June 6, 2018

BY EMAIL, COURIER & RESS

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

Re: EB-2018-0105 - Union Gas Limited - 2017 Disposition of Deferral Account Balances and 2017 Utility Earnings

Dear Ms. Walli:

Enclosed is the application and evidence submitted by Union Gas Limited ("Union") concerning the disposition and recovery of certain 2017 deferral and variance account balances.

Union is not proposing to dispose of DSM or Cap-and-Trade related deferral account balances in this proceeding. Union will file its 2016 and 2017 DSM deferral and variance accounts evidence following the completion of the audit of each year's program results. Union plans to file its 2017 Cap-and-Trade deferral accounts evidence along with the filing of its 2019-2020 Cap-and-Trade Compliance Plan.

The application is supported by evidence which is outlined below:

EXHIBIT A

Tab 1	2017 Deferral Account Balances
Tab 2	2017 Utility Results and Earnings Sharing
Tab 3	Allocation and Disposition of 2017 Deferral Account Balances and 2017 Earnings Sharing Amount
Tab 4	Incremental Transportation Contracting Analysis
Tab 5	May 30, 2018 Stakeholder Meeting Presentation

Union proposes that the impacts which result from the disposition of 2017 deferral account balances be implemented on January 1, 2019 to align with other rate changes implemented through the QRAM.

If you have any questions concerning this application and evidence please contact me at (519) 436-5334.

Yours truly,

[Original Signed by]

Vanessa Innis
Manager, Regulatory Applications

c.c.: Crawford Smith (Torys)
EB-2017-0087 Intervenors (2018 Rates)

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 Union Gas Limited for an order or orders clearing certain non-commodity related deferral accounts and sharing utility earnings pursuant to a Board-approved earnings sharing mechanism;

APPLICATION

1. Union Gas Limited ("Union") is a business corporation, incorporated under the laws of Ontario, with its head office in the Municipality of Chatham-Kent.

2. Union conducts an integrated natural gas utility business that combines the operations of selling, distributing, transmitting and storing gas within the meaning of the *Ontario Energy Board Act, 1998* (the "Act").

3. In EB-2016-0245, Union applied to the Ontario Energy Board (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, 2017. The Board approved Union's request. In doing so, the Board approved the continuation of certain deferral accounts.

4. The approved Incentive Regulation Mechanism ("IRM") 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%.

5. 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.

6. Union's 2017 actual utility earnings did not exceed this threshold therefore there is no earnings sharing.

7. Union applies for the approval of final balances for all 2017 deferral accounts as listed in Exhibit A, Tab 1, Appendix A, Schedule 1 and an order for final disposition of those balances, except for the balance in the Parkway West Project Costs Deferral Account (No. 179-136). Union applies for an order for interim disposition of the balance in this account, consistent with the treatment in the 2016 Deferrals proceeding (EB-2017-0091).

8. Union also applies to the Board for such interim order or orders approving interim rates or other charges and accounting orders as may from time to time appear appropriate or necessary.

9. Union further applies to the Board for all necessary orders and directions concerning pre-hearing and hearing procedures for the determination of this application.

10. 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.

11. The persons affected by this application are the customers resident or located in the municipalities, police villages and First Nations reserves served by Union, together with those to whom Union sells gas, or on whose behalf Union 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.

12. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1
Attention: Vanessa Innis
Manager, Regulatory Applications

Telephone: (519) 436-5334
Fax: (519) 436-4641

- and -

Torys LLP
Suite 3000, Maritime Life Tower
P.O. Box 270
Toronto-Dominion Centre
Toronto, Ontario
M5K 1N2
Attention: Crawford Smith

Telephone: (416) 865-8209
Fax: (416) 865-7380

DATED: June 6, 2018

UNION GAS LIMITED

[Original signed by]

Vanessa Innis
Manager, Regulatory Applications

2017 DEFERRAL ACCOUNT BALANCES

2017 YEAR-END DEFERRAL ACCOUNT BALANCES

Union has classified the deferral accounts approved by the Ontario Energy Board ("OEB" or "Board") for use in 2017 into three groups:

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

The net balance in the above deferral accounts results in a $2.199 million debit from ratepayers. This total includes deferral balances and interest calculated in accordance with Board-approved accounting orders as at December 31, 2017. The applicable short-term interest rates used were 1.10% for January through September 2017, and 1.50% for October through December 2017, as prescribed by the Board in EB-2006-0117.

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

GAS SUPPLY DEFERRAL ACCOUNTS

Account No. 179-107 Spot Gas Variance Account

There is no balance in this deferral account. 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 not prospectively recovered or refunded as part of the approved Quarterly Rate Adjustment Mechanism ("QRAM"). It has therefore been included in this submission. The balance in this deferral account is a credit to ratepayers of $4.133 million plus interest as of December 31, 2017 of $0.026 million, for a total of $4.159 million. The $4.133 million balance is the difference between the actual UDC incurred by Union and the amount of UDC collected in rates.

UDC Recovery in Rates

To meet customer demands across Union's franchise area and to meet the planned storage inventory levels at October 31, Union's 2017 approved rates included planned unutilized pipeline capacity of 9.5 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[1] and included in Union's 2017 Rates proceeding.[2]

---

[1] EB-2015-0181, Exhibit A, Tab 2, Appendix A, Schedule 1.
[2] EB-2016-0245, Rate Order, Working Papers, Schedule 23, pp. 2 and 3.

As discussed in the Gas Supply Memorandum in Union's 2017 Rates proceeding[3], in Union North, the upstream transportation capacity (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 Union's contract capacity is planned to be unutilized. In a warmer than normal year, Union may also incur UDC in Union South, and additional UDC in Union North, to balance supply with lower demands. Union manages its Union North and Union South transportation portfolios on an integrated basis and will determine the pipeline to leave unutilized, if necessary, based on the least cost option.

Union collected $11.899 million in rates for UDC during 2017 and recorded an associated interest credit of $0.026 million (see Table 1). Actual UDC costs in 2017 were $15.343 million offset by $7.577 million in released capacity value, resulting in a net cost of $7.766 million (see Table 2).

The variance between the amounts collected in rates and the actual UDC costs, including the interest credit of $0.026 million, results in a net credit to ratepayers in the UDC Variance Account of $4.159 million.

[3] EB-2016-0245, Exhibit A, Tab 3.

The balance of $4.159 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 DP customers in Union North West is a credit of $3.938 million and in Union North East, a credit of $0.236 million. The balance applicable to sales service customers in Union South is a debit of $0.015 million.

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

Table 1
UDC Variance Account by Operations Area

Line No.	Particulars ($000's)	Union North West	Union North East	Union South	Total Franchise Area
1	UDC Collected in Rates	(9,560)	(2,339)	-	(11,899)
2	Net UDC Costs Incurred (Table 2)	5,647	2,104	15	7,766
3	Variance (line 1 + line 2)	(3,913)	(235)	15	(4,133)
4	Interest	(25)	(1)	-	(26)
5	(Credit)/Debit to Operations Area	(3,938)	(236)	15	(4,159)

A description of each item follows:

UDC Collected in Rates

2017 Board-approved rates include $11.460 million of UDC associated with 12.6 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, 2017. On an actual basis in 2017, Union recovered $11.899 million in Union North West and Union North East (due to higher throughput than forecast primarily in November and December of 2017) and $0.0 million in Union South.

UDC Costs Incurred

The actual unutilized capacity in 2017 was 26.4 PJ. The level of unutilized capacity experienced in 2017 was largely due to planned unutilized capacity (and resulting UDC) and warmer than normal weather for the winter of 2016/2017.

The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $15.343 million which are offset, in part, by value generated from pipeline transportation releases totaling $7.577 million. Unutilized upstream transportation capacity due to supply that is ultimately not required, is released and sold on the secondary market to minimize UDC. Values generated from the transportation releases are 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 Franchise Area
1	UDC Costs Incurred	12,999	2,329	15	15,343
2	Released Capacity Revenue	(7,352)	(225)	-	(7,577)
3	Net UDC Costs (Credit)/Debit	5,647	2,104	15	7,766

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 $11.057 million.

In setting rates for 2017, the Board approved a forecast of optimization revenue of $14.918 million.[4] Of that amount, 90% or $13.426 million, was credited to ratepayers in the Board-approved 2017 rates.[5] On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $15.570 million in rates to ratepayers during 2017, $2.144 million greater than the Board-approved amount of $13.426 million. The credit is due to Union's actual sales service volumes exceeding the forecast sales service volumes in rates.[6] The main driver of actual sales service volumes exceeding the forecasted amount is customer growth since 2013.

Union earned $5.015 million in net revenues from upstream transportation optimization during 2017. In accordance with the Board-approved sharing methodology, 90% of this net revenue, or $4.513 million, is to be credited to customers. As stated above, $15.570 million has already been credited through rates; therefore, the deferral balance is a debit from ratepayers of $11.057 million

[4] EB-2016-0245, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[5] EB-2016-0245, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[6] EB-2011-0210, Decision and Rate Order, January 17, 2013, p. 16.

($15.570 million less $4.513 million).

Exhibit A, Tab 1, Appendix A, Schedule 2, provides a summary of the calculation of the balance in this deferral account. Union's 2017 actual Upstream Transportation Optimization revenue 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) 2017 weather in traditional delivery areas where Union would transact was between 2 - 5% 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.

STORAGE DEFERRAL ACCOUNTS

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 $1.183 million.

As shown in Table 3, the balance is calculated by comparing $3.368 million (90% of the actual 2017 Short-Term Storage and Other Balancing Services net revenue of $3.743 million) to the net revenue included in rates of $4.551 million.[7] The details of the balance are found at Exhibit A, Tab 1, Appendix A, Schedule 3.

Table 3
Deferral Summary: Short-term Storage and Other Storage Services

Line No.	Particulars ($000's)	Actual 2017
1	Net Revenue	3,743
2	Ratepayer Portion (90%)	3,368
3	Approved in Rates	4,551
4	Deferral Balance Payable to/(Collectable from) Ratepayers	(1,183)

Actual 2017 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $1.995 million were $0.505 million lower than the 2013 Board-approved forecast of $2.500 million.

The C1 Short-Term Firm Peak Storage revenues of $4.618 million were $3.264 million lower than the 2013 Board-approved forecast of $7.883 million. Actual utility storage requirements for 2017 were 4.5 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 6.8 PJ in 2017). 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.

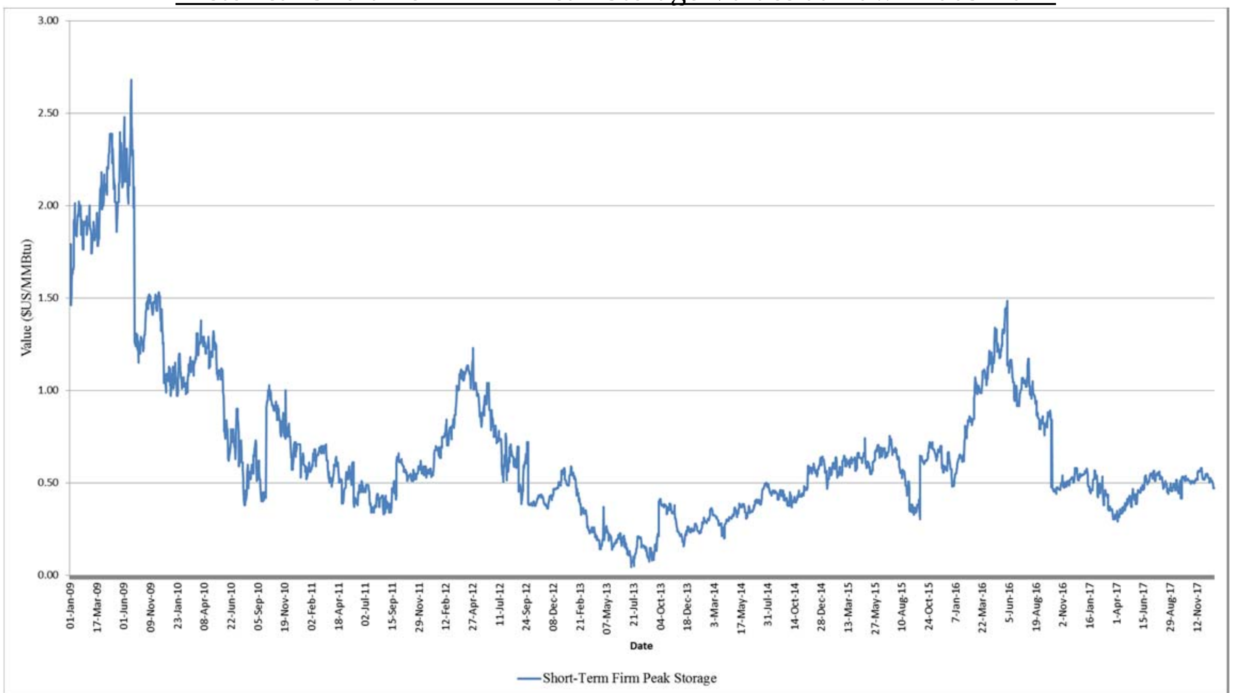
[7] EB-2011-0210, Decision and Rate Order, January 17, 2013, p. 16.

Year-over-year, actual utility storage requirements for 2017 were 0.4 PJ lower than the requirement in 2016, resulting in an increase in the C1 Short-Term Peak Storage available for sale (from 6.4 PJ in 2016 to 6.8 PJ in 2017). 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).[8]

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 2017 was $0.68/GJ ($4.618 million/6.8 PJ). Please see Figure 1 for Short-Term Peak Storage values in US dollars.

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

Figure 1
Historical Short-Term Firm Peak Storage Values at Dawn 2009-2017



Non-Utility Storage Balances for 2017

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 A, Tab 1, Appendix A, Schedule 4 shows the non-utility inventory balances for October and November of 2017.

During the 2017 injection season, the non-utility storage balance peaked on October 23, 2017 at 94% full with a balance of 103.9 PJ compared to available space of 110.4 PJ. At October 31, 2017, the date to which Union manages its storage balance, the non-utility balance was 93% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2017.

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 2017 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.[9] 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 2017, Union sold a total of 6.8 PJ of short-term peak storage. The total 6.8 PJ was excess utility space, calculated by deducting 93.2 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.

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

Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2017 was $4.618 million.

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

OTHER DEFERRAL ACCOUNTS

Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

There is no balance in this deferral account. 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

The GDAR Deferral Account records 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. The balance in this deferral account is a debit from ratepayers of $0.076 million.

The GDAR capital costs are made up of the costs associated with three separate Notices of Amendments to a Rule:

1. On October 14, 2011, the Board issued a Notice of Amendment to a Rule – Residential Customer Service Amendments to the Gas Distribution Access Rule

under docket number EB-2010-0280. Union incurred $1.475 million in capital costs in 2011 and 2012 to implement the amendments to GDAR.

2. On September 6, 2012, the Board issued a Notice of Amendment to a Rule – Eligible Low-Income Customer Service Policy Amendments to the GDAR, also under docket number EB-2010-0280. Union incurred $0.278 million in capital costs in 2012 to implement the Low Income Amendments to the GDAR.
3. On March 28, 2013, the Board issued a Notice of Amendment to a Rule – Amendments to the Natural Gas Reporting and Record Keeping Requirements in Relation to Residential and Low Income Customer Service Policies, also under docket number EB-2010-0280. Union incurred $0.468 million in capital costs in 2013 to implement the amendments to GDAR.

The capital costs relating to the three Amendments to a Rule discussed above can be found at Table 4 below. The costs include those associated with incremental internal resources and expenses as well as contractor services. Union's retail Customer Information Service system, Banner, is an outsourced solution provided by Vertex Business Services. Vertex is responsible for the sustainment and operation of the system as well as any required infrastructure changes. All system changes are completed by Vertex and charged to Union.

Table 4
GDAR Costs

Line No.	Particulars ($000's)	Residential Customer Service Amendments	Low Income Amendments	Reporting and Record Keeping Requirement Amendments	Total Capital Spend
		(2011, 2012)	(2012)	(2013)	
1	Resources (Salary & Expenses)	345	20	9	374
2	Contractor Services	1,130	258	459	1,847
3	Total Costs	1,475	278	468	2,221

Consistent with Union's 2013 Deferrals Disposition proceeding (EB-2014-0145), Union replaced the capital costs with the annual revenue requirement related to these capital costs. This is outlined in Table 5 below. Accordingly, the 2017 GDAR Deferral Account has a debit balance of $0.076 million. 2017 is the final year the capital costs associated with the three prior Notices of Amendments to a Rule are expected to have a revenue requirement impact.

Table 5
GDAR Costs by Year

Line No.	Particulars ($000's)	2012	2013	2014	2015	2016	**2017**	Total
1	Depreciation	219	497	555	555	336	**59**	2,221
2	Interest	80	82	57	31	10	**1**	261
3	Return	51	55	38	21	7	**1**	173
4	Current Tax	(156)	(141)	100	153	90	**15**	61
5	Total	194	493	750	760	443	**76**	2,716

Account No. 179-120 International Financial Reporting Standards ("IFRS") Conversion Costs

There is no balance in this deferral account. 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 2017.

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 Union to establish a deferral account to track revenues associated with CDM activities, to be shared 50/50 between Union and ratepayers. The Board-approved the accounting order for Union's CDM Deferral Account in Union's 2011 Rates application (EB-2010-0148). The balance in this deferral account is a credit to ratepayers of $0.245 million.

This balance represents 50% of the net revenue from the "Whole Home Pilot Delivery" between Union and the Independent Electric Systems Operators ("IESO"). 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.

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 Union as a result of volume variances associated with the disposition of deferral account balances.

The balance in this deferral account is a debit from ratepayers of $2.566 million plus interest as of December 31, 2017 of $0.024 million, for a total of $2.590 million. The $2.566 million balance represents an under-recovery of $1.966 million for the Board-approved deferral account balances in EB-2016-0118 (Union's 2015 Deferral Account Disposition) and an under-recovery of $0.647 million for the Board-approved deferral account balances in EB-2015-0276 (Union's 2014 DSM Deferral Account Disposition). Also included in the balance is a credit to ratepayers of $0.047 million due to rebills related to the above dispositions. Please see Exhibit A, Tab 1, Appendix A, Schedule 6, Page 1 for a summary of the applicable deferral account balances by application.

Union's 2015 Deferral Account Disposition (EB-2016-0118)

In its EB-2016-0118 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, 2016 to March 31, 2017. The total amount approved for prospective recovery from rate classes was $23.426 million. Please see Exhibit A, Tab 1, Appendix A, Schedule 6, Page 2, Column (e), based on the forecasted volumes as noted at Exhibit A, Tab 1, Appendix A, Schedule 6, Page 2, Column (a).

Actual volumes for the period October 1, 2016 to March 31, 2017 averaged approximately 8% lower than forecast due to warmer weather in the same period. As a result of the actual volumes being less than the forecasted volumes, Union recovered $21.460 million, which is $1.966 million less than the final deferral account balances approved for disposition in EB-2016-0118. Please see Exhibit A, Tab 1, Appendix A, Schedule 6, Page 2, Column (f) for the actual disposition of deferral accounts and Exhibit A, Tab 1, Appendix A, Schedule 6, Page 2, Column (g) for the variance between forecast and actual disposition.

Union's 2014 DSM Deferral Account Disposition (EB-2015-0276)

In its EB-2015-0276 Decision, the Board approved the prospective disposition of the total balances in the approved deferral accounts to general service rate classes through a temporary rate adjustment from October 1, 2016 to March 31, 2017. The total amount approved for prospective recovery from general service rate classes was $8.551 million. Please see Exhibit A, Tab 1, Appendix A, Schedule 6, Page 3, Column (e), based on the forecasted volumes as noted at Exhibit A, Tab 1, Appendix A, Schedule 6, Page 3, Column (a).

Actual volumes for general service rate classes from October 1, 2016 to March 31, 2017 averaged approximately 8% lower than forecast due to warmer weather in the same period. As a result of the actual volumes being less than the forecasted volumes, Union recovered $7.903 million, which is $0.647 million less than the final deferral account balances approved for disposition in EB-2015-0276. Please see Exhibit A, Tab 1, Appendix A, Schedule 6, Page 3, Column (f) for the actual disposition of deferral accounts and Exhibit A, Tab 1, Appendix A, Schedule 6, Page 3, 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 Union to include storage-related costs associated with the difference in target and actual NAC.

The balance in this deferral account is a credit to ratepayers of $2.926 million less interest as of December 31, 2017 of $0.012 million, for a total of $2.914 million.

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

Target and Actual NAC

The 2017 target NAC for each rate class was approved by the Board in Union's 2017 Rates proceeding (EB-2016-0245). The 2015 actual NAC, weather normalized using the 2017 weather normal, was used to determine the 2017 target NAC. Setting the 2017 target NAC based on the 2015 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 2017 actual NAC for each rate class is weather normalized using the 2017 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 6 provides the 2017 target and 2017 actual NAC by rate class.

Table 6
2017 Target and Actual NAC

Line No.	Particulars (m^3/customer)	Rate 01	Rate 10	Rate M1	Rate M2
		(a)	(b)	(c)	(d)
1	2017 Target NAC	2,844	164,329	2,738	166,297
2	2017 Actual NAC	2,835	163,483	2,764	166,969
3	Change in NAC (Target - Actual NAC)	9	846	(26)	(672)

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 2017 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 7 provides the NAC Deferral Account balances by rate class.

Table 7
2017 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	250	98	(1,153)	(188)	(993)
2	Storage Revenue Balances	148	66	(195)	(28)	(9)
3	Storage Cost Balances	(83)	(116)	(547)	(1,178)	(1,924)
4	Interest	2	1	3	6	12
5	Total NAC Deferral Balance	317	49	(1,892)	(1,388)	(2,914)

Storage Costs

The storage costs recognize that variances between the 2017 target NAC and the 2013 Board-approved NAC volumes change the storage requirements for each general service rate class. As Union's Board-approved storage rates during the IR term are not updated to reflect changes in storage requirements due to NAC variances, Union must capture the NAC-related change in storage costs in the NAC Deferral Account as per the Board's Decision in Union's 2013 Deferrals Disposition proceeding, where the Board stated, *"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."*[10]

To determine the change in storage requirements for each general service rate class due to NAC variances, Union calculated the NAC volume variance per customer between its 2017/2018 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, Union calculated the change in storage requirements for each of the general service rate classes due to variances in NAC. The 2017/2018 Gas Supply Plan volumes represent the April 1, 2017 to March 31, 2018 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2017. These general service rate class storage requirements are then used in the

[10] EB-2014-0145, Decision and Order, p. 9.

calculation of the total in-franchise utility storage space requirement at November 1, 2017. 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 at November 1, 2017.

For Rate M1, the NAC volume variance between the 2017/2018 Gas Supply Plan and the 2013 Board-approved volumes was a decrease of 7.74 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate M1 storage requirement by 0.88 PJ. This resulted in decreased storage costs of $0.547 million (Table 7, Line 3).

For Rate M2, the NAC volume variance between the 2017/2018 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 3.83 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.89 PJ and resulted in decreased storage costs of $1.178 million (Table 7, Line 3).

For Rate 01, the NAC volume variance between the 2017/2018 Gas Supply Plan and the 2013 Board-approved volumes was a decrease of 0.60 PJ. The majority of the NAC volume variance decrease occurred in the winter months, which decreased the Rate 01 storage requirement by 0.11 PJ and decreased storage costs by $0.083 million (Table 7, Line 3).

For Rate 10, the NAC volume variance between the 2017/2018 gas supply plan and the 2013 Board-approved volumes was an increase of 1.37 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate 10 storage requirement by 0.15 PJ and resulted in decreased storage costs of $0.116 million (Table 7, Line 3).

Overall, the NAC volume variance between the 2017/2018 Gas Supply Plan and the 2013 Board-approved volumes resulted in a decrease in general service storage requirements of 3.03 PJ. Accordingly, Union has included a storage cost credit of $1.924 million in the NAC Deferral Account. Please see Table 8 below for a summary of the change in general service storage requirements due to NAC volume variances by rate class.

Table 8
Change in General Service Storage Requirements from 2013 Board-approved
(Based on weather normalized NAC)

Line No.	Union South	(PJ)	Union North	(PJ)
	(a)	(b)	(c)	(d)
1	Rate M1	(0.88)	Rate 01	(0.11)
2	Rate M2	(1.89)	Rate 10	(0.15)
3	Total Union South	(2.77)	Total Union North	(0.26)

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

The 3.03 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 6.8 PJ of excess utility space available for sale for winter 2017/2018. The revenue from the sale of the 6.8 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 A, Tab 1, Appendix A, Schedule 7.

For Rate M1, actual NAC is higher than target NAC by 26 m^3/customer (Table 6, Line 3). As shown in Table 7 above, this results in a delivery and storage revenue credit of $1.348 million ($1.153 million and $0.195 million, respectively). In addition, the NAC volume variance decreases the Rate M1 storage requirement by 0.88 PJ. Accordingly, Union must refund $0.547 million (Table 7, Line 3) to recognize the decrease in Rate M1 storage requirements.

For Rate M2, actual NAC is higher than target NAC by 672 m^3/customer (Table 6, Line 3). As shown in Table 7 above, this results in a delivery and storage revenue credit of $0.216 million ($0.188 million and $0.028 million, respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.89 PJ. Accordingly, Union must refund $1.178 million (Table 7, Line 3) to recognize the decrease in Rate M2 storage requirements.

For Rate 01, actual NAC is less than target NAC by 9 m^3/customer (Table 6, Line 3). As shown in Table 7 above, this results in a delivery and storage revenue charge of $0.398 million ($0.250 million and $0.148 million, respectively). In addition, the NAC volume variance decreases the Rate 01 storage requirement by 0.11 PJ. Accordingly, Union must refund $0.083 million (Table 7, Line 3) to recognize the decrease in Rate 01 storage requirements.

For Rate 10, actual NAC is less than target NAC by 846 m^3/customer (Table 6, Line 3). As shown in Table 7 above, this results in a delivery and storage revenue charge of $0.164 million ($0.098 million and $0.066 million, respectively). In addition, the NAC volume variance decreases the Rate 10 storage requirement by 0.15 PJ. Accordingly, Union must refund $0.116 million (Table 7, Line 3) 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 $0.330 million plus interest as of December 31, 2017 of $0.001 million, for a total of $0.331 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 2017, there is no impact related to income tax, however, there is a credit balance of $0.330 million included in the deferral account related to Harmonized Sales Tax ("HST") changes as discussed below.

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.

Union has recorded 50% of the annual incremental savings in the Tax Variance Deferral Account since the HST Deferral Account used for the 2010 implementation of HST is closed.

To calculate the 2017 Tax Variance Deferral Account balance related to HST changes, Union reviewed the transactions from January 1, 2017 to December 31, 2017 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.

For 2017, the Tax Variance Deferral Account is a credit balance of $0.330 million. The calculation of the balance is provided in Table 9.

Table 9
50% of 2017 Net Savings from the Impact of HST Changes
to be Shared with Ratepayers

Line No.		Particulars ($ millions)
1	Capital Savings	0.012
2	O&M Savings	0.318
3	Compressor Fuel Savings	0.000
4	Tax Variance Deferral Account Balance	$0.330

Account No. 179-135 Unaccounted for Gas ("UFG") Volume Variance Account

There is no balance in this deferral account.

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. 2017 Board-approved rates included $11.676 million in UFG costs. Based on 2017 actual volumes, Union recovered $11.122 million in UFG costs for 2017. In comparison, Union's actual 2017 UFG costs were $13.830 million.

Accordingly, the difference between the UFG costs recovered in rates of $11.122 million and Union's actual UFG costs of $13.830 million is $2.708 million. The difference of $2.708 million is within the $5.0 million threshold established by the Board for the UFG Volume Deferral Account. As a result, the UFG Volume deferral account balance is zero.

Table 10
2017 UFG Variances from Board-Approved

Line No.	Particulars ($ millions)	2017 Actual	Recovered in 2017 Rates	Variance
1	Total UFG Costs	13.830	11.122	2.708
2	UFG Deferral Account Threshold			5.000
3	UFG Volume Deferral Account Balance			-

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 $0.526 million plus interest as of December 31, 2017 of $0.002 million, for a total of $0.528 million. The balance of $0.526 million includes a credit of $0.413 million which represents the difference between the costs of $17.182 million included in 2017 rates (EB-2016-0245) and the calculation of the actual revenue requirement for 2017 of $16.769 million as shown in Table 11.

The remaining $0.113 million credit represents a true-up regarding property taxes between the 2015 revenue requirement of $6.054 million included in the 2015 Deferrals proceeding (EB-

2016-0118) and the actual 2015 revenue requirement of $5.941 million. This true-up is due to the assessment authority not applying an assessment on the Parkway West compressor and buildings, and not reclassifying the land from Farm to Commercial.

Please refer to the *Capital Expenditures* section below for details about additional spend expected. Accordingly, Union is proposing that the balance in this deferral account be disposed of on an interim basis, consistent with the treatment in the 2016 Deferrals proceeding, and that the prudence review, as agreed to in the 2016 Deferrals proceeding Settlement Agreement, be part of a future proceeding. [11]

[11] EB-2017-0091, Settlement Proposal (Updated, August 28, 2017), p. 12.

Table 11
2017 Parkway West Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2017 Board-Approved (a)	2017 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	2,600	2,600
2	Cumulative Capital Expenditures	219,430	230,601	11,171
3	Average Investment	208,357	217,523	9,166
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	1,649	980	(669)
5	Depreciation Expense (1)	5,105	5,415	310
6	Property Taxes	521	535	14
7	Total Operating Expenses	7,274	6,930	(344)
8	Required Return (2)	12,032	12,312	280
9	Total Operating Expense and Return	19,306	19,242	(64)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	2,411	2,522	111
11	Income Taxes - Utility Timing Differences (4)	(4,536)	(4,994)	(458)
12	Total Income Taxes	(2,124)	(2,473)	(349)
13	Total Revenue Requirement	17,182	16,769	(413)

Notes:

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

(2) The required return assumes a capital structure of 64% long-term debt at 3.82% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2017 Actual required return calculation is as follows:

$217.523 million * 64% * 3.82% = $5.318 million plus

$217.523 million * 36% * 8.93% = $6.994 million for a total of $12.312 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 2017 capital expenditures on in-service assets are $2.600 million higher than 2017 Board-approved as shown in Table 12.

Table 12
Parkway West Capital Expenditures

Line No.	Particulars ($000's)	2017 Board-Approved	2017 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1	Plant Infrastructure	-	2,092	2,092
2	LCU Compressor	-	508	508
3	Total Capital Expenditures	-	2,600	2,600

Station infrastructure costs were $2.092 million higher than included in 2017 Board-approved rates due to timing of spend on miscellaneous labour required for final cleanup of the site and permitting closeout. The miscellaneous labour is mainly comprised of contract labour and replacing a faulty septic tank at the new operations building. Resolution of the “Heritage Houses” has been ongoing and is now forecasted for completion in late 2018 or early 2019 pending approval by the municipality. This involves Union working with the Town of Milton and the Milton Heritage Committee to determine the best alternative for managing the two residential houses.

Loss of Critical Unit (“LCU”) compressor costs were $0.508 million higher than 2017 Board-approved rates due mainly to miscellaneous labour required to complete final cleanup.

Average Investment

The average investment increase of $9.166 million from 2017 Board-approved is due to capital expenditures being $11.171 million higher than 2017 Board-approved on a cumulative basis.

Operating Expenses

Operating and maintenance expenses were $0.669 million below those costs included in the 2017 Board-approved rates. The decrease is a result of moderate temperatures which caused the Parkway C compressor to experience lower than anticipated operational hours. Combined, this provided an opportunity to reduce the scope of inspections and maintenance.

The increase in depreciation expense of $0.310 million relates to the higher average investment than included in 2017 Board-approved rates.

Required Return

The increase in the required return of $0.280 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 2017 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%.

