-year declining trend estimates of annual heating degree-days.

Table 4 provides the 2018 target and 2018 actual NAC by rate class.

Table 4
2018 Target and Actual NAC (m^3/customer)

Line No.	Particulars	Rate 01	Rate 10	Rate M1	Rate M2	Total
		(a)	(b)	(c)	(d)	(e)
1	2018 Target NAC	2,771	158,894	2,654	159,319	323,639
2	2018 Actual NAC	2,864	167,467	2,810	171,248	344,389
3	Change in NAC (Target - Actual NAC)	(92)	(8,573)	(156)	(11,929)	(20,750)

Delivery and Storage Revenues

The deferral account balance is calculated by multiplying the variance between the weather normalized target NAC and the weather normalized actual NAC by the 2013 Board-approved number of customers and the 2018 Board-approved delivery and storage rates for each general service rate class. A credit balance in the NAC Deferral Account reflects that the actual NAC is greater than the target NAC, while a debit balance in the NAC Deferral Account reflects that the actual NAC is less than the target NAC.

Table 5 provides the NAC Deferral Account balances by rate class. More details are set out in Exhibit C, Tab 1, Appendix A, Schedule 7.

Table 5
2018 NAC Deferral Account

Line No.	Particulars ($000s)	Rate 01	Rate 10	Rate M1	Rate M2	Total
		(a)	(b)	(c)	(d)	(e)
1	Delivery Revenue Balances	(2,650)	(1,024)	(7,612)	(3,823)	(15,109)
2	Storage Revenue Balances	(1,583)	(704)	(1,213)	(527)	(4,027)
3	Storage Cost Balances	(178)	(4)	8	(1,012)	(1,186)
4	Interest	(2,250)	227	(309)	1,672	(660)
5	Total NAC Deferral Balance	(6,661)	(1,505)	(9,127)	(3,690)	(20,983)

Storage Costs

The storage costs recognize that variances between the 2018 target NAC and the 2013 Board-approved NAC volumes change the storage requirements for each general service rate class. As Board-approved storage rates are not updated during the IR term to reflect changes in storage requirements due to NAC variances, the Company must capture the NAC-related change in storage costs in the NAC Deferral Account for the Union rate zones as per the Board's Decision in Union's 2013 Deferrals Disposition proceeding (EB-2014-0145), p. 9, *"starting in 2014, the NAC Deferral Account, which replaces the Average Use Per Customer Deferral Account, will include storage related revenues and costs for general service rate classes."*

To determine the change in storage requirements for each general service rate class due to NAC variances, the Company calculated the NAC volume variance per customer between its 2018/2019 Gas Supply Plan and the 2013 Board-approved volumes multiplied by the 2013 Board-approved number of customers.

Using the Board-approved aggregate excess methodology, the Company calculated the change in storage requirements for each of the general service rate classes due to variances in NAC. The 2018/2019 Gas Supply Plan volumes represent the April 1, 2018 to March 31, 2019 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2018. These general service rate class storage requirements are then used in the calculation of the total in-franchise utility storage space requirement at November 1, 2018. The difference between the total in-franchise utility storage requirement and the total 100 PJ of utility storage represents the excess utility storage capacity available for sale ("excess utility space") at November 1, 2018.

For Rate M1, the NAC volume variance between the 2018/2019 Gas Supply Plan and the 2013 Board-approved volumes was a decrease of 4.848 PJ. The majority of the NAC volume variance decrease occurred in the summer months, which increased the Rate M1 storage requirement by 0.013 PJ. This resulted in increased storage costs of $0.008 million (Table 5, Line 3).

For Rate M2, the NAC volume variance between the 2018/2019 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 6.602 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.647 PJ and resulted in decreased storage costs of $1.012 million (Table 5, Line 3).

For Rate 01, the NAC volume variance between the 2018/2019 Gas Supply Plan and the 2013 Board-approved volumes was a decrease of 0.338 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate 01 storage requirement by 0.233 PJ and decreased storage costs by $0.178 million (Table 5, Line 3).

For Rate 10, the NAC volume variance between the 2018/2019 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 1.599 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the

Rate 10 storage requirement by 0.005 PJ and resulted in decreased storage costs of $0.004 million (Table 5, Line 3).

Overall, the NAC volume variance between the 2018/2019 Gas Supply Plan and the 2013 Board-approved volumes resulted in a decrease in general service storage requirements of 1.873 PJ. Accordingly, the Company has included a storage cost credit of $1.186 million in the NAC Deferral Account. Please see Table 6 below for a summary of the change in general service storage requirements due to NAC volume variances by rate class.

Table 6
Change in General Service Storage Requirements from 2013 Board-approved
(Based on weather normalized NAC)

Union South	(PJ)	Union North	(PJ)
Rate M1	0.01	Rate 01	(0.23)
Rate M2	(1.65)	Rate 10	(0.00)
Total South	(1.63)	Total North	(0.24)

The reduction in storage activity has decreased storage deliverability costs, the commodity-related costs at Dawn and storage inventory carrying costs.

The 1.873 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 7.6 PJ of excess utility space available for sale for winter 2018/2019. The revenue from the sale of the 7.6 PJ of excess utility space is recorded in the Short-Term Storage and Other Balancing Deferral Account (Account No. 179-70).

Deferral Account Impacts

The detailed calculation of the NAC Deferral Account balance can be found at Exhibit C, Tab 1, Appendix A, Schedule 7.

For Rate M1, actual NAC is higher than target NAC by 156 m^3/customer (Table 4, Line 3). As shown in Table 5 above, this results in a delivery and storage revenue credit of $8.825 million ($7.612 million and $1.213 million respectively). In addition, the NAC volume variance increases the Rate M1 storage requirement by 0.013 PJ. Accordingly, the Company must collect an additional $0.008 million (Table 5, Line 3) from Rate M1 customers to recognize the increase in Rate M1 storage requirements.

For Rate M2, actual NAC is higher than target NAC by 11,929 m^3/customer (Table 4, Line 3). As shown in Table 5 above, this results in a delivery and storage revenue credit of $4.350 million ($3.823 million and $0.527 million respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.647 PJ. Accordingly, the Company must refund $1.012 million (Table 5, Line 3) to Rate M2 customers to recognize the decrease in Rate M2 storage requirements.

For Rate 01, actual NAC is higher than target NAC by 92 m^3/customer (Table 4, Line 3). As shown in Table 5 above, this results in a delivery and storage revenue charge of $4.233 million ($2.650 million and $1.583 million respectively). In addition, the NAC volume variance decreased the Rate 01 storage requirement by 0.233 PJ. Accordingly, the Company must refund an additional $0.178 million (Table 5, Line 3) to Rate 01 customers to recognize the decrease in Rate 01 storage requirements.

For Rate 10, actual NAC is higher than target NAC by 8,573 m^3/customer (Table 4, Line 2). As shown in Table 5 above, this results in a delivery and storage revenue charge of $1.728 million ($1.024 million and $0.704 million respectively). In addition, the NAC volume variance decreases the Rate 10 storage requirement by 0.005 PJ. Accordingly, the Company must refund $0.004 million (Table 5, Line 3) to Rate 10 customers to recognize the decrease in Rate 10 storage requirements.

ACCOUNT NO. 179-134 TAX VARIANCE DEFERRAL ACCOUNT

The balance in this deferral account is a credit to ratepayers of $1.354 million plus interest of $0.022 million, for a total of $1.376 million. The establishment of the Tax Variance Deferral Account was approved through the 2014-2018 Incentive Regulation Settlement Agreement (EB-2013-0202). The purpose of this account is to record 50% of the variance in costs resulting from the difference between the actual tax rates and the approved tax rates included in rates as approved by the Board. For 2018, there is a credit balance of $0.940 million related to the impact of the enactment of Bill C-97 which contains accelerated Capital Cost Allowance ("CCA") measures, and a credit balance of $0.413 million related to Harmonized Sales Tax changes discussed below.

Income Tax - Bill C-97 (Accelerated CCA)

Within the determination of 2018 utility results, and corresponding deferral and variance accounts sought for disposition as part of this proceeding, Enbridge Gas has reflected the impact of the enactment of accelerated CCA measures contained within Bill C-97, which received Royal Assent on June 21, 2019. Bill C-97 includes the following measures, with regards to the first year allowance, which accelerate CCA for capital investments:

- A 50% increase in the available CCA deduction in respect of property (for most asset classes) acquired after November 20, 2018 that becomes available for use before 2028, subject to a phase-out for property that becomes available for use after 2023.
- The suspension of the existing CCA half-year rule in respect of property acquired after November 20, 2018 that becomes available for use before 2028.

Enbridge Gas has recorded 50% of the income tax reduction (or earnings impact) of accelerated CCA, grossed-up for taxes, in the Union rate zones Tax Variance Deferral Account (exclusive of impacts related to capital pass-through projects which are subject to their own variance account treatment).

To calculate the 2018 income tax (or earnings) impact of the accelerated CCA, Enbridge Gas took total capital additions which qualified for accelerated CCA and backed out additions related to the capital pass-through projects. For the remaining additions, CCA was calculated utilizing the accelerated measures and compared against CCA calculated at the regular rate. The income tax (or earnings) impact of the variance between the two methodologies was then calculated, and subsequently grossed-up for taxes to determine the revenue requirement impact. Finally, 50% of the revenue requirement impact was recorded in the Union rate zones Tax Variance Deferral Account. The accelerated CCA impact related to capital pass-through projects was fully reflected in the determination of the variances recorded in the respective capital pass-through project deferral accounts. Please see Exhibit C, Tab 1, Appendix A, Schedule 8 for the calculation of the accelerated CCA impact in the Tax Variance Deferral Account.

Harmonized Sales Tax ("HST")

On July 1, 2010, HST came into effect in Ontario, combining provincial and federal taxes. On July 1, 2015, the input tax credit ("ITC") recapture for compressor fuel costs, and certain Operations and Maintenance ("O&M") and capital costs, was reduced as follows:

- 100% for the period from July 1, 2010 to June 30, 2015;
- 75% for the period from July 1, 2015 to June 30, 2016;
- 50% for the period from July 1, 2016 to June 30, 2017;
- 25% for the period from July 1, 2017 to June 30, 2018; and,

- 0% on or after July 1, 2018.

Enbridge Gas has recorded 50% of the annual incremental savings in the Union rate zones Tax Variance Deferral Account since the HST Deferral Account used for the 2010 implementation was closed.

To calculate the 2018 Tax Variance Deferral Account balance related to HST changes, transactions from January 1, 2018 to December 31, 2018 were reviewed for:

a) Capital and O&M purchases that are subject to the ITC recapture reduction including specified meals and entertainment costs, specified road vehicles and related fuel costs, specified energy costs, and specified telecommunications costs; and,
b) Compressor fuel costs.

The calculation of the 2018 balance is provided in Table 7.

Table 7
50% of 2018 Net Savings from the Impact of HST Changes to be Shared with Ratepayers

Line No.	Particulars	($ millions)
1	Capital Savings	0.024
2	O&M Savings	0.383
3	Compressor Fuel Savings	0.006
4	Tax Variance Deferral Account Balance	$0.413

Within the Board's MAADs and Rate Setting Decision, the Board approved ceasing the recording of HST related impacts commencing in 2019, but expanded the applicability of the Tax Variance Deferral Account to all of Enbridge Gas Inc. (i.e. both the EGD and Union rate zones).

ACCOUNT NO. 179-135 UNACCOUNTED FOR GAS ("UFG") VOLUME VARIANCE ACCOUNT

The balance in the UFG Volume Variance Account is a debit from ratepayers of $1.733 million, plus interest of $0.050 million, for a total debit from ratepayers of $1.783 million.

The establishment of the UFG Volume Variance Account was approved by the Board as part of the 2014-2018 Incentive Regulation Settlement Agreement (EB-2013-0202). The purpose of this account is to capture the difference between the unit cost of UFG recovered in the rates approved by the Board and actual UFG costs incurred, in excess of $5.0 million. 2018 Board-approved rates included $8.329 million in UFG costs for the Union rate zones. Based on 2018 actual volumes, the Company recovered $9.249 million in UFG costs for 2018. In comparison, actual 2018 UFG costs were $15.983 million.

Accordingly, the difference between the UFG costs recovered in rates of $8.329 million and actual UFG expense of $15.983 million is $7.653 million. The difference of $7.653 million is above the $5.0 million threshold established by the Board for the UFG Volume Variance Account. As a result, the UFG Volume Variance Account balance is a debit of $1.733 million from ratepayers. See Table 8 below.

Table 8
2018 UFG Variances from Board-approved

Line No.	Particulars ($ millions)	2018 Actual	Recovered in 2018 Rates	Variance
1	Net Utility UFG	15.983	8.329	(7.653)
2	Recovery Variance (1)			(0.920)
3	Total Utility UFG Variance (2)			(6.733)
4	$5M UFG Variance Account Threshold			5.000
5	UFG Volume Variance			(1.733)

Notes:
(1) Board-approved throughput was 32,010 10^6m^3 versus actual throughput of 35,978 10^6m^3.
(2) Board-approved UFG % is 0.219% versus actual UFG % of 0.379% for 2018. Subject to deferral account when in excess of +/- $5 million versus Board-approved.

ACCOUNT NO. 179-136 PARKWAY WEST PROJECT COSTS

In its Parkway West Project (EB-2012-0433) Decision, the Board approved the establishment of the Parkway West Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Parkway West Project and the revenue requirement included in rates.

The balance in this deferral account is a credit to ratepayers of $0.020 million less interest of $0.009 million for a total credit balance of $0.011 million. The balance of $0.020 million includes a debit of $0.133 million which represents the difference between the costs of $17.737 million included in 2018 rates (EB-2017-0087) and the calculation of the actual revenue requirement for 2018 of $17.870 million as shown in Table 9.

The remaining $0.153 million credit represents a true-up regarding property taxes between the 2016 revenue requirement of $15.045 million included in the Union Gas Limited 2016 Deferrals Disposition and Earnings Sharing Mechanism proceeding (EB-2017-0091) and the actual 2016 revenue requirement of $14.892 million. This true-up is due to the assessment authority not reclassifying the land from Farm to Commercial.

Table 9
2018 Parkway West Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	1,092	1,092
2	Cumulative Capital Expenditures	219,430	231,693	12,263
3	Average Investment	203,254	213,974	10,720
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	1,683	1,320	(363)
5	Depreciation Expense (1)	5,105	5,479	374
6	Property Taxes	532	572	40
7	Total Operating Expenses	7,320	7,372	52
8	Required Return (2)	11,737	12,111	374
9	Total Operating Expense and Return	19,057	19,483	426
	Income Taxes:			
10	Income Taxes - Equity Return (3)	2,352	2,480	128
11	Income Taxes - Utility Timing Differences (4)	(3,672)	(4,093)	(421)
12	Total Income Taxes	(1,320)	(1,613)	(293)
13	Total Revenue Requirement	17,737	17,870	133

Notes:

(1) Depreciation expense at 2013 Board-approved depreciation rates.

(2) equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:
$213.974 million * 64% * 3.82% = $5.231 million plus
$213.974 million * 36% * 8.93% = $6.880 million for a total of $12.111 million.

(3) Taxes related to the equity component of the return at a tax rate of 26.5%.

(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Capital Expenditures

The actual 2018 capital expenditures on in-service assets are $1.092 million higher than 2018 Board-approved as shown in Table 10.

Table 10
Parkway West Capital Expenditures

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
1	Plant Infrastructure	-	96	96
2	LCU Compressor	-	996	996
3	Total Capital Expenditures	-	1,092	1,092

Plant infrastructure costs were $0.096 million higher than costs included in 2018 Board-approved rates due to continuing resolution of the heritage homes. Resolution has been ongoing and is now forecasted for completion in 2019 pending approval by the municipality.

Loss of Critical Unit (“LCU”) compressor costs were $0.996 million higher than 2018 Board-approved rates due mainly to resolution of site deficiencies.

Average Investment

The average investment increase of $10.720 million from Board-approved is due to capital expenditures being $12.263 million higher than Board-approved on a cumulative basis.

Operating Expenses

Operating and maintenance expenses were $0.363 million below those costs included in the 2018 Board-approved rates. The decrease is a result of a Long Term Service Agreement that the Company elected not to enter into, the costs of which were included in 2018 Board-approved rates. After reviewing the life cycle value of the Long Term Service Agreement versus the install and ongoing subscription costs, the Company determined that the product offering would not achieve the desired return on investment.

The increase in depreciation expense of $0.374 million relates to the higher average investment than included in 2018 Board-approved rates.

Required Return

The increase in the required return of $0.374 million is the result of an increase in the average investment, partially offset by a decrease in the long term debt rate used in the calculation. The Board approved required return calculation was derived using a capital structure of 64% long-term debt at 4% and 36% equity at the Board-approved rate of return of 8.93%. The 2018 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.82% and 36% equity at the Board-approved rate of return of 8.93%.

Income Taxes

The Company’s actual tax rate for 2018 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.128 million increase in “Income Taxes-Equity Return” relates to an increase in the tax impact of the equity component of the required return resulting from an increase in average investment.

The $0.421 million decrease in "Income Taxes-Timing Differences" relates to a higher Capital Cost Allowance due to higher actual capital expenditures than included in 2018 Board-approved rates and the enactment of Bill C-97 accelerated CCA.

Project-To-Date Capital Costs

In addition to reviewing the capital spending and variance explanations for calendar year 2018 related to the deferral balance calculations for this project, Table 11 below is included for additional reference only. The table summarizes capital spending for this project-to-date as at December 31, 2018 which exceeds the Board-approved forecast by $12.263 million. Project-to-date information is also provided in the Brantford-Kirkwall/Parkway D Project Deferral Account (No. 179-137) written evidence below, along with the combined total for the two 2015 Dawn Parkway projects. Providing the combined capital spend is reflective of the management of the projects, given the two compressors were constructed together on the same new compressor station site. Overall, the capital spending for the combined projects at the end of 2018 is $5.590 million or less than 1.3% over the original estimates.

Table 11
Parkway West Project-To-Date Capital Costs
($000s)

Line No.	Year	Board-approved	Actual (as filed)	Variance
1	2014	73,978	80,929	6,951
2	2015	144,652	131,930	(12,722)
3	2016	800	15,142	14,342
4	2017	-	2,600	2,600
5	2018	-	1,092	1,092
6	Total	219,430	231,693	12,263
	Brantford-Kirkwall/Parkway D (179-137)			
7	Total	204,076	197,403	(6,673)
	Combined 2015 Dawn Parkway Projects			
8	Total	423,506	429,096	5,590

The Project-to-Date costs for the Parkway West project are higher than the Board-approved amount mainly due to contract and miscellaneous labour necessary to prepare the vacant land for the constructed facilities, as well as the permitting required at the site, and additional clean up and commissioning work. Additional details can be found in 2016 Deferrals (EB-2017-0091, Exhibit A, Tab 1, page 36). As noted above, 2018 capital spending is related to resolution of site deficiencies and continuing resolution of the heritage homes. Overall, the increased costs were largely mitigated by underspending on the Parkway D portion of the Brantford-Kirkwall/Parkway D project, resulting in overall costs for the combined projects varying less than 1.3% from approved costs.

ACCOUNT NO. 179-137 BRANTFORD-KIRKWALL/PARKWAY D PROJECT COSTS

In its Brantford-Kirkwall/Parkway D (EB-2013-0074) Decision, the Board approved the establishment of the Brantford-Kirkwall/Parkway D Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Brantford-Kirkwall/Parkway D Project and the revenue requirement included in rates.

The balance in this deferral account is a credit to ratepayers of $0.824 million plus interest of $0.029 million for a total credit to ratepayers of $0.853 million. The balance of $0.824 million represents the difference between the $15.902 million of costs included in 2018 rates (EB-2017-0087) and the calculation of the actual revenue requirement for 2018 of $15.078 million as shown in Table 12.

Table 12
2018 Brantford-Kirkwall Pipeline/Parkway D Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	-	-
2	Cumulative Capital Expenditures	204,076	197,404	(6,672)
3	Average Investment	188,206	182,727	(5,479)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses (1)	642	621	(21)
5	Depreciation Expense (2)	5,329	4,995	(334)
6	Property Taxes (3)	853	939	86
7	Total Operating Expenses	6,824	6,555	(269)
8	Required Return (4)	10,868	10,342	(526)
9	Total Operating Expense and Return	17,693	16,898	(795)
	Income Taxes:			
10	Income Taxes - Equity Return (5)	2,178	2,118	(60)
11	Income Taxes - Utility Timing Differences (6)	(3,969)	(3,938)	31
12	Total Income Taxes	(1,791)	(1,820)	(29)
13	Total Revenue Requirement (7)	15,902	15,078	(824)

Notes:

(1) 2018 Board-approved O&M expenses include $0.012 million for pipeline related O&M and $0.630 million of annual Compressor maintenance.

(2) Depreciation expense at 2013 Board-approved depreciation rates.

(3) 2018 Board-approved property taxes include $0.187 million for compression and $0.665 million for pipeline and building taxes.

(4) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:
$182.727 million * 64% * 3.82% = $4.467 million plus
$182.727 million * 36% * 8.93% = $5.875 million for a total of $10.342 million.

(5) Taxes related to the equity component of the return at a tax rate of 26.5%.

(6) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

(7) As per EB-2013-0074 Schedule 10-1 Line 9.

Capital Expenditures

There were no capital expenditures related to Brantford-Kirkwall/Parkway D Project Costs in 2018.

Average Investment

The average investment decrease of $5.479 million from Board-approved is due to capital expenditures being $6.672 million lower than Board-approved on a cumulative basis.

Operating Expenses

The decrease in depreciation expense of $0.334 million relates to the average investment being $5.479 million lower than Board-approved.

Required Return

The decrease in the required return of $0.526 million is the result of a decrease in the average rate base investment from the Board-approved $188.206 million to $182.727 million, as well as a decrease in the long-term debt rate used in the calculation. The Board-approved required return calculation was derived using a capital structure of 64% long-term debt at 4% and 36% equity at the Board-approved rate of return of 8.93%. The 2018 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.82%, and 36% equity at the Board-approved rate of return of 8.93%.

Project-To-Date Capital Costs

Table 13 is provided for additional reference only. The table summarizes capital spending for this project-to-date as at December 31, 2018 which is lower than the forecast by $6.673 million. No further capital spending is expected. Similar information is also provided in the Parkway West Project Deferral Account (No. 179-136) written evidence above, along with the combined total for the two 2015 Dawn Parkway projects.

Providing the combined capital spend is reflective of the management of the projects, given the two compressors were constructed together on the same new compressor station site. Overall, the capital spending for the combined projects at the end of 2018 is $5.590 million or less than 1.3% over the original estimates.

Table 13
Brantford-Kirkwall/Parkway D Project-To-Date Capital Costs
($000s)

Line No.	Year	Board-approved	Actual (as filed)	Variance
1	2015	200,069	188,042	(12,027)
2	2016	4,007	8,986	4,979
3	2017	-	375	375
4	2018	-	-	-
5	Total	204,076	197,403	(6,673)
	Parkway West Project (179-136)			
6	Total	219,430	231,693	12,263
	Combined 2015 Dawn Parkway Projects			
7	Total	423,506	429,096	5,590

The Project-to-Date costs for this project are lower than the Board-approved amount due to contingencies not being required for the Parkway D compressor portion of the project, which more than offsets higher actual costs of the Brantford-Kirkwall pipeline portion of the project. Additional details can be found in 2016 Deferrals Disposition and Earnings Sharing Mechanism evidence (EB-2017-0091, Exhibit A, Tab 1, pages 43-44).