When Union prepared its 2016 Rates application (EB-2015-0116), the long-term debt rate used was 4.0% which was consistent with the rate used in the Parkway West Project application. In 2015, when the project was brought into service, Union issued debt which reduced the average long-term debt rate to 3.82%. This rate will be used to calculate the debt portion of the utility required return through to and including 2018.

Income Taxes

Union's actual tax rate for 2017 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.111 million "Income Taxes-Equity Return" increase relates to an increase in the tax impact of the equity component of the required return resulting from an increase in average investment.

The $0.458 million "Income Taxes-Utility Timing Differences" decrease relates to a higher Capital Cost Allowance due to higher actual capital expenditures than included in Board-approved rates.

Project-To-Date Capital Costs

In addition to reviewing the capital spending and variance explanations for calendar year 2017 related to the deferral balance calculations for this project, Union has included Table 13 below for additional reference only. The table summarizes capital spending for this project to-date as at December 31, 2017 which exceeds the forecast by $11.171 million. Project-to-date information is also provided in the Brantford-Kirkwall/Parkway D Project Costs Deferral Account (No. 179-137) section 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 2017 is $4.498 million or less than 1.1% over the original estimates.

Table 13
Parkway West Project-To-Date Capital Costs
($000s)

Line No.	Year	Board-approved	Actual	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	Total	219,430	230,601	11,171
	Brantford-Kirkwall/Parkway D (179-137)			
6	Total	204,076	197,403	(6,673)
	Combined 2015 Dawn Parkway Projects			
7	Total	423,506	428,004	4,498

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 cleanup and commissioning work. Additional details can be found in 2016 Deferrals proceeding written evidence (EB-2017-0091, Exhibit A, Tab 1, p. 36). As noted above, 2017 capital spending is related to final cleanup of the site and permitting closeout. 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 1.1% 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 $0.864 million plus interest as of December 31, 2017 of $0.004 million, for a total of $0.868 million. The balance of $0.864 million includes a credit of $0.831 million which represents the difference between the $15.433 million of costs included in 2017 rates (EB-2016-0245) and the calculation of the actual revenue requirement for 2017 of $14.602 million as shown in Table 14.

The remaining $0.033 million credit represents a true-up regarding property taxes between the 2015 revenue requirement of $0.454 million as revised in the 2016 Deferrals proceeding (EB-

2017-0091) and the actual 2015 revenue requirement of $0.421 million. This true-up is due to the assessment authority not applying an assessment on the Parkway D compressor and compressor building for the jurisdiction to levy property taxes in 2015.

Table 14
2017 Brantford-Kirkwall Pipeline/Parkway D Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2017 Board-Approved (a)	2017 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	-	375	375
2	Cumulative Capital Expenditures	204,076	197,403	(6,673)
3	Average Investment	193,535	187,254	(6,281)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses (1)	642	627	(15)
5	Depreciation Expense (2)	5,329	4,990	(339)
6	Property Taxes (3)	853	959	106
7	Total Operating Expenses	6,824	6,576	(248)
8	Required Return (4)	11,176	10,599	(577)
9	Total Operating Expense and Return	18,001	17,175	(826)
	Income Taxes:			
10	Income Taxes - Equity Return (5)	2,240	2,171	(69)
11	Income Taxes - Utility Timing Differences (6)	(4,808)	(4,744)	64
12	Total Income Taxes	(2,568)	(2,573)	(5)
13	Total Revenue Requirement (7)	15,433	14,602	(831)

Notes:

(1) 2017 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) 2017 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 2017 Actual required return calculation is as follows:

$187.254 million * 64% * 3.82% = $4.578 million plus

$187.254 million * 36% * 8.93% = $6.021 million for a total of $10.599 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

The actual 2017 capital expenditures on in-service assets were $0.375 million higher than 2017 Board-approved as shown in Table 15.

Table 15
Brantford-Kirkwall Pipeline/Parkway D Compressor Capital Expenditures

Line No.	Particulars ($000's)	2017 Board-Approved	2017 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Brantford-Kirkwall Pipeline			
1	Pipelines	-	67	67
	Parkway D Compressor			
2	Compressor Equipment	-	308	308
3	Total Capital Expenditures	-	375	375

Pipelines costs of $0.067 million were incurred in 2017 due to rescheduled spend and environmental restoration.

Compressor equipment costs of $0.308 million were incurred in 2017 due mainly to miscellaneous labour required to complete cleanup.

Average Investment

The average investment decrease of $6.281 million from 2017 Board-approved is due to capital expenditures being $6.673 million lower than 2017 Board-approved on a cumulative basis.

Operating Expenses

The decrease in depreciation expense of $0.339 million relates to the average investment being $6.281 million lower than 2017 Board-approved.

The $0.106 million property tax increase relates to an increase in pipe rates and municipal tax rates for Brantford-Kirkwall.

Required Return

The decrease in the required return of $0.577 million is the result of a decrease in the average rate base investment from the Board-approved $193.535 million to $187.254 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 2017 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

In addition to reviewing the capital spending and variance explanations for calendar year 2017 related to the deferral balance calculations for this project, Union has included Table 16 below for additional reference only. The table summarizes capital spending for this project-to-date as at December 31, 2017 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 Costs Deferral Account (No. 179-136) section 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 2017 is $4.498 million or less than 1.1% over the original estimates.

Table 16
Brantford-Kirkwall/Parkway D Project-To-Date Capital Costs
($000s)

Line No.	Year	Board-approved	Actual	Variance
1	2015	200,069	188,042	(12,027)
2	2016	4,007	8,986	4,979
3	2017	-	375	375
4	Total	204,076	197,403	(6,673)
	Parkway West Project (179-136)			
5	Total	219,430	230,601	11,171
	Combined 2015 Dawn Parkway Projects			
6	Total	423,506	428,004	4,498

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 offset the higher actual costs of the Brantford-Kirkwall pipeline portion of the project. Additional details can be found in 2016 Deferrals proceeding written evidence (EB-2017-0091, Exhibit A, Tab 1, pp. 43-44).

Account No. 179-138 Parkway Obligation Rate Variance

The balance in this deferral account is a credit to ratepayers of $0.121 million. In the 2014 Rates Settlement Agreement (EB-2013-0365), parties agreed to permanently shift the Union South Direct Purchase (“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 Settlement, Union 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.

Union adjusted rates effective January 1, 2018 to reflect the PDO shift to Dawn by DP customers of 54 TJ/d and the reduction in obligated deliveries at Parkway by sales service customers of 8 TJ/d. To account for the actual effective date of November 1, 2017, Union is proposing to refund $0.121 million to ratepayers for the November 1, 2017 to December 31, 2017 period.

The $0.121 million credit includes a reduction in 2017 PDCI costs of $0.593 million offset by an increase in 2017 PDO costs of $0.472 million. The reduction in 2017 PDCI costs is related to the decrease of 62 TJ/d (54 TJ/d DP customers and 8 TJ/d sales service customers) in obligated deliveries at Parkway eligible for the PDCI credit for the period November 1, 2017 to December 31, 2017. The increase in 2017 PDO costs is related to the incremental demand and fuel costs associated with 54 TJ/d of Dawn-Parkway capacity used to facilitate the PDO shift.

The reduction in 2017 PDCI costs of $0.593 million was calculated as the PDCI rate paid during 2017 of $(0.158)/GJ/d applied to the 62 TJ/d of reduced obligated deliveries at Parkway for the period November 1, 2017 to December 31, 2017.

The increase in 2017 PDO costs of $0.472 million consists of an increase in Dawn-Parkway demand cost of $0.365 million and fuel cost of $0.107 million associated with the 54 TJ/d of Dawn-Parkway capacity. The Dawn-Parkway demand cost of $0.365 million was calculated as the 2017 OEB-approved daily M12 Dawn-Parkway transportation rate of $0.112/GJ/d applied to 54 TJ/d for the period November 1, 2017 to December 31, 2017. The fuel cost of $0.107 million was calculated as the Board-approved October 2016 QRAM Ontario Landed Reference Price of $4.881/GJ applied to the annual incremental compressor fuel requirements of 131 TJ for the period November 1, 2017 to December 31, 2017.

Exhibit A, Tab 1, Appendix A, Schedule 8 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 Settlement Agreement.

Account No. 179-139 Energy East Pipeline Consultation Costs

There is no balance in this deferral account. In accordance with its EB-2017-0087 Decision, the Board has approved the closure of this account effective January 1, 2018.

Account No. 179-141 Unaccounted for Gas ("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 Union's purchases and the applicable Board-approved reference price, applied to Union's actual UFG volumes. The balance in this deferral account is a debit from ratepayers of \$0.102 million plus interest as of December 31, 2017 of \$0.001 million, for a total of \$0.103 million.

During 2017, Union purchased 25,795 10^3m^3 of gas supply related to actual UFG volumes on behalf of ratepayers who do not provide UFG in kind as part of customer supplied fuel ("CSF").

The actual monthly cost of the Union South gas portfolio in 2017 was \$159.596/10^3m^3, which is \$3.95/10^3m^3 higher than the Board-approved reference prices included in rates. The result is a \$0.102 million balance to be collected from ratepayers, as shown in Table 17 below.

Table 17
Calculation of 2017 UFG Price Deferral

Line. No.		UFG Volumes (10^3m^3)
1	Experienced UFG [(1)]	108,901
2	UFG Collected through Customer Supplied Fuel	83,106
3	UFG Volumes – Union Supplied [(2)]	25,795
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Union Supplied [(2)]	25,795
5	Price Variance (\$/10^3m^3) [(3)]	(\$3.95)
6	Deferral Account Balance (\$ millions)	(\$0.102)

[(1)]Converted using the following heat values (38.81 Jan-Mar) (38.95 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 customer supplied fuel.
[(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 this deferral account is a credit to ratepayers of $6.296 million plus interest as of December 31, 2017 of $0.031 million, for a total of $6.327 million. The credit of $6.296 million represents the difference between the $29.121 million of costs included in 2017 rates (EB-2016-0245) and the calculation of the actual revenue requirement for 2017 of $22.825 million as shown in Table 18.

Table 18
2017 Lobo C Compressor/Hamilton-Milton Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2017 Board-Approved (a)	2017 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	12,482	17,149	4,667
2	Cumulative Capital Expenditures	390,715	345,361	(45,354)
3	Average Investment	376,925	328,149	(48,776)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	1,128	745	(383)
5	Depreciation Expense (1)	9,158	8,030	(1,128)
6	Property Taxes	1,149	1,096	(53)
7	Total Operating Expenses	11,435	9,871	(1,564)
8	Required Return (2)	22,732	17,622	(5,110)
9	Total Operating Expense and Return	34,167	27,493	(6,674)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	4,147	3,809	(338)
11	Income Taxes - Utility Timing Differences (4)	(9,192)	(8,477)	715
12	Total Income Taxes	(5,046)	(4,668)	378
13	Total Revenue Requirement	29,121	22,825	(6,296)

Notes:

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

(2) The 2017 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 2017 Actual required return calculation is as follows:
$328.149 million * 64% * 3.36% = $7.057 million plus
$328.149 million * 36% * 8.93% = $10.565 million for a total of $17.622 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 2017 capital expenditures on in-service assets were $4.667 million higher than 2017 Board-approved as shown in Table 19.

Table 19
Lobo C Compressor/Hamilton-Milton Pipeline Capital Expenditures

Line No.	Particulars ($000's)	2017 Board-Approved	2017 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Lobo C Compressor			
1	Land	3,000	1	(2,999)
2	Structures	-	5	5
3	Pipelines	29	60	31
4	Compressor Equipment	1,400	7,293	5,893
	Hamilton-Milton Pipeline			
5	Land	-	-	-
6	Land Rights	-	657	657
7	Pipelines	8,053	9,134	1,081
8	Total Capital Expenditures	12,482	17,149	4,667

Lobo C land costs were $2.999 million lower than the costs included in 2017 Board-approved rates due to the purchase of land in 2016 that was originally planned for 2017.

Lobo C structures and pipelines costs were slightly higher than the costs included in 2017 Board-approved rates due to remaining cleanup that occurred in 2017.

Lobo C compressor equipment costs were $5.893 million higher than the costs included in 2017 Board-approved rates due to higher contractor and material costs and for work that had been rescheduled from 2016 into 2017.

Hamilton-Milton land rights costs were $0.657 million higher than the costs included in 2017 Board-approved rates due to easement payments rescheduled from 2016 into 2017. Land easement payment is now forecast for completion in 2018.

The pipelines costs for Hamilton-Milton were $1.081 million higher than the costs include in 2017 Board-approved rates due to cleanup and post-construction work to meet environmental and permitting conditions.

Average Investment

The average investment decrease of $48.776 million from 2017 Board-approved is due to cumulative capital expenditures being $45.354 million lower than 2017 Board-approved.

Operating Expenses

Operating and maintenance expenses were $0.383 million lower than the costs included in 2017 Board-approved rates. The decrease is a result of moderate temperatures which caused the Lobo C compressor to experience lower than anticipated operational hours. Combined, this provided an opportunity to reduce the scope of inspections and maintenance.

The decrease in depreciation expense of $1.128 million relates to the lower average investment than included in 2017 Board-approved rates.

Required Return

The decrease in the required return of $5.110 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 2017 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

Union’s actual tax rate for 2017 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.338 million “Income Taxes-Equity Return” decrease relates to a decrease in the tax impact of the equity component of the required return resulting from a decrease in average investment.

The $0.715 million "Income Taxes-Utility Timing Differences" increase relates to a lower Capital Cost Allowance deduction due to the lower average investment in 2017 versus Board-approved.

Account No. 179-143 Unauthorized Overrun Non-Compliance Account

In its 2016 Rates Decision and Order (EB-2015-0116), the Board ordered Union 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 $0.008 million.

The charge was intentionally set to provide customers with the appropriate price signal to comply with Union's distribution service interruption.[12]

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.

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

The balance in this deferral account is a debit from ratepayers of $4.912 million plus interest as of December 31, 2017 of $0.006 million, for a total of $4.918 million. The balance of $4.912 million includes a debit of $4.900 million which represents the difference between the $6.758 million of costs included in 2017 rates (EB-2016-0245) and the calculation of the actual revenue requirement for 2017 of $11.658 million as shown in Table 20. The 2017 difference is mainly due to earlier in-service dates for assets than the forecast included in 2017 rates.

The remaining $0.012 million debit is comprised of two adjustments related to 2016: one for an interest rate true-up, and the other related to capital expenditures. The interest rate true-up is a $0.080 million credit to adjust the long-term debt rate from the estimate of 4.0% to the actual of 3.29%. This rate will be used to calculate the debt portion of the utility required return through to and including 2018. The offsetting $0.092 million debit is due to $6.344 million of assets that were incorrectly placed into service for accounting purposes in 2016 instead of 2017. The resulting decrease in 2016 capital expenditures causes a higher revenue requirement in 2016 due to utility timing differences associated with income taxes.

In the 2017 Dawn Parkway Project Settlement Proposal (EB-2015-0200), Union agreed to record in the deferral account variances in actual revenue generated from forecast surplus capacity of 30,393 GJ/d relative to the maximum annual revenue of $1.34 million that could be realized from the sale of long-term firm surplus capacity effective November 1, 2017. Union’s actual Dawn to Parkway surplus for winter 2017/2018 was in excess of 30,393 GJ/d, therefore no long-term Dawn to Parkway revenue was earned from the forecast surplus to apply against the deferral account.

Table 20
2017 Dawn H/Lobo D/Bright C Compressor Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2017 Board-Approved (a)	2017 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	500,838	489,299	(11,539)
2	Cumulative Capital Expenditures	608,238	574,297	(33,941)
3	Average Investment	171,034	258,892	87,858
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	602	1,184	582
5	Depreciation Expense (1)	11,310	8,975	(2,335)
6	Property Taxes	175	201	26
7	Total Operating Expenses	12,086	10,361	(1,725)
8	Required Return (2)	9,877	13,773	3,896
9	Total Operating Expense and Return	21,963	24,134	2,171
	Income Taxes:			
10	Income Taxes - Equity Return (3)	1,879	3,000	1,121
11	Income Taxes - Utility Timing Differences (4)	(17,084)	(15,476)	1,608
12	Total Income Taxes	(15,205)	(12,476)	2,729
13	Total Revenue Requirement	6,758	11,658	4,900

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 2017 Actual required return calculation is as follows:
$258.892 million * 64% * 3.29% = $5.451 million plus
$258.892 million * 36% * 8.93% = $8.322 million for a total of $13.773 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 2017 capital expenditures on in-service assets were $11.539 million lower than 2017 Board-approved as shown in Table 21.

Table 21
Dawn H/Lobo D/Bright C Compressor Capital Expenditures

Line No.	Particulars ($000's)	2017 Board-Approved	2017 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Dawn H			
1	Structures	3,644	34,832	31,188
2	Compressor Equipment	191,343	188,866	(2,477)
3	Metering	1,798	2,490	692
	Bright C			
4	Land	-	1,435	1,435
5	Structures	14,450	31,416	16,966
6	Pipelines	937	2,583	1,646
7	Compressor Equipment	148,034	111,512	(36,522)
	Lobo D			
8	Land	-	1,985	1,985
9	Structures	2,927	3,237	310
10	Compressor Equipment	137,705	110,943	(26,762)
11	Total Capital Expenditures	500,838	489,299	(11,539)

Dawn H structures costs were $31.188 million higher than the costs included in 2017 Board-approved rates because approximately $30.0 million of costs included in 2017 Board-approved rates were categorized as Dawn H compressor equipment rather than Dawn H structures. The remaining increase was attributable to increased material costs.

Dawn H compressor equipment costs were $2.477 million lower than the costs included in 2017 Board-approved rates because approximately $30.0 million of costs included in 2017 Board-approved rates were categorized as Dawn H compressor equipment rather than Dawn H structures. Additionally, there was approximately $6.031 million of an increase due to Dawn north yard tie-in work being rescheduled from 2016 into 2017 associated with logistics of installation timing. The remaining $21.492 million increase was primarily due to increased costs associated with timing of finalizing the construction and labour costs.

Dawn H metering costs were $0.692 million higher than the costs included in 2017 Board-approved rates due to additional 2017 cleanup work.

Bright C land costs were $1.435 million higher than the costs included in 2017 Board-approved rates due to the additional purchase of land to create defined buffers around the compressor stations.

Bright C structures costs were $16.966 million higher than the costs included in 2017 Board-approved rates due to $17.725 million being included in 2017 Board-approved rates as Bright C compressor equipment. This is partially offset by the modification of the Bright A&B structure being rescheduled to 2017 from 2016.

Bright C pipelines costs were $1.646 million higher than the costs included in 2017 Board-approved rates due to additional 2017 cleanup work.

Bright C compressor equipment costs were $36.522 million lower than the costs included in 2017 Board-approved rates due to lower material costs and company labour, as well as contingencies for unforeseen expenses not being required. Additionally, $17.725 million of costs included in 2017 Board-approved rates should have been categorized as Bright C structures.

Lobo D land costs were $1.985 million higher than the costs included in 2017 Board-approved rates due to the additional purchase of land for environmental mitigation which was not anticipated.

Lobo D structures costs were $0.310 million higher than the costs included in 2017 Board-approved rates due to higher material costs.

Lobo D compressor equipment costs were $26.762 million lower than the costs included in 2017 Board-approved rates due to lower material costs, company labour and outside services, as well as contingencies for unforeseen expenses not being required.

Average Investment

Although the project is under-budget on a cumulative basis, the average investment has increased by $87.858 million over the costs included in 2017 Board-approved rates due to the in-service dates of the facilities. 2017 Board-approved rates were based on an estimate of a November 2017 in-service date, compared to an actual in-service date of July 2017 for Lobo D, September 2017 for Bright C, and October 2017 for Dawn H.

Operating Expenses

Operating and maintenance expenses were $0.582 million higher than the costs included in 2017 Board-approved rates. The increase is due to an earlier in-service date than planned for Lobo D and Bright C compressors resulting in additional operating time and related costs to support unit availability for operations. Earlier staffing additions also occurred at Dawn H to allow for additional training and project commissioning support.

The $2.335 million depreciation expense decrease is due to cumulative capital expenditures being $33.941 million lower than 2017 Board-approved.

Required Return

The $3.896 million required return increase relates to the average rate base investment in 2017 being $87.858 million greater than Board-approved, 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 4.0% and 36% equity at the Board-approved return of 8.93%. The 2017 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

Union's actual tax rate for 2017 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $1.121 million "Income Taxes – Equity Return" increase relates to the higher required return in 2017 versus Board-approved.

The $1.608 million "Income Taxes – Utility Timing Differences" increase relates primarily to a lower actual Capital Cost Allowance versus the 2017 Board-approved amount due to the lower cumulative capital expenditures versus Board-approved.

<u>Account No. 179-149 Burlington-Oakville Project Costs</u>

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 $3.460 million plus interest as of December 31, 2017 of $0.017 million, for a total of $3.477 million. The balance of $3.460 million represents the difference between the $8.284 million of costs included in 2017 rates (EB-2016-0245) and the calculation of the actual revenue requirement for 2017 of $4.824 million as shown in Table 22.

Table 22
Burlington Oakville Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2017 Board-Approved (a)	2017 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	1,767	2,728	961
2	Cumulative Capital Expenditures	119,477	81,848	(37,629)
3	Average Investment	116,312	78,870	(37,442)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	16	-	(16)
5	Depreciation Expense (1)	2,390	1,668	(722)
6	Property Taxes	117	121	4
7	Total Operating Expenses	2,523	1,790	(733)
8	Required Return (2)	7,015	4,235	(2,780)
9	Total Operating Expense and Return	9,538	6,025	(3,513)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	1,280	916	(364)
11	Income Taxes - Utility Timing Differences (4)	(2,533)	(2,116)	417
12	Total Income Taxes	(1,254)	(1,201)	53
13	Total Revenue Requirement	8,284	4,824	(3,460)

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%. The 2017 Actual required return calculation is as follows:
$78.870 million * 64% * 3.36% = $1.696 million plus
$78.870 million * 36% * 8.93% = $2.539 million for a total of $4.235 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 $0.961 million compared to the 2017 Board-approved as shown in Table 23.

Table 23
Burlington Oakville Pipeline Project Capital Expenditures

Line No.	Particulars ($000's)	2017 Board-Approved (a)	2017 Actuals (b)	Difference (c) = (b - a)
1	Land Rights	-	-	-
2	Structures	-	-	-
3	Pipelines	1,745	1,932	187
4	Station Equipment	22	796	774
5	Total Capital Expenditures	1,767	2,728	961

Pipeline costs were $0.187 million higher than costs included in 2017 Board-approved rates due to an increase in contractor costs associated with the restoration of Right-Of-Way.

Station equipment costs were $0.774 million higher than costs included in 2017 Board-approved rates due to costs associated with station work which had been rescheduled from 2016 into 2017, as well as additional required station modifications which were identified and completed within 2017.

Average Investment

The average investment decrease of $37.442 million from 2017 Board-approved is due to the cumulative capital expenditures being $37.629 million lower than 2017 Board-approved.

Operating Expenses

The $0.722 million depreciation expense decrease relates to cumulative capital expenditures being lower than 2017 Board-approved.

Required Return

The $2.780 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 2017 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

Union's actual tax rate for 2017 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.364 million "Income Taxes – Equity Return" decrease relates to the lower required return in 2017 versus Board-approved.

The $0.417 million "Income Taxes – Utility Timing Differences" increase relates to a lower actual Capital Cost Allowance deduction due to the lower average investment in 2017 versus Board-approved.

Account No. 179-151 Ontario Energy Board ("OEB") Cost Assessment Variance Account

The balance in this deferral account is a debit from ratepayers of $1.159 million plus interest as of December 31, 2017 of $0.008 million, for a total of $1.167 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 material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application 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 Union's Board-approved rates, there is $2.5 million in OEB cost assessment amounts. In 2017, the total amount of cost assessment invoices was $3.659 million, resulting in a variance of $1.159 million. The calculation of the variance is shown in Table 24 below.

Table 24
OEB Cost Assessment Variance (January 1, 2017 to December 31, 2017)

Date	Actual OEB Cost Assessment	2013 Board-approved OEB Cost Assessment in Rates[1]	Incremental OEB Cost Assessment
	($ millions)	($ millions)	($ millions)
	(a)	(b)	(c) = (a) – (b)
01-Jan-17	0.901	0.625	0.276
01-Apr-17	0.936	0.625	0.311
01-Jul-17	0.936	0.625	0.311
01-Oct-17	0.886	0.625	0.261
Total	3.659	2.500	1.159

Notes:
(1) Quarterly amount of annual $2.5 million

Account No. 179-153 Base Service North T-Service TransCanada Capacity

There is no balance in this 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 2017.

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. In this Decision, the Board stated that Union may propose disposition of the 2017 deferral account balance in its 2018 IRM application and evidence.[13] However, consistent with its other capital pass-through projects, Union is requesting the 2017 balance in this deferral account be disposed of as part of this proceeding.

The balance in this deferral account is a debit from ratepayers of $0.083 million, which represents the 2017 actual net revenue requirement. Although the deferral balance would normally consist of the difference between the actual net revenue requirement and the net revenue requirement included in Board-approved rates, no amount was included in 2017 Rates (EB-2016-0245) based on the Board's Decision in the Panhandle Reinforcement Project proceeding.[14]

[13] EB-2016-0186, Decision and Order, p. 23.
[14] EB-2016-0186, Decision and Order, p. 23.

Table 25
2017 Panhandle Reinforcement Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2017 Board-Approved (5) (a)	2017 Actuals (b)	Difference (6) (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	243,651	189,653	(53,998)
2	Cumulative Capital Expenditures	243,651	189,653	(53,998)
3	Average Investment	28,751	22,610	(6,141)
	Revenue Requirement Calculation:			
	Operating Expenses:			
4	Operating and Maintenance Expenses	3	-	(3)
5	Depreciation Expense (1)	2,486	2,027	(459)
6	Property Taxes	261	261	-
7	Total Operating Expenses	2,750	2,288	(462)
8	Required Return (2)	1,660	1,203	(457)
9	Total Operating Expense and Return	4,410	3,491	(919)
	Income Taxes:			
10	Income Taxes - Equity Return (3)	333	262	(71)
11	Income Taxes - Utility Timing Differences (4)	(4,393)	(3,385)	1,008
12	Total Income Taxes	(4,060)	(3,123)	937
13	Total Revenue Requirement	350	368	
14	Incremental Project Revenue	250	285	
15	Net Revenue Requirement	100	83	

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 2017 Actual required return calculation is as follows:
$22.610 million * 64% * 3.29% = $0.476 million plus
$22.610 million * 36% * 8.93% = $0.727 million for a total of $1.203 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.
(5) Not included in 2017 Board-approved rates.
(6) For variance analysis and informational purposes only.

Capital Expenditures

As noted above, the balance in the deferral account is the 2017 actual net revenue requirement of $0.083 million. Explanations of the variance between the 2017 Board-approved and the 2017 actuals have been provided for reference only. The actual 2017 capital expenditures on in-service assets were $53.998 million lower than 2017 Board-approved as shown in Table 26.

Table 26
Panhandle Reinforcement Capital Expenditures

Line No.	Particulars ($000's)	2017 Board-Approved	2017 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1	Land	1,036	160	(876)
2	Land Rights	10,013	3,164	(6,849)
3	Pipelines	192,015	149,703	(42,312)
4	Measuring & Regulating	37,558	34,563	(2,995)
5	Metering	725	698	(27)
6	Salvage	2,303	1,365	(938)
7	Total Capital Expenditures	243,651	189,653	(53,998)

Land purchase costs were $0.876 million lower than 2017 Board-approved due to reduced land requirements upon finalization of the pipeline location.

Land rights costs were $6.849 million lower than 2017 Board-approved. Union required less additional easement than originally anticipated due to the location of the pipeline within the boundaries of the existing easement.

Pipelines costs were $42.312 million lower than 2017 Board-approved due to risk and cost contingencies not fully being required for construction. A large portion of this amount was attributable to the potential for a two-year build which was avoided. Lastly, costs associated with restoration and cleanup have been deferred to 2018 due to inclement weather in 2017.

Measuring & regulating costs were $2.995 million lower than 2017 Board-approved as estimated contingencies for unforeseen costs were not required.

Average Investment

The average investment has decreased by $6.141 million compared to 2017 Board-approved due to 2017 capital expenditures being $53.998 million lower than 2017 Board-approved.

Operating Expenses

The $0.459 million depreciation expense decrease is due to 2017 capital expenditures being $53.998 million lower than 2017 Board-approved.

Required Return

The $0.457 million required return decrease relates to the average rate base investment in 2017 being $6.141 million lower than Board-approved, 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 4.0% and 36% equity at the Board-approved rate of return of 8.93%. The 2017 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

Union's actual tax rate for 2017 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.071 million "Income Taxes – Equity Return" decrease relates to the lower required return in 2017 versus Board-approved.

The $1.008 million "Income Taxes – Utility Timing Differences" increase relates primarily to a lower actual Capital Cost Allowance due to the lower capital expenditures in 2017 versus Board-approved.

UNION GAS LIMITED
Deferral Account Balances
Year Ending December 31, 2017

Line No.	Account Number	Account Name	Balance ($000's)	Interest [1] ($000's)	Total ($000's)
		Gas Supply Accounts:			
1	179-107	Spot Gas Variance Account	-	-	-
2	179-108	Unabsorbed Demand Costs (UDC) Variance Account	(4,133)	(26)	(4,159)
3	179-131	Upstream Transportation Optimization	11,057	-	11,057
4	179-132	Deferral Clearing Variance Account - Supply	317	3	320 [3]
5	179-132	Deferral Clearing Variance Account - Transport	502	5	507 [3]
6		Total Gas Supply Accounts (Lines 1 through 5)	7,743	(18)	7,725 [2]
		Storage Accounts:			
7	179-70	Short-Term Storage and Other Balancing Services	1,183	-	1,183
		Other:			
8	179-103	Unbundled Services Unauthorized Storage Overrun	-	-	-
9	179-112	Gas Distribution Access Rule (GDAR) Costs	76	-	76
10	179-120	IFRS Conversion Cost	-	-	-
11	179-123	Conservation Demand Management (CDM)	(245)	-	(245)
12	179-132	Deferral Clearing Variance Account	1,747	16	1,763 [3]
13	179-133	Normalized Average Consumption	(2,926)	12	(2,914)
14	179-134	Tax Variance	(330)	(1)	(331)
15	179-135	Unaccounted for Gas (UFG) Volume Variance Account	-	-	-
16	179-136	Parkway West Project Costs	(526)	(2)	(528)
17	179-137	Brantford-Kirkwall/Parkway D Project Costs	(864)	(4)	(868)
18	179-138	Parkway Obligation Rate Variance	(121)	-	(121)
19	179-139	Energy East Pipeline Consultation Costs	-	-	-
20	179-141	Unaccounted for Gas (UFG) Price Variance Account	102	1	103
21	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	(6,296)	(31)	(6,327)
22	179-143	Unauthorized Overrun Non-Compliance Account	(8)	-	(8)
23	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	4,912	6	4,918
24	179-149	Burlington-Oakville Project Costs	(3,460)	(17)	(3,477)
25	179-151	OEB Cost Assessment Variance Account	1,159	8	1,167
26	179-153	Base Service North T-Service TransCanada Capacity	-	-	-
27	179-156	Panhandle Reinforcement Project Costs	83	-	83
28		Total Other Accounts (Lines 8 through 27)	(6,697)	(12)	(6,709)
29		**Total Deferral Account Balances (Lines 6 + 7 + 28)**	**2,229**	**(30)**	**2,199**

Notes:

[1] Interest balances as of December 31, 2017.

[2] With the exception of UDC (No. 179-108), Upstream Transportation Optimization (No. 179-131), Deferral Clearing Variance Account (No. 179-132) related to Supply and Transport, and a portion of the Spot Gas Variance Account (No. 179-107), all gas supply-related deferral account balances are disposed of through the QRAM process.