ACCOUNT NO. 179-138 PARKWAY OBLIGATION RATE VARIANCE

The balance in this deferral account is a debit from ratepayers of $0.288 million, plus interest of $0.005 million for a total debit to ratepayers of $0.293 million. In Union's 2014 Rates Settlement Agreement (EB-2013-0365), parties agreed to permanently shift the Union South DP Parkway Delivery Obligation ("PDO") to Dawn over time and agreed to the payment of a Parkway Delivery Commitment Incentive ("PDCI") for any continuing obligated Daily Contract Quantity ("DCQ") deliveries at Parkway beginning November 1, 2016. As part of the PDO Settlement Framework, parties agreed to record rate variances associated with the timing differences between the effective date of the PDO and PDCI changes and the inclusion of the cost impacts in approved rates in the Parkway Obligation Rate Variance Deferral Account.

Effective November 1, 2018, Halton Hills Generating Station ("HHGS") elected to convert to standard Rate T2 service and turn back its remaining M12 capacity of 70 TJ/day, as provided for in the PDO Settlement Framework. Upon conversion to standard Rate T2 service, the PDO Settlement Framework also provided for an increase to the HHGS Billing Contract Demand ("BCD") to equal its Contract Demand of 132 TJ/day (3,480,000 m^3/day).

Enbridge Gas adjusted rates effective January 1, 2019 to reflect the PDO shift to Dawn by HHGS of 70 TJ/d which was partially offset by the incremental revenue credit associated with the increased HHGS Rate T2 demand charges. To account for the actual effective date of November 1, 2018, Enbridge Gas is proposing to recover $0.288 million from ratepayers for the November 1, 2018 to December 31, 2018 period. The $0.288 million includes $0.521 million of Dawn Parkway demand costs associated with the 70 TJ/day of M12 turnback partially offset by a credit of $0.233 million for the increase in the HHGS Rate T2 demand charge revenue. Exhibit C, Tab 1, Appendix A, Schedule 9 provides the calculation of the Parkway Obligation Rate Variance deferral account balance. The calculation of the deferral account balance is consistent with the 2014 Rates PDO Settlement Framework.

ACCOUNT NO. 179-141 UFG PRICE VARIANCE ACCOUNT

In accordance with the Board's Decision in EB-2015-0010, the UFG Price Variance Account captures the variance between the average monthly price of the Company's purchases for Union rate zones and the applicable Board-approved reference price, applied to the Company's actual UFG volumes for the Union rate zones. For 2018, the balance in the UFG Price Variance Account is a debit from ratepayers of $2.028 million plus interest of $0.063 million for a total debit of $2.091 million.

During 2018, the Company purchased 58,674 10^3m^3 of gas supply related to actual UFG volumes on behalf of ratepayers in the Union rate zones. The actual UFG purchases exclude the actual UFG collected from ratepayers who provide UFG in kind as part of customer supplied fuel ("CSF").

The actual cost of the UFG purchases in 2018 is $34.56/$10^3m^3$ higher than the Board-approved reference prices included in rates, which results in a $2.028 million balance to be collected from ratepayers, as shown in Table 14 below.

Table 14
Calculation of 2018 UFG Price Variance

Line. No.		UFG Volumes (10^3m^3)
1	Experienced UFG (1)	121,984
2	UFG Collected through CSF	63,309
3	UFG Volumes – Utility Supplied (2)	58,674
		Deferral Calculation
4	UFG Volumes – Utility Supplied (10^3m^3) (2)	58,674
5	Price Variance ($/$10^3m^3$) (3)	($34.56)
6	Variance Account Balance ($ millions)	($2.028)

Notes:
(1) Converted using the following heat values (38.95 Jan-Mar) (38.89 Apr-Dec).
(2) UFG Volumes represent gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of CSF.
(3) Price variance represents weighted average cost, relative to Board-approved reference prices.

ACCOUNT NO. 179-142 LOBO C COMPRESSOR/HAMILTON-MILTON PIPELINE PROJECT COSTS

In its Dawn Parkway 2016 Expansion (EB-2014-0261) Decision, the Board approved the establishment of the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Lobo C Compressor/Hamilton-Milton Pipeline Project and the revenue requirement included in rates.

The balance in the Lobo C Compressor/Hamilton-Milton Pipeline Deferral Account is a credit to ratepayers of $5.836 million plus interest of $0.176 million for a total of $6.012 million. The credit of $5.836 million represents the difference between the $30.251 million of costs included in 2018 rates (EB-2017-0087) and the calculation of the actual revenue requirement for 2018 of $24.415 million as shown in Table 15.

Table 15
2018 Lobo C Compressor/Hamilton-Milton Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	2,464	2,464
2	Cumulative Capital Expenditures	390,715	347,824	(42,891)
3	Average Investment	372,457	329,689	(42,768)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	1,150	951	(199)
5	Depreciation Expense (1)	9,261	8,255	(1,006)
6	Property Taxes	1,172	1,096	(76)
7	Total Operating Expenses	11,583	10,302	(1,281)
8	Required Return (2)	22,462	17,704	(4,758)
9	Total Operating Expense and Return	34,045	28,006	(6,039)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	4,097	3,827	(270)
11	Income Taxes - Utility Timing Differences (4)	(7,892)	(7,418)	474
12	Total Income Taxes	(3,795)	(3,591)	204
13	Total Revenue Requirement	30,251	24,415	(5,836)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The 2018 required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is
$329.689 million * 64% * 3.36% = $7.090 million plus
$329.689 million * 36% * 8.93% = $10.615 million for a total of $17.704 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Capital Expenditures

The actual 2018 capital expenditures on in-service assets were $2.464 million higher than 2018 Board-approved as shown in Table 16.

Table 16
Lobo C Compressor/Hamilton-Milton Pipeline Capital Expenditures

Line No.	Particulars ($000's)	2018 Board-Approved	2018 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Lobo C Compressor			
1	Land	-	-	-
2	Structures	-	738	738
3	Pipelines	-	763	763
4	Compressor Equipment	-	(2,304)	(2,304)
	Hamilton-Milton Pipeline			
5	Land Rights	-	300	300
6	Structures and Improvements	-	1,282	1,282
7	Mains	-	1,685	1,685
8	Total Capital Expenditures	-	2,464	2,464

Lobo C structures and pipelines costs were $1.501 million higher than the costs included in 2018 Board-approved rates because the final infrastructure clean-up work had to be delayed until 2018 due to Lobo D construction.

Compressor Equipment costs were $2.304 million lower than the costs included in 2018 Board-approved rates as a result of the accrual allocation and the difference between the accrued and the actual invoiced amounts.

Land Rights for Hamilton-Milton Pipeline were $0.300 million higher due to land expropriation settlement.

Structures and Improvements for Hamilton-Milton Pipeline were $1.282 million higher due to late installation of RTU (Remote Telemetry Unit) facility at the Bronte Gate Station.

The cost of NPS 48 Pipelines for Hamilton-Milton Pipeline was $1.685 higher due to post-construction remediation work as well as restoration commitments to meet environmental and permitting conditions.

Average Investment

The average investment decrease of $42.768 million from Board-approved is due to cumulative capital expenditures being $42.891 million lower than Board-approved.

Operating Expenses

Operating and maintenance expenses were $0.199 million lower than the costs included in 2018 Board-approved rates. The decrease is a result of a lower level of maintenance required than what was assumed in 2018 Board-approved rates.

The decrease in depreciation expense of $1.006 million relates to the lower average investment as compared to 2018 Board-approved rates.

Required Return

The decrease in the required return of $4.758 million is the result of the decrease in the average rate base investment, as well as a decrease in the long-term debt rate used in the calculation. The Board-approved required return calculation was derived using a capital structure of 64% long-term debt at 4.4% and 36% equity at the Board-approved rate of return of 8.93%. The 2018 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.36%, and 36% equity at the Board-approved rate of return of 8.93%.

Income Taxes

The Company’s actual tax rate for 2018 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.270 million decrease in “Income Taxes-Equity Return” relates to a decrease in the tax impact of the equity component of the required return resulting from a decrease in average investment.

The $0.474 million increase in “Income Taxes-Utility Timing Differences” relates to a lower Capital Cost Allowance deduction due to the lower average investment in 2018 versus Board-approved and partially offset by the enactment of Bill C-97 accelerated CCA.

ACCOUNT NO. 179-143 UNAUTHORIZED OVERRUN NON-COMPLIANCE ACCOUNT

In Union's 2016 Rates Decision and Order (EB-2015-0116), the Board ordered the Company to establish the Unauthorized Overrun Non-Compliance Account to record any unauthorized overrun non-compliance charges incurred by interruptible distribution customers for not complying with a distribution interruption. The balance in this deferral account is a credit to ratepayers of $0.005 million.

The charge was intentionally set to provide customers with the appropriate price signal to comply with distribution service interruptions in the Union rate zones.[12]

[12] EB-2015-0116, Application and Evidence, Exhibit A, Tab 1, pp.14-17.

ACCOUNT NO. 179-144 LOBO D/BRIGHT C/DAWN H COMPRESSOR PROJECT COSTS

In its EB-2015-0116 Decision, the Board approved the establishment of the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Lobo D/Bright C/Dawn H Compressor Project and the revenue requirement included in rates.

The balance in this deferral account is a credit balance of $7.236 million plus interest of $0.213 million, for a total credit balance of $7.449 million. The balance of $7.236 million includes a credit of $6.319 million which represents the difference between the $42.639 million of costs included in 2018 rates (EB-2017-0087) and the calculation of the actual revenue requirement for 2018 of $36.320 million as shown in Table 17.

The remaining $0.917 million credit relates to the 2018 revenue generated through the sale of surplus Dawn Parkway system capacity of 30,393 GJ/day associated with the Lobo D/ Bright C/Dawn H Compressor Project. Consistent with the 2017 Deferrals Decision (EB-2018-0105), the 2018 revenue credit considers the sale of both short-term and long-term surplus capacity. The short-term revenue calculation is based on a proportional allocation of short-term transportation revenues, which the Board noted is a reasonable way to ensure ratepayers receive an offset to rates due the integrated nature of the Union system[13]. By November 2018, the surplus capacity has been deemed to be sold long-term and the revenue credit for November and December 2018 is calculated based on the 2018 approved Dawn-Parkway demand rate of $3.716 GJ/m (30,393 GJ/d x 2 x $3.716 GJ/m).

[13] EB-2018-0105 Decision and Order, p.10.

In addition to the 2018 balance, Enbridge Gas is also seeking approval of the final disposition of the 2017 revenue recorded in the Lobo D/ Bright C/ Dawn H Compressor Project Costs Deferral Account (179-144), which was approved on an interim basis as part of the 2017 Deferrals proceeding (EB-2018-0105). In its Rate Order Decision, the OEB agreed that the scope of any subsequent review shall be limited to the short-term transportation revenue and rate class allocations. The OEB also ordered Union to file evidence supporting the proportional allocation of 2017 short-term transportation revenue to the account and rate class allocations in the 2018 Deferral Account Disposition proceeding.[14] In accordance with this Decision, the Company has provided schedules to support the 2018 revenue calculation of $0.917 million and the 2017 revenue calculation of $0.216 million at Exhibit C, Tab 1, Appendix A, Schedule 10. The 2017 revenue calculation is consistent with the schedule filed in Union's EB-2018-0105, Draft Rate Order dated November 29, 2018, Working Papers, Schedule 3. The evidence supporting the rate class allocation of the 2017 and 2018 revenue credit is provided at Exhibit C, Tab 3.

[14] EB-2018-0105, Rate Order Decision dated December 6, 2018, p. 3.

Table 17
2018 Dawn H/Lobo D/Bright C Compressor Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	14,267	39,542	25,275
2	Cumulative Capital Expenditures	622,505	613,839	(8,666)
3	Average Investment	592,525	572,697	(19,828)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	3,623	2,035	(1,588)
5	Depreciation Expense (1)	19,416	16,035	(3,381)
6	Property Taxes	1,051	1,075	24
7	Total Operating Expenses	24,091	19,145	(4,946)
8	Required Return (2)	34,217	30,467	(3,750)
9	Total Operating Expense and Return	58,308	49,612	(8,696)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	6,510	6,637	127
11	Income Taxes - Utility Timing Differences (4)	(22,179)	(19,930)	2,249
12	Total Income Taxes	(15,669)	(13,292)	2,377
13	Total Revenue Requirement	42,639	36,320	(6,319)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.29% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as
$572.697 million * 64% * 3.29% = $12.059 million plus
$572.697 million * 36% * 8.93% = $18.409 million for a total of $30.467 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Capital Expenditures

The actual 2018 capital expenditures on in-service assets were $25.275 million higher than 2018 Board-approved as shown in Table 18.

Table 18
Dawn H/Lobo D/Bright C Compressor Capital Expenditures

Line No.	Particulars ($000's)	2018 Board-Approved	2018 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Dawn H			
1	Land	-	510	510
2	Structures	-	2,486	2,486
3	Compressor Equipment	5,661	9,969	4,308
4	Salvage	-	6,583	6,583
	Bright C			
5	Land	-	1,493	1,493
6	Structures	-	483	483
7	Compressor Equipment	4,314	7,805	3,491
	Lobo D			
8	Land	-	-	-
9	Structures	-	1,126	1,126
10	Compressor Equipment	4,292	9,087	4,795
11	Total Capital Expenditures	14,267	39,542	25,275

Dawn H lands costs were $0.510 million higher than costs included in 2018 Board-approved rates due to the additional purchase of land to create defined buffers around the compressor station.

Dawn H structures costs were $2.486 million higher due to final infrastructure cleanup not completed in 2017.

Dawn H compressor equipment costs were $4.308 million higher due to final compression cleanup not completed in 2017.

Dawn H salvage costs were $6.583 million higher because approximately $5.0 million of these costs were categorized in the 2018 Board-approved rates as plant abandonment within compressor equipment rather than salvage. The remaining increase was attributable to increased construction, material, and internal labour/expenses costs.

Bright C land costs were $1.493 million higher than the costs included in 2018 Board-approved rates due to the additional purchase of land to create defined buffers around the compressor stations.

Bright C structures costs were $0.483 million higher than the costs included in 2018 Board-approved rates due to site road infrastructure clean-up work not completed in 2017.

Bright C compressor costs were $3.491 million higher than the costs included in 2018 Board-approved rates due to additional yard piping work not completed in 2017.

Lobo D structures costs were $1.126 million higher than the costs included in the 2018 Board-approved rates due to site road drainage infrastructure clean-up work not completed in 2017.

Lobo D compressor equipment costs were $4.795 million higher due to additional compressor deficiency and yard piping work not completed in 2017.

Average Investment

The average investment decrease of $19.828 million from 2018 Board-approved is due to delays in the project's in-service timing of capital additions, as well as the cumulative capital expenditures being $8.666 million lower than 2018 Board-approved.

Operating Expenses

Operating and maintenance expenses were $1.588 million lower than the costs included in 2018 Board-approved rates. The decrease is primarily due to salaries and employee related costs associated with 10 fewer employees than what was included in Board-approved rates.

The $3.381 million depreciation expense decrease is due lower depreciable plant balances resulting from delays in the project's in-service timing of capital additions, as well as to the impact of cumulative capital expenditures being $8.666 million lower than Board-approved.

Required Return

The decrease in the required return of $3.750 million is the result of the decrease in the average rate base investment, as well as a decrease in the long-term rate used in the calculation.

The Board-approved required return calculation was derived using a capital structure of 64% long-term debt at 4% and 36% equity at the Board-approved return of 8.93%. The 2018 actual required return calculation was derived using a capital structure of 64% long term debt at 3.29% and 36% common equity at the Board-approved return of 8.93%.

Income Taxes

The Company's actual tax rate for 2018 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.127 million "Income Taxes – Equity Return" increase is due to an increase in the income tax rate. The 2018 Board-approved rates assume a tax rate of 25.5% compared to the income tax rate of 26.5% used in the calculation of 2018 actual income taxes on the equity return.

The $2.249 million increase in "Income Taxes – Utility Timing Difference" relates to a lower Capital Cost Allowance deduction due to the lower average investment in 2018 versus Board-approved as well as the increase in the income tax rate used in the calculation versus Board-approved, partially offset by a $0.248 million increase in Capital Cost Allowance deduction related to enactment of Bill C-97 accelerated CCA.

ACCOUNT NO. 179-149 BURLINGTON OAKVILLE PROJECT COSTS

In its EB-2015-0116 Decision, the Board approved the establishment of the Burlington Oakville Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Burlington Oakville Pipeline Project and the revenue requirement included in rates.

The balance in this deferral account is a credit to ratepayers of $3.361 million plus interest of $0.101 million for a total balance of $3.462 million. The $3.361 million represents the difference between the $8.531 million in costs included in 2018 rates (EB-2017-0087) and the calculation of the actual revenue requirement for 2018 of $5.170 million as shown in Table 19.

Table 19
Burlington Oakville Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	1,455	1,455
2	Cumulative Capital Expenditures	119,477	83,303	(36,174)
3	Average Investment	114,697	79,289	(35,408)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	16	-	(16)
5	Depreciation Expense (1)	2,408	1,720	(688)
6	Property Taxes	120	122	2
7	Total Operating Expenses	2,544	1,842	(702)
8	Required Return (2)	6,917	4,258	(2,659)
9	Total Operating Expense and Return	9,461	6,100	(3,361)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	1,262	920	(342)
11	Income Taxes - Utility Timing Differences (4)	(2,192)	(1,850)	342
12	Total Income Taxes	(930)	(930)	0
13	Total Revenue Requirement	8,531	5,170	(3,361)

Notes:

(1) Depreciation expense at 2013 Board-approved depreciation rates.

(2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 * 0.0336 + 0.36 * 0.0893)
The 2018 required return calculation is as follows:
$79.289 million * 64% * 3.36% = $1.705 million plus
$79.289 million * 36% * 8.93% = $2.553 million for a total of $4.258 million.

(3) Taxes related to the equity component of the return at a tax rate of 26.5%.

(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Capital Expenditures

The actual capital expenditures on in-service assets increased by $1.455 million compared to the 2018 Board-approved as shown in Table 20.

Table 20
Burlington Oakville Pipeline Project Capital Expenditures

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
1	Land Rights	-	-	-
2	Structures	-	-	-
3	Pipelines	-	449	449
4	Station Equipment	-	1,006	1,006
5	Total Capital Expenditures	-	1,455	1,455

Pipeline costs were $0.449 million higher than costs included in 2018 Board-approved rates due to a delayed outlet valve replacement at the Bronte Gate Station.

Station equipment costs were $1.006 million higher than costs included in 2018 Board-approved rates due a delayed outlet valve replacement at the Bronte Gas Station.

Average Investment

The average investment decrease of $35.408 million from Board-approved is due to the cumulative capital expenditures being $36.174 million lower than Board-approved.

Operating Expenses

The decrease in depreciation expense of $0.688 million relates to the cumulative capital expenditure being lower than Board-approved.

Required Return

The $2.659 million required return decrease is the result of the decrease in the average rate base investment, as well as a decrease in the long-term debt rate used in the calculation. The Board-approved required return calculation was derived using a capital structure of 64% long-term debt at 4.4% and 36% equity at the Board-approved rate of return of 8.93%. The 2018 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.36%, and 36% equity at the Board-approved rate of return of 8.93%.

Income Taxes

The Company's actual tax rate for 2018 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.342 million decrease in "Income Taxes – Equity Return" relates to the lower required return in 2018 versus Board-approved.

The $0.342 million increase in "Income Taxes – Utility Timing Difference" relates to a lower actual Capital Cost Allowance deduction due to the lower average investment in 2018 versus Board-approved and partially offset by the enactment of Bill C-97 accelerated CCA.

ACCOUNT NO. 179-151 ONTARIO ENERGY BOARD ("OEB") COST ASSESSMENT VARIANCE ACCOUNT

The balance in this deferral account is a debit from ratepayers of $1.203 million plus interest of $0.040 million, for a total of $1.243 million.

On February 9, 2016 the Board issued a letter to Regulated Entities subject to the OEB's Cost Assessment notifying stakeholders of changes to the OEB's Cost Assessment Model ("CAM"). As part of these changes, the Board established a variance account to record any differences between OEB cost assessments currently built into rates, and cost assessments that will result from the applications of the new cost assessment model effective April 1, 2016.

Entries to the account are made on a quarterly basis, when the OEB's cost assessment invoices are received. In the Board-approved rates for Union rate zones, there is $2.5 million in OEB cost assessment amounts. In 2018, the total amount of cost assessment invoices was $3.703 million, resulting in a variance of $1.203 million. The calculation of the variance is shown in Table 21 below.

In its Decision and Order on Union's 2017 Deferrals Disposition and Earnings Sharing Mechanism (EB-2018-0105) the Board approved a new OEB Cost Assessment Variance account for Union for 2018 that is subject to a $1 million materiality threshold[15].

[15] EB-2018-0105, 2017 Deferrals Disposition and Earnings Sharing Mechanism, Decision and Order, p. 13.

Table 21
OEB Cost Assessment Variance (January 1, 2018 to December 31, 2018)

Date	Actual OEB Cost Assessment ($ millions)	2013 Board-approved OEB Cost Assessment in Rates[1] ($ millions)	Incremental OEB Cost Assessment ($ millions)
	(a)	(b)	(c) = (a) – (b)
1-Jan-18	0.886	0.625	0.261
1-Apr-18	0.988	0.625	0.363
1-Jul-18	0.914	0.625	0.289
1-Oct-18	0.914	0.625	0.289
Total	3.703	2.500	1.203

Note:

(1) Quarterly amount of annual $2.5 million.

ACCOUNT NO. 179-153 BASE SERVICE NORTH T-SERVICE TRANSCANADA CAPACITY

There is no balance in the Base Service North T-Service TransCanada Capacity Deferral Account. The account was created in accordance with the Board's Decision in EB-2015-0181 to record differences between revenues and costs for the excess capacity from Parkway to the Union Point of Receipt as part of the Base Service offering of the North T-Service Transportation from Dawn. There was no difference between revenues and costs for the excess capacity in 2018.

ACCOUNT NO. 179-156 PANHANDLE REINFORCEMENT PROJECT COSTS

In its Panhandle Reinforcement Project (EB-2016-0186) Decision, the Board approved the establishment of the Panhandle Reinforcement Project Costs Deferral Account to track the differences between the actual net revenue requirement related to costs for the Panhandle Reinforcement Project and the net revenue requirement included in rates.

The balance in this deferral account is a credit to ratepayers of $2.341 million plus interest of $0.060 million for a total of $2.401 million. The balance of $2.341 million represents the difference between the net revenue requirement of $12.589 million included in 2018 rates (EB-2017-0087) and the calculation of the actual net revenue requirement for 2018 of $10.248 million as shown in Table 22.

Table 22
2018 Panhandle Reinforcement Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	30,612	36,644	6,032
2	Cumulative Capital Expenditures	242,843	226,297	(16,546)
3	Average Investment	223,023	203,491	(19,532)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	15	-	(15)
5	Depreciation Expense (1)	4,765	4,485	(280)
6	Property Taxes	1,569	1,716	147
7	Total Operating Expenses	6,349	6,201	(148)
8	Required Return (2)	12,879	10,826	(2,053)
9	Total Operating Expense and Return	19,228	17,027	(2,201)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	2,581	2,358	(223)
11	Income Taxes - Utility Timing Differences (4)	(6,116)	(5,530)	586
12	Total Income Taxes	(3,535)	(3,171)	364
13	Total Revenue Requirement	15,693	13,855	(1,838)
14	Incremental Project Revenue	3,104	3,607	503
15	Net Revenue Requirement	12,589	10,248	(2,341)

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return assumes a capital structure of 64% long-term debt at 3.29% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:
$203.491 million * 64% * 3.29% = $4.285 million plus
$203.491 million * 36% * 8.93% = $6.541 million for a total of $10.826 million.
(3) Taxes related to the equity component of the return at a tax rate of 26.5%.
(4) Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

Capital Expenditures

The actual 2018 capital expenditures on in-service assets were $6.032 million higher than 2018 Board-approved as shown in Table 23.