[3] Deferral Clearing Variance Account (No. 179-132) total balance of $2,590 ($320 + $507 + $1,763)

UNION GAS LIMITED
Upstream Transportation Optimization Deferral Account (No. 179-131)

Line No.	Particulars ($000's)	2013 Board Approved (a)	2016 Actual Total (b)	2017 Actual Total (c)
1	Base Exchange Revenue	9,118	3,358	5,015
2	FT RAM Exchange Revenue	5,800	-	-
3	Total Exchange Revenue	14,918	3,358	5,015
4	Exchange Revenue Subject to Deferral		3,358	5,015
5	Ratepayer portion - 90%	13,426	3,022	4,513
6	10% Union Incentive Payment		336	501
7	Less: Gas Supply Optimization Margin in Rates	13,426	14,668	15,570
8	2017 Deferral Account Balance receivable from Ratepayers		(11,646)	(11,057)

UNION GAS LIMITED

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

Line No.	Particulars ($000's)	Board-Approved 2013	Actual 2016	Actual 2017
		(a)	(b)	(c)
	Revenue			
1	C1 Off-Peak Storage	500	2,749	709
2	Supplemental Balancing Services	2,000	1,367	890
3	Gas Loans	-	19	15
4	Enbridge LBA	-	968	381
5		2,500	5,102	1,995
6	C1 ST Firm Peak Storage	7,883	5,627	4,618
7	Total Revenue (1)	10,383	10,729	6,613
	Costs			
8	O&M (2)	3,810	2,156	2,289
9	UFG (3)	316	514	262
10	Compressor Fuel (4)	1,201	530	320
11	Total Costs	5,327	3,199	2,870
12	Net Revenue (line 7 - 11)	5,056	7,530	3,743
13	Less Shareholder Portion (10%)	505	753	374
14	Ratepayer Portion	4,551	6,777	3,368
15	Approved in Rates	4,551	4,551	4,551
16	Deferral balance payable to/(collectable from) ratepayers	-	2,226	(1,183)

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 GAS LIMITED
Summary of Non-Utility Storage Balances

Date	Entitlement (PJ)	Balance (PJ)	% Full (%)	Date	Entitlement (PJ)	Balance (PJ)	% Full (%)
1-Oct-17	110.4	101.5	92%	1-Nov-17	110.4	102.0	92%
2-Oct-17	110.4	101.8	92%	2-Nov-17	110.4	102.7	93%
3-Oct-17	110.4	101.9	92%	3-Nov-17	110.4	103.3	94%
4-Oct-17	110.4	102.0	92%	4-Nov-17	110.4	103.9	94%
5-Oct-17	110.4	102.2	93%	5-Nov-17	110.4	104.6	95%
6-Oct-17	110.4	102.4	93%	6-Nov-17	110.4	105.0	95%
7-Oct-17	110.4	102.5	93%	7-Nov-17	110.4	104.8	95%
8-Oct-17	110.4	102.6	93%	8-Nov-17	110.4	104.8	95%
9-Oct-17	110.4	102.5	93%	9-Nov-17	110.4	104.3	95%
10-Oct-17	110.4	102.6	93%	10-Nov-17	110.4	103.7	94%
11-Oct-17	110.4	102.7	93%	11-Nov-17	110.4	103.6	94%
12-Oct-17	110.4	102.6	93%	12-Nov-17	110.4	103.6	94%
13-Oct-17	110.4	102.7	93%	13-Nov-17	110.4	103.4	94%
14-Oct-17	110.4	102.9	93%	14-Nov-17	110.4	103.6	94%
15-Oct-17	110.4	103.1	93%	15-Nov-17	110.4	104.0	94%
16-Oct-17	110.4	102.9	93%	16-Nov-17	110.4	104.5	95%
17-Oct-17	110.4	102.7	93%	17-Nov-17	110.4	104.8	95%
18-Oct-17	110.4	102.9	93%	18-Nov-17	110.4	105.2	95%
19-Oct-17	110.4	103.2	94%	19-Nov-17	110.4	105.5	96%
20-Oct-17	110.4	103.6	94%	20-Nov-17	110.4	105.4	96%
21-Oct-17	110.4	103.8	94%	21-Nov-17	110.4	105.8	96%
22-Oct-17	110.4	103.9	94%	22-Nov-17	110.4	106.1	96%
23-Oct-17	110.4	103.9	94%	23-Nov-17	110.4	106.4	96%
24-Oct-17	110.4	103.8	94%	24-Nov-17	110.4	107.1	97%
25-Oct-17	110.4	103.7	94%	25-Nov-17	110.4	107.7	98%
26-Oct-17	110.4	103.6	94%	26-Nov-17	110.4	108.1	98%
27-Oct-17	110.4	103.7	94%	27-Nov-17	110.4	106.1	96%
28-Oct-17	110.4	103.6	94%	28-Nov-17	110.4	106.8	97%
29-Oct-17	110.4	103.5	94%	29-Nov-17	110.4	107.1	97%
30-Oct-17	110.4	103.1	93%	30-Nov-17	110.4	107.7	98%
31-Oct-17	110.4	102.2	93%				

UNION GAS LIMITED
Allocation of Short Term Peak Storage Revenues Between Utility and Non Utility

Line No.	Particulars	Utility Storage Space	Short Term Peak Storage Sold	Revenue from Short Term Peak Storage
		(PJs)	(PJs)	($ millions)
1	Net Revenues from Short Term Peak Storage			4.6
2	Total Short Term Peak Storage Sales		6.8	
3	Storage Space reserved for Utility	100.0		
4	Utility Space Requirement	93.2		
5	Excess Utility Storage Space (line 3 - line 4)	6.8		
6	Total Utility Short Term Peak Storage Sales (line 2)		6.8	
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)			4.6
9	Short Term Peak Storage Net Revenues - Non Utility (line 7 / line 2 * line 1)			0.0

UNION GAS LIMITED
179-132 Deferral Variance Account
2015 Deferral Disposition (EB-2016-0118) and 2014 DSM Deferral Disposition (EB-2015-0276)
Dispositions Disposed of During 2017

Line No.	Particulars	2017: 2015 Deferral Disposition EB-2016-0118 ($000) (a)	2017: 2014 DSM Deferral Disposition EB-2015-0276 ($000) (b)	2017: Interest ($000) (c)	2017: Total Variance With Interest ($000) (d) = (a) + (b) + (c)
1	Total General Service for Prospective Recovery (Refund) - Delivery	1,111	635	16	1,763
2	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation	502	-	5	507
3	Total Prospective Recovery (Refund) - Gas Supply Commodity	317	-	3	320
4	Total	1,931	635	24	2,590

Notes:
Line 1: Includes a credit of $0.047 million for rebills

UNION GAS LIMITED
179-132 Deferral Variance Account
2015 Deferral Disposition (EB-2016-0118)
Disposition Period - October 1, 2016 to March 31, 2017

Line No.	Particulars	Rate Class	Forecast Volume (10^3m^3) (1) (a)	Actual Volume (10^3m^3) (b)	Volume Variance (10^3m^3) (c) = (a) - (b)	2017 Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (d)	Forecast ($000) (e) = (a) * (d)/ 100	Actual ($000) (f) = (b) * (d)/ 100	Variance ($000) (g) = (c) - (f)
	General Service for Prospective Recovery(Refund) - Delivery								
1	Small Volume General Service	01	790,336	708,702	81,634	0.6186	4,889	4,384	505
2	Large Volume General Service	10	258,683	243,583	15,100	0.4730	1,224	1,152	71
3	Small Volume General Service	M1	2,359,719	2,136,038	223,681	0.2283	5,387	4,876	511
4	Large Volume General Service	M2	882,624	846,163	36,461	0.1629	1,438	1,378	59
5	Total General Service for Prospective Recovery (Refund) - Delivery		4,291,362	3,934,485	356,877		12,937	11,791	1,146
	General Service for Prospective Recovery(Refund) - Gas Supply Transportation								
6	Small Volume General Service	01	790,336	708,702	81,634	0.5091	4,024	3,608	416
7	Large Volume General Service	10	257,433	241,077	16,356	0.5312	1,368	1,281	87
8	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation		1,047,769	949,779	97,990		5,391	4,889	502
	Prospective Recovery/(Refund) - Gas Supply Commodity								
9	Small Volume General Service	M1	2,104,190	1,964,295	139,896	0.1957	4,218	3,844	374
10	Large Volume General Service	M2	457,042	424,266	32,777	0.1957	807	830	(23)
11	Firm Com/Ind Contract	M4	19,180	24,173	(4,993)	0.1957	36	47	(11)
12	Interruptible Com/Ind Contract	M5	5,994	5,229	765	0.1957	19	10	8
13	Special Large Volume Contract	M7	17,842	9,068	8,775	0.1957	17	18	(1)
14	Large Wholesale	M9	-	15,379	(15,379)	0.1957	-	30	(30)
15	Small Wholesale	M10	279	176	103	0.1957	0	0	(0)
16	Total Prospective Recovery (Refund) - Gas Supply Commodity		2,604,528	2,442,585	161,943		5,097	4,780	317
17	Total Excluding Rebill Activity Adjustments						23,426	21,460	1,966
18	Rebill Activity Adjustments								(35)
19	Total								1,931

Notes:
(1) Forecast volume for the period October 1, 2016 to March 31, 2017

UNION GAS LIMITED
179-132 Deferral Variance Account
2014 DSM Deferral Disposition (EB-2015-0276)
Disposition Period - October 1, 2016 to March 31, 2017

Line No.	Particulars	Rate Class	2017 Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)	Forecast ($000)	Actual ($000)	Variance ($000)
			(a)	(b)	(c) = (a) - (b)	(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	790,336	708,702	81,634	0.0491	388	348	40
2	Large Volume General Service	10	258,683	243,583	15,100	0.1619	419	394	24
3	Small Volume General Service	M1	2,359,719	2,136,038	223,681	0.2082	4,914	4,448	466
4	Large Volume General Service	M2	882,624	846,163	36,461	0.3207	2,830	2,713	117
5	Total General Service for Prospective Recovery (Refund) - Delivery		4,291,362	3,934,485	356,877		8,551	7,903	647
6	Total Excluding Rebill Activity Adjustments						8,551	7,903	647
7	Rebill Activity Adjustments								(12)
8	Total								635

Notes:
(1) Forecast volume for the period October 1, 2016 to March 31, 2017

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

Line No.	Particulars		Rate 01 (a)	Rate 10 (b)	Rate M1 (c)	Rate M2 (d)	Net Account Balance (e)
1	2017 Target NAC: m^3		2,844	164,329	2,738	166,297	
2	2017 Actual NAC: m^3		2,835	163,483	2,764	166,969	
3	Actual change in NAC (line 1 - line 2)		9	846	(26)	(672)	
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) (line 3 x line 4)	(1)	2,848	1,715	(27,196)	(4,515)	(27,148)
6	2017 Net Annual Average Delivery Rate ($/$m^3$)	(2)	$0.088	$0.057	$0.042	$0.042	
7	2017 Net Annual Storage Rate ($/$m^3$)	(3)	$0.052	$0.038	$0.007	$0.006	
8	Delivery Rate Annual Balance Amount ($ 000)	(4)	$250	$98	($1,153)	($188)	($993)
9	Storage Rate Annual Balance Amount ($ 000) (line 5 x line 7)	(4)	$148	$66	($195)	($28)	($9)
10	Storage Cost Annual Balance Amount ($ 000)		($83)	($116)	($547)	($1,178)	($1,924)
11	Interest ($ 000)	(5)	$2	$1	$3	6	$12
12	Total Deferral Account Amounts ($ 000) (line 8+9+10+11)		$317	$49	($1,892)	($1,388)	($2,914)

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 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

UNION GAS LIMITED
2017 Parkway Obligation Rate Variance Summary
For the period November 1, 2017 to December 31, 2017

Line No.	Particulars ($000's)	PDO Cost Variance Dawn-Parkway Demand Costs (1)	PDO Cost Variance Compressor Fuel Costs (2)	PDO Cost Variance Total PDO Cost Variance	PDCI Cost Variance Dawn-Parkway Demand Costs (3)	PDCI Cost Variance Compressor Fuel Costs (4)	PDCI Cost Variance Total PDCI Cost Variance	Total Cost Variance
		(a)	(b)	(c) = (a + b)	(d)	(e)	(f) = (d + e)	(g) = (c + f)
1	Rate M1	185	17	202	(213)	(61)	(275)	(72)
2	Rate M2	62	6	68	(72)	(22)	(93)	(25)
3	Rate M4	18	3	21	(21)	(10)	(31)	(10)
4	Rate M5 - Firm	0	0	0	(0)	(0)	(0)	(0)
5	Rate M5 - Interruptible	0	2	2	0	(7)	(7)	(5)
6	Rate M7 - Firm	8	1	9	(10)	(4)	(14)	(4)
7	Rate M7 - Interruptible	0	0	0	0	0	0	0
8	Rate M9	3	1	4	(3)	(2)	(5)	(2)
9	Rate M10	0	0	0	(0)	(0)	(0)	(0)
10	Rate T1 - Firm	9	2	11	(10)	(9)	(19)	(8)
11	Rate T1 - Interruptible	0	0	0	0	(1)	(1)	(1)
12	Rate T2 - Firm	58	13	71	(67)	(46)	(113)	(42)
13	Rate T2 - Interruptible	0	0	0	0	(1)	(1)	(1)
14	Rate T3	21	3	24	(24)	(9)	(33)	(10)
15	Total South in-francise	365	48	413	(420)	(173)	(593)	(180)
16	Excess Utility Storage Space	-	-	-	-	-	-	-
17	Rate C1 - Firm	-	0	0	-	-	-	0
18	Rate C1 - Interruptible	-	11	11	-	-	-	11
19	Rate M12	-	47	47	-	-	-	47
20	Rate M13	-	-	-	-	-	-	-
21	Rate M16	-	(0)	(0)	-	-	-	- 0
22	Total Ex-franchise	-	58	58	-	-	-	58
23	Rate 01	-	0	0	-	-	-	0
24	Rate 10	-	0	0	-	-	-	0
25	Rate 20	-	0	0	-	-	-	0
26	Rate 100	-	0	0	-	-	-	0
27	Rate 25	-	-	-	-	-	-	-
28	Total North In-franchise	-	1	1	-	-	-	1
29	Total Costs (line 15+line 22+line 28)	365	107	472	(420)	(173)	(593)	(121)

Notes:
(1) Calculated as 54 TJ/d x $0.112/GJ/d x 61 = $0.365 million. Rate represents the 2017 OEB-approved M12 Dawn to Parkway demand rate per EB-2016-0245.
Allocated to rate classes in proportion to 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 OEB Decision.
(2) Tab 1, Appendix A, Schedule 8, p. 2, column (d).
(3) Calculated as 62 TJ/d x $0.112/GJ/d x 61 = ($0.420) million. Rate represents the 2017 OEB-approved M12 Dawn to Parkway demand rate per EB-2016-0245.
Allocated to rate classes in proportion to 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 OEB Decision.
(4) Calculated as 62 TJ/d x $0.046/GJ/d x 61 = ($0.173) million. Rate represents the average 2017 OEB-approved Dawn to Parkway (TCPL, EGT) fuel and commodity rate per EB 2016-0245 Rate M12 Schedule 'C' plus $0.009/GJ/d for the Rate M12 Dawn to Parkway Cap-and-Trade unit rate paid during 2017.
Allocated to rate classes in proportion to Union South in-franchise volumes east of Dawn per EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, pp. 13 & 14, Updated for OEB Decision.

UNION GAS LIMITED
2017 Commodity Cost Adjustments based on
Parkway Delivery Obligation Reduction of 54 TJ/d and 14 TJ/d of M12 Turnback from November 1, 2017 to December 31, 2017

Line No.	Particulars	2017 Rates Incremental PDO Compressor Fuel (1) (GJ)	2018 Rates Incremental PDO Compressor Fuel (2) (GJ)	Incremental PDO Compressor Fuel Difference (GJ)	Cost of Incremental PDO Compressor Fuel Difference ($000's) (3)
		(a)	(b)	(c) = (b - a)	(d)
1	Rate M1	60,196	80,943	20,748	17
2	Rate M2	21,297	28,637	7,340	6
3	Rate M4	9,708	13,053	3,346	3
4	Rate M5 - Firm	248	333	85	0
5	Rate M5 - Interruptible	6,729	9,049	2,319	2
6	Rate M7 - Firm	3,905	5,251	1,346	1
7	Rate M7 - Interruptible	-	-	-	-
8	Rate M9	2,005	2,696	691	1
9	Rate M10	6	8	2	0
10	Rate T1 - Firm	8,844	11,892	3,048	2
11	Rate T1 - Interruptible	942	1,267	325	0
12	Rate T2 - Firm	45,555	61,257	15,701	13
13	Rate T2 - Interruptible	1,070	1,439	369	0
14	Rate T3	9,001	12,103	3,102	3
15	Total South In-franchise	169,505	227,928	58,423	48
16	Excess Utility Storage Space	-	-	-	-
17	Rate C1 - Firm	1,535	2,052	518	0
18	Rate C1 - Interruptible	42,140	55,175	13,036	11
19	Rate M12	133,594	191,627	58,034	47
20	Rate M13	-	-	-	-
21	Rate M16	615	580	(35)	(0)
22	Total Ex-franchise	177,883	249,435	71,552	58
23	Rate 01	1,565	2,075	511	0
24	Rate 10	492	653	161	0
25	Rate 20	175	232	57	0
26	Rate 100	6	7	2	0
27	Rate 25	-	-	-	-
28	Total North In-franchise	2,238	2,968	730	1
29	Total (line 15 + line 22 + line 28)	349,626	480,331	130,705	107

Notes:
(1) EB-2016-0245, Rate Order, Working Papers, Schedule 20, p. 3, column (i).
(2) EB-2017-0087, Rate Order, Working Papers, Schedule 20, p. 3, column (i).
(3) Calculated as column (c) x $4.881/1000 x 61/365. Compressor fuel cost based on EB-2016-0247 October 2016 QRAM Ontario Landed Reference Price of $4.881/GJ.

2017 UTILITY RESULTS AND EARNINGS SHARING

2017 UTILITY RESULTS

For the year ended December 31, 2017, Union's actual revenue sufficiency from utility operations is $6.1 million, which is $1.2 million lower than the 2016 revenue sufficiency of $7.3 million. Table 1 provides the results from Union's actual utility operations for 2017.

Table 1

Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31, 2017

Line No.	Particulars ($ Millions)	Board Approved 2013	Actual 2016	Actual 2017	Increase/ (decrease) 2017 vs. 2016
		(a)	(b)	(c)	(d) = (c) - (b)
1	Gas sales and distribution revenue	1,448.8	1,514.5	1,857.0	
2	Cost of gas	701.4	700.4	1,031.0	
3	Gas distribution margin	747.4	814.1	826.0	11.9
4	Transportation	157.0	182.7	236.9	54.2
5	Storage	10.4	8.5	7.8	(0.7)
6	Other revenue	20.2	16.5	17.3	0.8
7	Expenses	643.8	695.6	743.1	47.5
8	Income taxes	17.1	4.4	(5.0)	(9.4)
9	Utility income	274.1	321.8	350.0	28.2
10	Cost of Capital	272.6	315.6	344.9	29.3
11	Revenue deficiency / (sufficiency) after tax	(1.5)	(6.2)	(5.1)	1.1
12	Provision for income taxes on deficiency / (sufficiency)	(0.5)	(2.2)	(1.8)	0.4
13	Distribution revenue deficiency/(sufficiency)	(2.0)	(8.4)	(7.0)	1.4
14	Shareholder portion of short-term storage revenue	0.5	0.8	0.4	(0.4)
15	Shareholder portion of optimization activity	1.5	0.3	0.5	0.2
16	Total revenue deficiency/(sufficiency)	-	(7.3)	(6.1)	1.2

The primary drivers of Union's 2017 financial results relative to 2016 are provided below.

Gas Distribution Margin

The increase in gas distribution margin of $11.9 million relative to 2016 was mainly driven by rate increases and growth in the number of customers being serviced by Union (and related natural gas usage).

Transportation Revenue

The increase in transportation revenue of $54.2 million relative to 2016 was mainly driven by increased M12 and C1 long-term transportation rates due to capital pass-through projects and the recovery of facility-related Cap-and-Trade costs starting in 2017.

Expenses

The increase in expenses of $47.5 million relative to 2016 was mainly driven by higher depreciation and O&M expenses. The increase in depreciation of $26.5 million relative to 2016 was mainly driven by new projects placed into service. The increase in O&M of $15.6 million relative to 2016 was mainly driven by salaries and integration-related costs related to the merger between Enbridge Inc. and Spectra Energy.

Income Taxes

The decrease in income taxes relative to 2016 of $9.4 million is primarily due to higher capital cost allowance (tax depreciation). The higher capital cost allowance is driven by increased levels of capital spending in 2015, 2016, and 2017.

2017 EARNINGS SHARING

The benchmark return on equity (“ROE”) for 2017 was 8.93%. Union’s actual ROE from utility operations in 2017 was 9.16% or 23 basis points above the 2017 benchmark ROE.

The calculation of ROE for 2017 is found at Exhibit A, Tab 2, Appendix B, Schedule 1. To calculate actual utility earnings, Union starts in column (a) with Union’s total corporate revenues and operating expenses; column (b) removes revenues and costs associated with Union’s non-utility storage operations; and 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, Union 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's non-utility storage operations are shown at Exhibit A, 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

Union is making the following adjustments to utility earnings (Exhibit A, Tab 2, Appendix B, Schedule 1, column (c)):

A) Demand Side Management ("DSM") Incentive
B) Charitable Donations
C) Facility Fees, Customer Deposit Interest and Foreign Exchange on Bank Balances
D) Other

A) DSM Incentive

Other revenue includes the revenue recorded for the 2017 DSM Incentive of $6.947 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.

B) Charitable Donations

Charitable donation costs incurred by the utility are not allowable as deductions from utility earnings and as a result $0.896 million in costs have been removed.

C) 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 $1.013 million have been added to operating expenses and foreign exchange loss on bank balances of $0.612 million has been included in other expenses to arrive at utility earnings.

D) Other

In Union's 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 $15.570 million has been shown as a cost of gas reduction.

Amounts relating to the Conservation Demand Management ("CDM") program of $0.245 million have been removed from operating and maintenance expenses since there is a separate deferral sharing mechanism in place.

Legal costs relating to the MAAD application currently before the Board (EB-2017-0306/EB-2017-0307) of $0.180 million have been removed from operating and maintenance expenses. They are outside the scope of the current IR term and will be borne by the shareholder.

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 A, 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 A, 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 A, Tab 2, Appendix A, Schedule 4.

Shareholder Portion of Net Short-Term Storage Revenue

The shareholder portion of net short-term storage revenue represents Union's 10% share of the actual net margin generated on the sale of excess utility storage space. The shareholder portion of $0.275 million, net of tax, has been removed from the earnings sharing calculation. The calculation can be found at Exhibit A, Tab 1, Appendix A, Schedule 3, column (c), line 13.

Shareholder Portion of Net Optimization Activity

The shareholder portion of net optimization activity represents Union's 10% share of the net margin generated on optimization activities. The shareholder portion of $0.369 million, net of tax, has been removed from the earnings sharing calculation. The calculation can be found at Exhibit A, 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 2017 ROE is 9.16%.

Please see Exhibit A, 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 Union and its 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 the ratepayers. For 2017, the difference is 23 basis points and therefore there is no earnings sharing. Please see Exhibit A, Tab 2, Appendix B, Schedule 1, column (d), line 35.

2017 UNREGULATED STORAGE

As directed by the Board in EB-2011-0210 Decision and Order, p. 79, Union has provided plant continuity schedules related to Union's non-utility storage business at Exhibit A, 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, Union has provided the service quality indicator results at Exhibit A, Tab 2, Appendix D.

UNION GAS LIMITED
Calculation of Revenue Deficiency/(Sufficiency)
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2016	Actual 2017
		(a)	(b)	(c)
1	Operating revenue	1,636,340	1,722,253	2,118,989
2	Cost of service	1,362,212	1,400,491	1,769,001
3	Utility income	274,128	321,762	349,988
4	Requested return	272,639	315,580	344,877
5	Revenue deficiency / (sufficiency) after tax	(1,489)	(6,182)	(5,112)
6	Provision for income taxes on deficiency / (sufficiency)	(509)	(2,229)	(1,843)
7	Distribution revenue deficiency / (sufficiency)	(1,998)	(8,411)	(6,954)
8	Shareholder portion of short-term storage revenue	506	753	374
9	Shareholder portion of optimization activity	1,492	336	502
10	Total revenue deficiency/ (sufficiency)	$ -	$ (7,322)	$ (6,078)

Filed: 2018-06-06
EB-2018-0105
Exhibit A
Tab 2
Appendix A
Schedule 2

UNION GAS LIMITED
Statement of Utility Income
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2016	Actual 2017
		(a)	(b)	(c)
	Operating Revenues:			
1	Gas sales and distribution	1,448,762	1,514,537	1,856,952
2	Transportation	156,997	182,683	236,937
3	Storage	10,383	8,503	7,796
4	Other	20,198	16,530	17,304
5		1,636,340	1,722,253	2,118,989
	Operating Expenses:			
6	Cost of gas	701,427	700,444	1,030,965
7	Operating and maintenance expenses	383,132	397,858	413,427
8	Depreciation	196,091	228,401	254,881
9	Other financing	1,179	985	1,013
10	Property and capital taxes	63,272	69,564	72,321
11		1,345,101	1,397,252	1,772,606
	Other Income (Expense)			
12	Gain/(Loss) on sale of assets	-	-	(3)
13	Gain/(Loss) on foreign exchange	-	1,159	(1,438)
14		-	1,159	(1,441)
15	Utility income before income taxes	291,239	326,160	344,941
16	Income taxes	17,111	4,398	(5,047)
17	Total utility income	$ 274,128	$ 321,762	$ 349,988

UNION GAS LIMITED
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	2016 Actual Corporate	2016 Actual Unregulated Storage	2016 Actual Adjustments	2016 Actual Utility	2017 Actual Corporate	2017 Actual Unregulated Storage	2017 Actual Adjustments	2017 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	1,529,204	-	(14,668)	1,514,537	1,872,522	-	(15,570) [i]	1,856,952
2	Transportation	156,641	(356)	-	156,997	182,195	(488)	-	182,683	236,498	(439)	-	236,937
3	Storage	96,441	86,059	-	10,383	95,598	87,095	-	8,503	126,928	119,133	-	7,796
4	Other	24,498	-	(4,300)	20,198	20,768	-	(4,237)	16,530	24,252	-	(6,947) [ii]	17,304
5		1,726,343	85,703	(4,300)	1,636,340	1,827,765	86,607	(18,905)	1,722,253	2,260,200	118,694	(22,517)	2,118,989
	Operating Expenses:												
6	Cost of gas	701,966	539	-	701,427	716,827	1,715	(14,668)	700,444	1,070,458	23,924	(15,570) [i]	1,030,965
7	Operating and maintenance expenses	397,112	12,986	(993)	383,132	414,496	13,410	(3,228)	397,858	427,708	13,450	(831) [iii]	413,427
8	Depreciation	205,804	9,713	-	196,091	239,080	10,679	-	228,401	265,117	10,236	-	254,881
9	Other financing	-	-	1,179	1,179	-	-	985	985	-	-	1,013 [iv]	1,013
10	Property and other taxes	64,674	1,402	-	63,272	71,199	1,635	-	69,564	73,690	1,369	-	72,321
11		1,369,556	24,640	186	1,345,101	1,441,601	27,439	(16,910)	1,397,252	1,836,973	48,979	(15,387)	1,772,606
	Other Income (Expense)												
12	Gain/(Loss) on sale of assets	-	-	-	-	(624)	(624)	-	-	(214)	(210)	-	(3)
13	Other	-	-	-	-	-	-	-	-	-	-	-	-
14	Gain/(Loss) on foreign exchange	-	-	-	-	1,592	39	(394)	1,159	(873)	(47)	(612) [v]	(1,438)
15		-	-	-	-	967	(585)	(394)	1,159	(1,087)	(257)	(612)	(1,441)
16	Earnings Before Interest and Taxes	$ 356,787	$ 61,063	$ (4,486)	$ 291,239	$ 387,132	$ 58,583	$ (2,389)	$ 326,160	$ 422,140	$ 69,457	$ (7,742)	$ 344,941

Notes:

i) Reclassification of optimization revenue as cost of gas

ii) Demand Side Management Incentive

iii)

Charitable donations	896
CDM Program	(245)
MAAD application legal costs	180
	831

iv) Facility fees and customer deposit interest

v) Foreign exchange gain on bank balances

UNION GAS LIMITED
Summary of Cost of Capital
Year Ended December 31

		2013 Board-Approved				2016 Actual				2017 Actual			
		Utility Capital Structure		Cost Rate	Return	Utility Capital Structure		Cost Rate	Return	Utility Capital Structure		Cost Rate	Return
Line No.	Particulars	($000s)	(%)	%	($000s)	($000s)	(%)	%	($000s)	($000s)	(%)	%	($000s)
1	Long-term debt	2,289,139	61.30%	6.53%	149,481	3,161,476	66.44%	5.12%	161,809	3,319,044	60.63%	4.98%	165,315
2	Unfunded short-term debt	(1,287)	(0.03%)	1.31%	(17)	(219,473)	(4.61%)	0.82%	(1,800)	80,163	1.46%	1.02%	818
3	Total debt	2,287,852	61.26%		149,464	2,942,003	61.83%		160,009	3,399,207	62.10%		166,133
4	Preference shares	102,248	2.74%	3.05%	3,117	103,384	2.17%	2.51%	2,597	104,095	1.90%	2.66%	2,769
5	Common equity	1,344,432	36.00%	8.93%	120,058	1,713,030	36.00%	8.93%	152,974	1,970,608	36.00%	8.93%	175,975
6	Total rate base	$ 3,734,532	100.00%		$ 272,639	$ 4,758,418	100.00%		$ 315,580	$ 5,473,910	100.00%		$ 344,877

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

Line No.	Volumes in 10^3m^3	Board Approved 2013					
		System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(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 Volum	3,533,882	1,118,404	208,642	1,575,911	8,220,317	14,657,156

Line No.	Volumes in 10^3m^3	Actual 2016					
		System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(g)	(h)	(i)	(j)	(k)	(l)
	General Service						
1	Rate M1 Firm	2,656,511	228,984	13,175	15,323	-	2,913,994
2	Rate M2 Firm	593,330	336,692	4,312	292,465	-	1,226,799
3	Rate 01 Firm	851,160	86,211	-	10,572	-	947,942
4	Rate 10 Firm	169,915	78,790	-	100,601	4,425	353,730
5	Total General Service	4,270,916	730,677	17,487	418,960	4,425	5,442,465
	Wholesale - Utility						
6	Rate M9 Firm	5,638	-	-	66,487	-	72,124
7	Rate M10 Firm	248	-	-	-	-	248
8	Total Wholesale - Utility	5,886	-	-	66,487	-	72,372
	Contract						
9	Rate M4	37,464	20,034	-	413,916	-	471,413
10	Rate M7	20,934	2,987	-	450,295	-	474,216
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	13,830	-	-	93,911	457,170	564,912
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,365,738	1,365,738
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	447,127	447,127
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,212,740	4,212,740
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	250,167	250,167
21	Rate M5	9,005	4,697	-	180,460	-	194,162
22	Rate 25	45,558	-	-	-	71,289	116,847
23	Rate 30	-	-	-	-	-	-
24	Total Contract	126,791	27,718	-	1,138,583	6,804,230	8,097,321
25	Total Throughput Volum	4,403,593	758,395	17,487	1,624,029	6,808,655	13,612,159