Table 23
Panhandle Reinforcement Capital Expenditures

Line No.	Particulars ($000's)	2018 Board-Approved (a)	2018 Actuals (b)	Difference (c) = (b - a)
1	Land	-	-	-
2	Land Rights	-	15	15
3	Pipelines	28,427	29,837	1,410
4	Measuring & Regulating - Transmission	118	2,539	2,421
5	Measuring & Regulating - Storage	2,067	4,268	2,201
6	Salvage	-	(15)	(15)
7	Total Capital Expenditures	30,612	36,644	6,032

Pipeline costs for the Panhandle NPS 36 were $1.410 million higher than Board-approved costs due to continued inclement weather during clean up activity in 2018. Right of way restoration has been ongoing and is now forecasted for completion in 2019.

Measuring & Regulating costs were $4.622 million higher than Board-approved costs due to delayed valve replacement and clean-up activities required in 2018.

Average Investment

The average investment decrease of $19.532 million from 2018 Board-approved is due to the capital expenditures being $16.546 million lower than Board-approved on a cumulative basis.

Operating Expense

The decrease in depreciation expense of $0.280 million relates the lower average investment than included in 2018 Board-approved rates.

The $0.147 million property tax increase relates to increases in provincial and municipal tax rates, partially offset by a reduced rate due to a loop adjustment.

Required Return

The decrease in the required return of $2.053 million is the result of a decrease in the average rate base investment, as well as a decrease in the long-term debt rate used in the calculation. The Board-approved required return calculation was derived using a capital structure of 64% long-term debt at 4% and 36% equity at the Board-approved rate of return of 8.93%. The 2018 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.29% and 36% equity at the Board-approved rate of return of 8.93%.

Income Taxes

Union’s actual tax rate for 2018 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.223 million decrease in “Income Taxes-Equity Return” relates to a lower required return in 2018 versus Board-approved.

The $0.586 million increase in “Income Taxes-Timing Differences” relates to a lower actual Capital Cost Allowance deduction due to the lower average investment in 2018 versus Board-approved and partially offset by the enactment of Bill C-97 accelerated CCA.

ACCOUNT NO. 179-157 PENSION AND OTHER POST-EMPLOYMENT BENEFITS VARIANCE ACCOUNT

In accordance with the Boards' EB-2015-0040 report to all regulated entities, dated September 14, 2017, titled "Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs", the Board ordered the establishment of the deferral account, effective January 1, 2018, to be used by utilities that are approved to recover their pension and OPEB costs on an accrual basis[16]. The Company recovers its pension and OPEB costs on an accrual basis for Union rate zones.

The purpose of the Pension and OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account is to track the differences between forecast accrual pension and OPEB amounts recovered in rates, and the actual cash payments made for both pension and OPEB, on a go-forward basis from the date the account was established.

In 2018, the Company's regulated transportation, storage and distribution rates were determined in accordance with the Board-approved 2014-2018 Incentive Regulation Application (EB-2013-0212). As per the Board's EB-2015-0040 report, "The approved accrual amount embedded in rates is not to change or escalate during an IRM or Custom IR term except in cases where in a Custom IR term, updated forecasts for subsequent years of the term were approved." As such, the Company's underlying pension and OPEB expenses were approved by the Board as part of Union's 2013 rates application (EB-2011-0210).

[16] EB-2015-0040, Regulatory Treatment of Pension and Other Post-employment Benefits ("OPEB") Costs, September 14, 2017, p. 2.

The total gross accrual based pension and OPEB costs recovered in rates, prior to capitalization, approved for 2013 in the EB-2011-0210 application were $47.4 million[17].

The Company capitalizes a portion of its total pension and OPEB accrual costs that are included in rates. Pension and OPEB expenses were capitalized at a rate of 14% in determining 2013 rates. To recognize that a portion of capitalized overhead would be recovered in 2013 rates as part of the depreciation expense, the capitalized expense amount has been offset by 3.1% to reflect the weighted average depreciation rate filed within the 2013 application. The calculation of the pension and OPEB expense net of capitalization is shown in Table 25.

Table 25
Calculation of Pension/OPEB Expense in Rates

Line No.	Particulars ($ millions)	
1	Total Pension/OPEB Expense	$ 47.4
2	Less: Capitalized Overheads @ 14%	6.6
3		40.8
4	Add: Depreciation of Capitalized Overheads @ 3.1%	0.2
5	Pension/OPEB Expense in Rates	$ 41.0

In 2018, the forecast accrual pension and OPEB expense amount recovered in rates of $41.0 million, is compared to the actual cash payments made for both pension and OPEB of $26.5 million, resulting in an annual $14.5 million credit variance.

In accordance with the Board's report (EB-2015-0040), when the cumulative forecasted accrual amount recovered in rates exceeds the cumulative actual cash payments, an asymmetrical carrying charge, to be returned to ratepayers, should be accrued based

[17] EB-2011-0210 Updated 2012-03-07, Exhibit D1, Tab 3, Table 4, page 10 of 16

on the opening monthly difference between amount recovered in rates and actual cash payments. The balance in the account is an interest credit to ratepayers of $0.228 million to December 31, 2018[18]. Please see Table 26 for a detailed calculation of the forecast accrual versus actual cash payments, and associated interest.

Table 26
Details of 2018 Interest Calculated on Forecast Accruals versus Actual Cash Payments
in Pension and OPEB Variance Account (No. 179-157)

Line No.	Particulars ($000's)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Forecast Accrual in Rates	3,415	3,415	3,415	3,415	3,415	3,415	3,415	3,415	3,415	3,415	3,415	3,415	40,984
2	Actual Cash Payments	1,366	1,930	1,545	1,670	3,785	3,709	3,712	1,000	1,527	2,153	1,729	2,347	26,474
3	Monthly Variance	-2,049	-1,485	-1,870	-1,745	369	294	297	-2,415	-1,888	-1,262	-1,686	-1,068	-14,509
4	Cumulative Variance	-2,049	-3,535	-5,405	-7,150	-6,780	-6,487	-6,190	-8,605	-10,493	-11,755	-13,441	-14,509	
5	OEB Prescribed CWIP Rate	2.99%	2.99%	2.99%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	3.35%	
6	Asymmetrical Interest	-	(5)	(9)	(15)	(20)	(19)	(18)	(18)	(24)	(29)	(33)	(38)	(228)

[18] Interest is as of December 31, 2018 as interest on this account is calculated on a cumulative account balance basis.

UNION RATE ZONES
DEFERRAL & VARIANCE ACCOUNT
FORECAST FOR CLEARANCE AT JANUARY 1, 2020

Line No.	Account Number	Account Name	Balance ($000's)	Interest ($000's)	Total ($000's)
	Gas Supply Accounts:				
1	179-107	Spot Gas Variance Account	-	-	-
2	179-108	Unabsorbed Demand Costs (UDC) Variance Account	(9,712)	(321)	(10,033)
3	179-131	Upstream Transportation Optimization	10,273	231	10,503
4	179-132	Deferral Clearing Variance Account - Supply	(403)	(14)	(417) [2]
5	179-132	Deferral Clearing Variance Account - Transport	(264)	(9)	(273) [2]
6	Total Gas Supply Accounts (Lines 1 through 5)		(107)	(113)	(220)
	Storage Accounts:				
7	179-70	Short-Term Storage and Other Balancing Services	1,413	32	1,445
	Other:				
8	179-103	Unbundled Services Unauthorized Storage Overrun	-	-	-
9	179-112	Gas Distribution Access Rule (GDAR) Costs	-	-	-
10	179-120	IFRS Conversion Cost	-	-	-
11	179-123	Conservation Demand Management (CDM)	(1,054)	(31)	(1,085)
12	179-132	Deferral Clearing Variance Account	(1,069)	(37)	(1,105) [2]
13	179-133	Normalized Average Consumption	(20,322)	(660)	(20,983)
14	179-134	Tax Variance	(1,354)	(22)	(1,376)
15	179-135	Unaccounted for Gas (UFG) Volume Variance Account	1,733	50	1,783
16	179-136	Parkway West Project Costs	(20)	9	(11)
17	179-137	Brantford-Kirkwall/Parkway D Project Costs	(824)	(29)	(853)
18	179-138	Parkway Obligation Rate Variance	288	5	293
19	179-141	Unaccounted for Gas (UFG) Price Variance Account	2,028	63	2,091
20	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	(5,836)	(176)	(6,012)
21	179-143	Unauthorized Overrun Non-Compliance Account	(5)	-	(5)
22	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	(7,236)	(213)	(7,449)
23	179-149	Burlington-Oakville Project Costs	(3,361)	(101)	(3,462)
24	179-151	OEB Cost Assessment Variance Account	1,203	40	1,243
25	179-153	Base Service North T-Service TransCanada Capacity	-	-	-
26	179-156	Panhandle Reinforcement Project Costs	(2,341)	(60)	(2,401)
27	179-157	Pension and OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account	-	(228)	(228) [1]
28	Total Other Accounts (Lines 8 through 27)		(38,170)	(1,390)	(39,560)
29	**Total Deferral Account Balances (Lines 6 + 7 + 28)**		**(36,864)**	**(1,471)**	**(38,335)**

Notes:
(1) Interest on the Pension & OPEB Forecast Accrual vs Actual Cash Payment Differential Variance Account is as of December 31st, 2018, as interest for this account is calculated on the cumulative account balance.

(2) Deferral Clearing Variance Account (No. 179-132) total balance of $1,795 ($417 + $273 + $1,105).

UNION RATE ZONES
Transportation Optimization Deferral Account (No. 179-131)

Line No.	Particulars ($000's)	2013 Board-approved	2017 Actual Total	2018 Actual Total
		(a)	(b)	(c)
1	Base Exchange Revenue	9,118	5,015	7,296
2	FT RAM Exchange Revenue	5,800	-	-
3	Total Exchange Revenue	14,918	5,015	7,296
4	Exchange Revenue Subject to Deferral		5,015	7,296
5	Ratepayer portion - 90%	13,426	4,513	6,567
6	10% Union Incentive Payment		501	730
7	Less: Gas Supply Optimization Margin in Rates	13,426	15,570	16,839
8	2018 Deferral Account Balance receivable from Ratepayers		(11,057)	(10,273)

UNION RATE ZONES

Details of Revenues and Costs and Calculation of Balance

in Short-Term Storage Deferral Account (No. 179-70)

Line No.	Particulars ($000's)	2013 Board-approved	2017 Actual	2018 Actual
		(a)	(b)	(c)
	Revenue			
1	C1 Off-Peak Storage	500	709	141
2	Supplemental Balancing Services	2,000	890	1,153
3	Gas Loans	-	15	15
4	Enbridge LBA	-	381	430
5		2,500	1,995	1,739
6	C1 ST Firm Peak Storage	7,883	4,618	5,011
7	Total Revenue (1)	10,383	6,613	6,750
	Costs			
8	O&M (2)	3,810	2,289	2,634
9	UFG (3)	316	262	247
10	Compressor Fuel (4)	1,201	320	382
11	Total Costs	5,327	2,870	3,264
12	Net Revenue (line 7 - 11)	5,056	3,743	3,487
13	Less Shareholder Portion (10%)	505	374	349
14	Ratepayer Portion	4,551	3,368	3,138
15	Approved in Rates	4,551	4,551	4,551
16	Deferral balance payable to/(collectable from) ratepayers	-	(1,183)	(1,413)

Notes:

(1) Based on short-term storage services provided.

(2) Revenue Requirement on 11.3 PJ's of board approved excess in-franchise storage capacity.

(3) Based on short-term storage volumes in proportion to total volumes.

(4) Based on short-term storage activity in proportion to total actual storage activity.

UNION RATE ZONES
Transportation Optimization Deferral Account (No. 179-131)

Line No.	Particulars ($000's)	2013 Board-approved	2017 Actual Total	2018 Actual Total
		(a)	(b)	(c)
1	Base Exchange Revenue	9,118	5,015	7,296
2	FT RAM Exchange Revenue	5,800	-	-
3	Total Exchange Revenue	14,918	5,015	7,296
4	Exchange Revenue Subject to Deferral		5,015	7,296
5	Ratepayer portion - 90%	13,426	4,513	6,567
6	10% Union Incentive Payment		501	730
7	Less: Gas Supply Optimization Margin in Rates	13,426	15,570	16,839
8	2018 Deferral Account Balance receivable from Ratepayers		(11,057)	(10,273)

UNION RATE ZONES
Details of Revenues and Costs and Calculation of Balance
in Short-Term Storage Deferral Account (No. 179-70)

Line No.	Particulars ($000's)	2013 Board-approved	2017 Actual	2018 Actual
		(a)	(b)	(c)
	Revenue			
1	C1 Off-Peak Storage	500	709	141
2	Supplemental Balancing Services	2,000	890	1,153
3	Gas Loans	-	15	15
4	Enbridge LBA	-	381	430
5		2,500	1,995	1,739
6	C1 ST Firm Peak Storage	7,883	4,618	5,011
7	Total Revenue (1)	10,383	6,613	6,750
	Costs			
8	O&M (2)	3,810	2,289	2,634
9	UFG (3)	316	262	247
10	Compressor Fuel (4)	1,201	320	382
11	Total Costs	5,327	2,870	3,264
12	Net Revenue (line 7 - 11)	5,056	3,743	3,487
13	Less Shareholder Portion (10%)	505	374	349
14	Ratepayer Portion	4,551	3,368	3,138
15	Approved in Rates	4,551	4,551	4,551
16	Deferral balance payable to/(collectable from) ratepayers	-	(1,183)	(1,413)

Notes:
(1) Based on short-term storage services provided.
(2) Revenue Requirement on 11.3 PJ's of board approved excess in-franchise storage capacity.
(3) Based on short-term storage volumes in proportion to total volumes.
(4) Based on short-term storage activity in proportion to total actual storage activity.

UNION RATE ZONE
Summary of Non-Utility Storage Balances

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-18	111.8	94.6	85%	1-Nov-18	111.8	97.0	87%
2-Oct-18	111.8	94.7	85%	2-Nov-18	111.8	97.6	87%
3-Oct-18	111.8	94.8	85%	3-Nov-18	111.8	98.4	88%
4-Oct-18	111.8	95.1	85%	4-Nov-18	111.8	99.2	89%
5-Oct-18	111.8	95.4	85%	5-Nov-18	111.8	99.9	89%
6-Oct-18	111.8	95.7	86%	6-Nov-18	111.8	101.0	90%
7-Oct-18	111.8	96.1	86%	7-Nov-18	111.8	101.9	91%
8-Oct-18	111.8	96.4	86%	8-Nov-18	111.8	102.3	91%
9-Oct-18	111.8	96.8	87%	9-Nov-18	111.8	102.5	92%
10-Oct-18	111.8	97.1	87%	10-Nov-18	111.8	102.6	92%
11-Oct-18	111.8	97.2	87%	11-Nov-18	111.8	102.7	92%
12-Oct-18	111.8	97.4	87%	12-Nov-18	111.8	102.5	92%
13-Oct-18	111.8	97.6	87%	13-Nov-18	111.8	102.4	92%
14-Oct-18	111.8	97.8	87%	14-Nov-18	111.8	102.2	91%
15-Oct-18	111.8	97.8	87%	15-Nov-18	111.8	102.3	92%
16-Oct-18	111.8	98.1	88%	16-Nov-18	111.8	102.4	92%
17-Oct-18	111.8	97.5	87%	17-Nov-18	111.8	102.6	92%
18-Oct-18	111.8	96.8	87%	18-Nov-18	111.8	102.6	92%
19-Oct-18	111.8	96.7	86%	19-Nov-18	111.8	102.5	92%
20-Oct-18	111.8	96.9	87%	20-Nov-18	111.8	102.5	92%
21-Oct-18	111.8	96.7	86%	21-Nov-18	111.8	102.4	92%
22-Oct-18	111.8	96.5	86%	22-Nov-18	111.8	102.3	91%
23-Oct-18	111.8	96.4	86%	23-Nov-18	111.8	102.3	92%
24-Oct-18	111.8	96.3	86%	24-Nov-18	111.8	102.9	92%
25-Oct-18	111.8	96.1	86%	25-Nov-18	111.8	103.4	93%
26-Oct-18	111.8	96.2	86%	26-Nov-18	111.8	103.9	93%
27-Oct-18	111.8	96.1	86%	27-Nov-18	111.8	103.9	93%
28-Oct-18	111.8	96.1	86%	28-Nov-18	111.8	104.1	93%
29-Oct-18	111.8	96.1	86%	29-Nov-18	111.8	102.1	91%
30-Oct-18	111.8	96.1	86%	30-Nov-18	111.8	102.5	92%
31-Oct-18	111.8	96.4	86%				

UNION RATE ZONE
Southern Operations Area
Allocation of Short Term Peak Storage Revenues Between Utility and Non Utility

Line No.	Particulars	Utility Storage Space (PJs)	Short Term Peak Storage Sold (PJs)	Revenue from Short Term Peak Storage ($ millions)
1	Net Revenues from Short Term Peak Storage			5.0
2	Total Short Term Peak Storage Sales		7.6	
3	Storage Space reserved for Utility	100.0		
4	Utility Space Requirement	92.4		
5	Excess Utility Storage Space (line 3 - line 4)	7.6		
6	Total Utility Short Term Peak Storage Sales (line 2)		7.6	
7	Total Non Utility Short Term Peak Storage Sales		0.0	
8	Short Term Peak Storage Net Revenues - Utility (line 6 / line 2 * line 1)			5.0
9	Short Term Peak Storage Net Revenues - Non Utility (line 7 / line 2 * line 1)			-

UNION RATE ZONES
179-132 Deferral Clearing Variance Account
2016 Deferral Disposition (EB-2017-0091)
Dispositions Disposed of During 2018

		2018		
Line No.	Particulars	2016 Deferral Disposition EB-2017-0091 ($000) (a)	Interest ($000) (b)	Total ($000) (c) = (a) + (b)
1	Total General Service for Prospective Recovery (Refund) - Delivery	(1,069)	(37)	(1,105)
2	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation	(264)	(9)	(273)
3	Total Prospective Recovery (Refund) - Gas Supply Commodity	(403)	(14)	(417)
4	Total	(1,736)	(60)	(1,795)

Notes:
Line 1: includes a credit of $0.061 million for rebills.

UNION RATE ZONES
179-132 Deferral Variance Account
2016 Deferral Disposition (EB-2017-0091)
Disposition Period - October 1, 2017 to March 31, 2018

Line No.	Particulars	Rate Class	Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	2018 Unit Rate for Prospective Recovery/(Refund) (cents/m^3)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c)	(d)	(e) = (a) * (d)/ 100	(f) = (b) * (d)/ 100	(g) = (c) - (f)
	General Service for Prospective Recovery(Refund) - Delivery								
1	Small Volume General Service	01	778,223	796,743	(18,520)	1.2219	9,509	9,735	(226)
2	Large Volume General Service	10	248,400	263,225	(14,825)	1.0857	2,697	2,858	(161)
3	Small Volume General Service	M1	2,363,019	2,433,864	(70,845)	0.5143	12,153	12,517	(364)
4	Large Volume General Service	M2	852,358	928,577	(76,219)	0.3363	2,866	3,123	(256)
5	Total General Service for Prospective Recovery (Refund) - Delivery		4,242,000	4,422,409	(180,409)		27,225	28,233	(1,008)
	General Service for Prospective Recovery(Refund) - Gas Supply Transportation								
6	Small Volume General Service	01	778,223	796,737	(18,514)	0.7678	5,975	6,117	(142)
7	Large Volume General Service	10	246,354	260,810	(14,456)	0.8439	2,079	2,201	(122)
8	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation		1,024,577	1,057,547	(32,970)		8,054	8,318	(264)
	Prospective Recovery/(Refund) - Gas Supply Commodity								
9	Small Volume General Service	M1	2,152,071	2,250,254	(98,183)	0.2371	5,328	5,335	(8)
10	Large Volume General Service	M2	416,626	464,231	(47,605)	0.2371	778	1,101	(323)
11	Firm Com/Ind Contract	M4	20,331	23,674	(3,342)	0.2371	36	56	(20)
12	Interruptible Com/Ind Contract	M5	3,023	4,222	(1,199)	0.2371	40	10	30
13	Special Large Volume Contract	M7	9,670	9,276	394	0.2371	(12)	22	(34)
14	Large Wholesale	M9	-	19,955	-	0.2371	-	47	(47)
15	Small Wholesale	M10	272	331	(59)	0.2371	(0)	1	(1)
16	Total Prospective Recovery (Refund) - Gas Supply Commodity		2,601,993	2,771,943	(149,994)		6,169	6,572	(403)
17	Total Excluding Rebill Activity Adjustments						41,449	43,124	(1,675)
18	Rebill Activity Adjustments								(61)
19	Total								(1,736)

Notes:
(1) Forecast volume for the period October 1, 2017 to March 31, 2018.

UNION RATE ZONES

Calculation of Balances by Rate Class in the NAC Deferral Account (No. 179-133)

Line No.	Particulars		Rate 01	Rate 10	Rate M1	Rate M2	Net Account Balance
			(a)	(b)	(c)	(d)	(e)
1	2018 Target NAC: m^3		2,771	158,894	2,654	159,319	
2	2018 Actual NAC: m^3		2,864	167,467	2,810	171,248	
3	Actual change in NAC: m^3 (line 1 - line 2)		(92)	(8,573)	(156)	(11,929)	
4	2013 Board Approved Number of Customers at December		323,287	2,064	1,067,757	6,778	1,399,886
5	Annual Volume Impact (10^3m^3)	(1)	(29,607)	(17,581)	(165,492)	(81,266)	(293,946)
6	2018 Net Annual Average Delivery Rate ($/m^3$)	(2)	$0.090	$0.058	$0.046	$0.047	
7	2018 Net Annual Storage Rate ($/m^3$)	(3)	$0.053	$0.040	$0.007	$0.006	
8	Delivery Rate Annual Balance Amount ($000)	(4)	($2,650)	($1,024)	($7,612)	($3,823)	($15,109)
9	Storage Rate Annual Balance Amount ($000)	(4)	($1,583)	($704)	($1,213)	($527)	($4,027)
10	Storage Cost Annual Balance Amount ($000)		($178)	($4)	$8	($1,012)	($1,186)
11	Interest ($000)	(5)	($2,250)	$227	($309)	$1,672	($660)
12	Total Deferral Account Amounts ($ 000) (line 8+9+10+11)		($6,661)	($1,505)	($9,127)	($3,690)	($20,983)

Notes:
(1) The annual volume is obtained from a monthly calculation of approved customers and the monthly usage variance.
(2) The Net Annual Average Delivery Rate is the average of monthly unit rates that are adjusted by quarterly QRAM rate adjustments.
(3) The Storage Rates are constant each month throughout the year.
(4) The annual revenue is obtained from a monthly calculation of volumes (line 5) and the monthly unit delivery and storage rates (line 6 and line 7).
(5) Interest is calculated on the monthly opening balance in the deferral account in accordance with the methodology approved by the Board in EB-2006-0117.