Line No.	Volumes in 10^3m^3	Actual 2017					
		System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(m)	(n)	(o)	(p)	(q)	(r)
	General Service						
1	Rate M1 Firm	2,668,054	202,643	967	16,259	-	2,887,923
2	Rate M2 Firm	603,585	331,644	942	275,202	-	1,211,373
3	Rate 01 Firm	854,157	69,059	-	10,105	-	933,321
4	Rate 10 Firm	174,872	74,443	-	94,729	4,392	348,435
5	Total General Service	4,300,668	677,789	1,909	396,295	4,392	5,381,052
	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 Volum	4,446,870	705,358	1,909	1,639,080	5,971,108	12,764,325

Filed: 2018-06-06
EB-2018-0105
Exhibit A
Tab 2
Appendix A
Schedule 6

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

		Board Approved 2013						Actual 2016						Actual 2017					
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	2,533,596	218,389	12,565	14,614	-	2,779,165	2,698,889	204,985	978	16,447	-	2,921,299
2	Rate M2 Firm	378,137	336,728	23,220	237,485	-	975,571	568,260	322,466	4,130	280,107	-	1,174,963	606,311	333,142	946	276,445	-	1,216,844
3	Rate 01 Firm	641,423	233,272	-	9,727	-	884,421	815,697	82,619	-	10,131	-	908,447	882,205	71,327	-	10,437	-	963,968
4	Rate 10 Firm	155,398	82,428	-	85,062	-	322,887	164,705	76,374	-	97,516	4,289	342,884	179,201	76,286	-	97,074	4,501	357,062
5	Total General Service	3,446,401	1,118,404	208,642	348,975	-	5,122,423	4,082,258	699,848	16,695	402,368	4,289	5,205,459	4,366,606	685,740	1,924	400,402	4,501	5,459,173
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	60,750	-	60,750	5,638	-	-	66,487	-	72,124	23,509	-	-	45,665	-	69,174
7	Rate M10 Firm	48	-	-	141	-	189	248	-	-	-	-	248	274	-	-	-	-	274
8	Total Wholesale - Utility	48	-	-	60,891	-	60,939	5,886	-	-	66,487	-	72,372	23,782	-	-	45,665	-	69,447
	Contract																		
9	Rate M4	16,855	-	-	387,823	-	404,678	37,464	20,034	-	413,916	-	471,413	40,356	20,534	-	488,870	-	549,760
10	Rate M7	-	-	-	147,143	-	147,143	20,934	2,987	-	450,295	-	474,216	22,229	2,803	-	482,660	-	507,692
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	13,514	-	-	110,097	506,191	629,802	13,830	-	-	93,911	457,170	564,912	13,127	-	-	95,981	392,391	501,499
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,895,488	1,895,488	-	-	-	-	1,365,738	1,365,738	-	-	-	-	1,029,145	1,029,145
15	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	548,986	548,986	-	-	-	-	447,127	447,127	-	-	-	-	458,243	458,243
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,880,297	4,880,297	-	-	-	-	4,212,740	4,212,740	-	-	-	-	3,762,498	3,762,498
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	272,712	272,712	-	-	-	-	250,167	250,167	-	-	-	-	257,343	257,343
21	Rate M5	14,152	-	-	520,981	-	535,132	9,005	4,697	-	180,460	-	194,162	6,806	4,232	-	129,610	-	140,648
22	Rate 25	42,913	-	-	-	116,643	159,555	45,558	-	-	-	71,289	116,847	39,902	-	-	-	67,095	106,997
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	87,433	-	-	1,166,044	8,220,317	9,473,795	126,791	27,718	-	1,138,583	6,804,230	8,097,321	122,420	27,569	-	1,197,120	5,966,716	7,313,825
25	Total Throughput Volume	3,533,882	1,118,404	208,642	1,575,911	8,220,317	14,657,156	4,214,935	727,565	16,695	1,607,438	6,808,519	13,375,153	4,512,808	713,309	1,924	1,643,188	5,971,216	12,842,446

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

		Board Approved 2013						Actual 2016						Actual 2017					
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	758,382	26,931	1,824	888	-	788,025	834,542	25,266	95	1,053	-	860,956
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	116,762	16,501	179	12,871	160	146,472	131,622	19,348	46	14,665	40	165,722
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	333,261	23,100	-	2,138	-	358,499	371,824	18,308	-	2,036	-	392,169
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	43,966	11,765	-	13,966	270	69,967	51,488	10,776	-	12,664	280	75,209
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,252,371	78,297	2,002	29,863	429	1,362,963	1,389,477	73,699	141	30,419	319	1,494,055
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	962	-	-	817	-	1,779	4,097	-	-	676	-	4,773
7	Rate M10 Firm	11	-	-	7	-	18	50	-	-	-	-	50	60	-	-	-	-	60
8	Total Wholesale - Utility	11	-	-	734	-	745	1,012	-	-	817	-	1,829	4,156	-	-	676	-	4,832
	Contract																		
9	Rate M4	3,407	-	-	11,786	-	15,193	6,945	708	-	15,088	-	22,742	8,176	818	-	19,545	-	28,539
10	Rate M7	-	-	-	4,127	-	4,127	3,850	267	-	9,903	-	14,020	4,433	302	-	10,839	-	15,575
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	1,854	1,854	-	-	-	-	3,001	3,001
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	3,103	-	-	9,098	11,137	23,337	3,100	-	-	6,119	10,189	19,408
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	304	304	-	-	-	-	306	306
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	12,626	12,626	-	-	-	-	10,621	10,621
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,368	1,368	-	-	-	-	1,476	1,476
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	464	-	-	-	8,791	9,255	(73)	-	-	-	9,870	9,797
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,700	7,700	-	-	-	-	6,619	6,619
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	3,930	-	-	-	45,868	49,798	-	-	-	-	52,903	52,903
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,344	1,344	-	-	-	-	1,315	1,315
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,721	3,721	-	-	-	-	5,388	5,388
21	Rate M5	2,801	-	-	12,913	-	15,713	1,643	154	-	5,965	-	7,762	1,330	147	-	4,936	-	6,413
22	Rate 25	10,172	-	-	-	3,273	13,445	8,838	-	-	-	2,173	11,011	8,039	-	-	-	1,874	9,914
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610	28,773	1,129	-	40,053	96,887	166,842	25,006	1,267	-	41,439	103,562	171,274
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,282,157	79,426	2,002	70,733	97,316	1,531,634	1,418,639	74,966	141	72,534	103,881	1,670,162
26	LRAM						-						538						628
27	Average Use / Normalized Average Consumption						-						23,278						(2,926)
28	Parkway Obligation Rate Variance						-						2,861						(161)
29	Capital Pass Through						-						2,539						207
30	Normalized Cap and Trade Revenue						-						-						233,916
31	Total Revenue						$ 1,448,762						1,560,850						1,901,826

Filed: 2018-06-06
EB-2018-0105
Exhibit A
Tab 2
Appendix A
Schedule 8

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

		Board Approved 2013						Actual 2016						Actual 2017					
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	732,935	26,717	1,809	881	-	762,342	809,239	24,891	94	1,037	-	835,262
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	110,940	16,242	176	12,670	157	140,185	126,198	18,637	45	14,126	38	159,043
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	321,839	22,469	-	2,067	-	346,375	367,206	18,112	-	2,012	-	387,329
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	42,469	11,445	-	13,565	268	67,747	50,795	10,621	-	12,480	276	74,172
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,208,183	76,874	1,985	29,183	425	1,316,649	1,353,438	72,261	138	29,655	314	1,455,806
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	962	-	-	817	-	1,779	4,097	-	-	676	-	4,773
7	Rate M10 Firm	11	-	-	7	-	18	50	-	-	-	-	50	60	-	-	-	-	60
8	Total Wholesale - Utility	11	-	-	734	-	745	1,012	-	-	817	-	1,829	4,156	-	-	676	-	4,832
	Contract																		
9	Rate M4	3,407	-	-	11,786	-	15,193	6,945	708	-	15,088	-	22,742	8,176	818	-	19,545	-	28,539
10	Rate M7	-	-	-	4,127	-	4,127	3,850	267	-	9,903	-	14,020	4,433	302	-	10,839	-	15,575
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	1,854	1,854	-	-	-	-	3,001	3,001
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	3,103	-	-	9,098	11,137	23,337	3,100	-	-	6,119	10,189	19,408
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	304	304	-	-	-	-	306	306
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	12,626	12,626	-	-	-	-	10,621	10,621
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,368	1,368	-	-	-	-	1,476	1,476
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	464	-	-	-	8,791	9,255	(73)	-	-	-	9,870	9,797
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,700	7,700	-	-	-	-	6,619	6,619
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	3,930	-	-	-	45,868	49,798	-	-	-	-	52,903	52,903
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,344	1,344	-	-	-	-	1,315	1,315
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,721	3,721	-	-	-	-	5,388	5,388
21	Rate M5	2,801	-	-	12,913	-	15,713	1,643	154	-	5,965	-	7,762	1,330	147	-	4,936	-	6,413
22	Rate 25	10,172	-	-	-	3,273	13,445	8,838	-	-	-	2,173	11,011	8,039	-	-	-	1,874	9,914
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610	28,773	1,129	-	40,053	96,887	166,842	25,006	1,267	-	41,439	103,562	171,274
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,237,968	78,003	1,985	70,053	97,311	1,485,321	1,382,600	73,528	138	71,771	103,876	1,631,913
26	LRAM						-						538						628
27	Average Use / Normalized Average Consumption						-						23,278						(2,926)
28	Parkway Obligation Rate Variance						-						2,861						(161)
29	Capital Pass Through						-						2,539						207
30	Cap and Trade Revenue						-						-						227,291
31	Total Revenue					$	1,448,762						1,514,537						1,856,952

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

Line No.	Particulars ($000's)	Board Approved 2013						Actual 2016						Actual 2017					
		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	368,263	26,717	1,809	881	-	397,671	397,910	24,891	94	1,037	-	423,932
2	Rate M2 Firm	19,898	17,612	2,631	11,466	-	51,607	28,868	16,242	176	12,670	157	58,112	33,974	18,637	45	14,126	38	66,819
3	Rate 01 Firm	118,812	41,509	-	928	-	161,249	147,414	13,505	-	965	-	161,884	158,048	11,354	-	1,016	-	170,419
4	Rate 10 Firm	9,524	5,578	-	4,876	-	19,979	9,882	4,659	-	4,882	268	19,691	11,245	4,911	-	5,194	276	21,627
5	Total General Service	451,532	123,643	27,301	18,159	-	620,636	554,427	61,124	1,985	19,398	425	637,358	601,177	59,793	138	21,374	314	682,797
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	73	-	-	817	-	889	536	-	-	676	-	1,212
7	Rate M10 Firm	2	-	-	7	-	10	15	-	-	-	-	15	19	-	-	-	-	19
8	Total Wholesale - Utility	2	-	-	734	-	736	87	-	-	817	-	904	554	-	-	676	-	1,230
	Contract																		
9	Rate M4	514	-	-	11,786	-	12,300	1,510	708	-	15,088	-	17,306	1,956	818	-	19,545	-	22,319
10	Rate M7	-	-	-	4,127	-	4,127	841	267	-	9,903	-	11,011	943	302	-	10,839	-	12,085
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	434	-	-	2,425	10,637	13,496	462	-	-	2,117	11,125	13,705	434	-	-	2,053	10,189	12,676
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	12,626	12,626	-	-	-	-	10,621	10,621
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,368	1,368	-	-	-	-	1,476	1,476
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,773	8,773	-	-	-	-	9,772	9,772
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,700	7,700	-	-	-	-	6,619	6,619
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	45,839	45,839	-	-	-	-	52,781	52,781
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,344	1,344	-	-	-	-	1,315	1,315
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,721	3,721	-	-	-	-	5,388	5,388
21	Rate M5	375	-	-	12,913	-	13,288	351	154	-	5,965	-	6,470	289	147	-	4,936	-	5,371
22	Rate 25	1,200	-	-	-	3,273	4,473	1,398	-	-	-	2,173	3,571	1,197	-	-	-	1,874	3,072
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	2,524	-	-	31,250	86,601	120,375	4,563	1,129	-	33,073	94,671	133,436	4,820	1,267	-	37,374	100,035	143,496
25	Subtotal	454,058	123,643	27,301	50,143	86,601	741,747	559,077	62,253	1,985	53,288	95,096	771,698	606,551	61,060	138	59,424	100,349	827,522
26	LRAM						-						538						628
27	Average Use / Normlalized Average Consumption						-						19,442						(2,941)
28	Parkway Obligation Rate Variance						-						2,861						(161)
29	Capital Pass Through						-						2,539						207
30	Cap and Trade Revenue						-						-						227,291
31	Total Revenue						$ 741,747						797,079						1,052,547

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

		Board Apprroved 2013						Actual 2016						Actual 2017					
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	1,037,178	64,868	2,388	1,063	-	1,105,497	1,061,695	55,360	1	1,093	-	1,118,149
2	Rate M2 Firm	3,172	2,594	241	771	-	6,778	4,371	2,382	22	833	-	7,608	4,256	2,371	-	760	-	7,387
3	Rate 01 Firm	242,644	80,300	-	343	-	323,287	318,440	23,853	-	653	-	342,946	327,139	18,909	-	639	-	346,687
4	Rate 10 Firm	930	845	-	289	-	2,064	1,283	570	-	332	5	2,190	1,375	564	-	294	5	2,238
5	Total General Service	1,084,047	240,904	72,630	2,305	-	1,399,886	1,361,272	91,673	2,410	2,881	5	1,458,241	1,394,465	77,204	1	2,786	5	1,474,461
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	3	-	3	1	-	-	2	-	3	1	-	-	2	-	3
7	Rate M10 Firm	1	-	-	1	-	2	2	-	-	-	-	2	3	-	-	-	-	3
8	Total Wholesale - Utility	1	-	-	4	-	5	3	-	-	2	-	5	4	-	-	2	-	6
	Contract																		
9	Rate M4	11	-	-	104	-	115	23	10	-	145	-	178	22	10	-	172	-	204
10	Rate M7	-	-	-	4	-	4	2	1	-	27	-	30	2	1	-	27	-	30
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	4	-	-	20	39	63	4	-	-	16	27	47	4	-	-	16	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	-	-	-	-	37	37	-	-	-	-	38	38
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	29	29	-	-	-	-	23	23	-	-	-	-	23	23
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	1	1	-	-	-	-	1	1	-	-	-	-	1	1
21	Rate M5	5	-	-	139	-	144	7	2	-	54	-	63	6	2	-	30	-	38
22	Rate 25	50	-	-	-	42	92	39	-	-	-	45	84	44	-	-	-	44	88
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	70	-	-	267	163	500	75	13	-	242	144	474	78	13	-	245	141	477
25	Total Number of Customers	1,084,118	240,904	72,630	2,576	163	1,400,391	1,361,350	91,686	2,410	3,125	149	1,458,720	1,394,547	77,217	1	3,033	146	1,474,944

UNION GAS LIMITED
Revenue from Regulated Storage and Transportation of Gas
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2016 Actual	2017 Actual
		(a)	(b)	(c)
	Revenue from Regulated Storage Services:			
1	C1 Off-Peak Storage	500	2,749	709
2	Supplemental Balancing Services	2,000	2,335	1,271
3	Gas Loans	-	19	15
4	C1 Short Term Firm Peak Storage	7,883	5,627	4,618
5	Short Term Storage and Balancing Services Deferral	-	(2,226)	1,183
6	Total Regulated Storage Revenue Net of Deferral	$ 10,383	$ 8,503	$ 7,796
	Revenue from Regulated Transportation Services:			
7	M12 Transportation	120,963	145,913	180,310
8	M12-X Transportation	13,896	17,130	20,144
9	C1 Long Term Transportation	7,039	9,154	18,410
10	C1 Short Term Transportation	11,067	7,923	8,318
11	Gross Exchange Revenue	14,918	3,358	5,015
12	Ratepayer Portion of Exchange Revenue	(13,426)	(3,022)	(4,513)
13	M13 Local Production	424	359	316
14	M16 Transportation	694	599	505
15	S&T:Transportation Revenue Cap & Trade	-	-	5,018
16	Other S&T Revenue	1,423	1,270	3,414
17	Total Regulated Transportation Revenue Net of Deferral	$ 156,997	$ 182,683	$ 236,937

UNION GAS LIMITED
Other Revenue
Year Ended December 31

Line No.	Particulars ($000's)	2013 Board Approved	2016 Actual	2017 Actual
1	Delayed payment charges	6,467	5,147	6,644
2	Account opening charges	7,000	6,817	6,395
3	Billing revenue	3,453	1,652	1,485
4	Mid market transactions	2,000	1,139	1,114
5	Other operating revenue	1,278	1,775	1,666
6	Total other revenue	$ 20,198	$ 16,530	$ 17,304

UNION GAS LIMITED
Operating and Maintenance Expense by Cost Type
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2016 Actual	2017 Actual
		(a)	(b)	(c)
1	Salaries/Wages	192,786	209,763	221,758
2	Benefits	81,083	63,498	60,709
3	Materials	9,958	8,757	10,239
4	Employee Training	14,330	13,189	12,426
5	Contract Services	66,376	68,775	70,599
6	Consulting	8,172	9,566	8,162
7	General	18,890	25,927	27,895
8	Transportation and Maintenance	9,761	9,676	9,845
9	Company Used Gas	2,611	2,048	1,936
10	Utility Costs	4,682	6,007	5,968
11	Communications	6,380	6,054	5,658
12	Demand Side Management Programs	24,031	45,960	48,052
13	Advertising	2,386	3,106	3,449
14	Insurance	9,056	8,126	6,785
15	Donations	788	3,207	899
16	Financial	1,871	2,626	2,724
17	Lease	4,191	4,627	4,733
18	Cost Recovery from Third Parties	(2,549)	(4,898)	(3,731)
19	Computers	6,465	10,867	10,782
20	Regulatory Hearing & OEB Cost Assessment	4,300	3,964	3,563
21	Outbound Affiliate Services	(13,706)	(15,905)	(15,842)
22	Inbound Affiliate Services	11,888	22,008	22,613
23	Bad Debt	6,250	3,650	4,050
24	Other	139	-	-
25	Total	470,139	510,596	523,272
26	Indirect Capitalization	(51,376)	(71,964)	(73,017)
27	Direct Capitalization	(21,652)	(24,136)	(22,547)
28	Total	397,111	414,496	427,708
29	Unregulated Storage	(12,883)	(13,410)	(13,450)
30	Non Utility Earnings Adjustments	(1,096)	(3,227)	(831)
31	Total Non Utility Costs	(13,979)	(16,637)	(14,281)
32	Total Net Utility Operating and Maintenance Expense	$ 383,132	$ 397,858	$ 413,427

UNION GAS LIMITED
Calculation of Utility Income Taxes
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2016 Actual	2017 Actual
		(a)	(b)	(c)
	Determination of Taxable Income			
1	Utility income before interest and income taxes	291,239	326,160	344,941
	Adjustments required to arrive at taxable utility income:			
2	Interest expense	(149,464)	(160,009)	(166,133)
3	Utility permanent differences	4,693	3,857	2,283
4		146,468	170,008	181,091
	Utility timing differences			
5	Capital Cost Allowance	(185,314)	(270,300)	(344,183)
6	Depreciation	196,091	228,401	254,881
7	Depreciation through clearing	2,265	3,044	2,867
8	Other	(32,921)	(66,185)	(65,329)
9	Gas Cost Deferrals and Other (current)	-	(78,363)	(2,655)
10		(19,879)	(183,403)	(154,418)
11	Taxable income	$ 126,589	$ (13,395)	$ 26,673
	Calculation of Utility Income Taxes			
12	Income taxes (line 11 * line 18)	32,280	(3,550)	7,068
13	Deferred tax on Gas Cost Deferrals	-	20,766	704
14	Deferred tax drawdown	(15,169)	(12,819)	(12,819)
15	Total taxes	$ 17,111	$ 4,398	$ (5,047)
	Tax Rates			
16	Federal tax	15.00%	15.00%	15.00%
17	Provincial tax	10.50%	11.50%	11.50%
18	Total tax rate	25.50%	26.50%	26.50%

UNION GAS LIMITED
Calculation of Capital Cost Allowance (CCA)
Year Ended December 31

Line No.		Particulars ($000s)	2013 Board-Approved Depreciable UCC Balance (a)	2013 Board-Approved Rate (%) (b)	2013 Board-Approved CCA (c)	2016 Actual Depreciable UCC Balance (d)	2016 Actual Rate (%) (e)	2016 Actual CCA (f)	2017 Actual Depreciable UCC Balance (g)	2017 Actual Rate (%) (h)	2017 Actual CCA (i)
	Class										
1	1	Buildings, structures and improvements, services, meters, mains	1,259,974	4%	50,399	1,171,075	4%	46,843	1,118,311	4%	44,732
2	1	Non-residential building acquired after March 19, 2007	83,527	6%	5,012	110,417	6%	6,625	111,588	6%	6,695
3	2	Mains acquired before 1988	147,495	6%	8,850	122,500	6%	7,350	114,246	6%	6,855
4	3	Buildings acquired before 1988	4,279	5%	214	3,660	5%	183	3,462	5%	173
5	6	Other buildings	173	10%	17	130	10%	13	112	10%	11
6	7	Compression equipment acquired after February 22, 2005	165,697	15%	24,855	358,627	15%	53,794	598,187	15%	89,728
7	8	Compression assets, office furniture, equipment	79,640	20%	15,928	162,925	20%	32,585	189,423	20%	37,885
8	10	Transportation, computer equipment	18,611	30%	5,583	16,963	30%	5,089	15,100	30%	4,530
9	12	Computer software, small tools	7,701	100%	7,701	4,696	100%	4,696	2,630	100%	2,630
10	13	Leasehold improvements (1)	332	N/A	113	2,396	N/A	628	1,827	N/A	545
11	14.1	Intangibles							2,079	5%	104
12	14.1	Intangibles (pre 2017)							21,949	7%	1,536
13	17	Roads, sidewalk, parking lot or storage areas	946	8%	76	738	8%	59	671	8%	54
14	38	Heavy work equipment	6,878	30%	2,063	3,340	30%	1,002	2,532	30%	760
15	41	Storage assets	8,019	25%	2,005	4,152	25%	1,038	5,841	25%	1,460
16	45	Computers - Hardware acquired after March 22, 2004	246	45%	111	40	45%	18	21	45%	10
17	49	Transmission pipeline additions acquired after February 23, 2005	204,628	8%	16,370	485,350	8%	38,828	666,696	8%	53,336
18	50	Computers hardware acquired after March 18, 2007	22,934	55%	12,614	23,156	55%	12,736	48,117	55%	26,464
19	51	Distribution pipelines acquired after March 18, 2007	556,733	6%	33,404	980,217	6%	58,813	1,111,254	6%	66,675
20		Total	$ 2,567,813		$ 185,314	$ 3,450,381		$ 270,300	$ 4,014,047		$ 344,183

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

UNION GAS LIMITED
Provision for Depreciation,Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2016 Actual	2017 Actual
1	Total provision for depreciation and amortization before adjustments (per page 3)	-	231,445	257,748
2	Adjustments: vehicle depreciation through clearing	-	3,044	2,867
3	Provision for depreciation amortization and depletion	$ -	$ 228,401	$ 254,881

UNION GAS LIMITED
Provision for Depreciation, Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved Average Plant (1)	2013 Board-Approved Rate (%)	2013 Board-Approved Provision	2016 Actual Average Plant (1)	2016 Actual Rate (%)	2016 Actual Provision	2017 Actual Average Plant (1)	2017 Actual Rate (%)	2017 Actual Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Intangible plant:									
1	Franchises and consents	-	-	-	$ 1,211	Amortized	62	1,186	Amortized	60
2	Intangible plant - Other	-	-	-	6,347	Amortized	122	3,421	Amortized	121
3		-		-	7,558		184	4,606		182
	Local Storage Plant									
4	Structures and improvements	-	2.85%	-	4,123	2.85%	118	4,414	2.85%	126
5	Gas holders - storage	-	2.54%	-	4,586	2.54%	116	4,604	2.54%	117
6	Gas holders - equipment	-	3.54%	-	16,805	3.54%	595	18,477	3.54%	654
7		-		-	25,515		829	27,494		897
	Storage:									
8	Land rights	-	2.10%	-	31,985	2.10%	672	31,985	2.10%	672
9	Structures and improvements	-	2.50%	-	62,159	2.50%	1,554	64,860	2.50%	1,622
10	Wells and lines	-	2.48%	-	90,391	2.48%	2,242	92,506	2.48%	2,294
11	Compressor equipment	-	2.68%	-	255,366	2.68%	6,844	373,329	2.68%	10,005
12	Measuring & regulating equipment	-	3.11%	-	58,272	3.11%	1,812	69,208	3.11%	2,152
13	Other equipment	-		-	1,197		-	-		-
14		-		-	499,370		13,123	631,888		16,745
	Transmission:									
15	Land rights	-	1.76%	-	49,754	1.76%	876	59,573	1.76%	1,048
16	Structures and improvements	-	2.03%	-	115,799	2.03%	2,351	146,751	2.03%	2,979
17	Mains	-	1.98%	-	1,421,508	1.98%	28,146	1,654,158	1.98%	32,752
18	Compressor equipment	-	3.23%	-	597,214	3.23%	19,290	802,626	3.23%	25,925
19	Measuring & regulating equipment	-	2.60%	-	223,081	2.60%	5,800	246,525	2.60%	6,410
20		-		-	2,407,357		56,463	2,909,633		69,115
	Distribution - Southern Operations:									
21	Land rights	-	1.65%	-	7,040	1.65%	116	7,533	1.65%	124
22	Structures and improvements	-	2.22%	-	131,482	2.22%	2,934	134,789	2.22%	3,003
23	Services - metallic	-	2.81%	-	121,858	2.81%	3,424	122,839	2.81%	3,452
24	Services - plastic	-	2.51%	-	838,168	2.51%	21,038	860,697	2.51%	21,604
25	Regulators	-	5.00%	-	72,811	5.00%	3,641	78,339	5.00%	3,917
26	Regulator and meter installations	-	2.80%	-	71,295	2.80%	1,996	72,295	2.80%	2,024
27	Mains - metallic	-	2.83%	-	466,282	2.83%	13,196	489,825	2.83%	13,862
28	Mains - plastic	-	2.31%	-	585,316	2.31%	13,521	607,056	2.31%	14,023
29	Measuring & regulating equipment	-	3.66%	-	39,378	3.66%	1,441	41,731	3.66%	1,527
30	Meters	-	3.82%	-	276,539	3.82%	10,564	296,569	3.82%	11,329
31	Other equipment	-		-	-	-	-	-		-
32		-		-	$ 2,610,170		$ 71,871	$ 2,711,672		$ 74,865

UNION GAS LIMITED
Provision for Depreciation, Amortization and Depletion
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved Average Plant (1)	2013 Board-Approved Rate (%)	2013 Board-Approved Provision	2016 Actual Average Plant (1)	2016 Actual Rate (%)	2016 Actual Provision	2017 Actual Average Plant (1)	2017 Actual Rate (%)	2017 Actual Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Distribution plant - Northern & Eastern Operations:									
1	Land rights	-	1.71%	-	$ 9,804	1.71%	168	9,945	1.71%	170
2	Structures & improvements	-	2.41%	-	64,866	2.41%	1,563	65,838	2.41%	1,587
3	Services - metallic	-	3.22%	-	103,044	3.22%	3,318	104,276	3.22%	3,358
4	Services - plastic	-	2.60%	-	433,331	2.60%	11,267	446,796	2.60%	11,617
5	Regulators	-	5.00%	-	28,454	5.00%	1,423	29,848	5.00%	1,492
6	Regulator and meter installations	-	2.92%	-	30,490	2.92%	890	35,004	2.92%	1,022
7	Mains - metallic	-	3.02%	-	445,850	3.02%	13,465	468,715	3.02%	14,155
8	Mains - plastic	-	2.38%	-	220,854	2.38%	5,256	224,870	2.38%	5,352
9	Compressor equipment	-	-	-	-	-	-	-	-	-
10	Measuring & regulating equipment	-	3.77%	-	128,996	3.77%	4,863	133,177	3.77%	5,021
11	Meters	-	4.03%	-	74,225	4.03%	2,991	82,063	4.03%	3,307
12	Other distribution equipment	-	-	-	-	-	-	-	-	-
13		-		-	1,539,913		45,204	1,600,532		47,081
	General:									
14	Structures and improvements	-	1.92%		58,734	1.92%	2,068	59,152	1.92%	1,530
15	Office furniture and equipment	-	6.67%	-	11,000	6.67%	726	10,231	6.67%	679
16	Office equipment - computers	-	25.00%	-	72,901	25.00%	16,252	83,385	25.00%	19,008
17	Transportation equipment	-	13.27%	-	54,218	13.27%	7,182	56,169	13.27%	7,510
18	Heavy work equipment	-	6.92%	-	14,867	6.92%	1,028	14,902	6.92%	1,041
19	Tools and other equipment	-	6.67%	-	33,618	6.67%	2,237	34,192	6.67%	2,270
20	Communications equipment & structures	-	6.67%	-	14,899	6.67%	982	13,593	6.67%	901
21	Other equipment	-	-	-	-	-	-	-	-	-
22		-		-	260,238		30,475	271,624		32,940
23	Regulatory Assets	-		-	397,634		13,296	477,079		15,924
24	Sub-total	-		-	7,747,753		231,445	8,634,528		257,748
25	Total provision for depreciation and amortization	-		-	-		231,445	-		257,748
26	Depreciation through clearing	-		-	-		3,044	-		2,867
27		-		-	$ 7,747,753		$ 228,401	$ 8,634,528		$ 254,881

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

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

Line No.	Particulars ($000's)	2013 Board-Approved	2016 Actual	2017 Actual
		(a)	(b)	(c)
1	Storage	11,562	158,941	91,618
2	Transmission	113,795	583,285	316,504
3	Distribution	131,797	182,522	197,415
4	General	37,215	30,432	34,940
5	Other	53,333	78,778	80,497
6	Total	$ 347,702	$ 1,033,958	$ 720,974
	Less: Parkway West Reliability, and Brantford-Kirkwall/Parkway D Project	80,000	24,128	2,976
		$ 267,702	$ 1,009,830	$ 717,998

UNION GAS LIMITED
Statement of Utility Rate Base
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved	2016 Actual	2017 Actual
		(a)	(b)	(c)
	Gas Utility Plant			
1	Gross plant at cost	6,361,532	7,682,951	8,628,204
2	Less: accumulated depreciation	(2,754,070)	(3,149,165)	(3,347,472)
3	Net utility plant	3,607,462	4,533,786	5,280,732
	Working Capital and Other Components			
4	Cash working capital	20,007	21,205	22,541
5	Gas in storage and line pack gas	163,109	184,471	146,489
6	Balancing gas	72,963	67,090	65,672
7	ABC receivable (gas in storage)	(44,901)	(12,985)	(17,087)
8	Inventory of stores, spare equipment	29,618	28,974	31,751
9	Prepaid and deferred expenses	4,955	4,857	2,231
10	Customer deposits	(48,231)	(39,380)	(40,963)
11	Customer interest	(764)	(107)	(110)
12	Total working capital and other components	196,757	254,125	210,524
13	Total rate base before deduction of accumulated deferred income taxes	3,804,218	4,787,911	5,491,256
14	Accumulated deferred income taxes	(69,686)	(29,493)	(17,345)
15	Total rate base	$ 3,734,532	$ 4,758,418	$ 5,473,910

UNION GAS LIMITED
Allocation of Fuel

Line No.	Particulars (GJ)	Board-Approved	%	2017 Actual	%	2016 Actual	%	2015 Actual	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	M12	3,616,843	77%	2,989,104	86%	1,746,256	85%	2,115,225	62%
2	Other	1,057,714	23%	495,297	14%	314,761	15%	1,286,425	38%
3	Total Fuel	4,674,557	100%	3,484,401	100%	2,061,017	100%	3,401,650	100%

UNION GAS LIMITED
Earnings Sharing Calculation
Calendar Year Ending December 31, 2017

Line No.	Particulars ($000s)	2017	Non-Utility Storage	Adjustments		2017 Utility
		(a)	(b)	(c)		(d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,872,522		(15,570)	i	1,856,952
2	Transportation	236,498	(439)	-		236,937
3	Storage	126,928	119,133	-		7,796
4	Other	24,252		(6,947)	ii	17,304
5		2,260,200	118,694	(22,517)		2,118,989
	Operating Expenses					
6	Cost of gas	1,070,458	23,924	(15,570)	i	1,030,965
7	Operating and maintenance expenses	427,708	13,450	(831)	iii	413,427
8	Depreciation	265,117	10,236			254,881
9	Other financing			1,013	iv	1,013
10	Property and other taxes	73,690	1,369			72,321
11		1,836,973	48,979	(15,387)		1,772,606
	Other					
12	Gain / (Loss) on sale of assets	(214)	(210)			(3)
13	Other / Huron Tipperary		-			-
14	Gain / (Loss) on foreign exchange	(873)	(47)	(612)	v	(1,438)
15		(1,087)	(257)	(612)		(1,441)
16	Earnings before interest and taxes	422,140	69,457	(7,742)		344,941
17	Income taxes					(5,047)
18	Total utility income subject to earnings sharing					349,988
	Less debt and preference share return components					
19	Long-term debt					165,315
20	Unfunded short-term debt					818
21	Preferred dividend requirements					2,769
22						168,902
	Less shareholder portions of:					
23	Net short-term storage revenue (after tax)					275
24	Net optimization activity (after tax)					369
25						643
26	Earnings subject to sharing					180,443
27	Common equity					1,970,608
28	Return on equity (line 26 / line 27)					9.16%
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

ii Demand-side management incentive

iii	Donations	896
	CDM program	(245)
	MAAD application legal costs	180
		831

iv Facility fees and customer deposit interest

v Foreign exchange gain on bank balances

UNION GAS LIMITED
Continuity of Property, Plant and Equipment
Calendar Year Ending December 31, 2017

Line No.	Particulars ($000's)	Balance Dec. 31/16 (a)	Capital Additions (b)	Transfers (c)	Retirements (d)	Balance Dec. 31/17 (e)
	Unregulated Gas Plant in Service:					
	Underground storage plant:					
1	Land	$ 2,156	23	-	-	$ 2,179
2	Land rights	29,930	-	-	-	29,930
3	Structures and improvements	25,733	185	5	-	25,924
4	Wells and lines	119,016	15,282	278	(16)	134,560
5	Compressor equipment	163,711	1,424	43	-	165,177
6	Measuring & regulating equipment	24,971	5,058	(3,806)	-	26,223
7	Base pressure gas	29,481	734	-	-	30,214
8	Other equipment	-	-	-	-	-
9		$ 394,999	22,705	(3,479)	(16)	$ 414,208
	General plant:					
10	Land	$ 17	-	-	-	$ 17
11	Structures & improvements	2,058	43	-	(16)	2,085
12	Office furniture & equipment	367	13	-	(11)	369
13	Office equipment - computers	3,150	1,836	-	(481)	4,505
14	Transportation equipment	2,365	204	-	(134)	2,434
15	Heavy work equipment	658	18	4	(15)	664
16	Tools & work equipment	1,197	128	(4)	(72)	1,250
17	Communication equipment	460	31	-	(10)	481
18	Other general equipment	-	-	-	-	-
19		$ 10,271	2,274	-	(740)	$ 11,805
20	Total gas plant in service	$ 405,270	24,979	(3,479)	(756)	$ 426,013
21	Gas plant under construction	14,409	(3,981)	-	-	10,428
22	Total unregulated property plant and equipment	$ 419,679	20,999	(3,479)	(756)	$ 436,442

UNION GAS LIMITED
Continuity of Accumulated Depreciation
Calendar Year Ending December 31, 2017

Line No.	Particulars ($000's)	Balance Dec. 31/16 (a)	Transfers (b)	Provisions (c)	Retirements (d)	Net Salvage /(Costs) (e)	Balance Dec. 31/17 (f)
	Unregulated Gas Plant in Service:						
	Underground storage plant:						
1	Land rights	$ 9,941	-	603	-	-	$ 10,544
2	Structures & improvements	10,783	5	763	-	-	11,551
3	Wells and lines	35,449	278	2,605	(8)	-	38,324
4	Compressor equipment	57,307	10	4,371	-	-	61,689
5	Measuring & regulating equipment	12,377	167	577	-	-	13,121
6		$ 125,858	460	8,919	(8)	-	$ 135,230
	General plant:						
7	Structures & improvements	442	-	61	(16)	-	487
8	Office furniture & equipment	171	-	27	(11)	-	187
9	Office equipment - computers	2,065	-	761	(481)	-	2,345
10	Transportation equipment	1,226	0	262	(134)	11	1,365
11	Heavy work equipment	106	2	36	(15)	-	129
12	Tools and other equipment	570	(2)	91	(72)	-	587
13	Communication equipment	252	-	36	(10)	-	278
14		$ 4,831	0	1,275	(740)	11	$ 5,377
15	Total unregulated gas plant in service	$ 130,689	460	10,194	(748)	11	$ 140,606

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2017

Line No.	Particulars ($000's)	UNREGULATED
1	Total unregulated provision for depreciation and amortization before adjustments (per page 2)	10,194
	Adjustments:	
2	Vehicle depreciation through clearing	(51)
3	Asset Retirement Obligation expense for Unregulated storage wells	93
4	Unregulated provision for depreciation amortization and depletion	**10,236**

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2017

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		24,144	Allocation		763
3	Wells and lines		123,949	Allocation		2,605
4	Compressor equipment		155,904	Allocation		4,371
5	Measuring & regulating equipment		25,567	Allocation		577
6	Other equipment					
7		$	359,495		$	8,919
	General:					
8	Structures & improvements	$	2,072	Allocation	$	61
9	Office furniture and equipment		368	Allocation		27
10	Office equipment - computers		3,827	Allocation		761
11	Transportation equipment		2,399	Allocation		262
12	Heavy work equipment		661	Allocation		36
13	Tools and other equipment		1,224	Allocation		91
14	Communications equipment		471	Allocation		36
15	Other equipment		-			
16		$	11,022		$	1,275
17	Sub-total		370,517			10,194
18	Total unregulated provision for depreciation and amortization before adjustments				$	10,194
19	Vehicle depreciation through clearing					(51)
20	Asset Retirement Obligation expense for Unregulated storage wells					93
21	Unregulated provision for depreciation amortization and depletion		370,517		$	**10,236**

Notes:

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

UNION GAS LIMITED
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-17	67,123	80,442	83.4
Feb-17	67,082	78,198	85.8
Mar-17	72,952	88,162	82.7
Apr-17	90,515	118,208	76.6
May-17	73,281	93,353	78.5
Jun-17	76,878	96,689	79.5
Jul-17	85,583	110,320	77.6
Aug-17	70,875	88,848	79.8
Sep-17	94,532	123,222	76.7
Oct-17	75,860	93,429	81.2
Nov-17	70,262	90,415	77.7
Dec-17	67,402	90,306	74.6
Total	912,345	1,151,592	79.2

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-17	1,459	63,547	2.3
Feb-17	1,196	61,923	1.9
Mar-17	1,803	69,015	2.6
Apr-17	3,441	94,633	3.6
May-17	2,562	76,685	3.3
Jun-17	2,508	79,293	3.2
Jul-17	3,638	89,238	4.1
Aug-17	2,451	71,874	3.4
Sep-17	3,584	99,407	3.6
Oct-17	2,461	77,796	3.2
Nov-17	3,588	75,103	4.8
Dec-17	3,139	72,766	4.3
Total	31,830	931,280	3.4

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)**
January	1,463,602	12,445	7,209	Change in load, previously low	76	Vacant, seasonal use (crop
February	1,463,670	10,390	7,135	estimate/read, previous vacant,	72	dryer), stopped meter,
March	1,464,556	13,977	7,820	seasonal use.	3,140	previous high estimate/read.
April	1,466,372	12,278	9,050		1,036	
May	1,487,593	13,145	10,286		626	
June	1,447,239	15,914	12,615		885	
July	1,472,194	19,801	16,228		986	
August	1,473,147	20,307	17,487		278	
September	1,475,170	14,660	11,867		77	
October	1,473,849	15,716	12,336		94	
November	1,478,278	9,670	6,731		134	
December	1,482,070	8,772	5,540		43	
Total	17,647,740	167,075	124,304		7,447	

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 or 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-17	2,133	1,450,132	0.1
Feb-17	2,146	1,451,486	0.1
Mar-17	4,107	1,452,870	0.3
Apr-17	2,174	1,452,551	0.1
May-17	1,185	1,451,768	0.1
Jun-17	1,512	1,452,801	0.1
Jul-17	1,215	1,452,926	0.1
Aug-17	1,468	1,453,367	0.1
Sep-17	1,739	1,456,186	0.1
Oct-17	2,118	1,459,650	0.1
Nov-17	2,236	1,465,261	0.2
Dec-17	2,153	1,468,221	0.1
Total	24,186	17,467,219	0.1

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-2017	14,631	14,707	99.5%
Feb-2017	14,917	15,034	99.2%
Mar-2017	18,314	18,413	99.5%
Apr-2017	15,421	15,545	99.2%
May-2017	16,169	16,345	98.9%
Jun-2017	15,199	15,323	99.2%
Jul-2017	14,157	14,355	98.6%
Aug-2017	15,022	15,234	98.6%
Sep-2017	15,510	15,655	99.1%
Oct-2017	18,304	18,492	99.0%
Nov-2017	18,077	18,302	98.8%
Dec-2017	10,759	10,865	99.0%
TOTAL	186,480	188,270	99.0%

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-2017	76	76		100.0%
Feb-2017	117	117		100.0%
Mar-2017	99	99		100.0%
Apr-2017	124	124		100.0%
May-2017	176	176		100.0%
Jun-2017	124	124		100.0%
Jul-2017	198	197	Computer issue with Service Suite caused the problem, it was not a person issue, no action taken.	99.5%
Aug-2017	212	212		100.0%
Sep-2017	145	145		100.0%
Oct-2017	188	188		100.0%
Nov-2017	225	225		100.0%
Dec-2017	106	106		100.0%
TOTAL	1790	1789		99.9%

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.

	Number of Emergency Calls Responded to Within 60 Minutes	Total Number of Emergency Calls Received	Percentage of Emergency Calls Responded within 60 Minutes (%)
Month	(1)	(2)	(3 = 1/2*100)
Jan-2017	1,099	1,111	98.9%
Feb-2017	890	895	99.4%
Mar-2017	970	980	99.0%
Apr-2017	906	912	99.3%
May-2017	1,084	1,094	99.1%
Jun-2017	1,065	1,078	98.8%
Jul-2017	1,032	1,046	98.7%
Aug-2017	1,185	1,198	98.9%
Sep-2017	1,156	1,169	98.9%
Oct-2017	1,331	1,341	99.3%
Nov-2017	1,473	1,481	99.5%
Dec-2017	1,410	1,429	98.7%
TOTAL	13,601	13,734	99.0%

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-17	321	321	100.0
Feb-17	190	190	100.0
Mar-17	223	223	100.0
Apr-17	189	189	100.0
May-17	225	225	100.0
Jun-17	164	164	100.0
Jul-17	174	174	100.0
Aug-17	179	179	100.0
Sep-17	180	180	100.0
Oct-17	211	211	100.0
Nov-17	217	217	100.0
Dec-17	161	161	100.0
Total	2,434	2,434	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-2017	69	88	78.4%
Feb-2017	49	56	87.5%
Mar-2017	55	63	87.3%
Apr-2017	460	480	95.8%
May-2017	1,176	1,221	96.3%
Jun-2017	1,339	1,435	93.3%
Jul-2017	1,245	1,322	94.2%
Aug-2017	1,366	1,494	91.4%
Sep-2017	1,011	1,147	88.1%
Oct-2017	1,675	1,918	87.3%
Nov-2017	1,122	1,332	84.2%
Dec-2017	303	345	87.8%
TOTAL	9,870	10,901	90.5%

ALLOCATION AND DISPOSITION OF 2017 DEFERRAL ACCOUNT BALANCES AND 2017 EARNINGS SHARING AMOUNT

The purpose of this evidence is to address the allocation and disposition of 2017 deferral account balances identified at Exhibit A, Tab 1, Appendix A, Schedule 1. There is no 2017 earnings sharing to allocate to rate classes, as described at Exhibit A, Tab 2.

The allocation of 2017 deferral account balances to rate classes is provided at Exhibit A, Tab 3, Appendix A, Schedule 1, p.1. The allocation of the gas supply deferral accounts for each of the Union North West and Union North East Zones is provided at Exhibit A, Tab 3, Appendix A, Schedule 1, p.2. Union introduced the Union North West and Union North East Zones as part of the Dawn Reference Price proceeding (EB-2015-0181), effective January 1, 2017. Exhibit A, Tab 3, Appendix A, Schedule 2 provides the unit disposition rates for Union’s in-franchise rate classes and summarizes the balances to be disposed of for Union’s ex-franchise rate classes. Exhibit A, Tab 3, Appendix A, Schedule 3 provides the estimated bill impacts of the proposed disposition for general service customers in Union South, Union North West and Union North East.

With the exception of the OEB Cost Assessment Variance Account (179-151) and Panhandle Reinforcement Project Costs Deferral Account (179-156), the allocation of 2017 deferral account balances to rate classes is consistent with the allocation methodologies approved by the Board in EB-2017-0091 (Union's 2016 Deferral Account Disposition proceeding), EB-2011-0210 (Union's 2013 Cost of Service proceeding), or in EB-2015-0181 (Union's Dawn Reference Price proceeding).

2017 GAS SUPPLY DEFERRAL ACCOUNTS

Account No. 179-107 Spot Gas Variance Account

There is no balance in the Spot Gas Variance Account at December 31, 2017.

Account No. 179-108 Unabsorbed Demand Cost Variance Account

Union proposes that the balance in the UDC Variance Account associated with 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 2017 Rates.

The UDC associated with Union South is applicable to sales service customers only. Accordingly, Union proposes that the portion of the balance in the UDC Variance Account related to Union South be allocated in proportion to sales service volumes.

Account No. 179-131 Upstream Transportation Optimization

Union proposes to allocate the balance in the Upstream Transportation Optimization Deferral Account between Union North West, Union North East and Union South based on the upstream transportation contracts used to serve each Zone.

Union 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 Zone (with delivery points of Centrat MDA, Union WDA, and Union SSMDA) and the Union North East Zone (with delivery points of Union NDA, Union NCDA and Union EDA). Union 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 2017 margin included in Board-approved gas supply transportation rates.

Union has allocated the balance to Union South based on the transportation optimization net revenues generated using upstream transportation contracts designed to serve Union South. Union 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 Board-approved gas supply commodity rates.

Account No. 179-132 Deferral Clearing Variance Account – Gas Supply Commodity and Transportation

Union 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 A, Tab 1, Appendix A, Schedule 6.

STORAGE DEFERRAL ACCOUNTS

Account No. 179-70 Short-Term Storage and Other Balancing Services

Union proposes to allocate the balance in the Short-Term Storage and Other Balancing Services Deferral Account between Union North and Union South in proportion to the 2013 Board-approved allocation of storage space related costs.

Union 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.

Union 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 2017 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, 2017.

Account No. 179-112 Gas Distribution Access Rule ("GDAR") Costs

Union proposes to allocate the balance in the GDAR Deferral Account in proportion to the 2013 Board-approved average number of customers in Rate 01 and Rate M1.

Account No. 179-120 IFRS Conversion Costs

There is no balance in the IFRS Conversion Costs Deferral Account at December 31, 2017.

Account No. 179-123 Conservation Demand Management ("CDM")

Union proposes to allocate the balance in the CDM Deferral Account to rate classes in proportion to the allocation of 2017 DSM costs in 2017 Rates.

Account No. 179-132 Deferral Clearing Variance Account – Delivery

Union 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 A, Tab 1, Appendix A, Schedule 6.

Account No. 179-133 Normalized Average Consumption ("NAC")

Union 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 2017 Rates.

Account No. 179-134 Tax Variance Deferral Account

Union 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

There is no balance in the UFG Volume Variance Account at December 31, 2017.

Account No. 179-136 Parkway West Project Costs

Union 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 2017 Rates. Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2017 Parkway West Project costs. Union is proposing to allocate the true-up of 2015 property taxes in proportion to the allocation of 2015 Project property tax costs.

Account No. 179-137 Brantford-Kirkwall/Parkway D Project Costs

Union 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 2017 Rates. Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2017 Brantford-Kirkwall/Parkway D Project costs. Union is proposing to allocate the true-up of 2015 property taxes in proportion to the allocation of 2015 Project property tax costs.

Account No. 179-138 Parkway Obligation Rate Variance

Union 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. 179-139 Energy East Pipeline Consultation Costs

There is no balance in the Energy East Pipeline Consultation Costs Deferral Account at December 31, 2017.

Account No. 179-141 Unaccounted for Gas Price Variance Account

Union proposes to allocate the balance in the UFG Price Variance Account to rate classes in proportion to the 2013 Board-approved allocation of UFG costs to customers for which Union provides fuel.

Account No. 179-142 Lobo C Compressor/Hamilton-Milton Pipeline Project Costs

Union 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 2017 Rates. Union determined the actual project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2017 Lobo C Compressor/Hamilton-Milton Pipeline Project costs.

Account No. 179-143 Unauthorized Overrun Non-Compliance Account

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

Union proposes to allocate the balance in 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 2017 Rates. Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2017 Lobo D/Bright C/Dawn H Compressor Project costs. Union is proposing to allocate the true-up of interest rate and capital expenditures in proportion to the allocation of 2016 Project return on rate base.

Account No. 179-149 Burlington-Oakville Project Costs

Union 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 2017 Rates. Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2017 Burlington-Oakville Project costs.

Account No. 179-151 OEB Cost Assessment Variance Account

Union 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 Deferral Account at December 31, 2017.

Account No. 179-156 Panhandle Reinforcement Project Costs

Union 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 and the forecasted Project net delivery revenue included in 2017 Rates. In accordance with the Board's Decision and Order in Union's Panhandle Reinforcement Project Leave to Construct application (EB-2016-0186), the 2017 net delivery revenue requirement of the Panhandle Project was not included in Union's 2017 rates. Union determined the allocation of actual Project net delivery revenue by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2017 Panhandle Reinforcement Project delivery costs, which was then reduced by the actual Project revenue allocated in proportion to the 2013 Board-approved Panhandle System and St. Clair System demand costs, updated for the Project.

DISPOSITION OF 2017 DEFERRAL ACCOUNT BALANCES

For general service Rate M1, Rate M2, Rate 01 and Rate 10 customers, Union proposes to dispose of the net 2017 deferral account balances prospectively, over the January 1, 2019 to June 30, 2019 time period. The prospective refund / recovery approach over six months is consistent with how Union disposed of the 2016 deferral account balances in EB-2017-0091.

For in-franchise contract and ex-franchise rate classes, Union is proposing to dispose of the net 2017 delivery-related deferral account balances as a one-time adjustment with January 2019 bills customers receive in February 2019. This one-time adjustment approach is consistent with how Union disposed of the 2016 deferral account balances in EB-2017-0091.

General Service Bill Impacts

General service bill impacts are presented at Exhibit A, 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, 2019 to June 30, 2019 is $6.87. This $6.87 charge consists of a delivery-related charge of $0.07 and a commodity-related charge of $6.80. For a bundled direct purchase residential customer the charge is $0.07.

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, 2019 to June 30, 2019 is $13.72. This $13.72 credit consists of a delivery-related charge of $4.00 and a gas transportation-related credit of $17.72. For a bundled direct purchase residential customer the credit is $13.72.

For a Rate 01 sales service residential customer in Union North East with annual consumption of 2,200 m^3, the charge for the period January 1, 2019 to June 30, 2019 is $6.36. This $6.36 charge consists of a delivery-related charge of $4.00 and a gas transportation-related charge of $2.36. For a bundled direct purchase residential customer the charge is $6.36.

UNION GAS LIMITED
Allocation of 2017 Deferral Account Balances

Line No.	Particulars ($000's)	Acct No.	Union North Rate 01	Union North Rate 10	Union North Rate 20	Union North Rate 100	Union North Rate 25	Union South M1	Union South M2	Union South M4	Union South M5A	Union South M7	Union South M9	Union South M10	Union South T1	Union South T2	Union South T3	Union South M12	Union South M13	Union South Excess Utility	Union South C1	Union South 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	(3,226)	(741)	(207)	-	-	12	3	0	0	0	0	0	-	-	-	-	-	-	-	-	(4,159)
3	Upstream Transportation Optimization	179-131	1,324	411	131	-	46	7,258	1,635	109	19	61	63	1	-	-	-	-	-	-	-	-	11,057
4	Deferral Clearing Variance Account - Supply (2)	179-132	-	-	-	-	-	377	(23)	(11)	8	(1)	(30)	-	-	-	-	-	-	-	-	-	320
5	Deferral Clearing Variance Account - Transport (2)	179-132	420	88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	507
6	Total Gas Supply Related Deferrals		(1,483)	(243)	(76)	-	46	7,647	1,615	98	27	60	33	1	-	-	-	-	-	-	-	-	7,725
	Storage Related Deferrals:																						
7	Short-Term Storage and Other Balancing Services	179-70	177	46	12	1	-	401	135	43	1	16	5	0	37	273	35	-	-	-	-	-	1,183
	Delivery Related Deferrals:																						
8	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Gas Distribution Access Rule (GDAR) Costs	179-112	18	-	-	-	-	58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76
10	IFRS Conversion Costs	179-120	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Conservation Demand Management	179-123	(34)	(12)	(7)	(8)	-	(90)	(42)	(11)	(15)	(4)	-	-	(6)	(15)	-	-	-	-	-	-	(245)
12	Deferral Clearing Variance Account - Delivery (2)	179-132	536	95	-	-	-	959	173	-	-	-	-	-	-	-	-	-	-	-	-	-	1,763
13	Normalized Average Consumption (NAC)	179-133	317	49	-	-	-	(1,892)	(1,388)	-	-	-	-	-	-	-	-	-	-	-	-	-	(2,914)
14	Tax Variance	179-134	(59)	(9)	(6)	(5)	(2)	(128)	(19)	(5)	(4)	(2)	(0)	(0)	(3)	(15)	(2)	(68)	(0)	(2)	(1)	(0)	(331)
15	Unaccounted for Gas (UFG) Volume Variance Account	179-135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Parkway West Project Costs	179-136	(3)	(13)	(3)	1	1	176	19	10	5	2	1	0	10	57	3	(799)	0	(0)	4	0	(528)
17	Brantford-Kirkwall/Parkway D Project Costs	179-137	(20)	(8)	(0)	2	1	16	(6)	(2)	2	(1)	(1)	(0)	(0)	(5)	(4)	(840)	0	1	(1)	(0)	(868)
18	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	(72)	(25)	(10)	(5)	(4)	(2)	(0)	(9)	(43)	(10)	47	-	-	11	(0)	(121)
19	Energy East Pipeline Consultation Costs	179-139	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Unaccounted for Gas (UFG) Price Variance Account	179-141	12	4	1	0	-	49	16	7	9	2	1	-	-	-	-	-	1	-	-	1	103
21	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	523	22	73	81	30	1,552	95	16	71	(3)	(6)	(0)	27	53	(46)	(8,809)	1	32	(40)	2	(6,327)
22	Unauthorized Overrun Non-Compliance Account	179-143	-	-	-	-	-	(3)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(2)	(0)	-	-	-	-	-	(8)
23	Lobo D/Bright C/ Dawn H Compressor Project Costs	179-144	317	73	35	19	6	559	144	35	11	16	5	0	18	106	32	3,538	0	7	(2)	0	4,918
24	Burlington-Oakville Project Costs	179-149	364	54	39	31	11	(1,488)	(654)	(219)	22	(80)	(27)	(1)	(191)	(1,473)	(189)	310	(2)	12	3	0	(3,477)
25	OEB Cost Assessment Variance Account	179-151	234	20	17	15	7	590	55	21	23	6	1	0	15	41	5	110	0	4	2	0	1,167
26	Base Service North T-Service TransCanada Capacity Account	179-153	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Panhandle Reinforcement Project Costs	179-156	(570)	(86)	(62)	(48)	(17)	(598)	40	287	(36)	148	(3)	(0)	176	1,154	(16)	(557)	(0)	(19)	243	47	83
28	Total Delivery-Related Deferrals		1,636	188	86	88	37	(313)	(1,593)	128	82	81	(32)	(1)	36	(142)	(228)	(7,068)	0	34	220	50	(6,709)
29	Total 2017 Storage and Delivery Disposition (Line 7 + Line 28)		1,813	235	99	89	37	89	(1,458)	171	83	96	(26)	(1)	73	131	(193)	(7,068)	0	34	220	50	(5,526)
30	Total 2017 Deferral Account Disposition (Line 6 + Line 29)		330	(8)	23	89	83	7,735	157	269	110	156	7	0	73	131	(193)	(7,068)	0	34	220	50	2,199
31	2017 Earnings Sharing (3)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Grand Total (Line 30 + Line 31)		330	(8)	23	89	83	7,735	157	269	110	156	7	0	73	131	(193)	(7,068)	0	34	220	50	2,199

Notes:
(1) Exhibit A, Tab 1, Appendix A, Schedule 1.
(2) Exhibit A, Tab 1, Appendix A, Schedule 6.
(3) Exhibit A, Tab 2, Appendix B, Schedule 1.

UNION GAS LIMITED

Allocation of 2017 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	(3,044)	(691)	(203)	-	-	(3,938)
3	Upstream Transportation Optimization	179-131	491	177	50	-	10	728
4	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
5	Deferral Clearing Variance Account - Transport	179-132	302	67	-	-	-	369
6	Total Gas Supply Related Deferrals		(2,251)	(447)	(152)	-	10	(2,841)
	Union North East							
	Gas Supply Related Deferrals:							
7	Spot Gas Variance Account	179-107	-	-	-	-	-	-
8	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(182)	(50)	(4)	-	-	(236)
9	Upstream Transportation Optimization	179-131	833	233	80	-	36	1,183
10	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
11	Deferral Clearing Variance Account - Transport	179-132	118	21	-	-	-	138
12	Total Gas Supply Related Deferrals		769	204	76	-	36	1,085
	Total							
	Gas Supply Related Deferrals:							
13	Spot Gas Variance Account	179-107	-	-	-	-	-	-
14	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(3,226)	(741)	(207)	-	-	(4,174)
15	Upstream Transportation Optimization	179-131	1,324	411	131	-	46	1,911
16	Deferral Clearing Variance Account - Supply	179-132	-	-	-	-	-	-
17	Deferral Clearing Variance Account - Transport	179-132	420	88	-	-	-	507
18	Total Gas Supply Related Deferrals		(1,483)	(243)	(76)	-	46	(1,755)

Notes:
(1) Exhibit A, Tab 3, Appendix A, Schedule 1, p.1.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2017 Deferral Account Disposition

Line No.	Particulars	Rate Class	2017 Deferral Balances ($000's)	2017 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	1,813	-	1,813	597,947	0.3032
2	Large Volume General Service	10	235	-	235	203,103	0.1156
3	Small Volume General Service	M1	89	-	89	1,824,914	0.0049
4	Large Volume General Service	M2	(1,458)	-	(1,458)	692,517	(0.2105)

Notes:
(1) Forecast volume for the period January 1, 2019 to June 30, 2019.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2017 Deferral Account Disposition

Line No.	Particulars	Rate Class	2017 Deferral Balances ($000's)	2017 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	(2,251)	-	(2,251)	167,583	(1.3435)
2	Large Volume General Service	10	(447)	-	(447)	47,114	(0.9484)
	Union North East						
3	Small Volume General Service	01	769	-	769	430,364	0.1786
4	Large Volume General Service	10	204	-	204	154,170	0.1324

Notes:
(1) Forecast volume for the period January 1, 2019 to June 30, 2019.

UNION GAS LIMITED
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2017 Deferral Account Disposition

Line No.	Particulars	Rate Class	2017 Deferral Balances ($000's)	2017 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	7,647	-	7,647	1,684,028	0.4540
2	Large Volume General Service	M2	1,615	-	1,615	355,260	0.4540
3	Firm Com/Ind Contract	M4	98	-	98	23,759	0.4540
4	Interruptible Com/Ind Contract	M5	27	-	27	2,766	0.4540
5	Special Large Volume Contract	M7	60	-	60	8,184	0.4540
6	Large Wholesale	M9	33	-	33	13,837	0.4540
7	Small Wholesale	M10	1	-	1	216	0.4540
8	Total				9,480	2,088,050	0.4540

Notes:
(1) Forecast sales service volumes for the period January 1, 2019 to June 30, 2019.
(2) Unit rate for prospective recovery/refund for each rate class equal to the gas supply commodity weighted-average unit rate.

UNION GAS LIMITED
Contract Unit Rates for One-Time Adjustment - Delivery
2017 Deferral Account Disposition

Line No.	Particulars	Rate Class	2017 Deferral Balances ($000's)	2017 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2017 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	23	-	23	108,708	0.0207
2	Medium Volume Firm Service (2)	20T	68	-	68	391,395	0.0173
3	Large Volume High Load Factor (2)	100T	88	-	88	1,029,988	0.0086
4	Large Volume Interruptible	25	37	-	37	88,743	0.0413
	Union South						
5	Firm Com/Ind Contract	M4	171	-	171	550,689	0.0311
6	Interruptible Com/Ind Contract	M5	83	-	83	140,489	0.0591
7	Special Large Volume Contract	M7	96	-	96	506,549	0.0190
8	Large Wholesale	M9	(26)	-	(26)	69,559	(0.0381)
9	Small Wholesale	M10	(1)	-	(1)	276	(0.1981)
10	Contract Carriage Service	T1	73	-	73	458,724	0.0160
11	Contract Carriage Service	T2	131	-	131	3,766,529	0.0035
12	Contract Carriage- Wholesale	T3	(193)	-	(193)	258,356	(0.0747)

Notes:
(1) Sales and Bundled-T customers only.
(2) T-Service customers only.

UNION GAS LIMITED
Contract Unit Rates for One-Time Adjustment - Gas Supply Transportation and Bundled Storage
2017 Deferral Account Disposition

Line No.	Particulars	Rate Class	2017 Deferral Balances ($000's)	2017 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2017 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	(152)	-	(152)	1,644	$10^3m^3/d$	(9.2648)
2	Large Volume Interruptible	25	10	-	10	18,775	10^3m^3	0.0512
	Union North East							
3	Medium Volume Firm Service	20	76	-	76	4,265	$10^3m^3/d$	1.7859
4	Large Volume Interruptible	25	36	-	36	21,716	10^3m^3	0.1680
	Storage ($/GJ)							
5	Bundled-T Storage Service	20T/100T	10	-	10	155,904	GJ/d	0.061

UNION GAS LIMITED
Storage and Transportation Service Amounts for Disposition
2017 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2017 Deferral Balances	2017 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c)
1	Transportation	M12	(7,068)	-	(7,068)
2	Transportation of Locally Produced Gas	M13	0	-	0
3	Cross Franchise Transportation	C1	220	-	220
4	Storage and Transportation Services	M16	50	-	50

Notes:
(1) Ex-franchise Rate M12, Rate M13, Rate M16 and Rate C1 customer specific amounts determined using approved deferral account allocation methodologies.