Filed: 2019-07-17
EB-2019-0105
Exhibit C
Tab 1
Appendix A
Schedule 8

UNION RATE ZONES

Calculation of the 2018 Bill C-97 Accelerated CCA Impact to be Shared with Ratepayers through the Tax Variance Deferral Account (No. 179-134)

Line No.	Class	Particulars ($000s)	Total Additions Qualifying for Accel. CCA (a)	Capital Pass-Through Additions (c)	Additions Net of Capital Pass-Through (c)	Accel. CCA Depreciable UCC Balance (d)	Regular CCA Depreciable UCC Balance (e)	Rate (%) (f)	Accelerated CCA (g)	Regular CCA (h)
1	1	Buildings, structures and improvements, services, meters, mains	-	-	-	-	-	4%	0.0	0.0
2	1	Non-residential building acquired after March 19, 2007	2,952.7	1,719.0	1,233.7	1,850.6	616.9	6%	111.0	37.0
3	2	Mains acquired before 1988	-	-	-	-	-	6%	0.0	0.0
4	3	Buildings acquired before 1988	-	-	-	-	-	5%	0.0	0.0
5	6	Other buildings	-	-	-	-	-	10%	0.0	0.0
6	7	Compression equipment acquired after February 22, 2005	7,775.4	4,438.3	3,337.1	5,005.7	1,668.6	15%	750.8	250.3
7	8	Compression assets, office furniture, equipment	7,616.0	100.0	7,516.0	11,274.0	3,758.0	20%	2,254.8	751.6
8	10	Transportation, computer equipment	34.6	-	34.6	51.9	17.3	30%	15.6	5.2
9	12	Computer software, small tools	325.9	-	325.9	325.9	163.0	100%	325.9	163.0
10	13	Leasehold improvements	-	-	-	-	-	N/A	0.0	0.0
11	14.1	Intangibles	79.5	-	79.5	119.3	39.8	5%	6.0	2.0
12	14.1	Intangibles (pre 2017)	-	-	-	-	-	7%	0.0	0.0
13	17	Roads, sidewalk, parking lot or storage areas	-	-	-	-	-	8%	0.0	0.0
14	38	Heavy work equipment	823.6	-	823.6	1,235.4	411.8	30%	370.6	123.5
15	41	Storage assets	187.1	141.0	46.1	69.2	23.1	25%	17.3	5.8
16	45	Computers - Hardware acquired after March 22, 2004	-	-	-	-	-	45%	0.0	0.0
17	49	Transmission pipeline additions acquired after February 23, 2005	1,870.0	584.3	1,285.7	1,928.6	642.9	8%	154.3	51.4
18	50	Computers hardware acquired after March 18, 2007	1,424.1	-	1,424.1	2,136.2	712.1	55%	1,174.9	391.6
19	51	Distribution pipelines acquired after March 18, 2007	30,251.5	-	30,251.5	45,377.3	15,125.8	6%	2,722.6	907.5
20		Total	$ 53,340.4	6,982.6	46,357.8	69,373.8	$ 23,178.9		$ 7,903.8	$ 2,688.9

CCA Variance (g) - (h)	5,214.9
Tax Rate	26.5%
Earnings Impact of Accelerated CCA	1,381.9
Earnings Impact Grossed-up for Taxes	1,880.2
50% to be shared with Ratepayers through the Tax Variance Account	940.1

UNION RATE ZONES
2018 Parkway Obligation Rate Variance Summary
For the period November 1, 2018 to December 31, 2018
Based on 70 TJ per day of M12 Dawn-Parkway capacity and the T2 Billing Contract Demand Revenue Credit

Line No.	Particulars	2013 Approved Dawn-Parkway Design Day Demands (1) (10^3m^3/d)	Dawn-Parkway Demand Costs of 70 TJ/d (2) ($000's)		Rate T2 BCD Revenue Credit ($000's)		Total Deferral Balance ($000's)
		(a)	(b)		(c)		(d) = (b + c)
1	Rate M1	22,132	264		(118)		146
2	Rate M2	7,435	89		(40)		49
3	Rate M4	2,162	26		(12)		14
4	Rate M5 Firm	20	0		(0)		0
5	Rate M5 Interruptible	-	-		-		-
6	Rate M7 Firm	997	12		(5)		7
7	Rate M7 Interruptible	-	-		-		-
8	Rate M9	356	4		(2)		2
9	Rate M10	11	0		(0)		0
10	Rate T1 Firm	1,068	13		(6)		7
11	Rate T1 Interruptible	-	-		-		-
12	Rate T2 Firm	6,931	83		(37)		46
13	Rate T2 Interruptible	-	-		-		-
14	Rate T3	2,511	30		(13)		17
15	Total	43,624	521	(3)	(233)	(4)	288

Notes:

(1) Union South In-franchise Design Day Demand allocation factor per EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, p. 7, line 2, Updated for Board Decision.

(2) Allocated in proportion to column (a), 70 TJ/d of Dawn-Parkway capacity turnback as of November 1, 2018 per EB-2018-0305, Exhibit B1, Tab 1, Schedule 1, Appendix I, column (g), line 21.

(3) Calculated as 70 TJ x $0.122/GJ/d x 61 d = $0.521 million. Rate represents the Board-approved M12 Dawn-Parkway demand rate per EB-2017-0087.

(4) Allocated in proportion to column (a). Incremental revenue of $0.233 million associated with the Rate T2 BCD increase calculated at 2018 Rate T2 rates.

UNION RATE ZONES
Calculation of Allocation of 2018 Short Term Transportation Revenues to the Lobo D / Bright C / Dawn H Compressor Project Cost Deferral Account

Particulars (000's)	Volume (GJ/d) [1] (a)	Actual Revenue ($) [2] (b)	Project Surplus Allocation (%) (c) = 30,393 GJ/d / (a)	Revenue Allocation ($) (d) = (b) x (c)
January 2018	307	$ 1,613	9.9%	$ 160
February 2018	196	$ 880	15.5%	$ 136
March 2018	124	$ 735	24.5%	$ 180
April 2018	134	$ 149	22.6%	$ 34
May 2018	7	$ 14	100%	$ 14
June 2018	15	$ 34	100%	$ 34
July 2018	58	$ 58	52.4%	$ 30
August 2018	63	$ 78	48.5%	$ 38
September 2018	83	$ 72	36.7%	$ 26
October 2018	67	$ 87	45.3%	$ 40
November 2018 [3]	30	$ 113	100%	$ 113
December 2018 [3]	30	$ 113	100%	$ 113
Total		$ 3,946		$ 917

Notes
[1] Actual average short-term firm daily contract demand plus interruptible average daily throughput volumes for easterly Dawn-Parkway system paths.
[2] Actual short-term transportation revenues earned on easterly Dawn Parkway system paths.
[3] Sold long-term at Dawn to Parkway M12 Rate of $3.716 $/GJ.

UNION RATE ZONES
Calculation of Allocation of 2017 Short Term Transportation Revenues to the Lobo D / Bright C / Dawn H Compressor Project Cost Deferral Account

Particulars (000's)	Volume (GJ/d) [1] (a)	Actual Revenue ($) [2] (b)	Project Surplus Allocation (%) (c) = 30,393 GJ/d / (a)	Revenue Allocation ($) [3] (d) = (b) x (c)
October 2017	243	$ 65	12.5%	$ 1
November 2017	323	$ 752	9.4%	$ 71
December 2017	244	$ 1,154	12.5%	$ 144
Total		$ 1,972		$ 216

Notes
(1) Actual average short-term firm daily contract demand plus interruptible average daily throughput volumes for easterly Dawn-Parkway system paths.
(2) Actual short-term transportation revenues earned on easterly Dawn Parkway system paths.
(3) All compressors in-service as of October 27, 2017. October Revenue Allocation prorated for 4 days (4/31).

2018 UTILITY RESULTS AND EARNINGS SHARING
UNION RATE ZONES

2018 UTILITY RESULTS

For the year ended December 31, 2018 Union rate zones' actual revenue sufficiency from utility operations is $20.9 million, which is $14.8 million higher than the 2017 revenue sufficiency of $6.1 million. Table 1 provides the actual utility operations results for 2018.

Table 1

Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31

Line No.	Particulars ($ Millions)	Board Approved 2013	Actual 2017	Actual 2018	Increase/ (decrease) 2018 vs. 2017
		(a)	(b)	(c)	(d) = (c) - (b)
1	Gas sales and distribution revenue	1,448.8	1,857.0	1,793.1	
2	Cost of gas	701.4	1,031.0	907.1	
3	Gas distribution margin	747.4	826.0	886.0	60.0
4	Transportation	157.0	236.9	258.9	21.9
5	Storage	10.4	7.8	8.2	0.4
6	Other revenue	20.2	17.3	17.8	0.5
7	Expenses	643.8	743.1	799.8	56.7
8	Income taxes	17.1	(5.0)	(6.0)	(1.0)
9	Utility income	274.1	350.0	377.0	27.0
10	Cost of Capital	272.6	344.9	360.9	16.0
11	Revenue deficiency/(sufficiency) after tax	(1.5)	(5.1)	(16.2)	(11.0)
12	Provision for income taxes on deficiency / (sufficiency)	(0.5)	(1.8)	(5.8)	(4.0)
13	Distribution revenue deficiency/(sufficiency)	(2.0)	(7.0)	(22.0)	(15.0)
14	Shareholder portion of short-term storage revenue	0.5	0.4	0.3	(0.0)
15	Shareholder portion of optimization activity	1.5	0.5	0.7	0.2
16	Total revenue deficiency/(sufficiency)	-	(6.1)	(20.9)	(14.8)

The primary drivers of Union rate zones' 2018 financial results relative to 2017 are provided below.

Gas Distribution Margin

The increase in gas distribution margin of $60.0 million relative to 2017 was mainly driven by increased throughput volumes due to colder weather, rate increases and growth in the number of customers being serviced by Enbridge Gas in the Union rate zones (and related natural gas usage).

Transportation Revenue

The increase in transportation revenue of $21.9 million relative to 2017 was mainly driven by increased M12 and C1 long-term transportation rates due to capital pass-through projects.

Expenses

The increase in expenses of $56.7 million relative to 2017 was mainly driven by higher depreciation and O&M expenses. The increase in depreciation of $22.0 million relative to 2017 was mainly driven by new projects placed into service. The increase in O&M of $33.5 million relative to 2017 was mainly driven by salaries and benefits, as well as an increase in contract services, partially offset by cost recoveries on Compressor projects.

Income Taxes

The decrease in income taxes relative to 2017 of $1.0 million is primarily due to utility tax timing differences resulting from higher capital cost allowance due to increased capital spending in 2015, 2016, 2017 and 2018, and the enactment of Bill C-97 accelerated CCA, offset by higher utility income before tax resulting from rate increases, customer growth, and a full year of revenue from capital pass-through projects.

2018 EARNINGS SHARING

The benchmark return on equity ("ROE") for 2018 was 8.93%. Union rate zones' actual ROE from utility operations in 2018 was 9.64% or 71 basis points above the 2018 benchmark ROE.

The calculation of ROE for 2018 is found at Exhibit C, Tab 2, Appendix B, Schedule 1. To calculate Union rate zones actual utility earnings Enbridge Gas starts in column (a) with Union rate zones' specific total corporate revenues and operating expenses; column (b) removes revenues and costs associated with Union rate zones' specific non-utility storage operations; column (c) makes adjustments that would normally be made under cost of service to arrive at utility income. To arrive at utility earnings for the purposes of earnings sharing, Enbridge Gas deducts: income taxes, interest and preferred dividends, and the shareholder portion of net short-term storage revenue and net optimization activity. The adjustments are discussed in more detail below.

Non-Utility Storage Operations

The revenues and costs for Union rate zones' non-utility storage operations are shown at Exhibit C, Tab 2, Appendix B, Schedule 1, column (b). The utility and non-utility financial information was allocated using the methodology approved by the Board in EB-2011-0210.

Adjustments

The following adjustments were made to utility earnings (Exhibit C, Tab 2, Appendix B, Schedule 1, column (c)):

A) Bill C-97 (Accelerated Capital Cost Allowance ("CCA"));
B) Demand Side Management ("DSM") Incentive;
C) Charitable Donations;

D) Facility Fees, Customer Deposit Interest and Foreign Exchange on Bank Balances; and,

E) Other.

A) Bill C-97 (Accelerated CCA)

Gas sales revenue has been reduced by a total of $2.194 million to reflect the 2018 revenue requirement impact of accelerated CCA provisions contained in Bill C-97, which was enacted on June 21, 2019. The adjustments offset the grossed-up utility income tax reduction that results from incorporating the accelerated CCA provisions, and are required to appropriately reflect updates to amounts captured in the Capital Pass-Through and Tax Variance Deferral Accounts, which were not reflected in the year-end 2018 results. The full revenue requirement impact of accelerated CCA on 2018 capital additions associated with capital pass-through projects, a reduction of $0.314 million, has been reflected in the corresponding capital pass-through project variance account balances sought for disposition within this proceeding. The revenue requirement impact of accelerated CCA on 2018 capital additions, excluding those associated with capital pass-through projects, a reduction of $1.880 million are to be shared 50/50 with ratepayers through the Tax Variance Deferral Account. As a result, gas sales revenue has been reduced by $0.940 million to reflect the ratepayers 50% share which has been included in the Tax Variance Deferral Account balance sought for disposition, while a further $0.940 million reduction reflects the elimination of the shareholder 50% which should not be included in the determination of utility earnings sharing results.

Gas sales revenue has also been reduced by $0.413 million to reflect the elimination of the shareholder 50% of HST tax impacts, in conjunction with the corresponding ratepayer portion which is also reflected in the Tax Variance Account balance sought for disposition.

B) DSM Incentive

Other revenue includes the revenue recorded for the 2018 DSM Incentive of $6.119 million. The DSM Incentive amount is an incentive to the company to encourage it to actively pursue DSM activities. To ensure that the full amount of the DSM Incentive accrues to the company and that the incentive is maintained, the DSM Incentive revenue is removed from the earnings sharing calculation.

C) Charitable Donations

Charitable donation costs incurred by the utility are not allowable as deductions from utility earnings and as a result $2.547 million in costs have been removed.

D) Facility Fees, Customer Deposit Interest and Foreign Exchange on Bank Balances

Facility fees, customer deposit interest and foreign exchange on bank balances are recorded in the company's corporate results as interest expense. Since these items should be included in utility earnings, and are not part of the utility interest calculation, they need to be adjusted. As a result, facility fees and customer deposit interest of $0.998 million have been added to operating expenses, and a foreign exchange gain on bank balances of $0.493 million has been included in other expenses to arrive at utility earnings.

E) Other

In the corporate results, the transportation optimization built into distribution rates was reclassified to transportation revenue as an offset to the actual optimization revenue earned. In order to align with Board-approved presentation, this adjustment of $16.839 million has been shown as a cost of gas reduction.

Amounts relating to the Conservation Demand Management ("CDM") program of $1.054 million have been removed from operating and maintenance expenses since there is a separate deferral sharing mechanism in place.

Income Taxes

The calculation of utility income taxes is the same approach used for rate making under cost of service.

Current utility income taxes are calculated using utility income before interest and taxes less deemed interest costs, and permanent and timing differences to arrive at taxable income multiplied by the current tax rates. The calculation can be found at Exhibit C, Tab 2, Appendix A, Schedule 14.

Interest and Preferred Dividends

The calculation of interest and preferred dividends is the same approach used for rate making under cost of service.

Utility interest expense is calculated using actual utility rate base, deemed capital structure, and actual average interest rates. The calculation can be found at Exhibit C, Tab 2, Appendix A, Schedule 4.

Preferred share dividend requirements are calculated using actual utility rate base, deemed capital structure, and actual dividend requirements. The calculation can be found at Exhibit C, Tab 2, Appendix A, Schedule 4.

Shareholder Portion of Net Short-Term Storage Revenue

The shareholder portion of net short-term storage revenue represents Enbridge Gas' 10% share of the actual net margin generated on the sale of excess utility storage space for the Union rate zones. The shareholder portion of $0.256 million, net of tax, has been removed from the earnings sharing calculation. The gross calculation can be found at Exhibit C, Tab 1, Appendix A, Schedule 3, column (c), line 13.

Shareholder Portion of Net Optimization Activity

The shareholder portion of net optimization activity represents the Company's 10% share of the net margin generated on optimization activities for the Union rate zones. The shareholder portion of $0.536 million, net of tax, has been removed from the earnings sharing calculation. The gross calculation can be found at Exhibit C, Tab 1, Appendix A, Schedule 2, column (c), line 6.

Return on Equity

Actual ROE is determined using utility earnings calculated as described above divided by deemed common equity at 36% of actual utility rate base. The actual 2018 ROE is 9.64%. Please see Exhibit C, Tab 2, Appendix B, Schedule 1, column (d), line 28.

Earnings Subject to Sharing

The actual ROE is compared to the benchmark ROE. If the difference between the actual ROE and the benchmark ROE is greater than 100 basis points, but less than 200 basis points, the excess earnings are shared 50/50 between Enbridge Gas and Union rate zones ratepayers. If the difference between the actual ROE and the benchmark ROE exceeds 200 basis points, the excess over 200 basis points is shared 90/10 to the benefit of ratepayers. For 2018, the difference is 71 basis points and therefore there is no earnings sharing. Please see Exhibit C, Tab 2, Appendix B, Schedule 1, column (d), line 35.

2018 UNREGULATED STORAGE

As directed by the Board in the EB-2011-0210 Decision and Order, p. 79, plant continuity schedules related to Enbridge Gas's non-utility storage business in the Union rate zones have been provided at Exhibit C, Tab 2, Appendix C, Schedules 1 to 3.

SERVICE QUALITY RESULTS

As set out in Union's 2014-2018 Incentive Regulation Settlement Agreement, p. 40, the Company has provided the service quality indicator results at Exhibit C, Tab 2, Appendix D.

UNION RATE ZONES
Calculation of Revenue Deficiency/(Sufficiency)
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2017	Actual 2018
		(a)	(b)	(c)
1	Operating revenue	1,636,340	2,118,989	2,077,965
2	Cost of service	1,362,212	1,769,001	1,700,962
3	Utility income	274,128	349,988	377,002
4	Requested return	272,639	344,877	360,852
5	Revenue deficiency / (sufficiency) after tax	(1,489)	(5,112)	(16,150)
6	Provision for income taxes on deficiency / (sufficiency)	(509)	(1,843)	(5,823)
7	Distribution revenue deficiency / (sufficiency)	(1,998)	(6,954)	(21,973)
8	Shareholder portion of short-term storage revenue	506	374	349
9	Shareholder portion of optimization activity	1,492	502	730
11	Total revenue deficiency/ (sufficiency)	$ -	$ (6,078)	$ (20,894)

UNION RATE ZONES
Statement of Utility Income
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2017	Actual 2018
		(a)	(b)	(c)
	Operating Revenues:			
1	Gas sales and distribution	1,448,762	1,856,952	1,793,117
2	Transportation	156,997	236,937	258,879
3	Storage	10,383	7,796	8,163
4	Other	20,198	17,304	17,805
5		1,636,340	2,118,989	2,077,965
	Operating Expenses:			
6	Cost of gas	701,427	1,030,965	907,143
7	Operating and maintenance expenses	383,132	413,427	446,928
8	Depreciation	196,091	254,881	276,867
9	Other financing	1,179	1,013	998
10	Property and capital taxes	63,272	72,321	76,297
11		1,345,101	1,772,606	1,708,234
	Other Income (Expense)			
12	Gain/(Loss) on sale of assets	-	(3)	21
13	Gain/(Loss) on foreign exchange	-	(1,438)	1,239
14		-	(1,441)	1,260
15	Utility income before income taxes	291,239	344,941	370,991
16	Income taxes	17,111	(5,047)	(6,012)
17	Total utility income	$ 274,128	$ 349,988	$ 377,002

UNION RATE ZONES
Statement of Earnings Before Interest and Taxes
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved Corporate	2013 Board-Approved Unregulated Storage	2013 Board-Approved Adjustments	2013 Board-Approved Utility	2017 Actual Corporate	2017 Actual Unregulated Storage	2017 Actual Adjustments	2017 Actual Utility	2018 Actual Corporate	2018 Actual Unregulated Storage	2018 Actual Adjustments	2018 Actual Utility
		(a)	(b)	(c)	(d)=(a)-(b)+(c)	(e)	(f)	(g)	(h)=(e)-(f)+(g)	(i)	(j)	(k)	(l)=(i)-(j)+(k)
	Operating Revenues:												
1	Gas sales and distribution	1,448,762	-	-	1,448,762	1,872,522	-	(15,570) (i)	1,856,952	1,812,564	-	(19,447) (i)	1,793,117
2	Transportation	156,641	(356)	-	156,997	236,498	(439)	-	236,937	258,512	(367)	-	258,879
3	Storage	96,441	86,059	-	10,383	126,928	119,133	-	7,796	151,772	143,609	-	8,163
4	Other	24,498	-	(4,300)	20,198	24,252	-	(6,947) (ii)	17,304	23,924	-	(6,119) (ii)	17,805
5		1,726,343	85,703	(4,300)	1,636,340	2,260,200	118,694	(22,517)	2,118,989	2,246,773	143,242	(25,566)	2,077,965
	Operating Expenses:												
6	Cost of gas	701,966	539	-	701,427	1,070,458	23,924	(15,570) (i)	1,030,965	960,481	36,499	(16,839) (i)	907,143
7	Operating and maintenance expenses	397,112	12,986	(993)	383,132	427,708	13,450	(831) (iii)	413,427	461,872	13,451	(1,494) (iii)	446,928
8	Depreciation	205,804	9,713	-	196,091	265,117	10,236	-	254,881	287,543	10,676	-	276,867
9	Other financing	-	-	1,179	1,179	-	-	1,013 (iv)	1,013	-	-	998 (iv)	998
10	Property and other taxes	64,674	1,402	-	63,272	73,690	1,369	-	72,321	77,786	1,489	-	76,297
11		1,369,556	24,640	186	1,345,101	1,836,973	48,979	(15,387)	1,772,606	1,787,683	62,115	(17,335)	1,708,234
	Other Income (Expense)												
12	Gain/(Loss) on sale of assets	-	-	-	-	(214)	(210)	-	(3)	(1,803)	(1,824)	-	21
13	Other	-	-	-	-	-	-	-	-	-	-	-	-
14	Gain/(Loss) on foreign exchange	-	-	-	-	(873)	(47)	(612) (v)	(1,438)	3,028	2,282	493 (v)	1,239
15		-	-	-	-	(1,087)	(257)	(612)	(1,441)	1,225	458	493	1,260
16	Earnings Before Interest and Taxes	$ 356,787	$ 61,063	$ (4,486)	$ 291,239	$ 422,140	$ 69,457	$ (7,742)	$ 344,941	$ 460,315	$ 81,585	$ (7,738)	$ 370,991

Notes:

i)	Reclassification of optimization revenue as cost of gas	(16,839)
	Reduction to revenue to reflect the impact of Bill C-97 (accelerated CCA), enacted June 21, 2019:	
	Impact captured in CPT deferral accounts	(314)
	Ratepayer 50% of non-CPT CCA impact captured in Tax Variance Account	(940)
	Elimination for shareholder 50% of non-CPT CCA impact	(940)
	Total Asset CCA Impact	(2,194)
	Elimination for shareholder 50% of HST tax variance impact	(413)
		(19,447)
ii)	Demand Side Management Incentive	
iii)	Charitable donations	2,547
	CDM Program	(1,054)
		1,494
iv)	Facility fees and customer deposit interest	
v)	Foreign exchange gain on bank balances	

UNION RATE ZONES
Summary of Cost of Capital
Year Ended December 31

Line No.	Particulars	2013 Board-Approved Utility Capital Structure ($000s)	2013 Board-Approved Utility Capital Structure (%)	2013 Board-Approved Cost Rate %	2013 Board-Approved Return ($000s)	2017 Actual Utility Capital Structure ($000s)	2017 Actual Utility Capital Structure (%)	2017 Actual Cost Rate %	2017 Actual Return ($000s)	2018 Actual Utility Capital Structure ($000s)	2018 Actual Utility Capital Structure (%)	2018 Actual Cost Rate %	2018 Actual Return ($000s)
1	Long-term debt	2,289,139	61.30%	6.53%	149,481	3,319,044	60.63%	4.98%	165,315	3,572,945	59.37%	4.51%	161,247
2	Unfunded short-term debt	(1,287)	(0.03%)	1.31%	(17)	80,163	1.46%	1.02%	818	187,550	3.12%	1.72%	3,226
3	Total debt	2,287,852	61.26%		149,464	3,399,207	62.10%		166,133	3,760,495	62.48%		164,473
4	Preference shares	102,248	2.74%	3.05%	3,117	104,095	1.90%	2.66%	2,769	91,262	1.52%	3.18%	2,901
5	Common equity	1,344,432	36.00%	8.93%	120,058	1,970,608	36.00%	8.93%	175,975	2,166,613	36.00%	8.93%	193,479
6	Total rate base	$ 3,734,532	100.00%		$ 272,639	$ 5,473,910	100.00%		$ 344,877	$ 6,018,370	100.00%		360,852

UNION RATE ZONES
Total Weather Normalized Throughput Volume by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2017						Actual 2018					
Line No.	Volumes in 10^3m^3	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702	-	2,939,543	2,668,054	202,643	967	16,259	-	2,887,923	2,922,893	208,576	(0)	20,081	-	3,151,550
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-	975,571	603,585	331,644	942	275,202	-	1,211,373	626,755	360,562	-	290,311	-	1,277,628
3	Rate 01 Firm	641,423	233,272	-	9,727	-	884,421	854,157	69,059	-	10,105	-	933,321	920,267	67,711	-	11,540	-	999,518
4	Rate 10 Firm	155,398	82,428	-	85,062	-	322,887	174,872	74,443	-	94,729	4,392	348,435	179,148	74,012	-	97,177	4,174	354,511
5	Total General Service	3,446,401	1,118,404	208,642	348,975	-	5,122,423	4,300,668	677,789	1,909	396,295	4,392	5,381,052	4,649,064	710,861	(0)	419,110	4,174	5,783,208
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	60,750	-	60,750	23,509	-	-	45,665	-	69,174	27,915	-	-	51,031	-	78,946
7	Rate M10 Firm	48	-	-	141	-	189	274	-	-	-	-	274	410	-	-	-	-	410
8	Total Wholesale - Utility	48	-	-	60,891	-	60,939	23,782	-	-	45,665	-	69,447	28,325	-	-	51,031	-	79,356
	Contract							-	-	-	-	-	-	-	-	-	-	-	-
9	Rate M4	16,855	-	-	387,823	-	404,678	40,356	20,534	-	488,870	-	549,760	44,094	23,408	-	589,260	-	656,761
10	Rate M7	-	-	-	147,143	-	147,143	22,229	2,803	-	482,660	-	507,692	26,514	3,164	-	484,158	-	513,836
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	13,514	-	-	110,097	506,191	629,802	13,127	-	-	95,981	392,391	501,499	13,385	-	-	98,068	366,651	478,104
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,895,488	1,895,488	-	-	-	-	1,029,145	1,029,145	-	-	-	-	1,038,045	1,038,045
15	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	548,986	548,986	-	-	-	-	458,243	458,243	-	-	-	-	466,596	466,596
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,880,297	4,880,297	-	-	-	-	3,762,498	3,762,498	-	-	-	-	4,101,435	4,101,435
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	272,712	272,712	-	-	-	-	257,343	257,343	-	-	-	-	279,794	279,794
21	Rate M5	14,152	-	-	520,981	-	535,132	6,806	4,232	-	129,610	-	140,648	6,721	3,514	-	63,772	-	74,007
22	Rate 25	42,913	-	-	-	116,643	159,555	39,902	-	-	-	67,095	106,997	71,301	-	-	-	84,825	156,126
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	87,433	-	-	1,166,044	8,220,317	9,473,795	122,420	27,569	-	1,197,120	5,966,716	7,313,825	162,015	30,086	-	1,235,257	6,337,347	7,764,704
25	Total Throughput Volume	3,533,882	1,118,404	208,642	1,575,911	8,220,317	14,657,156	4,446,870	705,358	1,909	1,639,080	5,971,108	12,764,325	4,839,404	740,947	(0)	1,705,397	6,341,521	13,627,268

UNION RATE ZONES
Throughput Volume by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

Board Approved 2013

Line No.	Volumes in 10^3m^3	System Sales (a)	ABC-T (b)	ABC-Unbundled (c)	Bundled-T (d)	T-Service (e)	Total (f)
	General Service						
1	Rate M1 Firm	2,271,443	465,977	185,421	16,702	-	2,939,543
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-	975,571
3	Rate 01 Firm	641,423	233,272	-	9,727	-	884,421
4	Rate 10 Firm	155,398	82,428	-	85,062	-	322,887
5	Total General Service	3,446,401	1,118,404	208,642	348,975	-	5,122,423
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	60,750	-	60,750
7	Rate M10 Firm	48	-	-	141	-	189
8	Total Wholesale - Utility	48	-	-	60,891	-	60,939
	Contract						
9	Rate M4	16,855	-	-	387,823	-	404,678
10	Rate M7	-	-	-	147,143	-	147,143
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	13,514	-	-	110,097	506,191	629,802
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,895,488	1,895,488
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	548,986	548,986
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,880,297	4,880,297
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	272,712	272,712
21	Rate M5	14,152	-	-	520,981	-	535,132
22	Rate 25	42,913	-	-	-	116,643	159,555
23	Rate 30	-	-	-	-	-	-
24	Total Contract	87,433	-	-	1,166,044	8,220,317	9,473,795
25	Total Throughput Volume	3,533,882	1,118,404	208,642	1,575,911	8,220,317	14,657,156

Actual 2017

Line No.	Volumes in 10^3m^3	System Sales (g)	ABC-T (h)	ABC-Unbundled (i)	Bundled-T (j)	T-Service (k)	Total (l)
	General Service						
1	Rate M1 Firm	2,698,889	204,985	978	16,447	-	2,921,299
2	Rate M2 Firm	606,311	333,142	946	276,445	-	1,216,844
3	Rate 01 Firm	882,205	71,327	-	10,437	-	963,968
4	Rate 10 Firm	179,201	76,286	-	97,074	4,501	357,062
5	Total General Service	4,366,606	685,740	1,924	400,402	4,501	5,459,173
	Wholesale - Utility						
6	Rate M9 Firm	23,509	-	-	45,665	-	69,174
7	Rate M10 Firm	274	-	-	-	-	274
8	Total Wholesale - Utility	23,782	-	-	45,665	-	69,447
	Contract						
9	Rate M4	40,356	20,534	-	488,870	-	549,760
10	Rate M7	22,229	2,803	-	482,660	-	507,692
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	13,127	-	-	95,981	392,391	501,499
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,029,145	1,029,145
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	458,243	458,243
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	3,762,498	3,762,498
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	257,343	257,343
21	Rate M5	6,806	4,232	-	129,610	-	140,648
22	Rate 25	39,902	-	-	-	67,095	106,997
23	Rate 30	-	-	-	-	-	-
24	Total Contract	122,420	27,569	-	1,197,120	5,966,716	7,313,825
25	Total Throughput Volume	4,512,808	713,309	1,924	1,643,188	5,971,216	12,842,446

Actual 2018

Line No.	Volumes in 10^3m^3	System Sales (m)	ABC-T (n)	ABC-Unbundled (o)	Bundled-T (p)	T-Service (q)	Total (r)
	General Service						
1	Rate M1 Firm	2,960,778	211,279	(0)	20,341		3,192,398
2	Rate M2 Firm	634,774	365,175		294,026		1,293,975
3	Rate 01 Firm	948,438	69,784		11,893		1,030,116
4	Rate 10 Firm	184,314	76,146		99,979	4,294	364,734
5	Total General Service	4,728,304	722,384	(0)	426,240	4,294	5,881,223
	Wholesale - Utility						
6	Rate M9 Firm	27,915			51,031		78,946
7	Rate M10 Firm	410					410
8	Total Wholesale - Utility	28,325	-	-	51,031	-	79,356
	Contract						
9	Rate M4	44,094	23,408		589,260		656,761
10	Rate M7	26,514	3,164		484,158		513,836
11	Rate 20 Storage						
12	Rate 20 Transportation	13,385			98,068	366,651	478,104
13	Rate 100 Storage						
14	Rate 100 Transportation					1,038,045	1,038,045
15	Rate T-1 Storage						
16	Rate T-1 Transportation					466,596	466,596
17	Rate T-2 Storage						
18	Rate T-2 Transportation					4,101,435	4,101,435
19	Rate T-3 Storage						
20	Rate T-3 Transportation					279,794	279,794
21	Rate M5	6,721	3,514		63,772		74,007
22	Rate 25	71,301				84,825	156,126
23	Rate 30						
24	Total Contract	162,015	30,086	-	1,235,257	6,337,347	7,764,704
25	Total Throughput Volume	4,918,645	752,470	(0)	1,712,527	6,341,641	13,725,283

UNION RATE ZONES
Weather Normalized Gas Sales Revenue by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2017						Actual 2018					
Line No.	Particulars ($000's)	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	693,117	58,944	24,671	889	-	777,621	834,542	25,266	95	1,053	-	860,956	809,351	23,785	(0)	1,275	-	834,411
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	131,622	19,348	46	14,665	40	165,722	119,168	21,467	-	15,874	-	156,509
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	371,824	18,308	-	2,036	-	392,169	365,428	16,851	-	2,226	-	384,505
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	51,488	10,776	-	12,664	280	75,209	47,028	10,466	-	12,454	204	70,151
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,389,477	73,699	141	30,419	319	1,494,055	1,340,974	72,570	(0)	31,829	204	1,445,577
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	4,097	-	-	676	-	4,773	4,261	-	-	775	-	5,036
7	Rate M10 Firm	11	-	-	7	-	18	60	-	-	-	-	60	84	-	-	-	-	84
8	Total Wholesale - Utility	11	-	-	734	-	745	4,156	-	-	676	-	4,832	4,345	-	-	775	-	5,120
	Contract																		
9	Rate M4	3,407	-	-	11,786	-	15,193	8,176	818	-	19,545	-	28,539	7,929	1,077	-	26,636	-	35,642
10	Rate M7	-	-	-	4,127	-	4,127	4,433	302	-	10,839	-	15,575	4,402	325	-	12,252	-	16,979
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	3,001	3,001	-	-	-	-	2,937	2,937
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	3,100	-	-	6,119	10,189	19,408	3,087	-	-	5,899	15,531	24,517
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	306	306	-	-	-	-	235	235
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	10,621	10,621	-	-	-	-	10,172	10,172
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,476	1,476	-	-	-	-	1,305	1,305
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	(73)	-	-	-	9,870	9,797	-	-	-	-	11,466	11,466
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	6,619	6,619	-	-	-	-	6,490	6,490
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	52,903	52,903	-	-	-	-	62,533	62,533
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,315	1,315	-	-	-	-	1,300	1,300
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	5,388	5,388	-	-	-	-	5,642	5,642
21	Rate M5	2,801	-	-	12,913	-	15,713	1,330	147	-	4,936	-	6,413	1,155	125	-	2,305	-	3,586
22	Rate 25	10,172	-	-	-	3,273	13,445	8,039	-	-	-	1,874	9,914	12,781	-	-	-	2,309	15,091
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610	25,006	1,267	-	41,439	103,562	171,274	29,354	1,528	-	47,092	119,920	197,894
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,418,639	74,966	141	72,534	103,881	1,670,162	1,374,673	74,098	(0)	79,697	120,124	1,648,592
26	LRAM						-						628						412
27	Average Use / Normalized Average Consumption						-						(2,926)						(20,322)
28	Parkway Obligation Rate Variance						-						(161)						-
29	Capital Pass Through (CPT)						-						207						(410)
30	Normalized Cap and Trade Revenue						-						233,916						143,544
31	Community Expansion						-						-						131
32	Bill C-97 (Accelerated CCA) Ratepayer Revenue Adjustment*						-						-						(1,254)
33	Bill C-97 (Accelerated CCA) 50% Shareholder Revenue Adjustment						-						-						(940)
34	Tax Variance (HST) 50% Shareholder Revenue Adjustment						-						-						(413)
35	Total Revenue					$	1,448,762						1,901,826						1,769,339

*includes revenue reduction related to 50% ratepayer portion of Bill C-97 in the Tax Variance Account and 100% of Bill C-97 CPT impact.

UNION RATE ZONES
Total Gas Sales Revenue by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2017						Actual 2018					
Line No.	Particulars ($000's)	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	693,117	58,944	24,671	889	-	777,621	809,239	24,891	94	1,037	-	835,262	817,585	23,903	(0)	1,282	-	842,770
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	126,198	18,637	45	14,126	38	159,043	121,010	21,719	-	16,061	-	158,790
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	367,206	18,112	-	2,012	-	387,329	375,169	17,230	-	2,280	-	394,680
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	50,795	10,621	-	12,480	276	74,172	48,617	10,776	-	12,826	209	72,429
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,353,438	72,261	138	29,655	314	1,455,806	1,362,382	73,628	(0)	32,449	209	1,468,668
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	4,097	-	-	676	-	4,773	4,261	-	-	775	-	5,036
7	Rate M10 Firm	11	-	-	7	-	18	60	-	-	-	-	60	84	-	-	-	-	84
8	Total Wholesale - Utility	11	-	-	734	-	745	4,156	-	-	676	-	4,832	4,345	-	-	775	-	5,120
	Contract																		
9	Rate M4	3,407	-	-	11,786	-	15,193	8,176	818	-	19,545	-	28,539	7,929	1,077	-	26,636	-	35,642
10	Rate M7	-	-	-	4,127	-	4,127	4,433	302	-	10,839	-	15,575	4,402	325	-	12,252	-	16,979
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	3,001	3,001	-	-	-	-	2,937	2,937
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	3,100	-	-	6,119	10,189	19,408	3,087	-	-	5,899	15,531	24,517
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	306	306	-	-	-	-	235	235
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	10,621	10,621	-	-	-	-	10,172	10,172
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,476	1,476	-	-	-	-	1,305	1,305
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	(73)	-	-	-	9,870	9,797	-	-	-	-	11,466	11,466
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	6,619	6,619	-	-	-	-	6,490	6,490
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	52,903	52,903	-	-	-	-	62,533	62,533
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,315	1,315	-	-	-	-	1,300	1,300
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	5,388	5,388	-	-	-	-	5,642	5,642
21	Rate M5	2,801	-	-	12,913	-	15,713	1,330	147	-	4,936	-	6,413	1,155	125	-	2,305	-	3,586
22	Rate 25	10,172	-	-	-	3,273	13,445	8,039	-	-	-	1,874	9,914	12,781	-	-	-	2,309	15,091
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610	25,006	1,267	-	41,439	103,562	171,274	29,354	1,528	-	47,092	119,920	197,894
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,382,600	73,528	138	71,771	103,876	1,631,913	1,396,081	75,157	(0)	80,316	120,129	1,671,683
26	LRAM						-						628						412
27	Average Use / Normalized Average Consumption						-						(2,926)						(20,322)
28	Parkway Obligation Rate Variance						-						(161)						-
29	Capital Pass Through (CPT)						-						207						(410)
30	Cap and Trade Revenue						-						227,291						144,231
31	Community Expansion						-						-						131
32	Bill C-97 (Accelerated CCA) Ratepayer Revenue Adjustment*						-						-						(1,254)
33	Bill C-97 (Accelerated CCA) 50% Shareholder Revenue Adjustment						-						-						(940)
34	Tax Variance (HST) 50% Shareholder Revenue Adjustment						-						-						(413)
35	Total Revenue					$	1,448,762						1,856,952						1,793,117

UNION RATE ZONES
Delivery Revenue by Service type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Approved 2013						Actual 2017						Actual 2018					
Line No.	Particulars ($000's)	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	303,298	58,944	24,671	889	-	387,801	397,910	24,891	94	1,037	-	423,932	427,168	23,903	(0)	1,282	-	452,353
2	Rate M2 Firm	19,898	17,612	2,631	11,466	-	51,607	33,974	18,637	45	14,126	38	66,819	37,681	21,719	-	16,061	-	75,461
3	Rate 01 Firm	118,812	41,509	-	928	-	161,249	158,048	11,354	-	1,016	-	170,419	167,625	10,551	-	1,155	-	179,332
4	Rate 10 Firm	9,524	5,578	-	4,876	-	19,979	11,245	4,911	-	5,194	276	21,627	11,660	5,133	-	5,430	209	22,432
5	Total General Service	451,532	123,643	27,301	18,159	-	620,636	601,177	59,793	138	21,374	314	682,797	644,135	61,307	(0)	23,927	209	729,577
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	536	-	-	676	-	1,212	579	-	-	775	-	1,354
7	Rate M10 Firm	2	-	-	7	-	10	19	-	-	-	-	19	29	-	-		-	29
8	Total Wholesale - Utility	2	-	-	734	-	736	554	-	-	676	-	1,230	608	-	-	775	-	1,384
	Contract																		
9	Rate M4	514	-	-	11,786	-	12,300	1,956	818	-	19,545	-	22,319	2,215	1,077	-	26,636	-	29,928
10	Rate M7	-	-	-	4,127	-	4,127	943	302	-	10,839	-	12,085	1,020	325	-	12,252	-	13,597
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	434	-	-	2,425	10,637	13,496	434	-	-	2,053	10,189	12,676	546	-	-	2,038	15,531	18,115
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	10,621	10,621	-	-	-	-	10,172	10,172
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,476	1,476	-	-	-	-	1,305	1,305
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	9,772	9,772	-	-	-	-	11,463	11,463
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	6,619	6,619	-	-	-	-	6,490	6,490
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	52,781	52,781	-	-	-	-	62,469	62,469
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,315	1,315	-	-	-	-	1,300	1,300
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	5,388	5,388	-	-	-	-	5,642	5,642
21	Rate M5	375	-	-	12,913	-	13,288	289	147	-	4,936	-	5,371	280	125	-	2,305	-	2,711
22	Rate 25	1,200	-	-	-	3,273	4,473	1,197	-	-	-	1,874	3,072	2,167	-	-	-	2,309	4,476
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	2,524	-	-	31,250	86,601	120,375	4,820	1,267	-	37,374	100,035	143,496	6,227	1,528	-	43,231	116,682	167,668
25	Subtotal	454,058	123,643	27,301	50,143	86,601	741,747	606,551	61,060	138	59,424	100,349	827,522	650,970	62,835	(0)	67,933	116,891	898,629
26	LRAM						-						628						412
27	Average Use / Normlalized Average Consumption						-						(2,941)						(17,853)
28	Tax Rate Change Impact Adjustment						-						-						-
29	Parkway Obligation Rate Variance						-						(161)						-
30	Capital Pass Through (CPT)						-						207						(410)
31	Cap and Trade Revenue						-						227,291						144,231
32	Community Expansion						-						-						131
33	Bill C-97 (Accelerated CCA) Ratepayer Revenue Adjustment*						-						-						(1,254)
34	Bill C-97 (Accelerated CCA) 50% Shareholder Revenue Adjustment						-						-						(940)
35	Tax Variance (HST) 50% Shareholder Revenue Adjustment						-						-						(413)
34	Total Revenue					$	741,747						1,052,547						1,022,533

UNION RATE ZONES
Total Customers by Service Type and Rate Class
All Customer Rate Classes
Year Ended December 31

		Board Apprroved 2013						Actual 2017						Actual 2018					
Line No.	Particulars	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	837,301	157,165	72,389	902	-	1,067,757	1,061,695	55,360	1	1,093	-	1,118,149	1,086,206	47,763	-	1,154	-	1,135,123
2	Rate M2 Firm	3,172	2,594	241	771	-	6,778	4,256	2,371	-	760	-	7,387	4,355	2,369	-	852	-	7,576
3	Rate 01 Firm	242,644	80,300	-	343	-	323,287	327,139	18,909	-	639	-	346,687	334,787	16,562	-	659	-	352,008
4	Rate 10 Firm	930	845	-	289	-	2,064	1,375	564	-	294	5	2,238	1,211	556	-	295	5	2,067
5	Total General Service	1,084,047	240,904	72,630	2,305	-	1,399,886	1,394,465	77,204	1	2,786	5	1,474,461	1,426,559	67,250	-	2,960	5	1,496,774
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	3	-	3	1	-	-	2	-	3	1	-	-	2	-	3
7	Rate M10 Firm	1	-	-	1	-	2	3	-	-	-	-	3	3	-	-	-	-	3
8	Total Wholesale - Utility	1	-	-	4	-	5	4	-	-	2	-	6	4	-	-	2	-	6
	Contract																		
9	Rate M4	11	-	-	104	-	115	22	10	-	172	-	204	26	11	-	170	-	207
10	Rate M7	-	-	-	4	-	4	2	1	-	27	-	30	2	1	-	28	-	31
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	4	-	-	20	39	63	4	-	-	16	24	44	5	-	-	15	24	44
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	17	17	-	-	-	-	11	11	-	-	-	-	11	11
15	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	35	35	-	-	-	-	38	38	-	-	-	-	36	36
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	29	29	-	-	-	-	23	23	-	-	-	-	25	25
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	1	1	-	-	-	-	1	1	-	-	-	-	1	1
21	Rate M5	5	-	-	139	-	144	6	2	-	30	-	38	6	3	-	30	-	39
22	Rate 25	50	-	-	-	42	92	44	-	-	-	44	88	35	-	-	-	44	79
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	70	-	-	267	163	500	78	13	-	245	141	477	74	15	-	243	141	473
25	Total Number of Customers	1,084,118	240,904	72,630	2,576	163	1,400,391	1,394,547	77,217	1	3,033	146	1,474,944	1,426,637	67,265	-	3,205	146	1,497,253

UNION RATE ZONES
Revenue from Regulated Storage and Transportation of Gas
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2017 Actual	2018 Actual
		(a)	(b)	(c)
	Revenue from Regulated Storage Services:			
1	C1 Off-Peak Storage	500	709	141
2	Supplemental Balancing Services	2,000	1,271	1,583
3	Gas Loans	-	15	15
4	C1 Short Term Firm Peak Storage	7,883	4,618	5,011
5	Short Term Storage and Balancing Services Deferral	-	1,183	1,413
6	Total Regulated Storage Revenue Net of Deferral	$ 10,383	$ 7,796	$ 8,163
	Revenue from Regulated Transportation Services:			
7	M12 Transportation	120,963	180,310	192,688
8	M12-X Transportation	13,896	20,144	21,812
9	C1 Long Term Transportation	7,039	18,410	25,460
10	C1 Short Term Transportation	11,067	8,318	9,546
11	Gross Exchange Revenue	14,918	5,015	7,296
12	Ratepayer Portion of Exchange Revenue (1)	(13,426)	(4,513)	(6,567)
13	M13 Local Production	424	316	248
14	M16 Transportation	694	505	1,096
15	S&T:Transportation Revenue Cap & Trade	-	5,018	3,061
16	Other S&T Revenue	1,423	3,414	4,238
17	Total Regulated Transportation Revenue Net of Deferral	$ 156,997	$ 236,937	$ 258,879