UNION GAS LIMITED
General Service Customer Bill Impacts

Line No.	Particulars	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (1)	Volume (m^3) (2)	Bill Impact ($)
		(a)	(b)	(c) = (a x b) / 100
	Small Volume General Service			
	Rate M1 - Union South			
1	Delivery	0.0049	1,498	0.07
2	Commodity	0.4540	1,498	6.80
3		0.4589		6.87
4	Sales Service			6.87
5	Direct Purchase			0.07
	Rate 01 - Union North West			
6	Delivery	0.3032	1,319	4.00
7	Commodity	-	1,319	-
8	Transportation	(1.3435)	1,319	(17.72)
9		(1.0403)		(13.72)
10	Sales Service			(13.72)
11	Direct Purchase Bundled T			(13.72)
	Rate 01 - Union North East			
12	Delivery	0.3032	1,319	4.00
13	Commodity	-	1,319	-
14	Transportation	0.1786	1,319	2.36
15		0.4818		6.36
16	Sales Service			6.36
17	Direct Purchase Bundled T			6.36
	Large Volume General Service			
	Rate M2 - Union South			
18	Delivery	(0.2105)	49,129	(103.42)
19	Commodity	0.4540	49,129	223.05
20		0.2435		119.63
21	Sales Service			119.63
22	Direct Purchase			(103.42)
	Rate 10 - Union North West			
18	Delivery	0.1156	54,302	62.77
19	Commodity	-	54,302	-
20	Transportation	(0.9484)	54,302	(515.00)
21		(0.8328)		(452.23)
22	Sales Service			(452.23)
23	Direct Purchase Bundled T			(452.23)
	Rate 10 - Union North East			
24	Delivery	0.1156	54,302	62.77
25	Commodity	-	54,302	-
26	Transportation	0.1324	54,302	71.90
27		0.2480		134.67
28	Sales Service			134.67
29	Direct Purchase Bundled T			134.67

Notes:
(1) Exhibit A, Tab 3, Appendix A, Schedule 2, pp. 1-3, column (e).
(2) Average consumption, per customer, for the period January 1, 2019 to June 30, 2019.
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.

INCREMENTAL TRANSPORTATION CONTRACTING ANALYSIS

INTRODUCTION

Pursuant to Union's 2005-0520 Settlement Agreement[1], the purpose of this evidence is to provide the analysis used by Union to support its decision to enter into new firm transportation capacity through the following contracts:

1. Panhandle Eastern Transportation Contract Renewals
    a. 10,000 Dth/day Panhandle Field Zone to Ojibway – Firm Transportation
    b. 25,000 Dth/day Panhandle Field Zone to Ojibway – Firm Transportation
2. TransCanada (15 year) contract resulting from 2017 New Capacity Open Season
    a. 2,000 GJ/day Union Parkway Belt to Union NCDA – Firm Transportation
3. TransCanada (1 year) contracts
    a. 981 GJ/day Empress to Union EDA – Firm Transportation
    b. 1,106 GJ/day Empress to Union WDA – Firm Transportation
4. NEXUS Contingency Contracts
    a. DTE Energy (up to 1 year), 30,000 Dth/day MichCon to St.Clair– Firm Transportation
    b. Vector (November 2017 to March 2018), 60,000 Dth/day Chicago to Dawn– Firm Transportation

[1] EB-2005-0520 Settlement Agreement, page 13, subsections 3.1, paragraph 2; and, Appendix B – Incremental Transportation Contracting Analysis.

1. PANHANDLE EASTERN TRANSPORTATION CONTRACTS RENEWAL

Capacity History

Union has an operational requirement to deliver a minimum of 60,000 GJ/day at the Ojibway interconnect to serve its sales service customers on a Design Day. Previously, in order to meet this requirement, Union held contracts for 27,000 Dth/day (28,487 GJ/day) and 10,000 Dth/day (10,551 GJ/day) of firm transportation on Panhandle Eastern to Union's system at Ojibway. Both contracts included Right of First Refusal ("ROFR") provisions. In addition, Union contracted for a third party delivered service of 21,000 GJ/day delivered at Ojibway until October 2019, however, this service does not have renewal rights.

Union discussed its requirements for Ojibway deliveries in detail in the Panhandle Reinforcement Project (EB-2016-0186) and Union's 2018 Rates (EB-2017-0087) proceedings. A "Summary of Contracted Ojibway Deliveries" was filed in EB-2016-0186 and has been included as Exhibit A, Tab 4, Appendix A, Schedule 1.

Renegotiated Capacity (long-term)

Union renegotiated its transportation contracts with Panhandle Eastern to secure long-term capacity to Ojibway; consistent with Union's need to meet long-term Design Day requirements along the Panhandle Transmission System. These contracts replace the three contracts discussed above with volumes tiered to match the total requirement.

Contract Parameters

- Transportation provider: Panhandle Eastern Pipe Line Company, LP
- Service: Firm Transportation
- Term: November 1, 2017 through October 31, 2027
- Capacity:
    - o 10,000 Dth/day (10,551 GJ/day) November 1, 2017 – October 31, 2019
    - o Contract increases by 12,000 Dth/day on November 1, 2019 to a total of 22,000 Dth/day
        - 22,000 Dth/day (23,211 GJ/day) November 1, 2019 – October 31, 2027
- Current Rate: US$0.4687/Dth/day at 100% Load Factor (exclusive of fuel)
- Primary Receipt Point: Panhandle Field Zone (Cheyenne Plains)
- Delivery Point: Union (Ojibway)
- Renewal Rights: Right of First Refusal

Contract Parameters

- Transportation provider: Panhandle Eastern Pipe Line Company, LP
- Service: Firm Transportation
- Term: November 1, 2017 through October 31, 2025
- Capacity:
    - o 25,000 Dth/day (26,376 GJ/day) November 1, 2017 – October 31, 2019
    - o Contract increases by 10,000 Dth/day on November 1, 2019 to a total of 35,000 Dth/day

    - 35,000 Dth/day (36,927 GJ/day) November 1, 2019 – October 31, 2025

- Current Rate: US$0.4687/Dth/day at 100% Load Factor (exclusive of fuel)
- Primary Receipt Point: Panhandle Field Zone (Cheyenne Plains)
- Delivery Point: Union (Ojibway)
- Renewal Rights: Right of First Refusal

Rationale for Transportation Capacity

As mentioned above, the supply arrangement Union has with a third party for delivery at Ojibway expires on October 31, 2019. That supply arrangement along with the existing Panhandle Eastern contracts allows Union to meet its long-term Design Day supply requirements. Starting November 1, 2019, this requirement will be met by the renegotiated Panhandle Eastern contracts. Union has negotiated ROFR provisions for access to the long-term rights for this capacity.

The benefits of this capacity are:

i. Lands gas at Ojibway to support system integrity. Deliveries to the Ojibway interconnect are required to support Design Day demand in the Windsor area market and supplement Union's transmission capabilities from Dawn;

ii. Landed cost of gas flowing to Union along this route is competitively priced;

iii. Supports the acquisition of secure supply from the Panhandle Field Zone, maintaining Union's supply diversity of contract terms and basins;

iv. Provides Union with both receipt and delivery flexibility within the path;

v. Contract has renewal provisions (Right of First Refusal) which provide contractual rights for Union to retain access to this capacity in future years if required; and,

vi. Firm transportation contracts are consistent with the gas supply principle of ensuring secure and reliable gas supply to Union's service territory.

Incremental Contracting Analysis Form

Union filed a comparison of landed costs for the Panhandle Eastern contracts relative to the alternatives reviewed by Union in Union's 2018 Rates proceeding (EB-2017-0087). This comparison is provided in Exhibit A, Tab 4, Appendix A, Schedule 2, p.1.

2. TRANSCANADA (15 YEAR) CONTRACT RESULTING FROM 2017 NEW CAPACITY OPEN SEASON

Capacity History

Union holds 8,796 GJ/day of firm transportation on TransCanada from Empress to the Union NCDA that is currently renewed annually (24 month notice required for termination). The annual Gas Supply Plan identified a Design Day shortfall of 2,000 GJ/day in Union's North East Zone.

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service
- Term: November 1, 2017 through October 31, 2032
- Capacity: 2,000 GJ/day
- Current Rate: C$0.2554/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Union Parkway Belt
- Delivery Point: Union NCDA
- Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice required)

Rationale for Transportation Capacity

Union required this capacity to meet forecast system growth in Union's North East Zone.

The benefits of this capacity are:

i. Supports Union's objective of structuring a portfolio with diversity of contract terms and supply basins;
ii. Firm transportation contracts are consistent with the gas supply principle of ensuring secure and reliable gas supply to Union's service territory;
iii. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation in the future; and,

iv. Low unabsorbed demand charge ("UDC") exposure relative to alternative pipeline routes due to the low demand charge on this route.

Incremental Contracting Analysis Form

A comparison of landed costs for the Union NCDA contract relative to the alternatives reviewed by Union has been provided in Exhibit A, Tab 4, Appendix A, Schedule 3.

3. TRANSCANADA (1 YEAR) CONTRACTS

a. Empress to Union EDA (981 GJ/day) – Firm Transportation
b. Empress to Union WDA (1,106 GJ/day) – Firm Transportation

New Capacity

Union entered into one-year, firm transportation long-haul contracts with TransCanada for 981 GJ/day of capacity from Empress to the Union EDA and 1,106 GJ/day of capacity from Empress to the Union WDA.

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service
- Term: November 1, 2017 through October 31, 2018
- Capacity: 981 GJ/day

- Current Rate: C$2.033/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Union EDA
- Renewal Rights: None

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service
- Term: November 1, 2017 through October 31, 2018
- Capacity: 1,106 GJ/day
- Current Rate: C$1.033/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Union WDA
- Renewal Rights: None

Rationale for Transportation Capacity

The annual Gas Supply Plan identified winter of 2017/2018 Design Day shortfalls of 981 GJ/day in the Union EDA and 1,106 GJ/day in the Union WDA. TransCanada was offering capacity to these delivery areas through an Existing Capacity Open Season.

The benefits of this capacity are:

i. Provides firm transportation capacity to meet the Design Day demand;
ii. Short-term commitment aligns with the gas year and provides flexibility to evaluate needs in future years; and,
iii. Firm transportation contracts are consistent with the gas supply principle of ensuring secure and reliable gas supply to Union's service territory.

Incremental Contracting Analysis Form

The only firm transportation capacity available to these delivery areas is TransCanada capacity from Empress. Thus, a landed cost comparison is not applicable.

4. NEXUS CONTINGENCY CONTRACTING

a. DTE Energy (up to 1 year), 30,000 Dth/day MichCon to St. Clair– Firm Transportation
b. Vector (November 2017 to March 2018), 60,000 Dth/day Chicago to Dawn– Firm Transportation

Capacity History and Incremental Capacity

Union holds a contract for 60,000 Dth/day of DTE/MichCon capacity with an expiry date of the earlier of the NEXUS in-service date or October 31, 2018. Union was notified by NEXUS Pipeline on August 1, 2017 that the in-service date was expected to be delayed to 2018. To ensure supply requirements were met for 2017/2018, Union increased its

DTE/MichCon capacity by 30,000 Dth/day to hold 90,000 Dth/day of capacity as a bridge to the NEXUS in-service date. Union also secured 60,000 Dth/day of capacity on Vector for November 1, 2017 through March 31, 2018. Options being evaluated for supply required after March 31, 2018 include contracting for Vector capacity, if available, or sourcing supply at Dawn. Union continues to monitor requirements until NEXUS is in service.

Contract Parameters

- Transportation provider: DTE Gas Company
- Service: Firm Transportation
- Term: November 1, 2017 until the earlier of service commencement date with NEXUS Gas Transmission LLC or October 31, 2018
- Capacity: 90,000 Dth/day (94,955 GJ/day)
- Current Rate : US$0.0567/Dth/day at 100% load factor (exclusive of fuel)
- Primary Receipt Points: MichCon Generic, interconnect with PEPL/DTE Gas Co.
- Delivery Point: Union (St. Clair)
- Renewal Rights: by written consent of the parties

The benefits of this capacity are:

i. The end date is linked to the in-service date for NEXUS transportation capacity;

ii. Firm transportation contract is consistent with the gas supply principle of ensuring secure and reliable gas supply to Union's service territory at a reasonable cost;

iii. Landed cost of gas flowing to Union along this route is competitively priced;

iv. MichCon is a liquid market hub that receives competing gas supplies from the WCSB, the U.S. Midwest, Appalachia (Marcellus/Utica), Gulf and the Rockies basins which supports Union's objective of diversity of supply basins;

v. Provides a fixed-rate toll over the contract term which provides toll certainty on a portion of Union's upstream transportation; and,

vi. Low unabsorbed demand charge ("UDC") exposure relative to alternative upstream pipeline routes due to the low demand charge on this route.

Contract Parameters

- Transportation provider: Vector Pipeline L.P. / Vector Pipeline Limited Partnership
- Service: Firm Transportation (FT-1)
- Term: November 1, 2017 through March 31, 2018
- Capacity: 60,000 Dth/day (63,303 GJ/day)
- Current Rate: US$0.1878/Dth/day (at 100% load factor)
- Primary Receipt Points: Chicago (Alliance/Guardian/Northern Border Interconnects)
- Delivery Point: Dawn
- Renewal Rights: Not Included

The benefits of this capacity are:

i. Firm transportation contracts are consistent with the gas supply principle of ensuring secure and reliable gas supply to Union's service territory;
ii. Landed cost of gas flowing to Union along this route is competitively priced;
iii. Lands gas on Union's system to support diversity of deliveries;
iv. Chicago is a liquid market hub that receives competing gas supplies from the WCSB, the U.S. Midwest, Appalachia (Marcellus/Utica), Gulf and the Rockies basins which supports Union's objective of diversity of supply basins;
v. Provides Union with both receipt and delivery flexibility within the path;
vi. Provides a fixed-rate toll over the contract term which provides toll certainty on a portion of Union's upstream transportation; and,
vii. Low unabsorbed demand charge ("UDC") exposure relative to alternative upstream pipeline routes due to the low demand charge on this route.

Rationale for Transportation Capacity

The need to backstop delays to the NEXUS in-service date was discussed in Union's 2018 Rates Proceeding (EB-2017-0087). The NEXUS Contingency Contracts adhere to Union's supply principles which are designed to ensure customers receive secure, diverse gas supply at prudently incurred costs. Union considered all available options to ensure the needs identified in the Gas Supply Plan were met, including the impacts of in-service delays for new transportation projects.

Incremental Contracting Analysis Form

A comparison of landed costs for these contracts relative to the other alternatives reviewed by Union is included in Exhibit A, Tab 4, Appendix A, Schedule 2, pp. 2 and 3.

Summary of Contracted Ojibway Deliveries

#	Evidentiary Reference	Capacity (TJ/day)	Description/Parties	Start	Expiry	Union/ Obligated Delivery	Renewable
1	Exhibit B.FRPO.3, part b)	26	PEPL FZ Contract (19605): Union capacity on PEPL	Existing	October 2017	Yes	Yes[1]
2	Exhibit B.FRPO.3, part b)	11	PEPL FZ Contract (43059): Union capacity on PEPL	Existing	October 2017	Yes	Yes
3	Exhibit B.FRPO.3, part b)	2	PEPL FZ Contract (36203): Union capacity on PEPL	Existing	October 2017	Yes	No
4	Exhibit B.FRPO.3, part b)	21	PEPL/Trunkline Contract; Union capacity on PEPL	Existing	October 2017	Yes	No
5	Exhibit B.LPMA.11, part a) Exhibit K1.4, page 3	21	Existing 3rd party delivered service	Existing (November 2016)	October 2019	Yes	No[2]
6	Exhibit K1.4, page 3 Exhibit K2.1, Attachment 1, Page 25, Bullet 3	23	PEPL FZ Contract: Union capacity on PEPL	November 2019	October 2027	Yes	Yes[3]
7	Exhibit K1.4, page 3 Exhibit K2.1, Attachment 1, Page 25, Bullet 1	26	PEPL FZ Contract: Union capacity on PEPL	November 2017	October 2025	Yes	Yes
8	Exhibit K1.4, page 3 Exhibit K2.1, Attachment 1, Page 25, Bullet 2	11	PEPL FZ Contract: Union capacity on PEPL	November 2017	October 2025	Yes	Yes
9	Exhibit K1.4, page 3 Exhibit K2.1, Attachment 1, Page 25, Bullet 4	35	Rover C1 Ojibway to Dawn Contract: Rover capacity on Union	November 2017	October 2025	No	Yes

[1] Renewed through new agreements on Lines 7 and 8
[2] The delivered service on line 5 will replace the expiring contracts on Lines 3 and 4 for the period November 2017 to October 2019
[3] Replaces delivered service on Line 5

Panhandle Landed Cost Analysis

2017-2027 Transportation Contracting Analysis

	Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/G	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
(2)	**TCPL Niagara**	Niagara	-0.293	4.2342	0.1801	0.0000	0.0110	0.1911	$4.43	**$5.62**	Dawn
(2)	**NEXUS**	Dominion Sth Point	-0.914	3.6134	0.7991	0.0000	0.0956	0.8947	$4.51	**$5.72**	Dawn
(1)	**Dawn**	Dawn	0.036	4.5633	0.0000	0.0000	0.0000	0.0000	$4.56	**$5.79**	Dawn
	PEPL SH (Max FT Rate)	PEPL (REX - Putnam)	-0.201	4.3262	0.1791	0.0091	0.0592	0.2475	$4.57	**$5.81**	Dawn
(2)	**Vector (2016-2022)**	Chicago	-0.172	4.3551	0.1802	0.0017	0.0456	0.2275	$4.58	**$5.82**	Dawn
	PEPL SH (REX - Audrain Max FT Rate)	PEPL (REX - Audrain)	-0.223	4.3041	0.2385	0.0167	0.1023	0.3575	$4.66	**$5.92**	Dawn
(1)	**Vector (Max Rate)**	Chicago	-0.172	4.3551	0.2704	0.0017	0.0456	0.3177	$4.67	**$5.93**	Dawn
(1)	**GLGT to TCPL (Max Rate)**	Northern Michigan	-0.178	4.3492	0.3096	0.0091	0.0678	0.3865	$4.74	**$6.01**	Dawn
(2) *	**Panhandle Longhaul (Max FT Rate)**	Panhandle Field Zone	-0.325	4.2023	0.4540	0.0438	0.1664	0.6641	$4.87	**$6.18**	Dawn
(2)	**Trunkline / Panhandle (2012-2017)**	Trunkline ELA Zone	0.028	4.5550	0.2195	0.0262	0.1794	0.4251	$4.98	**$6.32**	Dawn
	Trunkline / Panhandle (Max Rate)	Trunkline Field Zone 1A	-0.056	4.4716	0.3591	0.0237	0.1608	0.5436	$5.02	**$6.37**	Dawn
(1)	**TCPL SWDA**	Empress	-1.074	3.4532	1.4147	0.0000	0.1506	1.5653	$5.02	**$6.37**	Dawn
	Trunkline / Panhandle (Max Rate)	Trunkline ELA Zone	0.028	4.5550	0.4828	0.0262	0.1794	0.6884	$5.24	**$6.66**	Dawn

(1) For Reference Only
(2) Existing Union Gas Contract
* indicates path referenced in evidence for this analysis

Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2017 - Oct 2018	Nov 2018 - Oct 2019	Nov 2019 - Oct 2020	Nov 2020 - Oct 2021	Nov 2021 - Oct 2022	Nov 2022 - Oct 2023	Nov 2023 - Oct 2024	Nov 2024 - Oct 2025	Nov 2025 - Oct 2026	Nov 2026 - Oct 2027	Average Annual Gas Supply Cost $US/mmBtu Col (D) above
	Henry Hub (NYMEX)	Henry Hub	$4.20	$4.09	$4.03	$4.03	$4.27	$4.42	$4.64	$4.90	$5.26	$5.43	$4.53
	TCPL Niagara	Niagara	$4.10	$3.89	$3.88	$3.81	$3.94	$4.05	$3.96	$4.52	$5.09	$5.10	$4.23
	NEXUS	Dominion Sth Point	$3.46	$3.28	$3.23	$3.18	$3.29	$3.38	$3.31	$3.85	$4.53	$4.62	$3.61
	Dawn	Dawn	$4.34	$4.16	$4.15	$4.09	$4.32	$4.41	$4.46	$4.89	$5.35	$5.47	$4.56
	PEPL SH (Max FT Rate)	PEPL (REX - Putnam)	$4.10	$3.92	$3.91	$3.87	$4.07	$4.18	$4.24	$4.67	$5.08	$5.23	$4.33
	Vector (2016-2022)	Chicago	$4.11	$3.93	$3.93	$3.89	$4.11	$4.21	$4.27	$4.70	$5.13	$5.27	$4.36
	PEPL SH (REX - Audrain Max FT Rate)	PEPL (REX - Audrain)	$4.05	$3.88	$3.88	$3.84	$4.05	$4.16	$4.22	$4.66	$5.07	$5.22	$4.30
	Vector (Max Rate)	Chicago	$4.11	$3.93	$3.93	$3.89	$4.11	$4.21	$4.27	$4.70	$5.13	$5.27	$4.36
	GLGT to TCPL (Max Rate)	Northern Michigan	$4.13	$3.93	$3.93	$3.88	$4.11	$4.21	$4.26	$4.68	$5.12	$5.25	$4.35
	Panhandle Longhaul (Max FT Rate)	Panhandle Field Zone	$3.93	$3.75	$3.79	$3.76	$3.96	$4.06	$4.12	$4.55	$4.97	$5.12	$4.20
	Trunkline / Panhandle (2012-2017)	Trunkline ELA Zone	$4.25	$4.14	$4.06	$4.05	$4.29	$4.44	$4.66	$4.92	$5.28	$5.45	$4.55
	Trunkline / Panhandle (Max Rate)	Trunkline Field Zone 1A	$4.15	$4.04	$3.98	$3.98	$4.22	$4.36	$4.58	$4.84	$5.19	$5.37	$4.47
	TCPL SWDA	Empress	$3.28	$3.03	$3.08	$3.04	$3.24	$3.34	$3.37	$3.75	$4.14	$4.26	$3.45
	Trunkline / Panhandle (Max Rate)	Trunkline ELA Zone	$4.25	$4.14	$4.06	$4.05	$4.29	$4.44	$4.66	$4.92	$5.28	$5.45	$4.55

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q4 2016 Base Case		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	$1 US =	$1.339 CDN	From Bank of Canada Closing Rate November 1, 2016
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Nov-16		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

DTE Landed Cost Analysis

Nov 2017 - Oct 2018 Transportation Contracting Analysis

DRAFT

	Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/G	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
(2)	**TCPL Niagara**	Niagara	-0.628	2.3492	0.1939	0.0000	0.0046	0.1985	$2.55	**$3.02**	Kirkwall
	Dawn	Dawn	-0.068	2.9092	0.0000	0.0000	0.0000	0.0000	$2.91	**$3.45**	Dawn
(2)	**DTE (Michcon) (2010-2020)**	SE Michigan	-0.168	2.8096	0.0788	0.0034	0.0347	0.1168	$2.93	**$3.47**	Dawn
*	**DTE (Michcon) 2017 Rate (Current C1 Toll)**	SE Michigan	-0.168	2.8096	0.0988	0.0034	0.0347	0.1369	$2.95	**$3.49**	Dawn
	Panhandle(Max FT Rate)	PEPL (REX - Putnam)	-0.234	2.7440	0.1805	0.0125	0.0411	0.2341	$2.98	**$3.53**	Dawn
*	**DTE (Michcon) 2017 Rate (FCST C1 Toll)**	SE Michigan	-0.168	2.8096	0.1604	0.0034	0.0347	0.1984	$3.01	**$3.57**	Dawn
(2)	**Vector (2016-2022)**	Chicago	-0.167	2.8104	0.1800	0.0017	0.0312	0.2129	$3.02	**$3.59**	Dawn
(2)	**Panhandle Longhaul (2012-2017)**	Panhandle Field Zone	-0.442	2.5354	0.3499	0.0474	0.1105	0.5079	$3.04	**$3.61**	Dawn
	PEPL SH (Max FT Rate)	PEPL (REX - Audrain)	-0.234	2.7440	0.2399	0.0200	0.0715	0.3314	$3.08	**$3.65**	Dawn
	Vector (Max Rate)	Chicago	-0.167	2.8104	0.2714	0.0017	0.0312	0.3043	$3.11	**$3.69**	Dawn
(2)	**Trunkline / Panhandle (2012-2017)**	Trunkline Field Zone 1A	-0.110	2.8673	0.2211	0.0274	0.0964	0.3450	$3.21	**$3.81**	Dawn
(2)	**Trunkline / Panhandle (2012-2017)**	Trunkline ELA Zone	-0.110	2.8673	0.2211	0.0299	0.1102	0.3612	$3.23	**$3.83**	Dawn
	GLGT to TCPL (Max Rate)	Northern Michigan	-0.130	2.8479	0.3462	0.0056	0.0301	0.3819	$3.23	**$3.83**	Dawn
(2)	**NEXUS / St. Clair (Union Neg Rate)**	Dominion Sth Point	-0.555	2.4229	0.8005	0.0034	0.0641	0.8680	$3.29	**$3.90**	Dawn
	Trunkline / Panhandle (Max Rate)	Trunkline Field Zone 1A	-0.110	2.8673	0.3607	0.0271	0.0964	0.4843	$3.35	**$3.97**	Dawn
	ANR-GLGT-TCPL (Max Rate)	ANR - Fayetteville	-0.092	2.8850	0.7045	0.0220	0.0640	0.7905	$3.68	**$4.36**	Dawn
	TCPL SWDA (DAWN)	Empress	-0.877	2.1002	1.5710	0.0000	0.0747	1.6457	$3.75	**$4.44**	Dawn

(1) For Reference Only
(2) Existing Union Gas Contract
* indicates path referenced in evidence for this analysi

Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	**Point of Supply Col (B) above**	**Nov 2017 - Oct 2018**	**Average Annual Gas Supply Cost $US/mmBtu Col (D) above**	**Fuel Ratio Forecasts Col (G) above**
	Henry Hub (NYMEX)	Henry Hub	$2.98	$2.98	
	TCPL Niagara	Niagara	$2.35	$2.35	0.20%
	Dawn	Dawn	$2.91	$2.91	0.00%
	DTE (Michcon) (2010-2020)	SE Michigan	$2.81	$2.81	1.23%
	DTE (Michcon) 2017 Rate (Current C1 Toll)	SE Michigan	$2.81	$2.81	1.23%
	Panhandle(Max FT Rate)	PEPL (REX - Putnam)	$2.74	$2.74	1.50%
	DTE (Michcon) 2017 Rate (FCST C1 Toll)	SE Michigan	$2.81	$2.81	1.23%
	Vector (2016-2022)	Chicago	$2.81	$2.81	1.11%
	Panhandle Longhaul (2012-2017)	Panhandle Field Zone	$2.54	$2.54	4.36%
	PEPL SH (Max FT Rate)	PEPL (REX - Audrain)	$2.74	$2.74	2.61%
	Vector (Max Rate)	Chicago	$2.81	$2.81	1.11%
	Trunkline / Panhandle (2012-2017)	Trunkline Field Zone 1A	$2.87	$2.87	3.36%
	Trunkline / Panhandle (2012-2017)	Trunkline ELA Zone	$2.87	$2.87	3.84%
	GLGT to TCPL (Max Rate)	Northern Michigan	$2.85	$2.85	1.06%
	NEXUS / St. Clair (Union Neg Rate)	Dominion Sth Point	$2.42	$2.42	2.65%
	Trunkline / Panhandle (Max Rate)	Trunkline Field Zone 1A	$2.87	$2.87	3.36%
	ANR-GLGT-TCPL (Max Rate)	ANR - Fayetteville	$2.89	$2.89	2.22%
	TCPL SWDA (DAWN)	Empress	$2.10	$2.10	3.56%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICE July 24, 2017		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	$1 US =	$1.251 CDN	From Bank of Canada Daily Rate July 24, 2017
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Jul-17		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

Vector Landed Cost Analysis

DRAFT

Nov 2017 - Mar 2018 Transportation Contracting Analysis

	Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/G	Point of Delivery	Comments
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)	
(2)	**TCPL Niagara**	Niagara	-0.425	2.7408	0.1910	0.0000	0.0045	0.1955	$2.94	**$3.54**	Kirkwall	
(2)	**DTE (Michcon) (2010-2020)**	SE Michigan	-0.074	3.0918	0.0784	0.0033	0.0381	0.1198	$3.21	**$3.87**	Dawn	
	Panhandle(Max FT Rate)	PEPL (REX - Putnam)	-0.140	3.0263	0.1801	0.0125	0.0463	0.2388	$3.27	**$3.93**	Dawn	
	Dawn	Dawn	0.135	3.3008	0.0000	0.0000	0.0000	0.0000	$3.30	**$3.97**	Dawn	
(2)	**Panhandle Longhaul (2012-2017)**	Panhandle Field Zone	-0.352	2.8138	0.3495	0.0474	0.1259	0.5227	$3.34	**$4.02**	Dawn	
	PEPL SH (REX - Audrain Max FT Rate)	PEPL (REX - Audrain)	-0.140	3.0263	0.2395	0.0200	0.0808	0.3403	$3.37	**$4.05**	Dawn	
(2)	**Vector (2016-2022)**	Chicago	-0.002	3.1633	0.1800	0.0017	0.0337	0.2154	$3.38	**$4.07**	Dawn	Contract Term Apr 16 - Oct 22, Rate effective Dec 1, 2017
*	**Vector Open Season**	Chicago	-0.002	3.1633	0.1850	0.0017	0.0337	0.2204	$3.38	**$4.07**	Dawn	
(2)	**Trunkline / Panhandle (2012-2017)**	Trunkline Field Zone 1A	-0.105	3.0608	0.2207	0.0274	0.1024	0.3505	$3.41	**$4.11**	Dawn	Negotiated Rate
(2)	**Trunkline ELA / Panhandle (2012-2017)**	Trunkline ELA Zone	-0.105	3.0608	0.2207	0.0298	0.1180	0.3685	$3.43	**$4.13**	Dawn	Negotiated Rate
	GLGT to TCPL (Max Rate)	Northern Michigan	-0.044	3.1218	0.3438	0.0056	0.0290	0.3784	$3.50	**$4.21**	Dawn	
	Vector (Max Rate)	Chicago	-0.002	3.1633	0.3023	0.0017	0.0337	0.3377	$3.50	**$4.22**	Dawn	
	Trunkline Z1A to Dawn (Max Rate)	Trunkline Field Zone 1A	-0.105	3.0608	0.3603	0.0271	0.1024	0.4898	$3.55	**$4.28**	Dawn	
(2)	**NEXUS / St. Clair (Union Neg Rate)**	Dominion Sth Point	-0.429	2.7368	0.8000	0.0033	0.0724	0.8758	$3.61	**$4.35**	Dawn	
	TCPL Empress to Union SWDA (DAWN)	Empress	-0.980	2.1858	1.5471	0.0000	0.0733	1.6204	$3.81	**$4.58**	Dawn	
	ANR-GLGT-TCPL (Max Rate)	ANR - Fayetteville	-0.090	3.0763	0.7016	0.0220	0.0638	0.7874	$3.86	**$4.65**	Dawn	

(1) For Reference Only
(2) Existing Union Gas Contract
* indicates path referenced in evidence for this analysis

Assumptions used in Developing Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2017 - Mar 2018	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub (NYMEX)	Henry Hub	$3.17	$3.17	
	TCPL Niagara	Niagara	$2.74	$2.74	0.17%
	DTE (Michcon) (2010-2020)	SE Michigan	$3.09	$3.09	1.23%
	Panhandle(Max FT Rate)	PEPL (REX - Putnam)	$3.03	$3.03	1.53%
	Dawn	Dawn	$3.30	$3.30	0.00%
	Panhandle Longhaul (2012-2017)	Panhandle Field Zone	$2.81	$2.81	4.47%
	PEPL SH (REX - Audrain Max FT Rate)	PEPL (REX - Audrain)	$3.03	$3.03	2.67%
	Vector (2016-2022)	Chicago	$3.16	$3.16	1.07%
	Vector Open Season	Chicago	$3.16	$3.16	1.07%
	Trunkline / Panhandle (2012-2017)	Trunkline Field Zone 1A	$3.06	$3.06	3.34%
	Trunkline ELA / Panhandle (2012-2017)	Trunkline ELA Zone	$3.06	$3.06	3.85%
	GLGT to TCPL (Max Rate)	Northern Michigan	$3.12	$3.12	0.93%
	Vector (Max Rate)	Chicago	$3.16	$3.16	1.07%
	Trunkline Z1A to Dawn (Max Rate)	Trunkline Field Zone 1A	$3.06	$3.06	3.34%
	NEXUS / St. Clair (Union Neg Rate)	Dominion Sth Point	$2.74	$2.74	2.65%
	TCPL Empress to Union SWDA (DAWN)	Empress	$2.19	$2.19	3.35%
	ANR-GLGT-TCPL (Max Rate)	ANR - Fayetteville	$3.08	$3.08	2.07%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICE August 9, 2017		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	$1 US =	$1.271 CDN	From Bank of Canada Daily Rate August 9, 2017
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Aug-17		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