UNION RATE ZONES
Other Revenue
Year Ended December 31

Line No.	Particulars ($000's)	2013 Board Approved	2017 Actual	2018 Actual
1	Delayed payment charges	6,467	6,644	7,266
2	Account opening charges	7,000	6,395	5,975
3	Billing revenue	3,453	1,485	1,305
4	Mid market transactions	2,000	1,114	970
5	Other operating revenue	1,278	1,666	2,289
6	Total other revenue	$ 20,198	$ 17,304	$ 17,805

UNION RATE ZONES
Operating and Maintenance Expense by Cost Type
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2017 Actual	2018 Actual
		(a)	(b)	(c)
1	Salaries/Wages	192,786	221,758	244,494
2	Benefits	81,083	60,709	65,937
3	Materials	9,958	10,239	12,091
4	Employee Training	14,330	12,426	12,076
5	Contract Services	66,376	70,599	77,412
6	Consulting	8,172	8,162	11,131
7	General	18,890	27,895	27,969
8	Transportation and Maintenance	9,761	9,845	10,209
9	Company Used Gas	2,611	1,936	2,003
10	Utility Costs	4,682	5,968	5,528
11	Communications	6,380	5,658	4,119
12	Demand Side Management Programs	24,031	48,052	51,190
13	Advertising	2,386	3,449	3,285
14	Insurance	9,056	6,785	2,323
15	Donations	788	899	2,615
16	Financial	1,871	2,724	2,028
17	Lease	4,191	4,733	4,812
18	Cost Recovery from Third Parties	(2,549)	(3,731)	(11,051)
19	Computers	6,465	10,782	7,767
20	Regulatory Hearing & OEB Cost Assessment	4,300	3,563	4,676
21	Outbound Affiliate Services	(13,706)	(15,842)	(9,507)
22	Inbound Affiliate Services	11,888	22,613	22,949
23	Bad Debt	6,250	4,050	4,689
24	Other	139	-	-
25	Total	470,139	523,272	558,745
26	Indirect Capitalization	(51,376)	(73,017)	(76,037)
27	Direct Capitalization	(21,652)	(22,547)	(20,836)
28	Total	397,111	427,708	461,873
29	Unregulated Storage	(12,883)	(13,450)	(13,451)
30	Non Utility Earnings Adjustments	(1,096)	(831)	(1,494)
31	Total Non Utility Costs	(13,979)	(14,281)	(14,945)
32	Total Net Utility Operating and Maintenance Expense	$ 383,132	$ 413,427	$ 446,928

UNION RATE ZONES
Calculation of Utility Income Taxes
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2017 Actual	2018 Actual
		(a)	(b)	(c)
	Determination of Taxable Income			
1	Utility income before interest and income taxes	291,239	344,941	370,991
	Adjustments required to arrive at taxable utility income:			
2	Interest expense	(149,464)	(166,133)	(164,473)
3	Utility permanent differences	4,693	2,283	1,441
4		146,468	181,091	207,959
	Utility timing differences			
5	Capital Cost Allowance	(185,314)	(344,183)	(394,842)
6	Depreciation	196,091	254,881	276,868
7	Depreciation through clearing	2,265	2,867	2,598
8	Other	(32,921)	(65,329)	(62,773)
9	Gas Cost Deferrals and Other (current)	-	(2,655)	36,135
10		(19,879)	(154,418)	(142,014)
11	Taxable income	$ 126,589	$ 26,673	$ 65,945
	Calculation of Utility Income Taxes			
12	Income taxes (line 11 * line 19)	32,280	7,068	17,475
13	Deferred tax on Gas Cost Deferrals	-	704	(9,576)
14	Capital Asset Review benefit (CAR)	-	-	(1,092)
15	Deferred tax drawdown	(15,169)	(12,819)	(12,819)
16	Total taxes	$ 17,111	$ (5,047)	$ (6,012)
	Tax Rates			
17	Federal tax	15.00%	15.00%	15.00%
18	Provincial tax	10.50%	11.50%	11.50%
19	Total tax rate	25.50%	26.50%	26.50%

UNION RATE ZONES
Calculation of Capital Cost Allowance (CCA)
Year Ended December 31

Line No.	Class	Particulars ($000s)	2013 Board-Approved Depreciable UCC Balance (a)	2013 Board-Approved Rate (%) (b)	2013 Board-Approved CCA (c)	2017 Actual Depreciable UCC Balance (d)	2017 Actual Rate (%) (e)	2017 Actual CCA (f)	2018 Actual Depreciable UCC Balance (g)	2018 Actual Rate (%) (h)	2018 Actual CCA (i)
1	1	Buildings, structures and improvements, services, meters, mains	1,259,974	4%	50,399	1,118,311	4%	44,732	1,079,504	4%	43,180
2	1	Non-residential building acquired after March 19, 2007	83,527	6%	5,012	111,588	6%	6,695	122,121	6%	7,327
3	2	Mains acquired before 1988	147,495	6%	8,850	114,246	6%	6,855	108,302	6%	6,498
4	3	Buildings acquired before 1988	4,279	5%	214	3,462	5%	173	3,312	5%	166
5	6	Other buildings	173	10%	17	112	10%	11	102	10%	10
6	7	Compression equipment acquired after February 22, 2005	165,697	15%	24,855	598,187	15%	89,728	779,768	15%	116,965
7	8	Compression assets, office furniture, equipment	79,640	20%	15,928	189,423	20%	37,885	229,166	20%	45,833
8	10	Transportation, computer equipment	18,611	30%	5,583	15,100	30%	4,530	17,558	30%	5,267
9	12	Computer software, small tools	7,701	100%	7,701	2,630	100%	2,630	4,018	100%	4,018
10	13	Leasehold improvements (1)	332	N/A	113	1,827	N/A	545	1,803	N/A	434
11	14.1	Intangibles				2,079	5%	104	5,404	5%	270
12	14.1	Intangibles (pre 2017)				21,949	7%	1,536	20,617	7%	1,443
13	17	Roads, sidewalk, parking lot or storage areas	946	8%	76	671	8%	54	624	8%	50
14	38	Heavy work equipment	6,878	30%	2,063	2,532	30%	760	3,421	30%	1,026
15	41	Storage assets	8,019	25%	2,005	5,841	25%	1,460	8,037	25%	2,009
16	45	Computers - Hardware acquired after March 22, 2004	246	45%	111	21	45%	10	13	45%	6
17	49	Transmission pipeline additions acquired after February 23, 2005	204,628	8%	16,370	666,696	8%	53,336	745,639	8%	59,651
18	50	Computers hardware acquired after March 18, 2007	22,934	55%	12,614	48,117	55%	26,464	38,005	55%	20,903
19	51	Distribution pipelines acquired after March 18, 2007	556,733	6%	33,404	1,111,254	6%	66,675	1,329,750	6%	79,785
20		Total	$ 2,567,813		$ 185,314	$ 4,014,047		$ 344,183	$ 4,497,165		$ 394,842

Notes:
(1) The CCA rate depends on the type of the leasehold and the terms of the lease.

UNION RATE ZONES
Provision for Depreciation,Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2017 Actual	2018 Actual
1	Total provision for depreciation and amortization before adjustments (per page 3)	-	257,748	279,466
2	Adjustments: vehicle depreciation through clearing	-	2,867	2,598
3	Provision for depreciation amortization and depletion	$ -	$ 254,881	$ 276,868

UNION RATE ZONES
Provision for Depreciation, Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved Average Plant (1)	Rate (%)	Provision		2017 Actual Average Plant (1)	Rate (%)		Provision		2018 Actual Average Plant (1)	Rate (%)		Provision
		(a)	(b)	(c)		(d)	(e)		(f)		(g)	(h)		(i)
	Intangible plant:													
1	Franchises and consents	-	-	-	$	1,186	Amortized		60		1,175	Amortized		60
2	Intangible plant - Other	-	-	-		3,421	Amortized		121		495	Amortized		5
3		-		-		4,606			182		1,670			65
	Local Storage Plant													
4	Structures and improvements	-	2.85%	-		4,414	2.85%		126		4,672	2.85%		133
5	Gas holders - storage	-	2.54%	-		4,604	2.54%		117		4,609	2.54%		117
6	Gas holders - equipment	-	3.54%	-		18,477	3.54%		654		19,749	3.54%		699
7		-		-		27,494			897		29,029			949
	Storage:													
8	Land rights	-	2.10%	-		31,985	2.10%		672		31,985	2.10%		672
9	Structures and improvements	-	2.50%	-		64,860	2.50%		1,622		68,148	2.50%		1,704
10	Wells and lines	-	2.48%	-		92,506	2.48%		2,294		93,751	2.48%		2,325
11	Compressor equipment	-	2.68%	-		373,329	2.68%		10,005		471,267	2.68%		12,630
12	Measuring & regulating equipment	-	3.11%	-		69,208	3.11%		2,152		82,369	3.11%		2,562
13	Other equipment	-		-		0			-		-			-
14		-		-		631,888			16,745		747,520			19,892
	Transmission:													
15	Land rights	-	1.76%	-		59,573	1.76%		1,048		61,915	1.76%		1,090
16	Structures and improvements	-	2.03%	-		146,751	2.03%		2,979		163,253	2.03%		3,314
17	Mains	-	1.98%	-		1,654,158	1.98%		32,752		1,765,830	1.98%		34,964
18	Compressor equipment	-	3.23%	-		802,626	3.23%		25,925		931,970	3.23%		30,106
19	Measuring & regulating equipment	-	2.60%	-		246,525	2.60%		6,410		265,516	2.60%		6,901
20		-		-		2,909,633			69,115		3,188,484			76,374
	Distribution - Southern Operations:													
21	Land rights	-	1.65%	-		7,533	1.65%		124		7,830	1.65%		129
22	Structures and improvements	-	2.22%	-		134,789	2.22%		3,003		134,563	2.22%		3,021
23	Services - metallic	-	2.81%	-		122,839	2.81%		3,452		123,639	2.81%		3,474
24	Services - plastic	-	2.51%	-		860,697	2.51%		21,604		885,056	2.51%		22,215
25	Regulators	-	5.00%	-		78,339	5.00%		3,917		81,940	5.00%		4,097
26	Regulator and meter installations	-	2.80%	-		72,295	2.80%		2,024		71,633	2.80%		2,006
27	Mains - metallic	-	2.83%	-		489,825	2.83%		13,862		511,817	2.83%		14,484
28	Mains - plastic	-	2.31%	-		607,056	2.31%		14,023		632,901	2.31%		14,620
29	Measuring & regulating equipment	-	3.66%	-		41,731	3.66%		1,527		43,004	3.66%		1,574
30	Meters	-	3.82%	-		296,569	3.82%		11,329		320,039	3.82%		12,225
31	Other equipment	-		-		-			-		-			-
32		-		-	$	2,711,672		$	74,865	$	2,812,422		$	77,846

UNION RATE ZONES
Provision for Depreciation, Amortization and Depletion
Year Ended December 31

		2013 Board-Approved			2017 Actual			2018 Actual		
Line No.	Particulars ($000s)	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Distribution plant - Northern & Eastern Operations:									
1	Land rights	-	1.71%	-	$ 9,945	1.71%	170	10,172	1.71%	174
2	Structures & improvements	-	2.41%	-	65,838	2.41%	1,587	66,634	2.41%	1,606
3	Services - metallic	-	3.22%	-	104,276	3.22%	3,358	105,586	3.22%	3,400
4	Services - plastic	-	2.60%	-	446,796	2.60%	11,617	459,280	2.60%	11,941
5	Regulators	-	5.00%	-	29,848	5.00%	1,492	31,290	5.00%	1,564
6	Regulator and meter installations	-	2.92%	-	35,004	2.92%	1,022	39,806	2.92%	1,162
7	Mains - metallic	-	3.02%	-	468,715	3.02%	14,155	532,023	3.02%	16,067
8	Mains - plastic	-	2.38%	-	224,870	2.38%	5,352	229,616	2.38%	5,465
9	Compressor equipment	-	-	-	-	-	-	-	-	-
10	Measuring & regulating equipment	-	3.77%	-	133,177	3.77%	5,021	137,748	3.77%	5,193
11	Meters	-	4.03%	-	82,063	4.03%	3,307	85,210	4.03%	3,434
12	Other distribution equipment	-	-	-	-	-	-	-	-	-
13		-		-	1,600,532		47,081	1,697,366		50,007
	General:									
14	Structures and improvements	-	1.92%		59,152	1.92%	1,530	64,472	1.92%	1,346
15	Office furniture and equipment	-	6.67%	-	10,231	6.67%	679	10,173	6.67%	676
16	Office equipment - computers	-	25.00%	-	83,385	25.00%	19,008	92,658	25.00%	21,393
17	Transportation equipment	-	13.27%	-	56,169	13.27%	7,510	59,381	13.27%	7,885
18	Heavy work equipment	-	6.92%	-	14,902	6.92%	1,041	15,398	6.92%	1,068
19	Tools and other equipment	-	6.67%	-	34,192	6.67%	2,270	35,074	6.67%	2,333
20	NGV	-	-	-	-		-	670		27
21	Communications equipment & structures	-	6.67%	-	13,593	6.67%	901	13,845	6.67%	920
22	Other equipment	-	-	-	-	-	-	-	-	-
23		-		-	271,624		32,940	291,671		35,648
24	Regulatory Assets	-		-	477,079		15,924	558,905		18,685
25	Sub-total	-		-	8,634,528		257,748	9,327,067		279,466
26	Total provision for depreciation and amortization	-		-	-		257,748	-		279,466
27	Depreciation through clearing	-		-	-		2,867	-		2,598
28		-		-	$ 8,634,528		$ 254,881	$ 9,327,067		$ 276,868

Notes:
(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

UNION RATE ZONES

Capital Expenditure by Function
Includes IDC and Overheads
Year Ended December 31

Line No.	Particulars ($000's)	2013 Board-Approved	2017 Actual	2018 Actual
		(a)	(b)	(c)
1	Storage	11,562	91,618	25,700
2	Transmission	113,795	316,504	95,668
3	Distribution	131,797	197,415	270,665
4	General	37,215	34,940	43,931
5	Other	53,333	80,497	83,224
6	Total	$ 347,702	$ 720,974	$ 519,188
	Less: Parkway West Reliability, and Brantford-Kirkwall/Parkway D Project	80,000	2,976	1,092
		$ 267,702	$ 717,998	$ 518,096

UNION RATE ZONES
Statement of Utility Rate Base
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2017 Actual	2018 Actual
		(a)	(b)	(c)
	Gas Utility Plant			
1	Gross plant at cost	6,361,532	8,628,204	9,398,633
2	Less: accumulated depreciation	(2,754,070)	(3,347,472)	(3,524,240)
3	Net utility plant	3,607,462	5,280,732	5,874,393
	Working Capital and Other Components			
4	Cash working capital	20,007	22,541	24,027
5	Gas in storage and line pack gas	163,109	146,489	110,072
6	Balancing gas	72,963	65,672	55,747
7	ABC receivable (gas in storage)	(44,901)	(17,087)	(28,065)
8	Inventory of stores, spare equipment	29,618	31,751	32,173
9	Prepaid and deferred expenses	4,955	2,231	1,163
10	Customer deposits	(48,231)	(40,963)	(46,515)
11	Customer interest	(764)	(110)	(84)
12	Total working capital and other components	196,757	210,524	148,518
13	Total rate base before deduction of accumulated deferred income taxes	3,804,218	5,491,256	6,022,911
14	Accumulated deferred income taxes	(69,686)	(17,345)	(4,541)
15	Total rate base	$ 3,734,532	$ 5,473,910	$ 6,018,370

UNION RATE ZONES
Allocation of Fuel

Line No.	Particulars (GJ)	Board-approved	%	2018 Actual	%	2017 Actual	%	2016 Actual	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	M12	3,616,843	77%	3,767,891	78%	2,989,104	86%	1,746,256	85%
2	Other	1,057,714	23%	1,073,409	22%	495,297	14%	314,761	15%
3	Total Fuel	4,674,557	100%	4,841,300	100%	3,484,401	100%	2,061,017	100%

UNION RATE ZONES
Earnings Sharing Calculation
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000s)	2018 (a)	Non-Utility Storage (b)	Adjustments (c)		2018 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,812,564	-	(19,447)	i.	1,793,117
2	Transportation	258,512	(367)	-		258,879
3	Storage	151,772	143,609	-		8,163
4	Other	23,924	-	(6,119)	ii	17,805
5		2,246,773	143,242	(25,566)		2,077,965
	Operating Expenses					
6	Cost of gas	960,481	36,499	(16,839)	i.	907,143
7	Operating and maintenance expenses	461,872	13,451	(1,494)	iii	446,928
8	Depreciation	287,543	10,676	-		276,867
9	Other financing	-	-	998	iv	998
10	Property and other taxes	77,786	1,489	-		76,297
11		1,787,683	62,115	(17,335)		1,708,234
	Other					
12	Gain / (Loss) on sale of assets	(1,803)	(1,824)	-		21
13	Other / Huron Tipperary	-	-	-		-
14	Gain / (Loss) on foreign exchange	3,028	2,282	493	v	1,239
15		1,225	458	493		1,260
16	Earnings before interest and taxes	460,315	81,585	(7,738)		370,991
17	Income taxes					(6,012)
18	Total utility income subject to earnings sharing					377,002
	Less debt and preference share return components					
19	Long-term debt					161,247
20	Unfunded short-term debt					3,226
21	Preferred dividend requirements					2,901
22						167,374
	Less shareholder portions of:					
23	Net short-term storage revenue (after tax)					256
24	Net optimization activity (after tax)					536
25						793
26	Earnings subject to sharing					208,836
27	Common equity					2,166,613
28	Return on equity (line 26 / line 27)					9.64%
29	Benchmark return on equity					9.93%
30	50% earnings sharing % (line 28 - line 29, maximum 1%)					0.00%
31	90% earnings sharing % (if line 30=1%, then line 28 - line 29 - line 30)					0.00%
32	50% earnings sharing $ (line 27 x line 30 x 50%)					-
33	90% earnings sharing $ (line 27 x line 31 x 90%)					-
34	Total earnings sharing $ (line 32 + line 33)					-
35	Pre-tax earnings sharing (line 34 / (1 minus tax rate)					-

Notes:

i	Reclassification of optimization revenue as cost of gas	(16,839)
	Reduction to revenue to reflect the impact of Bill C-97 (accelerated CCA), enacted June 21, 2019:	
	Impact captured in CPT deferral accounts	(314)
	Ratepayer 50% of non-CPT CCA impact captured in Tax Variance Account	(940)
	Elimination for shareholder 50% of non-CPT CCA impact	(940)
	Total Asset CCA Impact	(2,194)
	Elimination for shareholder 50% of HST tax variance impact	(413)
	Total	(19,447)
ii	Demand-side management incentive	
iii	Donations	2,547
	CDM program	(1,054)
		1,494
iv	Facility fees and customer deposit interest	
v	Foreign exchange gain on bank balances	

UNION RATE ZONES
Continuity of Property, Plant and Equipment
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000's)	Balance Dec. 31/17 (a)	Capital Additions (b)	Transfers (c)	Retirements (d)	Balance Dec. 31/18 (e)
	Unregulated Gas Plant in Service:					
	Underground storage plant:					
1	Land	$ 2,179	0	65	(0)	$ 2,244
2	Land rights	29,930	-	-	-	29,930
3	Structures and improvements	25,924	114	(0)	(314)	25,723
4	Wells and lines	134,560	11,736	1,184	(920)	146,560
5	Compressor equipment	165,177	2,527	87	(5,590)	162,201
6	Measuring & regulating equipment	26,223	1,153	(4,068)	(39)	23,269
7	Base pressure gas	30,214	-	-	-	30,214
8	Other equipment	-	-	-	-	-
9		$ 414,208	15,530	(2,733)	(6,864)	$ 420,142
	General plant:					
10	Land	$ 17	-	-	-	$ 17
11	Structures & improvements	2,085	411	-	(15)	2,481
12	Office furniture & equipment	369	1	-	(3)	367
13	Office equipment - computers	4,505	256	-	(539)	4,222
14	Transportation equipment	2,434	286	-	(165)	2,556
15	Heavy work equipment	664	39	-	(11)	692
16	Tools & work equipment	1,250	96	-	(42)	1,303
17	NGV	-	(8)	60	-	52
18	Communication equipment	481	17	-	(11)	487
19	Other general equipment	-				-
20		$ 11,805	1,097	60	(787)	$ 12,175
21	Total gas plant in service	$ 426,013	16,628	(2,673)	(7,651)	$ 432,317
22	Gas plant under construction	10,428	(4,335)	-	-	6,093
23	Total unregulated property plant and equipment	$ 436,442	12,293	(2,673)	(7,651)	$ 438,411

UNION RATE ZONES
Continuity of Accumulated Depreciation
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000's)	Balance Dec. 31/17 (a)	Transfers (b)	Provisions (c)	Retirements (d)	Net Salvage /(Costs) (e)	Other Adjustments (f)	Balance Dec. 31/18 (g=a+b+c+d+e+f)
	Unregulated Gas Plant in Service:							
	Underground storage plant:							
1	Land	$ -	18	-	-	-	(18)	-
2	Land rights	10,544	-	603	-	-	-	11,147
3	Structures & improvements	11,551	1	748	(261)	-	0	12,039
4	Wells and lines	38,324	875	2,946	(334)	-	26	41,838
5	Compressor equipment	61,689	121	4,271	(5,529)	-	-	60,553
6	Measuring & regulating equipment	13,121	(85)	611	(31)	-	-	13,617
7		$ 135,230	931	9,180	(6,154)	-	8	139,194
	General plant:							
8	Structures & improvements	487		52	(15)			524
9	Office furniture & equipment	187	-	26	(3)	-	-	210
10	Office equipment - computers	2,345	-	829	(539)	-	-	2,634
11	Transportation equipment	1,365	-	326	(165)	19	-	1,544
12	Heavy work equipment	129	-	44	(11)	-	-	162
13	Tools and other equipment	587	-	90	(42)	-	-	635
14	NGV	-	47	1	-	-	-	48
15	Communication equipment	278	-	36	(11)	-	-	302
16		$ 5,377	47	1,404	(787)	19	-	6,060
17	Total unregulated gas plant in service	$ 140,606	978	10,584	(6,941)	19	8	145,254

UNION RATE ZONES
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000's)	UNREGULATED
1	Total unregulated provision for depreciation and amortization before adjustments (per page 2)	10,584
	Adjustments:	
2	Vehicle depreciation through clearing	(45)
3	Asset Retirement Obligation expense for Unregulated storage wells	109
4	Unregulated provision for depreciation amortization and depletion	**10,648**

UNION RATE ZONES
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2018

Line No.	Particulars ($000's)		Average Plant (1) (a)	Rate (%) (b)		Total Provision
	Storage:					
1	Land rights	$	29,930	Allocation	$	603
2	Structures and improvements		23,956	Allocation		748
3	Wells and lines		137,887	Allocation		2,946
4	Compressor equipment		154,733	Allocation		4,271
5	Measuring & regulating equipment		24,715	Allocation		611
6	Other equipment					
7		$	371,222		$	9,180
	General:					
8	Structures & improvements	$	2,283	Allocation	$	52
9	Office furniture and equipment		368	Allocation		26
10	Office equipment - computers		4,363	Allocation		829
11	Transportation equipment		2,495	Allocation		326
12	Heavy work equipment		678	Allocation		44
13	Tools and other equipment		1,277	Allocation		90
14	NGV		26			1
15	Communications equipment		484	Allocation		36
16	Other equipment		-			
17		$	11,974		$	1,404
18	Sub-total		383,196			10,584
19	Total unregulated provision for depreciation and amortization before adjustments				$	10,584
20	Vehicle depreciation through clearing					(45)
21	Asset Retirement Obligation expense for Unregulated storage wells					109
22	Unregulated provision for depreciation amortization and depletion		383,196		$	**10,648**

Notes:

(1) Average of the opening and closing plant balances (excluding fully depreciated assets) was used to calculate the annual depreciation provision.

UNION GAS RATE ZONE

Service Quality Indicator Results

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

S.2.1.9.A – TELEPHONE ANSWERING PERFORMANCE

S.2.1.9.A.1 Call Answering Service Level (CASL)

Measurement Calculation: CASL = Number of calls reaching a distributor's general inquiry number answered within 30 seconds dividedby the number of calls received by a distributor's general inquiry number (CASL should be rounded to the first decimal number, e.g.74.45% becomes 74.5%)

OEB Approved Standard: Yearly performance shall be 75% with a minimum monthly standard of 40%

Month	Number of Calls Reaching a Distributor's General Inquiry Number Answered Within 30 Seconds (1)	Number of Calls Received by a Distributor's General Inquiry Number (2)	Call Answering Service Level (%) (3 = 1 / 2 * 100)
Jan-18	62,417	84,433	73.9
Feb-18	63,754	80,238	79.5
Mar-18	81,734	103,488	79.0
Apr-18	66,681	92,346	72.2
May-18	69,096	85,425	80.9
Jun-18	84,532	110,782	76.3
Jul-18	61,446	80,714	76.1
Aug-18	66,202	81,075	81.7
Sep-18	80,984	107,536	75.3
Oct-18	67,628	89,959	75.2
Nov-18	69,988	84,476	82.8
Dec-18	65,037	81,909	79.4
Total	839,499	1,082,381	77.6

S.2.1.9.A.2 Abandon Rate (AR)

Measurement Calculation: AR = Number of calls abandoned while waiting for a live agent divided by the total number of calls requesting to speak to a live agent. (AR should be rounded to the first decemial number, e.g. 8.55% becomes 8.6%)

OEB Approved Standard: Performance shall not exceed 10% on a yearly basis

Month	Number of Calls abondoned while waiting for a live agent (1)	Total Number of Calls requesting to speak to a live agent (2)	Abandon Rate (%) (3 = 1 / 2 * 100)
Jan-18	1,935	67,576	2.9
Feb-18	1,256	63,430	2.0
Mar-18	1,924	80,781	2.4
Apr-18	2,878	73,504	3.9
May-18	1,499	68,812	2.2
Jun-18	2,773	88,799	3.1
Jul-18	1,531	65,016	2.4
Aug-18	1,163	66,393	1.8
Sep-18	2,809	88,215	3.2
Oct-18	2,514	75,781	3.3
Nov-18	927	68,639	1.4
Dec-18	1,259	65,337	1.9
Total	22,468	872,283	2.6

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

S.2.1.9.B - BILLING PERFORMANCE

S.2.1.9.B - Billing Performance

Measurement Calculation: The billing performance standard is a quality assurance standard. The standard requires gas distributors to have a verifiable quality assurance program in place. No specific metric is attached to this requirement.

OEB Approved Standard: Manual checks must be done to validate data when meter reads fall outside criteria, as set out in the quality assurance program, for excessively high or low usage.

Month	Total Number of Billings (1)	Total Number of Manual Checks Done as per QAP (2)	Total Number of Manual Checks Done When Meter Reads Show Excessively High Usage as per QAP Criteria (3)	Brief Explanation for Excessively High Usage (In 100 Words or less) (4)	Total Number of Manual Checks Done When Meter Reads Show Excessively Low Usage as per QAP Criteria (5)	Brief Explanation for Excessively Low Usage (In 100 Words or less) (6)
Jan-18	1,484,257	15,944	4,803	Change in load, previously low	3,343	Vacant, seasonal use (crop
Feb-18	1,484,378	16,260	6,335	estimate/read, previous vacant,	5,993	dryer), stopped meter,
Mar-18	1,484,821	16,469	10,482	seasonal use.	1,585	previous high estimate/read.
Apr-18	1,486,164	13,721	9,235		1,328	
May-18	1,490,103	18,415	14,085		1,573	
Jun-18	1,490,483	22,766	16,992		1,749	
Jul-18	1,492,612	22,855	18,388		630	
Aug-18	1,494,374	32,191	27,886		755	
Sep-18	1,496,044	20,809	16,719		128	
Oct-18	1,486,924	18,344	14,680		196	
Nov-18	1,500,337	10,897	6,983		210	
Dec-18	1,504,945	10,029	6,673		134	
Total	17,895,442	218,700	153,261		17,624	

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

S.2.1.9.C – METER READING PERFORMANCE

S.2.1.9.C.1 Meter Reading Performance Measurement (MRPM)

Measurement Calculation: MRPM = Number of meters with no read for 4 consecutive months of more divided by the total number of active meters to be read (MRPM should be rounded to the first decimal number, e.g. 0.45% becomes 0.5%)

OEB Approved Standard: Measurement shall not exceed 0.5% on a yearly basis

Month	Number of meters with no read for consecutive 4 months or more (1)	Total number of active meters to be read (2)	Meter reading performance measurement (%) (3 = 1 / 2 * 100)
Jan-18	4,630	1,470,784	0.3
Feb-18	7,887	1,471,804	0.5
Mar-18	13,406	1,473,344	0.9
Apr-18	15,866	1,474,232	1.1
May-18	4,734	1,473,585	0.3
Jun-18	2,011	1,474,069	0.1
Jul-18	2,155	1,474,577	0.1
Aug-18	2,774	1,475,636	0.2
Sep-18	4,113	1,478,444	0.3
Oct-18	4,112	1,482,235	0.3
Nov-18	5,035	1,487,067	0.3
Dec-18	3,008	1,489,304	0.2
Total	69,731	17,725,081	0.4

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

S.2.1.9.D - SERVICE APPOINTMENT RESPONSE TIME

S.2.1.9.D.1 - Appointments Met Within the Designated Time Period

Measurement Calculation: AMWDTP - Number of appointments met within the 4 hour scheduled time/date divided by total number of appointments scheduled in the reporting month.

OEB Approved Standard: The minimum performance standard for this measurement shall be 85% averaged over a year.

Month	Number of Appointments Met Within the 4-Hour Scheduled Time/Date (1)	Number of Appointments Scheduled in the Reporting Month (2)	Appointments Met Within the Designated Time Period (%) (3 = 1/2*100)
Jan-2018	13,577	13,715	99.0%
Feb-2018	12,937	13,050	99.1%
Mar-2018	16,479	16,571	99.4%
Apr-2018	15,179	15,328	99.0%
May-2018	16,062	16,234	98.9%
Jun-2018	15,377	15,539	99.0%
Jul-2018	14,264	14,461	98.6%
Aug-2018	15,004	15,208	98.7%
Sep-2018	15,653	15,895	98.5%
Oct-2018	21,069	21,436	98.3%
Nov-2018	17,923	18,116	98.9%
Dec-2018	10,126	10,247	98.8%
TOTAL	183,650	185,800	98.8%

S.2.1.9.D.2 - Time to reschedule a Missed Appointment (TRMA)

Measurement Calculation: TRMA - The distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment time.

OEB Approved Standard: 100% of affected customers will receive a call offering to reschedule work within 2 hours of the end of the original appointment time.

Month	Total Number of Customer Appointments Missed (1)	Total Number of Customers Who Received a Call Offering to Reschedule Within 2 Hrs. of the End of the Original Appointment Time Missed (2)	Brief Explanation of the Reasons Customers Did Not Receive a Call Within the Time Limit (in 50 words) (3)	Percentage of Customers Who Received a Call Within 2 Hrs (4 = 2/1 *100)
Jan-2018	138	138		100.0%
Feb-2018	113	113		100.0%
Mar-2018	92	92		100.0%
Apr-2018	149	149		100.0%
May-2018	172	172		100.0%
Jun-2018	162	162		100.0%
Jul-2018	197	197		100.0%
Aug-2018	204	204		100.0%
Sep-2018	242	241	Human error. Mistook rep for someone else and did not think it required a response. An email communication was sent and the importance of the missed commitment notification process was reviewed at a depatment meeting.	99.6%
Oct-2018	367	366	The order was dispatched to the contractor and was not followed up on. There was a subsequent review with the process coordinator as to the process of dispatching orders to cotractors and how to review potential misses.	99.7%
Nov-2018	193	192	The order did not come over to Advantex.	99.5%
Dec-2018	121	120	Human error. The employee did not see or respond to the missed commitments email. There was follow up with the employee's supervisor.	99.2%
TOTAL	2150	2146		99.8%

S.2.1.9 SERVICE QUALITY REQUIREMENTS FOR (SQR) FORM

S.2.1.9.E - GAS EMERGENCY RESPONSE

S.2.1.9.E.1 - Percentage of Emergency Calls Responded Within One Hour (ECRWOH)

Measurement Calculation: ECRWOH - Number of emergency calls responded to within 60 minutes divided by total number of emergency calls in the year.

OEB Approved Standard: The minimum performance standard shall be that 90% of customers have received a response within 60 minutes of their call reaching a live person. The standard shall be calculated on an annual basis.

Month	Number of Emergency Calls Responded to Within 60 Minutes (1)	Total Number of Emergency Calls Received (2)	Percentage of Emergency Calls Responded within 60 Minutes (%) (3 = 1/2*100)
Jan-2018	1,393	1,411	98.7%
Feb-2018	1,263	1,273	99.2%
Mar-2018	979	984	99.5%
Apr-2018	1,141	1,145	99.7%
May-2018	1,334	1,345	99.2%
Jun-2018	1,100	1,110	99.1%
Jul-2018	1,161	1,165	99.7%
Aug-2018	1,231	1,238	99.4%
Sep-2018	1,197	1,204	99.4%
Oct-2018	1,375	1,386	99.2%
Nov-2018	1,469	1,479	99.3%
Dec-2018	1,191	1,204	98.9%
TOTAL	14,834	14,944	99.3%

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.C – CUSTOMER COMPLAINT WRITTEN RESPONSE
S.2.1.9.F.1 Number of Days to provide a written response (NDPAWR)
Measurement Calculation: NDPAWR = Number of complaints requiring response responded to within 10 days divided by the number of number of complaints requiring a written response. (NDPAWR should be rounded to the first decimal number, e.g. 79.45% becomes 79.5%)
OEB Approved Minimum Standard: measurement shall be that 80% of customers have received written reponses in 10 days of the distributor receiving the complaint

Month	Number of complaints requiring a written response responded to within 10 days (1)	Number of complaints requiring a written response (2)	NDPAWR Percentage (%) (3 = 1 / 2 * 100)
Jan-18	212	212	100.0
Feb-18	179	179	100.0
Mar-18	184	184	100.0
Apr-18	157	157	100.0
May-18	153	153	100.0
Jun-18	166	166	100.0
Jul-18	153	153	100.0
Aug-18	152	152	100.0
Sep-18	122	122	100.0
Oct-18	202	202	100.0
Nov-18	177	177	100.0
Dec-18	148	148	100.0
Total	2,005	2,005	100.0

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM

S.2.1.9.G - RECONNECTION RESPONSE TIME

S.2.1.9.G.1 - Number of Days to Reconnect a Customer (NDTRAC)

Measurement Calculation: NDTRAC - Number of reconnections completed within 2 business days divided by total number of reconnections completed.

OEB Approved Standard: Minimum standard shall be that 85% of customers are reconnected within 2 business days of bringing their accounts into good standing. This will be tracked on a monthly basis.

Month	Number of Reconnections Completed Within 2 Business Days (1)	Total Number of Reconnections Completed (2)	Number of Days to Reconnect a Customer Percentage (%) (3 = 1/2*100)
Jan-2018	129	146	88.4%
Feb-2018	43	48	89.6%
Mar-2018	75	78	96.2%
Apr-2018	418	426	98.1%
May-2018	922	958	96.2%
Jun-2018	1,250	1,328	94.1%
Jul-2018	1,054	1,122	93.9%
Aug-2018	1,091	1,196	91.2%
Sep-2018	1,125	1,274	88.3%
Oct-2018	2,212	2,534	87.3%
Nov-2018	793	916	86.6%
Dec-2018	208	247	84.2%
TOTAL	9,320	10,273	90.7%

ALLOCATION AND DISPOSITION OF 2018 DEFERRAL ACCOUNT BALANCES AND 2018 EARNINGS SHARING AMOUNT UNION RATE ZONES

The purpose of this evidence is to address the allocation and disposition of 2018 deferral account balances identified at Exhibit C, Tab 1, Appendix A, Schedule 1 for the Union rate zones. There is no 2018 earnings sharing to allocate to rate classes, as described at Exhibit C, Tab 2.

The allocation of 2018 deferral account balances to Union South and Union North rate classes is provided at Exhibit C, Tab 3, Appendix A, Schedule 1. Exhibit C, Tab 3, Appendix A, Schedule 2, provides the unit disposition rates for Union South and Union North in-franchise rate classes and summarizes the balances to be disposed of for ex-franchise rate classes. Exhibit C, Tab 3, Appendix A, Schedule 3, provides the estimated general service bill impacts of the proposed disposition for the Union South, Union North West and Union North East rate zones.

With the exception of the Unaccounted for Gas Price Variance Account (179-141) and Pension and Other Post-Employment Benefits Variance Account (179-157), the allocation of 2018 deferral account balances to rate classes is consistent with the allocation methodologies approved by the Board in EB-2018-0105 (Union’s 2017 Deferral Account Disposition proceeding) or in EB-2011-0210 (Union’s 2013 Cost of Service proceeding). As part of this application, Enbridge Gas is also proposing an allocation of the revenue recorded in the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account (179-144), which was approved on an interim basis by the Board in EB-2018-0105 (Union’s 2017 Deferral Account Disposition proceeding).

2018 GAS SUPPLY RELATED DEFERRAL ACCOUNTS

Account No. 179-107 Spot Gas Variance Account

There is no balance in the Spot Gas Variance Account at December 31, 2018.

Account No. 179-108 Unabsorbed Demand Cost Variance Account

Enbridge Gas proposes that the balance in the UDC Variance Account for Union North West and Union North East be allocated to firm Rate 01, Rate 10 and Rate 20 sales service and bundled direct purchase customers in proportion to 2013 Board-approved excess of peak day demands over average annual demands for each zone, respectively. This allocation is consistent with the allocation of UDC in 2018 Rates.

There is no balance in the UDC Variance Account for Union South.

Account No. 179-131 Upstream Transportation Optimization

Enbridge Gas proposes to allocate the balance in the Upstream Transportation Optimization Deferral Account between Union North West, Union North East and Union South rate classes based on the upstream transportation contracts used to serve each zone.

Enbridge Gas has allocated the balance to each Union North zone based on the transportation optimization net revenues generated using upstream transportation and STS contracts designed to serve the Union North West (with delivery points of Centrat MDA, Union WDA, Union SSMDA) and the Union North East (with delivery points of Union NDA, Union NCDA and Union EDA). Enbridge Gas proposes that the portion of the balance related to Union North West and Union North East be allocated to rate classes in proportion to the allocation of the 2018 margin included in Board-approved gas supply transportation rates.

Enbridge Gas has allocated the balance to Union South based on the transportation optimization net revenues generated using upstream transportation contracts designed to serve Union South. Enbridge Gas proposes that the portion of the balance related to Union South be allocated to sales service customers in proportion to sales service volumes. This proposal is consistent with the manner in which this margin is included in approved gas supply commodity rates.

Account No. 179-132 Deferral Clearing Variance Account – Gas Supply Commodity and Transportation

Enbridge Gas proposes to allocate the gas supply commodity and gas supply transportation-related balances in the Deferral Clearing Variance Account to rate classes based on the recovery variance associated with differences between the forecast and actual volumes from the disposition of deferral account balances for each rate class, per Exhibit C, Tab 1, Appendix A, Schedule 6.

STORAGE-RELATED DEFERRAL ACCOUNTS

Account No. 179-70 Short-Term Storage and Other Balancing Services

Enbridge Gas proposes to allocate the balance in the Short-Term Storage and Other Balancing Services Deferral Account between the Union North and Union South rate zones in proportion to the 2013 Board-approved allocation of storage space related costs.

Enbridge Gas proposes to allocate the portion of the balance related to Union North to firm Rate 01, Rate 10, Rate 20 and Rate 100 in proportion to the 2013 Board-approved excess of peak day demands over average day demands. This approach is consistent with the approved allocation of storage demand costs to Union North rate classes.

Enbridge Gas proposes to allocate the portion of the balance related to Union South rate classes in proportion to the 2013 Board-approved design (peak) day demand.

The proposed disposition is also consistent with the allocation methodology for storage and other balancing services margin approved in 2018 Rates.

OTHER DEFERRAL ACCOUNTS

Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

There is no balance in the Unbundled Services Unauthorized Storage Overrun Deferral Account at December 31, 2018.

Account No. 179-112 Gas Distribution Access Rule ("GDAR") Costs

There is no balance in the GDAR Costs Deferral Account at December 31, 2018.

Account No. 179-120 IFRS Conversion Costs

There is no balance in the IFRS Conversion Costs Account at December 31, 2018.

Account No. 179-123 Conservation Demand Management ("CDM")

Enbridge Gas proposes to allocate the balance in the CDM Deferral Account to rate classes in proportion to the allocation of 2018 DSM costs in 2018 Rates.

Account No. 179-132 Deferral Clearing Variance Account

Enbridge Gas proposes to allocate the delivery-related balance in the Deferral Clearing Variance Account to rate classes based on the recovery variance associated with differences between the forecast and actual volumes from the disposition of deferral account balances for each rate class, per Exhibit C, Tab 1, Appendix A, Schedule 6.

Account No. 179-133 Normalized Average Consumption ("NAC")

Enbridge Gas proposes to allocate the balance in the NAC Deferral Account to general service rate classes in proportion to the margin variances by rate class resulting from the difference between the actual NAC and the target NAC included in

2018 Rates.

Account No. 179-134 Tax Variance

Enbridge Gas proposes to allocate the balance in the Tax Variance Deferral Account to rate classes in proportion to the 2013 Board-approved allocation of rate base. This approach is consistent with how tax changes are allocated in Board-approved rates.

Account No. 179-135 Unaccounted for Gas ("UFG") Volume Variance Account

Enbridge Gas proposes to allocate the balance in the UFG Volume Variance Account to rate classes based on the Board-approved allocation of UFG volumes, updated for 2018 activity.

Account No. 179-136 Parkway West Project Costs

Enbridge Gas proposes to allocate the balance in the Parkway West Project Costs Deferral Account to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2018 Rates. Enbridge Gas determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2018 Parkway West Project costs. Enbridge Gas is proposing to allocate the true-up of 2016 property taxes in proportion to the allocation of 2016 Project property tax costs.

Account No. 179-137 Brantford-Kirkwall/Parkway D Project Costs

Enbridge Gas proposes to allocate the balance in the Brantford-Kirkwall/Parkway D Project Costs Deferral Account to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2018 Rates. Enbridge Gas determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2018 Brantford-Kirkwall/Parkway D Project costs.

Account No. 179-138 Parkway Obligation Rate Variance

Enbridge Gas proposes to allocate the balance in the Parkway Obligation Rate Variance Account to rate classes in accordance with Union's 2014 Rates Settlement Agreement (EB-2013-0365). Consistent with the Settlement Agreement and the Board-approved cost allocation methodology, the Dawn-Parkway demand costs have been allocated to Union South in-franchise rate classes in proportion to the 2013 Board-approved Dawn-Parkway design day demands. The Dawn-Parkway commodity costs have been allocated to Union South in-franchise rate classes in proportion to 2013 Board-approved delivery volumes for customers located east of Dawn.

Account No. 179-141 Unaccounted for Gas Price Variance Account

Enbridge Gas proposes to allocate the balance in the UFG Price Variance Account to rate classes based on the actual UFG gas supply purchases made by the Company in 2018 for the Union rate zones. UFG purchases are made on behalf of customers for which Enbridge Gas provides fuel (utility supplied fuel) and on behalf of customers who provide fuel in kind when the actual UFG variance is greater than the amount of UFG collected through customer supplied fuel. The UFG price variance related to utility supplied and customer supplied fuel is allocated to rate classes in proportion to volumes consistent with the Board-approved allocation methodology of UFG costs, updated for 2018 activity.

Account No. 179-142 Lobo C Compressor/Hamilton-Milton Pipeline Project Costs

Enbridge Gas proposes to allocate the balance in the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account to rate classes in proportion to the difference between the actual project costs and the forecasted project costs included in 2018 Rates. Enbridge Gas determined the actual project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2018 Lobo C Compressor/Hamilton-Milton Pipeline Project costs.

Account No. 179-143 Unauthorized Overrun Non-Compliance

Union proposes to allocate the balance in the Unauthorized Overrun Non-Compliance Account to rate classes in proportion to 2013 Board-approved Union South firm in-franchise demands per Exhibit G3, Tab 5, Schedule 21, updated for the EB-2011-0210 Board Decision.

Account No. 179-144 Lobo D/Bright C/Dawn H Compressor Project Costs

Enbridge Gas proposes to allocate the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2018 Rates. Enbridge Gas determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2018 Lobo D/Bright C/Dawn H Compressor Project costs. Consistent with Union's 2017 Deferral Account Disposition proceeding, Enbridge Gas proposes to allocate the revenue associated with the 30,393 GJ/d excess capacity of the Project in proportion to the 2013 Board-approved distance weighted Dawn-Parkway design day demands, updated for the Project demands.

As part of Union's 2017 Deferral Account Disposition proceeding[1], the Board approved the 2017 disposition of the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account on an interim basis and ordered Union to file evidence to support the allocation of 2017 short-term transportation revenue with the 2018 Deferral Account Disposition proceeding. Accordingly, Enbridge Gas has provided the allocation of both the 2017 revenue of $0.216 million and 2018 revenue of $0.917 million at Exhibit C, Tab 3, Appendix A, Schedule 1, p.3. The proposed allocation of revenue is consistent with the allocation of Dawn-Parkway demand costs of the Project and results in rate class impacts that are consistent with the Project revenue impacts included in 2018 Rates.

Account No. 179-149 Burlington-Oakville Project Costs

Enbridge Gas proposes to allocate the balance in the Burlington-Oakville Project Costs Deferral Account to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2018 Rates. Enbridge Gas determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2018 Burlington-Oakville Project costs.

Account No. 179-151 OEB Cost Assessment Variance Account

Enbridge Gas proposes to allocate the balance in the OEB Cost Assessment Variance Account to rate classes in proportion to 2013 Board-approved Administrative & General O&M Expense per Exhibit G3, Tab 2, Schedule 2, updated for the EB-2011-0210 Board Decision.

Account No. 179-153 Base Service North T-Service TransCanada Capacity

There is no balance in the Base Service North T-Service TransCanada Capacity Account at December 31, 2018.

Account No. 179-156 Panhandle Reinforcement Project Costs

Enbridge Gas proposes to allocate the balance in the Panhandle Reinforcement Project Costs Deferral Account to rate classes in proportion to the difference between the actual Project net delivery revenue requirement and the forecasted Project net delivery revenue requirement included in 2018 Rates. Enbridge Gas determined the allocation of actual Project revenue requirement by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2018 Panhandle Reinforcement Project revenue requirement. The revenue requirement of the Project is reduced by the actual Project-related revenue, which is allocated to rate classes in proportion to the 2013 Board-approved Ojibway/St. Clair design day demands,

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[1] EB-2018-0105 Decision and Rate Order, December 6, 2018.

updated for the Project demands.

Account No. 179-157 Pension and Other Post-Employment Benefits Variance Account

Enbridge Gas proposes to allocate the balance in the Pension and Other Post-Employment Benefits Variance Account to rate classes in proportion to 2013 Board-approved Employee Benefits costs per Exhibit G3, Tab 2, Schedule 2, updated for the EB-2011-0210 Board Decision. This approach is consistent with the allocation of labour costs in the 2013 Board-approved cost allocation study.