NCDA Analysis
2017-2032 Transportation Contracting Analysis

Route	Point of Supply	Basis Differential $US/mmBtu	Supply Cost $US/mmBtu	Unitized Demand Charge $US/mmBtu	Commodity Charge $US/mmBtu	Fuel Charge $US/mmBtu	100% LF Transportation Inclusive of Fuel $US/mmBtu	Landed Cost $US/mmBtu	Landed Cost $Cdn/G	Point of Delivery	Comments
(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	**(K)**	(L)	
TCPL SH - NCDA	Dawn	0.177	7.6769	0.3271	0.0080	0.0747	0.4098	$8.09	**$9.15**	Dawn	Includes Union C1 rate for Dawn to Parkway
TCPL LH - NCDA	Empress	-0.722	6.7782	1.6868	0.0000	0.2106	1.8974	$8.68	**$9.81**	Dawn	

Assumptions used in Developing Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	**Point of Supply Col (B) above**	**Nov 2017 - Oct 2018**	**Nov 2018 - Oct 2019**	**Nov 2019 - Oct 2020**	**Nov 2020 - Oct 2021**	**Nov 2021 - Oct 2022**	**Nov 2022 - Oct 2023**	**Nov 2023 - Oct 2024**	**Nov 2024 - Oct 2025**	**Nov 2025 - Oct 2026**	**Nov 2026 - Oct 2027**	**Nov 2027 - Oct 2028**	**Nov 2028 - Oct 2029**
Henry Hub (NYMEX)	Henry Hub	$4.62	$5.43	$6.12	$6.59	$6.81	$6.89	$7.06	$7.23	$7.56	$8.03	$8.44	$8.90
TCPL SH - NCDA	Dawn	$4.82	$5.62	$6.29	$6.76	$6.98	$7.07	$7.24	$7.42	$7.75	$8.21	$8.63	$9.08
TCPL LH - NCDA	Empress	$4.03	$4.78	$5.42	$5.87	$6.09	$6.18	$6.36	$6.55	$6.88	$7.33	$7.72	$8.15

Sources for Assumptions:

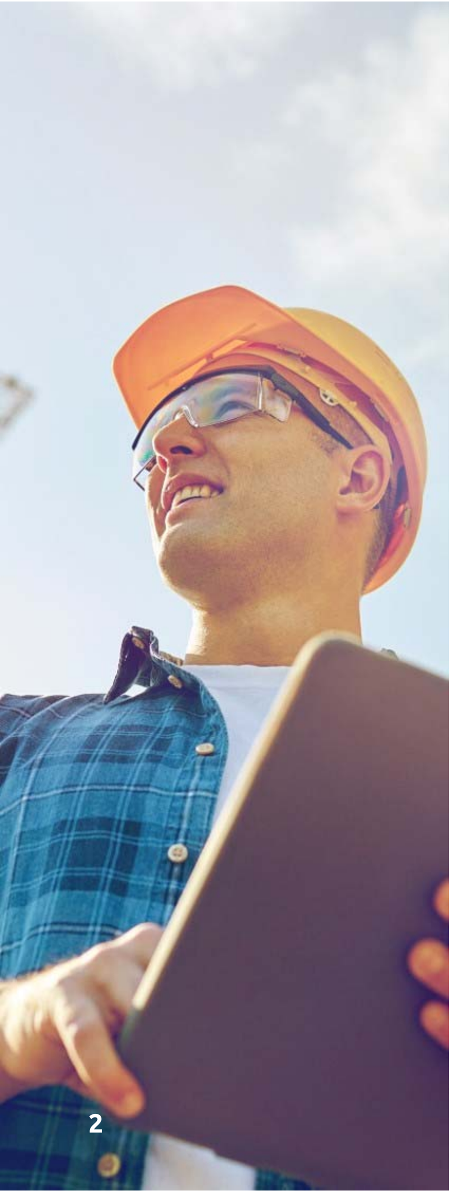
Gas Supply Prices (Col D):	ICF Q1 2015 Base Case		
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast		
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis		
Foreign Exchange (Col K)	$1 US =	$1.193 CDN	From Bank of Canada Daily Rate January 15, 2015
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Jan-15		

Paths included in analysis are those with comparable services available for contracting, as well as relevant benchmarks and currently contracted paths.

2018 Annual Stakeholder Meeting

May 30, 2018

uniongas
An Enbridge Company



Agenda

Opening Comments

Mark Kitchen
Director, Regulatory Affairs

2017 Utility Financial Results

Greg Tetreault
Manager, Regulatory Accounting

Facilities Expansion Projects

Andrea Seguin
Director, Business Development & Upstream Regulation

Gas Supply Update

Cheryl Newbury
Director, Gas Supply & Customer Support

Residential Customer Perceptions of Union Gas

Jeff Okrucky
Director, New Business

Community Expansion

Jeff Okrucky
Director, New Business

Wrap-up

Mark Kitchen
Director, Regulatory Affairs

uniongas
An Enbridge Company

2017 Utility Financial Results

Greg Tetreault

Manager, Regulatory Accounting

unionGas
An Enbridge Company

Agenda

- 2017 Utility Financial Results
- Capital Spend
- Deferral Accounts
  - Summary of 2017 Deferral Accounts
  - Transportation Optimization
  - Capital Pass-Through Project Accounts
  - Unabsorbed Demand Costs ("UDC")
  - Normalized Average Consumption ("NAC")
- 2018 Trends and Cost Pressures
- Service Quality Requirements and Billing Performance

uniongas
An Enbridge Company

2017 Utility Financial Results

Particulars ($ millions)	Earnings Before Interest and Taxes	Rate Base	Return on Equity
2013 Board-approved	291.2	3,734.5	8.93%
2016 Actual			
Weather normalized	338.6	4,758.4	9.78%
Weather	(12.4)		
2016 Total	326.2	4,758.4	9.24%
2017 Actual			
Weather normalized	355.5	5,473.9	9.55%
Weather	(10.5)		
2017 Total	344.9	5,473.9	9.16%

uniongas
An Enbridge Company

2017 Utility Financial Results – Cont’d

- **2017 vs 2016 Actuals** - $19 million increase

- Transportation Revenue - $54 million increase
  - Increased M12 / C1 rates due to capital pass-through projects, as well as recovery of facility-related Cap-and-Trade costs

- Distribution Margin - $12 million increase
  - Customer growth / usage and rate increases

- Operating Expenses - $47 million increase
  - Higher depreciation and employee costs

uniongas
An Enbridge Company

2017 Utility Financial Results – Cont'd

- **2017 Actuals vs 2013 Board-approved -** $54 million increase

- Transportation Revenue - $80 million increase
  - Increased M12 / C1 rates due to capital pass-through projects, as well as recovery of facility-related Cap-and-Trade costs

- Distribution Margin - $79 million increase
  - Customer growth and rate increases, partially offset by warmer weather

- Operating Expenses - $99 million increase
  - Higher depreciation, DSM program charges and salaries and wages, partially offset by lower pension costs

- Other Items - $6 million decrease

uniongas
An Enbridge Company

Capital Spend

Particulars ($ millions)	2016 Actual	2017 Actual	Variance
Storage	158.9	91.6	(67.3)
Transmission	583.3	316.5	(266.8)
Distribution	182.5	197.4	14.9
General	30.4	34.9	4.5
Other	78.8	80.5	1.7
Total	**1,034.0**	**721.0**	**(313.0)**

- Capital pass-through project spend:
  - 2016: $691 million
  - 2017: $365 million
- Storage & Transmission variance primarily driven by higher capital pass-through project spend in 2016:
  - Storage - Dawn H Compression (2017 Dawn-Parkway)
  - Transmission – 2016 and 2017 Dawn-Parkway projects
  - Decrease partially offset by increased spend for Panhandle Reinforcement

uniongas
An Enbridge Company

Deferral Accounts

Summary of 2017 Deferral Accounts

Account Number	Account Name	Balance ($ millions)*
179-131	Upstream Transportation Optimization	11.1
**	Combined Capital Pass-Through Project Accounts	(6.2)
179-108	Unabsorbed Demand Costs Variance Account	(4.2)
179-133	Normalized Average Consumption	(2.9)
**	Other	4.4
	Total Deferral Account Balances at Dec. 31, 2017	2.2

*Account balances include interest to Dec 31, 2017.

**Combination of various deferral accounts.

uniongas
An Enbridge Company

Upstream Transportation Optimization

Particulars ($ millions)	Board-approved	Actuals	Variance
Base exchanges	9.1	5.0	(4.1)
FT-RAM exchanges	5.8	-	(5.8)
Total exchanges revenue (pre-tax)	14.9	5.0	(9.9)
Less: Shareholder portion (10%)	(1.5)	(0.5)	1.0
Ratepayer portion (90%)	13.4	4.5	(8.9)
Less: Subsidy in rates	(13.4)	(15.6)	(2.2)
Deferral Balance Receivable	**-**	**11.1**	**11.1**

- Lower Total Exchange Revenue in 2017 than included in 2017 Board-approved rates primarily due to:
  - Elimination of TransCanada FT-RAM program
  - Changing market dynamics
  - Warmer weather compared to Board-approved created less demand and lower prices for exchanges

uniongas
An Enbridge Company

Capital Pass-Through Project Accounts

- **Total Deferral Balance** - $6.2 million payable

- Parkway West - $0.5 million payable
- Brantford-Kirkwall/Parkway D - $0.9 million payable
- Lobo C Compressor/Hamilton-Milton - $6.3 million payable
- Dawn H/Lobo D/Bright C Compressor - $4.9 million receivable
- Burlington-Oakville - $3.5 million payable
- Panhandle Reinforcement - $0.1 million receivable

uniongas
An Enbridge Company

Unabsorbed Demand Costs Variance Account

2017 UDC Variance Account by Operational Area ($000s)	Union North East	Union North West	Union South	Total Franchise Area
UDC Costs Incurred	2,329	12,999	15	15,343
Released Capacity Revenue	(225)	(7,352)	-	(7,577)
Net UDC Costs	2,104	5,647	15	7,766
UDC Collected in Rates	(2,339)	(9,560)	-	(11,899)
Variance	(235)	(3,913)	15	(4,133)
Interest	(1)	(25)	-	(26)
Total Payable	**(236)**	**(3,938)**	**15**	**(4,159)**

- Higher actual unutilized capacity due to warmer weather offset by higher mitigation activity resulted in lower costs
- As a result of mitigation activity, net UDC costs were lower than the amount collected in rates, resulting in a $4.159 million payable

uniongas
An Enbridge Company

NAC

2017 NAC Deferral Account ($ millions)	Rate 01	Rate 10	Rate M1	Rate M2	All Rates
Total NAC Deferral Balance	**0.3**	**0.0**	**(1.9)**	**(1.4)**	**(2.9)**

2017 Target and Actual NAC (m3/customer)	Rate 01	Rate 10	Rate M1	Rate M2
2017 Target NAC	2,844	164,329	2,738	166,297
2017 Actual NAC	2,835	163,483	2,764	166,969
Change in NAC (Target - Actual NAC)	9	846	(26)	(672)
% Change in NAC	**0.32%**	**0.51%**	**-0.95%**	**-0.40%**

- The same methodology agreed to by parties in EB-2013-0202 (Union’s 2014 to 2018 IRM Settlement Agreement) was used in calculating the balance in the deferral account
- The $2.9 million payable includes a $1.9 million credit related to storage costs

uniongas
An Enbridge Company

2018 Trends & Cost Pressures

- General cost pressures:
  - Salaries and wages
  - Line locates
  - Facility costs, including hydro
  - Increased operating and maintenance costs
  - Materials (plastic pipe)
- Increased costs to maintain safe and reliable operations:
  - Asset Management (Integrity, facility security)
  - Bare & unprotected pipe
  - Municipal replacement
  - IT software maintenance & major application modernization/lifecycle
- Annual delivery rate increases of 40% of inflation are not sufficient to offset cost pressures

uniongas
An Enbridge Company

Service Quality Requirements and Billing Performance

Service Quality Requirements	Target	Actual
Call Answering Service Level - Annual	75.0%	79.2%
Call Answering Service Level - Monthly	40.0%	>70.0% each
Abandon Rate	<10%	3.4%
Meter Reading Performance Measurement	<0.5%	0.1%
Appointments Met Within the Designated Time Period	85.0%	99.1%
Time to Reschedule a Missed Appointment	100.0%	99.9%
Percentage of Emergency Calls Responded Within One Hour	90.0%	99.0%
Number of Days to Provide a Written Response	80.0%	100.0%
Number of Days to Reconnect a Customer	85.0%	90.5%

Billing Performance	Actual
Total Number of Billings	17,647,740
Total Number of Manual Checks Done as per QAP	167,075
Total Number of Manual Checks Done when Meter Reads Show Excessively High Usage as per QAP Criteria	124,304
Total Number of Manual Checks Done when Meter Reads Show Excessively Low Usage as per QAP Criteria	7,447

uniongas
An Enbridge Company

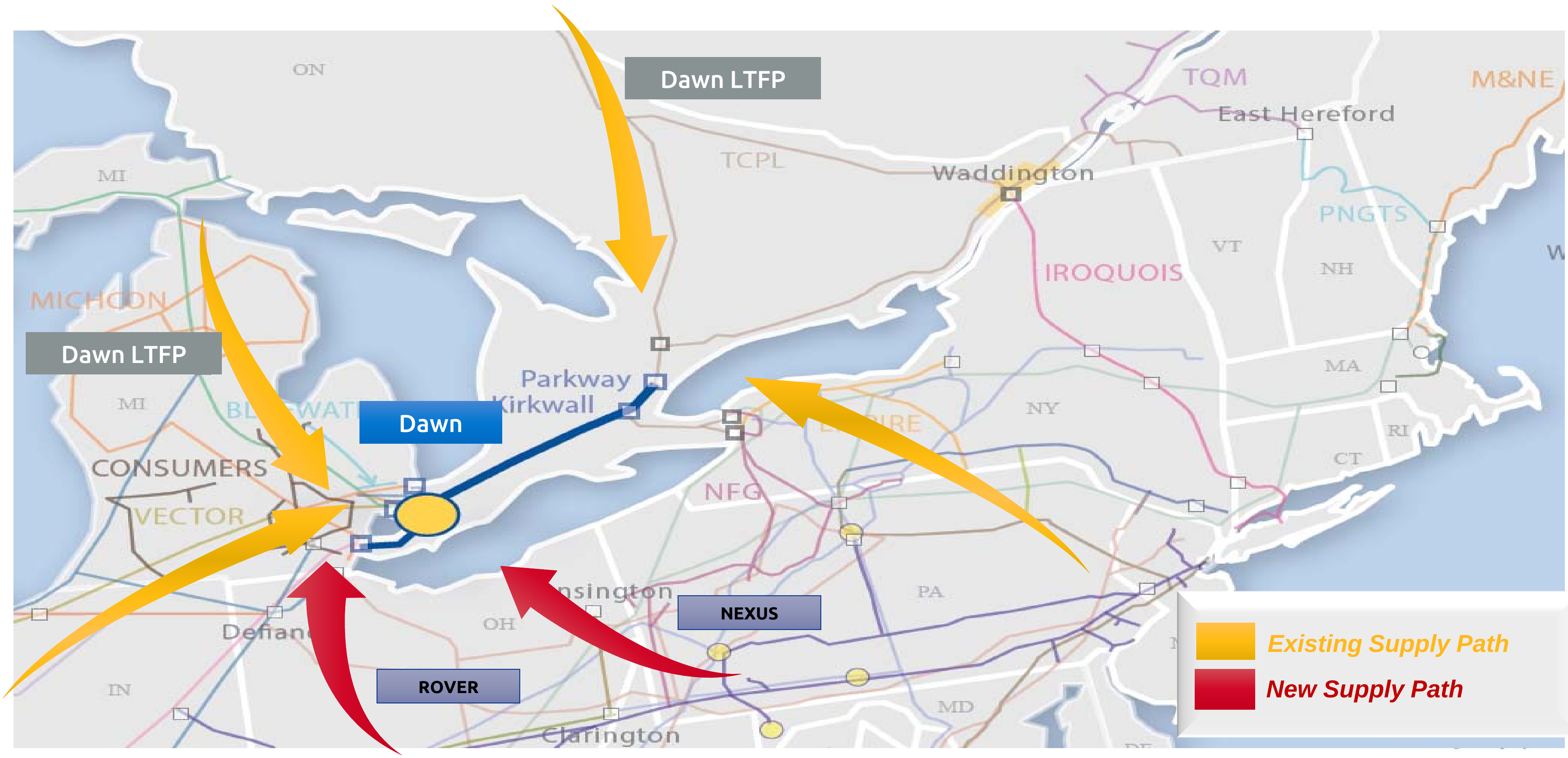
Facilities Expansion Projects

Andrea Seguin

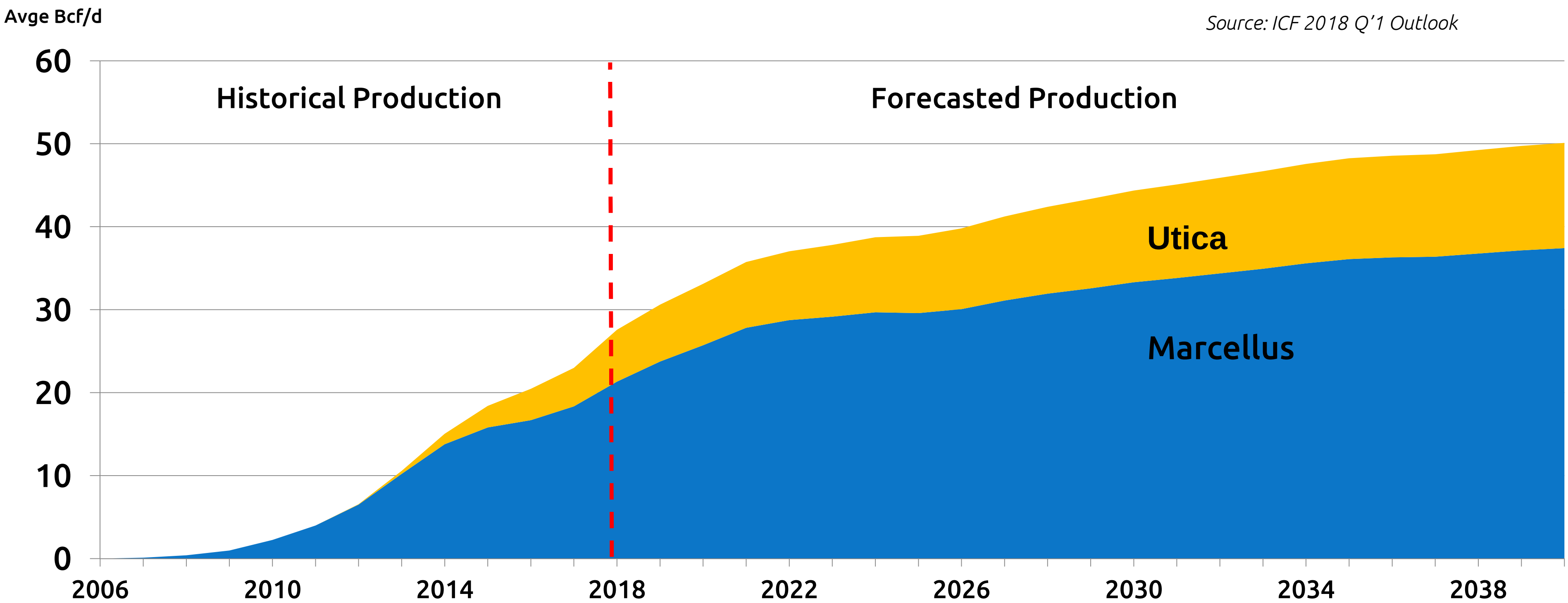
Director, Business Development & Upstream Regulation

uniongas
An Enbridge Company

Sourcing Supply at the Dawn Hub
Diversity = Reliability/Competitive Pricing



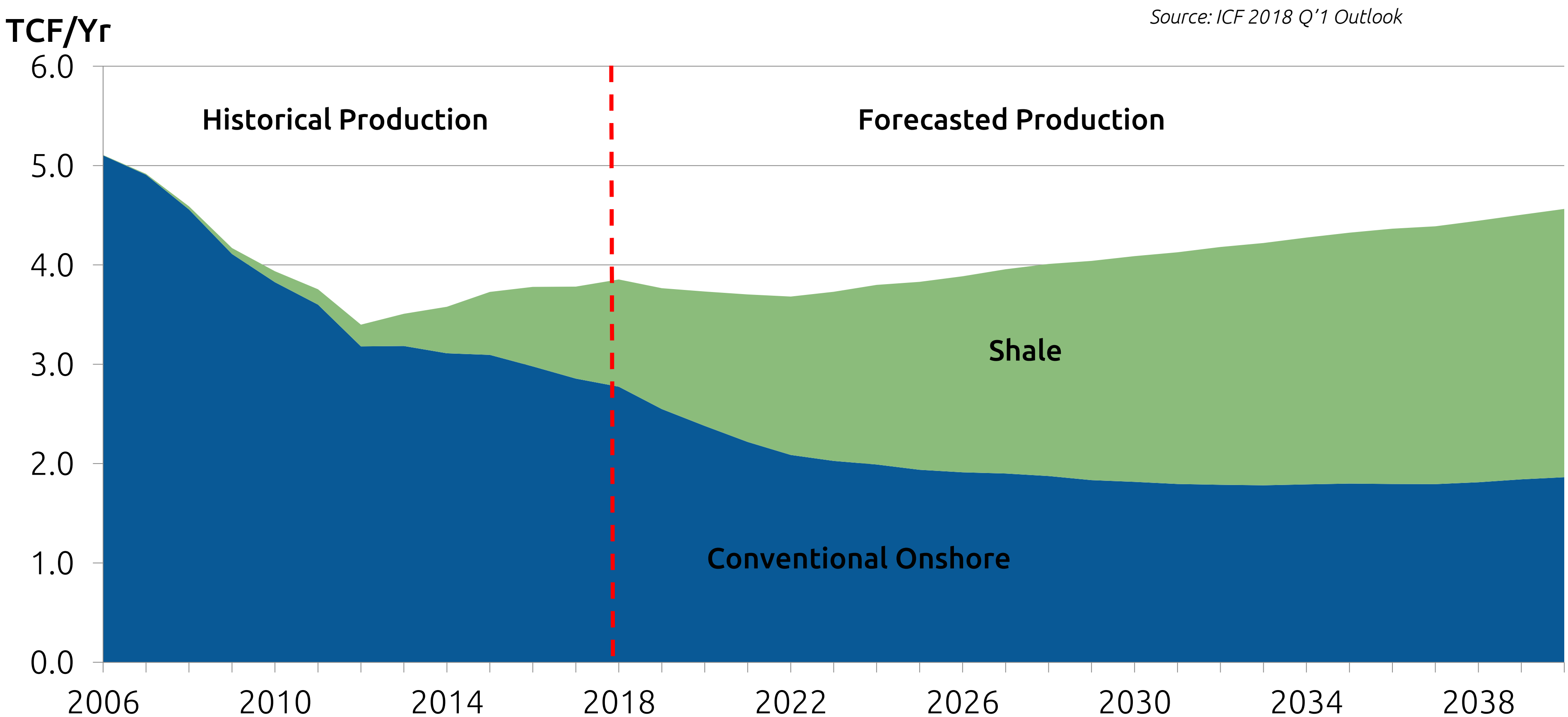
Marcellus/Utica Production Growth



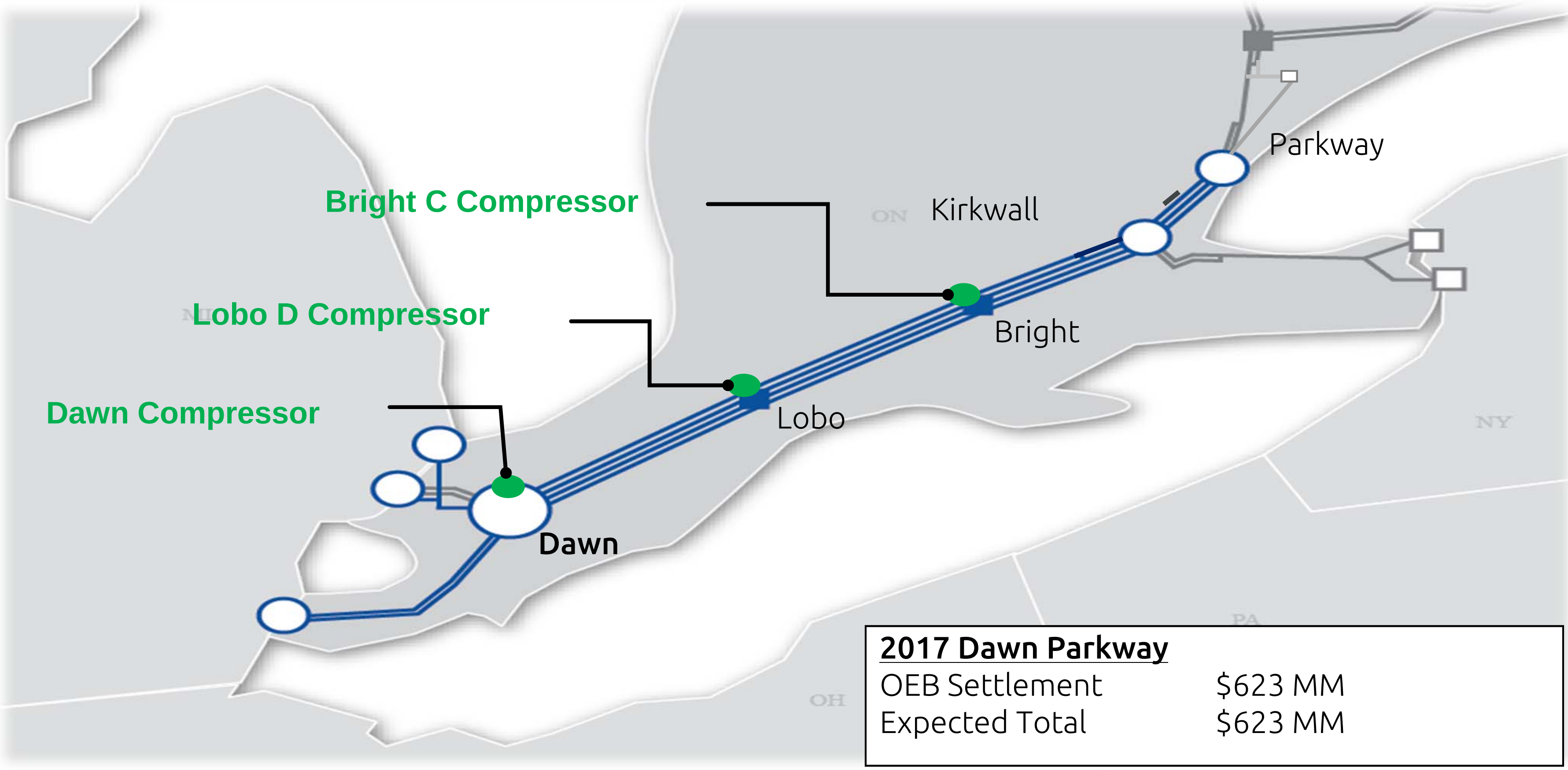
Production is forecasted to nearly double by 2040

uniongas
An Enbridge Company

WCSB Production Growth



2017 Dawn Parkway Expansion



2017 Dawn Parkway	
OEB Settlement	$623 MM
Expected Total	$623 MM

2017 Dawn Parkway Expansion

uniongas
An Enbridge Company

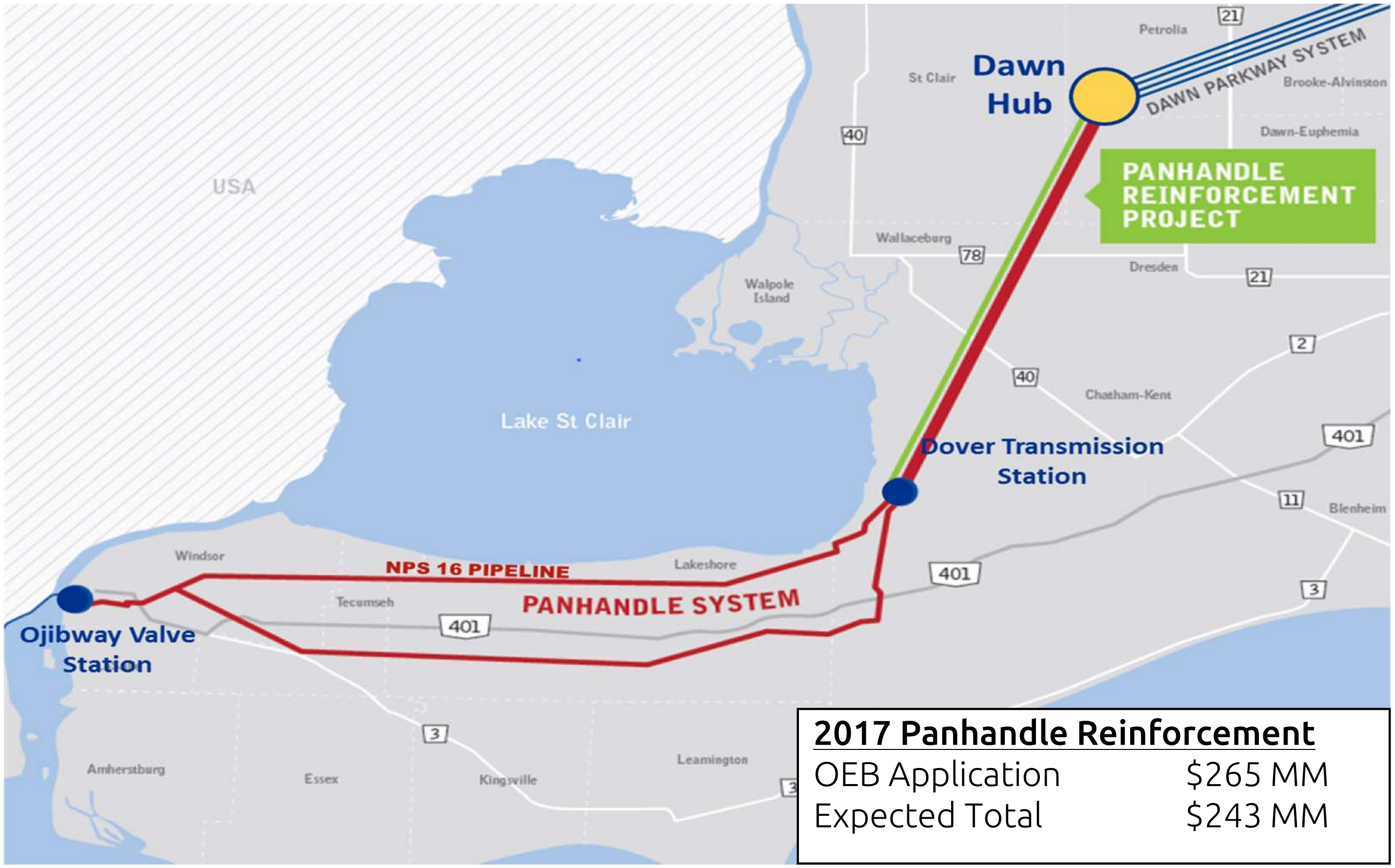
Future Dawn Parkway System Demands

- Union Gas continues to receive requests for incremental Dawn Parkway System capacity commencing as early as 2018