DISPOSITION OF 2018 DEFERRAL ACCOUNT BALANCES

For general service Rate M1, Rate M2, Rate 01 and Rate 10 customers, Enbridge Gas proposes to dispose of the net 2018 deferral account balances prospectively over the January 1, 2020 to June 30, 2020 time period. The prospective refund / recovery approach over six months is consistent with the methodology used for the disposition of Union's 2017 deferral account balances in EB-2018-0105.

For Union South and Union North in-franchise contract and ex-franchise rate classes, Enbridge Gas is proposing to dispose of the net 2018 delivery-related deferral account balances as a one-time adjustment with January 2020 bills customers receive in February 2020. This approach is consistent with the methodology used for the disposition of Union's 2017 deferral account balances in EB-2018-0105.

GENERAL SERVICE BILL IMPACTS

General service bill impacts are presented at Exhibit C, Tab 3, Appendix A, Schedule 3.

For a Rate M1 sales service residential customer in Union South with annual consumption of 2,200 m^3, the charge for the period January 1, 2020 to June 30, 2020 is \$0.96. This \$0.96 charge consists of a delivery-related credit of \$5.90 (line 1, column (c)) and a commodity-related charge of \$6.86 (line 2, column (c)). For a bundled DP residential customer the credit is \$5.90.

For a Rate 01 sales service residential customer in Union North West with annual consumption of 2,200 m^3, the credit for the period January 1, 2020 to June 30, 2020 is \$57.21. This \$57.21 credit consists of a delivery-related credit of \$13.07 (line 6, column (c)) and a gas transportation-related credit of \$44.14 (line 8, column (c)). For a bundled DP residential customer the credit is \$57.21.

For a Rate 01 sales service residential customer in Union North East with annual consumption of 2,200 m^3, the credit for the period January 1, 2020 to June 30, 2020 is \$21.83. This \$21.83 credit consists of a delivery-related credit of \$13.07 (line 12, column (c)) and a gas transportation-related credit of \$8.76 (line 14, column (c)). For a bundled DP residential customer the credit is \$21.83.

ENBRIDGE GAS INC.
Union Rate Zones
Allocation of Deferral Deferral Account Balances

			Union North					Union South															
Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	M1	M2	M4	M5A	M7	M9	M10	T1	T2	T3	M12	M13	Excess Utility	C1	M16	Total (1)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
	Gas Supply Related Deferrals:																						
1	Spot Gas Variance Account	179-107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(7,749)	(1,831)	(453)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10,033)
3	Upstream Transportation Optimization	179-131	107	(47)	1	-	90	8,274	1,781	123	19	75	78	1	-	-	-	-	-	-	-	-	10,503
4	Deferral Clearing Variance Account - Supply (2)	179-132	-	-	-	-	-	(8)	(334)	(20)	31	(35)	(49)	(1)	-	-	-	-	-	-	-	-	(417)
5	Deferral Clearing Variance Account - Transport (2)	179-132	(147)	(126)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(273)
6	Total Gas Supply Related Deferrals		(7,789)	(2,003)	(452)	-	90	8,266	1,447	103	49	40	30	0	-	-	-	-	-	-	-	-	(220)
	Storage Related Deferrals:																						
7	Short-Term Storage and Other Balancing Services	179-70	216	57	15	1	-	490	165	53	1	19	6	0	45	333	43	-	-	-	-	-	1,445
	Delivery Related Deferrals:																						
8	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Gas Distribution Access Rule (GDAR) Costs	179-112	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	IFRS Conversion Costs	179-120	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Conservation Demand Management	179-123	(157)	(53)	(30)	(32)	-	(418)	(179)	(47)	(62)	(17)	-	-	(27)	(63)	-	-	-	-	-	-	(1,085)
12	Deferral Clearing Variance Account - Delivery (2)	179-132	(248)	(176)	-	-	-	(400)	(281)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,105)
13	Normalized Average Consumption (NAC)	179-133	(6,661)	(1,505)	-	-	-	(9,127)	(3,690)	-	-	-	-	-	-	-	-	-	-	-	-	-	(20,983)
14	Tax Variance	179-134	(244)	(38)	(27)	(21)	(7)	(534)	(81)	(20)	(17)	(7)	(1)	(0)	(14)	(62)	(8)	(284)	(0)	(8)	(3)	(0)	(1,376)
15	Unaccounted for Gas (UFG) Volume Variance Account	179-135	35	12	6	0	2	229	93	47	5	37	6	0	28	219	19	789	3	-	240	14	1,783
16	Parkway West Project Costs	179-136	5	(4)	(1)	(0)	0	69	8	4	2	1	0	0	4	23	2	(126)	0	(0)	2	0	(11)
17	Brantford-Kirkwall/Parkway D Project Costs	179-137	(5)	(8)	1	3	1	57	(3)	(0)	4	(1)	(1)	(0)	1	(0)	(5)	(899)	0	1	1	0	(853)
18	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	149	50	15	0	7	2	0	7	47	17	-	-	-	-	-	293
19	Unaccounted for Gas (UFG) Price Variance Account	179-141	85	30	14	0	5	558	226	115	13	90	14	0	16	129	11	465	7	-	298	15	2,091
20	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	489	22	69	76	28	1,421	83	13	66	(3)	(6)	(0)	23	35	(45)	(8,278)	1	30	(39)	2	(6,012)
21	Unauthorized Overrun Non-Compliance Account	179-143	-	-	-	-	-	(2)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	-	-	-	-	-	(5)
22	Lobo D/Bright C/ Dawn H Compressor Project Costs	179-144	434	19	47	52	20	1,286	92	19	54	(2)	(7)	0	44	86	(25)	(9,687)	0	116	3	(1)	(7,449)
23	Burlington-Oakville Project Costs	179-149	356	53	38	30	11	(1,481)	(648)	(217)	21	(79)	(27)	(1)	(190)	(1,457)	(187)	306	(4)	11	3	0	(3,462)
24	OEB Cost Assessment Variance Account	179-151	249	22	19	16	7	628	59	22	25	6	1	0	16	44	5	117	0	5	3	0	1,243
25	Base Service North T-Service TransCanada Capacity Account	179-153	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Panhandle Reinforcement Project Costs	179-156	133	20	14	11	4	(367)	(182)	(156)	7	(39)	0	0	(165)	(1,281)	3	96	0	4	(417)	(86)	(2,401)
27	Pension & OPEB Forecast Accrual vs Actual Cash Payment Diffe	179-157	(46)	(4)	(4)	(3)	(2)	(112)	(11)	(5)	(5)	(1)	(0)	(0)	(3)	(8)	(1)	(22)	(0)	-	(0)	(0)	(228)
28	Total Delivery-Related Deferrals		(5,576)	(1,609)	145	133	70	(8,044)	(4,464)	(211)	112	(9)	(18)	(0)	(259)	(2,291)	(214)	(17,522)	6	159	90	(56)	(39,560)
29	Total 2018 Storage and Delivery Disposition (Line 7 + Line 27)		(5,360)	(1,552)	160	134	70	(7,555)	(4,300)	(158)	113	10	(12)	(0)	(214)	(1,957)	(171)	(17,522)	6	159	90	(56)	(38,115)
30	Total 2018 Deferral Account Disposition (Line 6 + Line 28)		(13,149)	(3,555)	(292)	134	161	711	(2,853)	(55)	162	50	18	(0)	(214)	(1,957)	(171)	(17,522)	6	159	90	(56)	(38,335)
31	2018 Earnings Sharing (3)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Grand Total (Line 30 + Line 31)		(13,149)	(3,555)	(292)	134	161	711	(2,853)	(55)	162	50	18	(0)	(214)	(1,957)	(171)	(17,522)	6	159	90	(56)	(38,335)

Notes:
(1) Exhibit C, Tab 1, Appendix A, Schedule 1.
(2) Exhibit C, Tab 1, Appendix A, Schedule 6.
(3) Exhibit C, Tab 2, Appendix B, Schedule 1.

ENBRIDGE GAS INC.
Union Rate Zones
Allocation of 2018 Gas Supply Related Deferral Accounts by Union North East and Union North West

Line No.	Particulars ($000's)	Acct No.	Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	Total (1)
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (sum b:f)
	Union North West							
	Gas Supply Related Deferrals:							
1	Spot Gas Variance Account	179-107	-	-	-	-	-	-
2	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(6,287)	(1,427)	(418)	-	-	(8,132)
3	Upstream Transportation Optimization	179-131	1,094	294	101	-	111	1,600
4	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
5	Deferral Clearing Variance Account - Transport	179-132	(43)	(32)	-	-	-	(74)
6	Total Gas Supply Related Deferrals		(5,235)	(1,165)	(318)	-	111	(6,606)
	Union North East							
	Gas Supply Related Deferrals:							
7	Spot Gas Variance Account	179-107	-	-	-	-	-	-
8	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(1,463)	(404)	(35)	-	-	(1,901)
9	Upstream Transportation Optimization	179-131	(987)	(341)	(100)	-	(21)	(1,448)
10	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
11	Deferral Clearing Variance Account - Transport	179-132	(105)	(95)	-	-	-	(199)
12	Total Gas Supply Related Deferrals		(2,554)	(839)	(134)	-	(21)	(3,548)
	Total							
	Gas Supply Related Deferrals:							
13	Spot Gas Variance Account	179-107	-	-	-	-	-	-
14	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(7,749)	(1,831)	(453)	-	-	(10,033)
15	Upstream Transportation Optimization	179-131	107	(47)	1	-	90	152
16	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
17	Deferral Clearing Variance Account - Transport	179-132	(147)	(126)	-	-	-	(273)
18	Total Gas Supply Related Deferrals		(7,789)	(2,003)	(452)	-	90	(10,154)

Notes:
(1) Exhibit C, Tab 3, Appendix A, Schedule 1, p.1.

ENBRIDGE GAS INC.
Union Rate Zones
Allocation of 2017 and 2018 Transportation Revenue associated with 30,393 GJ/d Excess Capacity

Line No.	Particulars	Allocation Factor (1) ($10^6 m^3$/d x km)	Allocation Factor (1) (%)	2017 Revenue Allocation (2) ($000's)	2018 Revenue Allocation (2) ($000's)
		(a)	(b)	(c)	(d)
	Union South Rate Zone				
1	Rate M1	1,820	5.3%	12	49
2	Rate M2	612	1.8%	4	16
3	Rate M4	178	0.5%	1	5
4	Rate M5	2	0.0%	0	0
5	Rate M7	82	0.2%	1	2
6	Rate M9	29	0.1%	0	1
7	Rate M10	1	0.0%	0	0
8	Rate T1	88	0.3%	1	2
9	Rate T2	570	1.7%	4	15
10	Rate T3	207	0.6%	1	6
11	Total Union South Rate Zone	3,588	10.5%	23	97
	Ex-Franchise				
12	Excess Utility	-	0.0%	-	-
13	Rate C1	-	0.0%	-	-
14	Rate M12	28,879	84.8%	183	778
15	Rate M13	-	0.0%	-	-
16	Rate M16	-	0.0%	-	-
17	Total Ex-Franchise	28,879	84.8%	183	778
	Union North Rate Zone				
18	Rate 01	1,191	3.5%	8	32
19	Rate 10	312	0.9%	2	8
20	Rate 20	83	0.2%	1	2
21	Rate 100	6	0.0%	0	0
22	Rate 25	-	0.0%	-	-
23	Total Union North Rate Zone	1,592	4.7%	10	43
24	Total (line 11 + line 17 + line 23)	34,060	100.0%	216	917

Notes:
(1) 2013 Board-approved distance weighted Dawn-Parkway design day demands, updated for the Project demands as per EB-2015-0200, Exhibit A, Tab 10, Page 6, Table 10-1, line 6, UPDATED.
(2) Allocated in proportion to column (b).

ENBRIDGE GAS INC.
Union Rate Zones
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2018 Deferral Account Disposition

Line No.	Particulars	Rate Class	2018 Deferral Balances ($000's)	2018 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
1	Small Volume General Service	01	(5,360)	-	(5,360)	614,546	(0.8721)
2	Large Volume General Service	10	(1,552)	-	(1,552)	196,814	(0.7885)
3	Small Volume General Service	M1	(7,555)	-	(7,555)	1,918,685	(0.3937)
4	Large Volume General Service	M2	(4,300)	-	(4,300)	677,667	(0.6345)

Notes:
(1) Forecast volume for the period January 1, 2020 to June 30, 2020.

ENBRIDGE GAS INC.
Union Rate Zones
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2018 Deferral Account Disposition

Line No.	Particulars	Rate Class	2018 Deferral Balances ($000's)	2018 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North West						
1	Small Volume General Service	01	(5,235)	-	(5,235)	177,683	(2.9464)
2	Large Volume General Service	10	(1,165)	-	(1,165)	48,528	(2.4000)
	Union North East						
3	Small Volume General Service	01	(2,554)	-	(2,554)	436,863	(0.5846)
4	Large Volume General Service	10	(839)	-	(839)	146,447	(0.5727)

Notes:
(1) Forecast volume for the period January 1, 2020 to June 30, 2020.

ENBRIDGE GAS INC.
Union Rate Zones
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2018 Deferral Account Disposition

Line No.	Particulars	Rate Class	2018 Deferral Balances ($000's)	2018 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (2)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
1	Small Volume General Service	M1	8,266	-	8,266	1,779,170	0.4582
2	Large Volume General Service	M2	1,447	-	1,447	335,256	0.4582
3	Firm Com/Ind Contract	M4	103	-	103	26,721	0.4582
4	Interruptible Com/Ind Contract	M5	49	-	49	3,159	0.4582
5	Special Large Volume Contract	M7	40	-	40	9,260	0.4582
6	Large Wholesale	M9	30	-	30	13,837	0.4582
7	Small Wholesale	M10	0	-	0	960	0.4582
8	Total				9,935	2,168,363	0.4582

Notes:
(1) Forecast sales service volumes for the period January 1, 2020 to June 30, 2020.
(2) Unit rate for prospective recovery/refund for each rate class equal to the gas supply commodity weighted-average unit rate.

ENBRIDGE GAS INC.
Union Rate Zones
Contract Unit Rates for One-Time Adjustment - Delivery
2018 Deferral Account Disposition

Line No.	Particulars	Rate Class	2018 Deferral Balances ($000's)	2018 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2018 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
			(a)	(b)	(c) = (a + b)	(d)	(e) = (c / d) * 100
	Union North						
1	Medium Volume Firm Service (1)	20	39	-	39	111,710	0.0345
2	Medium Volume Firm Service (2)	20T	111	-	111	368,062	0.0303
3	Large Volume High Load Factor (2)	100T	133	-	133	1,038,311	0.0128
4	Large Volume Interruptible	25	70	-	70	156,345	0.0450
	Union South						
5	Firm Com/Ind Contract	M4	(158)	-	(158)	655,590	(0.0241)
6	Interruptible Com/Ind Contract	M5	113	-	113	74,239	0.1516
7	Special Large Volume Contract	M7	10	-	10	512,402	0.0020
8	Large Wholesale	M9	(12)	-	(12)	78,356	(0.0151)
9	Small Wholesale	M10	(0)	-	(0)	408	(0.0491)
10	Contract Carriage Service	T1	(214)	-	(214)	465,539	(0.0460)
11	Contract Carriage Service	T2	(1,957)	-	(1,957)	4,099,141	(0.0478)
12	Contract Carriage- Wholesale	T3	(171)	-	(171)	278,781	(0.0615)

Notes:
(1) Sales and Bundled-T customers only.
(2) T-Service customers only.

ENBRIDGE GAS INC.
Union Rate Zones
Contract Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage
2018 Deferral Account Disposition

Line No.	Particulars	Rate Class	2018 Deferral Balances ($000's)	2018 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2018 Actual Volume/ Demand	Billing Units	Unit Volumetric/ Demand Rate (cents/m3)
			(a)	(b)	(c) = (a + b)	(d)		(e) = (c / d) * 100
	Gas Supply Charges							
	Union North West							
1	Medium Volume Firm Service	20	(318)	-	(318)	1,644	$10^3m^3/d$	(19.3195)
2	Large Volume Interruptible	25	111	-	111	47,087	10^3m^3	0.2366
	Union North East							
3	Medium Volume Firm Service	20	(134)	-	(134)	4,652	$10^3m^3/d$	(2.8883)
4	Large Volume Interruptible	25	(21)	-	(21)	24,385	10^3m^3	(0.0866)
	Storage ($/GJ)							
5	Bundled-T Storage Service	20T/100T	12	-	12	155,904	GJ/d	0.074

ENBRIDGE GAS INC.
Union Rate Zones
Storage and Transportation Service Amounts for Disposition
2018 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2018 Deferral Balances	2018 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c)
1	Transportation	M12	(17,522)	-	(17,522)
2	Transportation of Locally Produced Gas	M13	6	-	6
3	Cross Franchise Transportation	C1	90	-	90
4	Storage and Transportation Services	M16	(56)	-	(56)

Notes:
(1) Ex-franchise Rate M12, Rate M13, Rate M16 and Rate C1 customer specific amounts determined using approved deferral account allocation methodologies.

ENBRIDGE GAS INC.
Union Rate Zones
General Service Customer Bill Impacts

Line No.	Particulars	Unit Rate for Prospective Recovery/(Refund) (cents/m³) (1)	Volume (m³) (2)	Bill Impact ($)
		(a)	(b)	(c) = (a x b) / 100
	Small Volume General Service			
	Rate M1 - Union South			
1	Delivery	(0.3937)	1,498	(5.90)
2	Commodity	0.4582	1,498	6.86
3		0.0645		0.96
4	Sales Service			0.96
5	Direct Purchase			(5.90)
	Rate 01 - Union North West			
6	Delivery	(0.8721)	1,498	(13.07)
7	Commodity	-	1,498	-
8	Transportation	(2.9464)	1,498	(44.14)
9		(3.8185)		(57.21)
10	Sales Service			(57.21)
11	Direct Purchase Bundled T			(57.21)
	Rate 01 - Union North East			
12	Delivery	(0.8721)	1,498	(13.07)
13	Commodity	-	1,498	-
14	Transportation	(0.5846)	1,498	(8.76)
15		(1.4567)		(21.83)
16	Sales Service			(21.83)
17	Direct Purchase Bundled T			(21.83)
	Large Volume General Service			
	Rate M2 - Union South			
18	Delivery	(0.6345)	49,129	(311.72)
19	Commodity	0.4582	49,129	225.11
20		(0.1763)		(86.61)
21	Sales Service			(86.61)
22	Direct Purchase			(311.72)
	Rate 10 - Union North West			
23	Delivery	(0.7885)	54,302	(428.17)
24	Commodity	-	54,302	-
25	Transportation	(2.4000)	54,302	(1,303.26)
26		(3.1885)		(1,731.43)
27	Sales Service			(1,731.43)
28	Direct Purchase Bundled T			(1,731.43)
	Rate 10 - Union North East			
29	Delivery	(0.7885)	54,302	(428.17)
30	Commodity	-	54,302	-
31	Transportation	(0.5727)	54,302	(310.99)
32		(1.3612)		(739.16)
33	Sales Service			(739.16)
34	Direct Purchase Bundled T			(739.16)

Notes:
(1) Exhibit C, Tab 3, Appendix A, Schedule 2, pp. 1-3, column (e).
(2) Average consumption, per customer, for the period January 1, 2020 to June 30, 2020.
Rate 01 volume based on annual consumption of 2,200 m^3.
Rate 10 volume based on annual consumption of 93,000 m^3.
Rate M1 volume based on annual consumption of 2,200 m^3.
Rate M2 volume based on annual consumption of 73,000 m^3.

REPORTING AND REFERENCE MATERIAL

EGD Rate Zone

Within the EB-2012-0459 Decision, the Board indicated various annual reporting requirements which were either proposed or agreed to by the Company and also further requirements determined by the Board. The status of each item is described in the following paragraphs.

The EB-2012-0459 Decision highlighted that Enbridge would annually file a Productivity Report within its ESM Application and a Benchmarking Study at the end of the Custom IRM term. This information would have been used if Enbridge applied for rebasing following its Custom IRM term. Since the Company did not rebase and has since amalgamated with Union, it is not providing a Productivity Report. However, as per the Decision and Order in the EB-2017-0306/0307 amalgamation application, Enbridge Gas will file a Benchmarking Study in its next rebasing application.

The Decision highlighted that Enbridge agreed to annually provide the same information as Union provided in relation to section 12.1 of the Union 2014 to 2018 Settlement Agreement, and also to provide the same RRR filings as Union filed, such as SQR results. All of that information is provided in this application within the B series of exhibits.

Enbridge also agreed to hold an Annual Stakeholder Day each year during the Custom IRM term. In the MAADs Decision and Order[1], the OEB notes that the stakeholder meetings held during the previous rate-setting terms have been informative and have assisted in providing both the OEB and stakeholders on both historic and prospective

[1] EB 2017-0306/EB-2017-0307, section 7.3, page 53

issues, but it did not order Enbridge Gas to have annual stakeholder meetings. No Annual Stakeholder Day was held in 2019.

The Decision also required Enbridge to report annually on the status of major projects such as the GTA and WAMS, on the progress of the System Integrity Program, on the progress of an updated Asset Management Planning process and to report on and provide a Gas Supply Planning Memorandum.

a. As per the report of the Board: Framework for the Assessment of Distributor Gas Supply Plans[2], EGI filed a five year Gas Supply Plan in EB-2019-0137 dated May 1st, 2019.
b. The GTA project was complete in March 2016, with the exception of Ashtonbee Station which went in service in June 2017. Enbridge included its final update report on the GTA project in the EB-2017-0102, 2016 ESM proceeding (Exhibit D, Tab 1, Schedule 2).
c. The WAMS project was complete and in use in October 2016. Enbridge included its final update report on the WAMS project in the EB-2017-0102, 2016 ESM proceeding (Exhibit D, Tab 3, Schedule 1).
d. Enbridge made significant progress in advancing its asset management framework to facilitate and govern asset investment planning. Enbrdige continues to evolve its asset management practices and has filed a robust Asset Management Plan ("AMP") as part of its 2019 Annual rate application[3].

Union Rate Zones

Pursuant to the EB-2005-0520 Settlement Agreement[4], Union agreed to provide an Incremental Transportation Contracting Analysis to support its decision to enter into new

[2] EB-2017-0129, dated October 25th, 2018
[3] Exhibit C1, Tab 2, Schedule 1, EB-2018-0305, dated December 14, 2018
[4] EB-2005-0520 Settlement Agreement, page 13, subsection 3.1, paragraph 2; and Appendix B

firm transportation capacity. The Incremental Transportation Contracting Analysis was filed as part of Enbridge Gas's five year Gas Supply Plan[5].

Union also agreed to hold an Annual Stakeholder Day each year during its 2014 to 2018 IR term[6]. As stated above, in the MAADs Decision and Order[7], the OEB notes that that the stakeholder meetings held during the previous rate-setting terms have been informative and have assisted in providing both the OEB and stakeholders on both historic and prospective issues, but it will not order Enbridge Gas to have annual stakeholder meetings. No annual stakeholder Day was held in 2019.

The materials noted above for each rate zone are included within this proceeding for information purposes. Enbridge Gas is not seeking any relief on these items.

[5] EB-2019-0137, dated May 1st, 2019, page 79-80
[6] EB-2013-0202, dated July 31, 2012 , Settlement Agreement, page 28, section 12.2
[7] EB 2017-0306/EB-2017-0307, section 7.3, page 53