- Potential binding open season for Dawn Parkway System transportation in Q3 2018 for 2021 service or earlier

uniongas
An Enbridge Company

2017 Panhandle Reinforcement Project

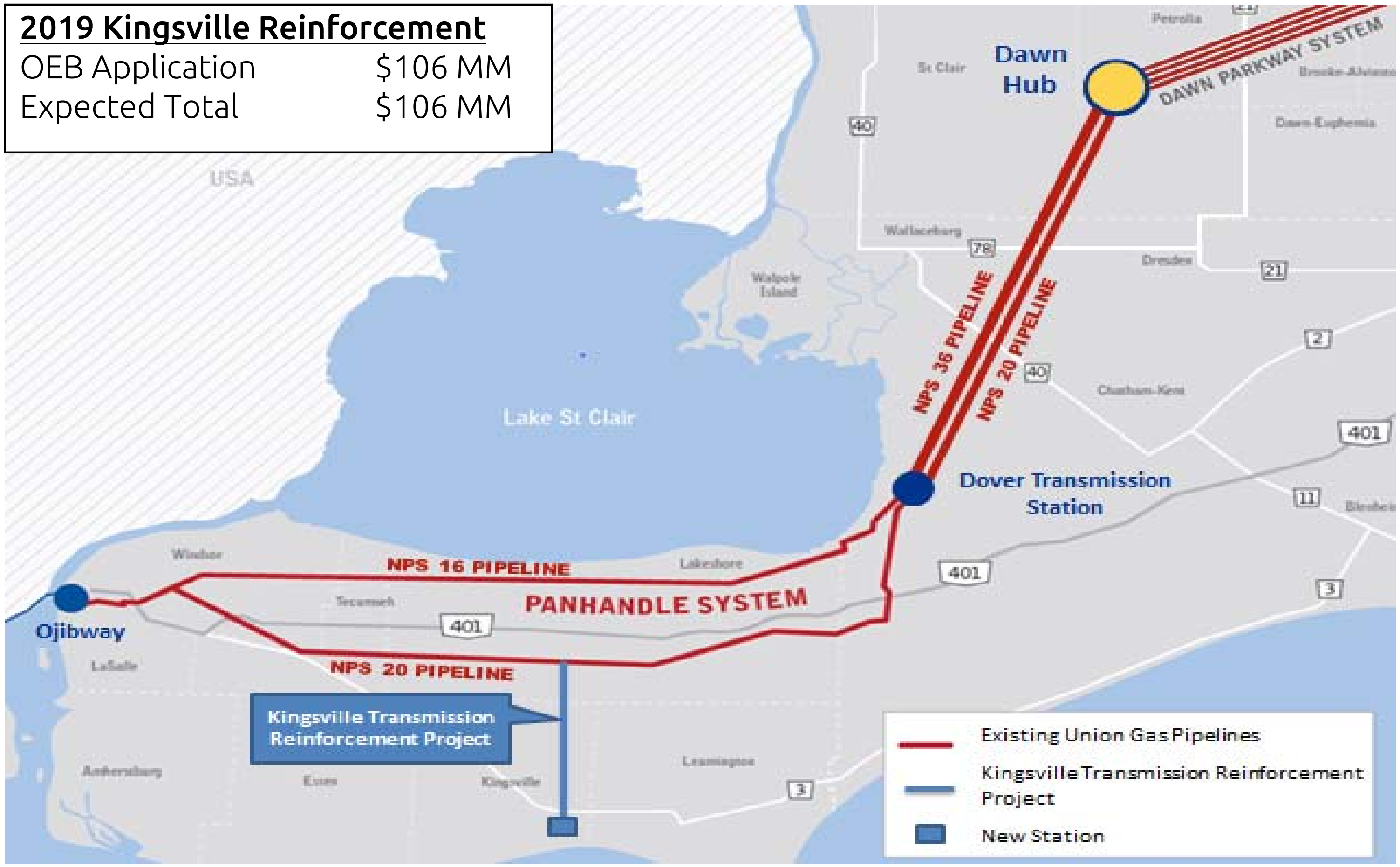


uniongas
An Enbridge Company

2017 Panhandle Reinforcement Project

uniongas
An Enbridge Company

2019 - Kingsville Transmission Reinforcement Project

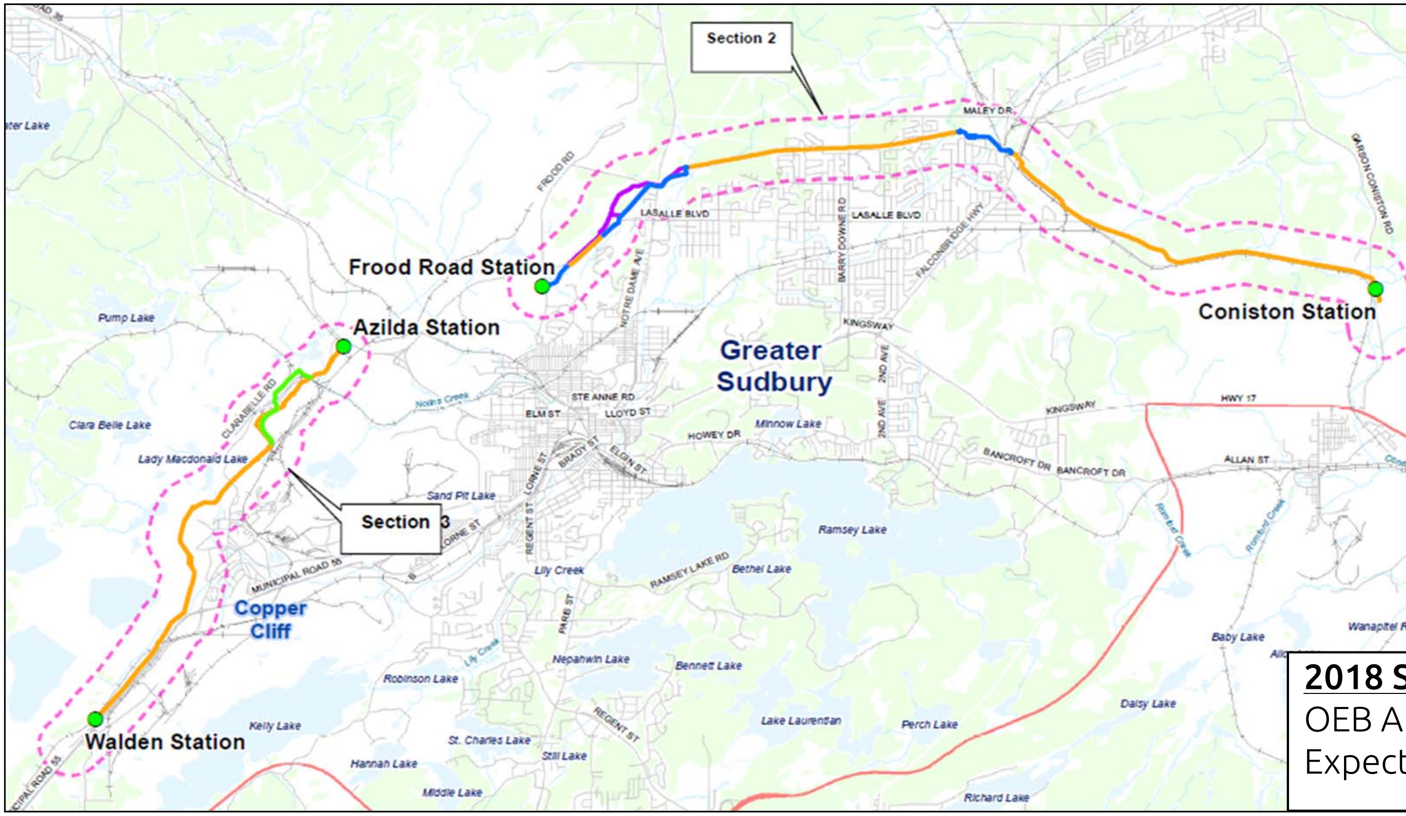


uniongas
An Enbridge Company

2019 - Kingsville Transmission Reinforcement Project

uniongas
An Enbridge Company

2018 - Sudbury Replacement Project



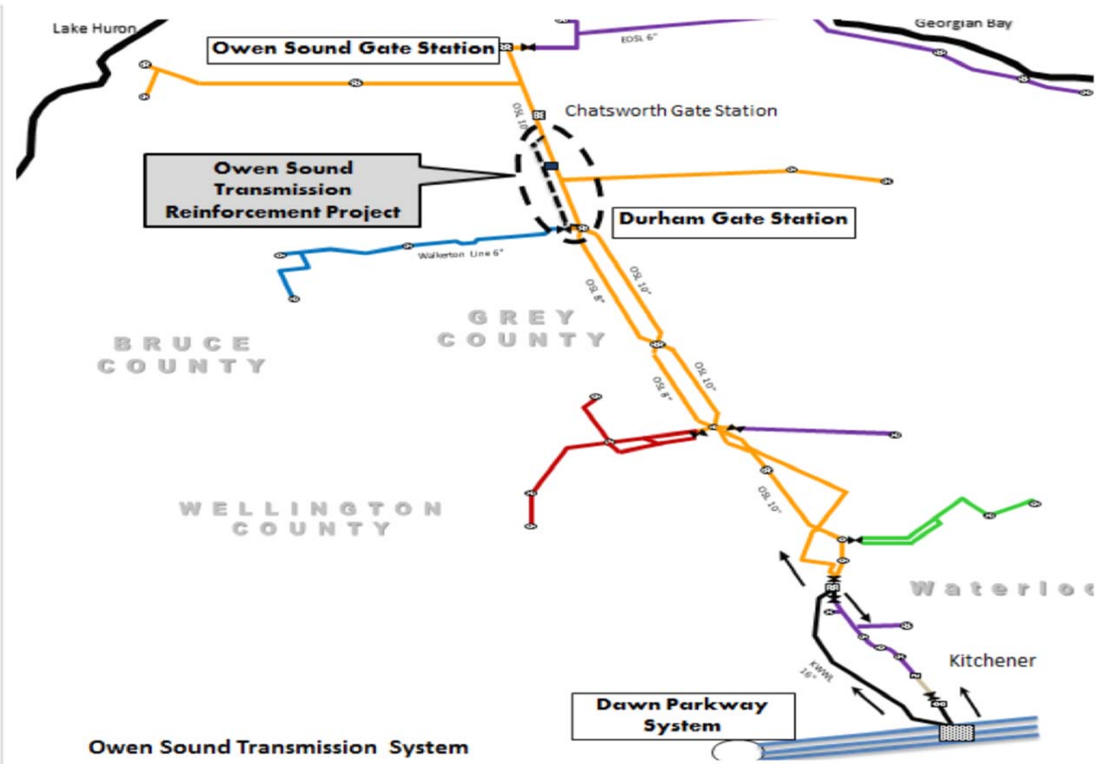
Scope

- Lift 20 kilometres of NPS 10 and replace with NPS 12 pipeline
- Station Upgrades
- November 1, 2018 in-service

2018 Sudbury Replacement Project

OEB Application	$74 MM
Expected Total	$74 MM

2019 - Owen Sound Transmission Reinforcement (OSTRP)



- Up to 30 kilometres of NPS 12 pipeline
- New EPCOR custody transfer station
- Capital - Up to $53 MM
- In-Service Date: November 1, 2019

Reinforcement required to meet significant growth in demand

uniongas
An Enbridge Company

Gas Supply Update

Cheryl Newbury

Director, Gas Supply & Customer Support

uniongas
An Enbridge Company

Agenda

2017/2018 Winter Experience

Gas Supply Plan Recap

- 2017/2018 Plan
- Future Trends

unionGas An Enbridge Company

2017/2018 Winter Experience

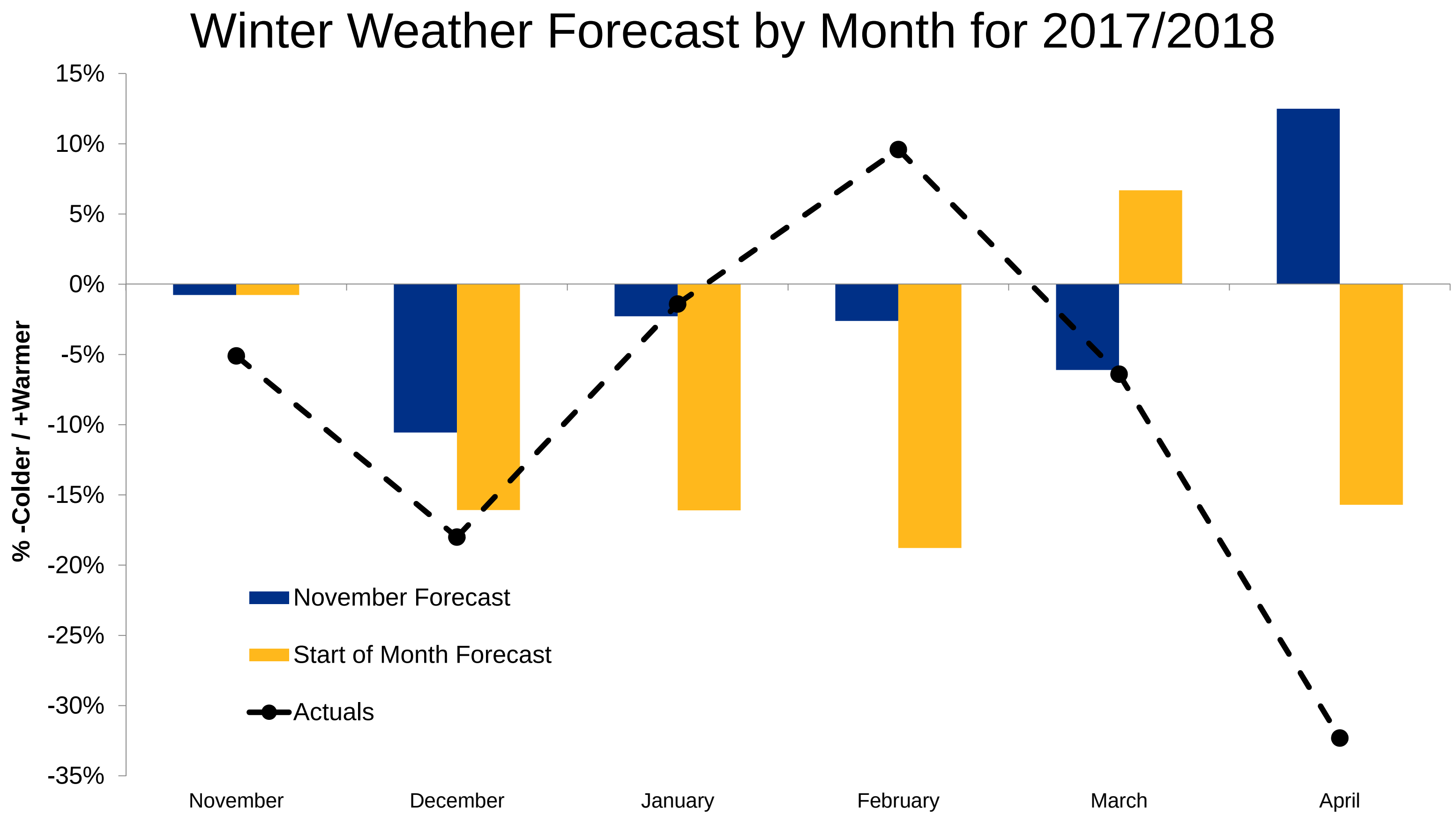
Winter 2017/2018 Actual vs Normal

Month	% Warmer than Normal	% Colder than Normal
November		5.1%
December		**18.0%**
January		1.4%
February	**9.6%**	
March		6.4%
April		**32.3%**

4% colder than normal in Winter 2017/2018

uniongas
An Enbridge Company

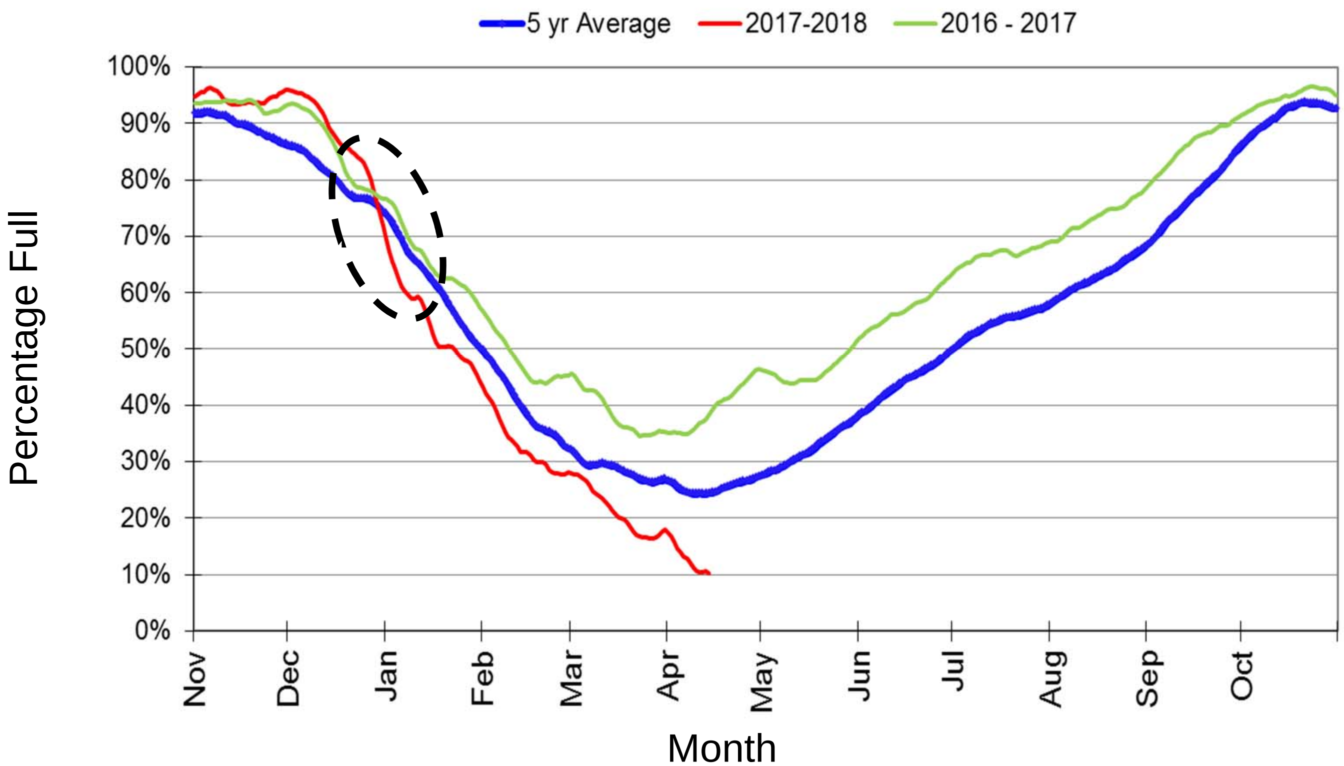
Weather Forecast Variability



Forecasted vs. actual weather varied significantly

Storage Operation

Union Storage Percentage Full



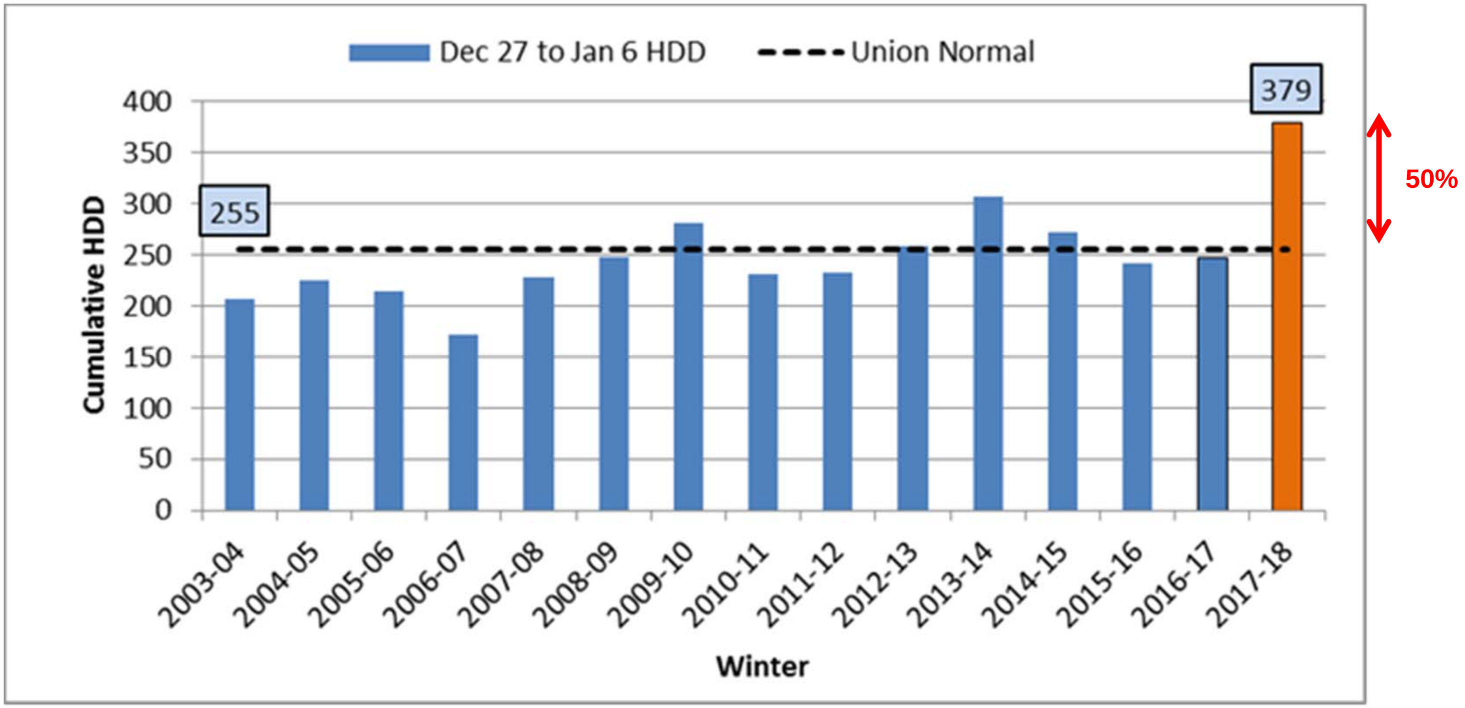
20% of storage inventory withdrawn in 13 days

uniongas
An Enbridge Company

Extreme Cold Weather –

Comparison to Historical Temperature (2003-2018)

Union Gas Weather
December 27 to January 6



2017/2018 – 50% colder than normal, record breaking demand

uniongas
An Enbridge Company

Extreme Cold Weather –

The Benefit of Dawn

Dawn Continues to Play a Critical Role

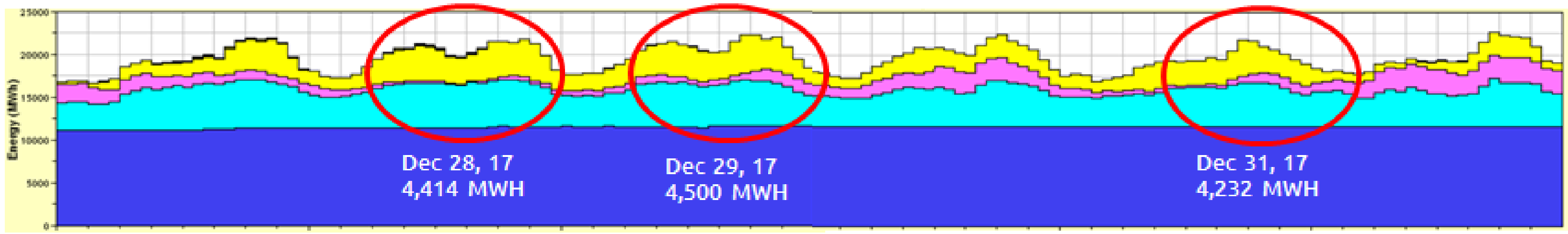
- **Storage**: Set 10 of historical top 25 withdrawal days
  - Physical peak: January 1, 2018 – 4.2 PJ
  - 54% of Union's market served from storage December 27-January 3
- **Parkway Discharge (Compressed)**: Set 14 of historical top 25 days
  - Physical peak: December 28, 2017 – 3.6 PJ
- **Dawn Send-out**: 16 of historical top 25 Dawn to Parkway send-out days
  - Physical peak: January 5, 2018 – 6.5 PJ

Union Gas system reliability and flexibility was critical to meet firm demands

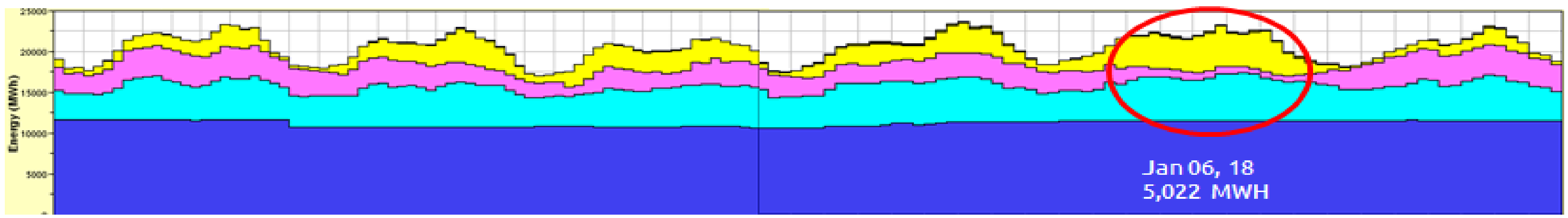
uniongas
An Enbridge Company

Extreme Cold Weather –

Ontario Power Operations



December 27 - January 1, 2018



January 2 - 7, 2018

Nuclear | Hydro | Wind | Gas | Solar | Biofuel

Reliability: natural gas used to meet peak demands

Source: Sygration

uniongas
An Enbridge Company

2017/2018 Winter Summary

Union Gas storage and transmission systems were able to meet all firm demands through three distinct winter events:

- 11 days of extreme cold
- Significant weather forecast variability
- Prolonged winter season

All firm demands met, no major system interruptions

uniongas
An Enbridge Company

Gas Supply Plan Outlook 2017/2018 Plan

uniongas
An Enbridge Company

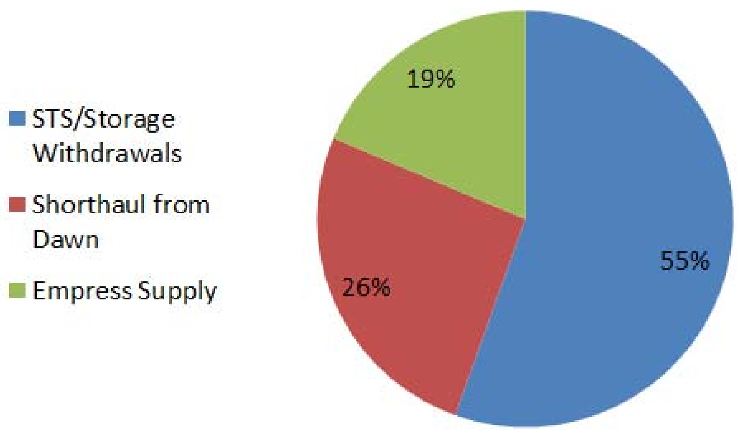
Gas Supply Plan Recap

- Plan period covers November 1, 2017 to October 31, 2018
- The corresponding Gas Supply Memorandum was filed as part of Union's 2018 Rates Application (EB-2017-0087)
- Total supply required for system sales service is 179 PJ for 2017/2018; a decrease of 2 PJ over the 2016/2017 plan
- In-franchise storage allocation at November 2017 is 93.2 PJ; a decrease of 0.4 PJ from the 2016/2017 plan
- The Gas Supply Plan identified additional transportation capacity of approximately 2 TJ/d to meet Design Day requirements in the North

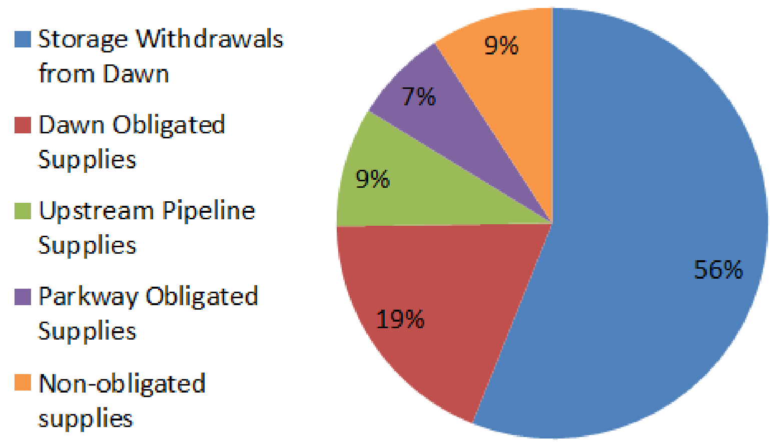
uniongas
An Enbridge Company

Union Design Day Supplies

Union North Design Day
524 TJ/d



Union South Design Day
3,027 TJ/d



- Increase in Design Day requirement
  Union North – 6 TJ/d
  Union South – 106 TJ/d

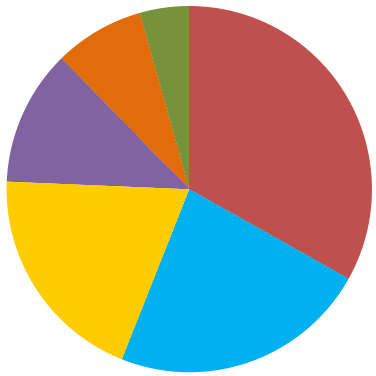
unongas
An Enbridge Company

Change in Supply Portfolio

2017/2018 – Pre Nexus

Pipeline (Supply Point)	%	Avg. Daily Qty (TJ/d)
Dawn/Other	33%	160
Vector (Chicago)	23%	111
DTE (Michcon)	20%	95
Panhandle (Field Zone/Ojibway)	12%	58
TransCanada (WCSB)	8%	38
TransCanada (Niagara)	4%	21

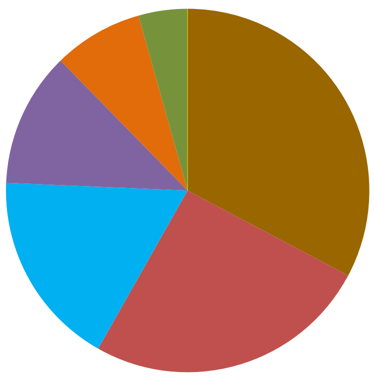
Pre Nexus



2017/2018 – Post Nexus

Pipeline (Supply Point)	%	Avg. Daily Qty (TJ/d)
NEXUS	33%	158
Dawn/Other	25%	123
Vector (Chicago)	18%	84
Panhandle (Field Zone/Ojibway)	12%	58
TransCanada (WCSB)	8%	38
TransCanada (Niagara)	4%	21

Post NEXUS



Continuing to incorporate TCPL and NEXUS contracts into the portfolio

uniongas
An Enbridge Company

Future Trends

uniongas
An Enbridge Company

Areas Being Monitored

- NEXUS Project Status
- 2018-2020 TransCanada Mainline Tolls
- Renewable Natural Gas (“RNG”)
- Distributor Gas Supply Planning Framework
- Post-2020 TransCanada Mainline Tolls
- Cap-and-Trade Compliance Planning

uniongas
An Enbridge Company

Residential Customer Perceptions of Union Gas

Jeff Okrucky

Director, New Business

unionGas
An Enbridge Company

Measuring Customer Perceptions

Union Gas measures customer perceptions of the company and service provided on an ongoing basis:

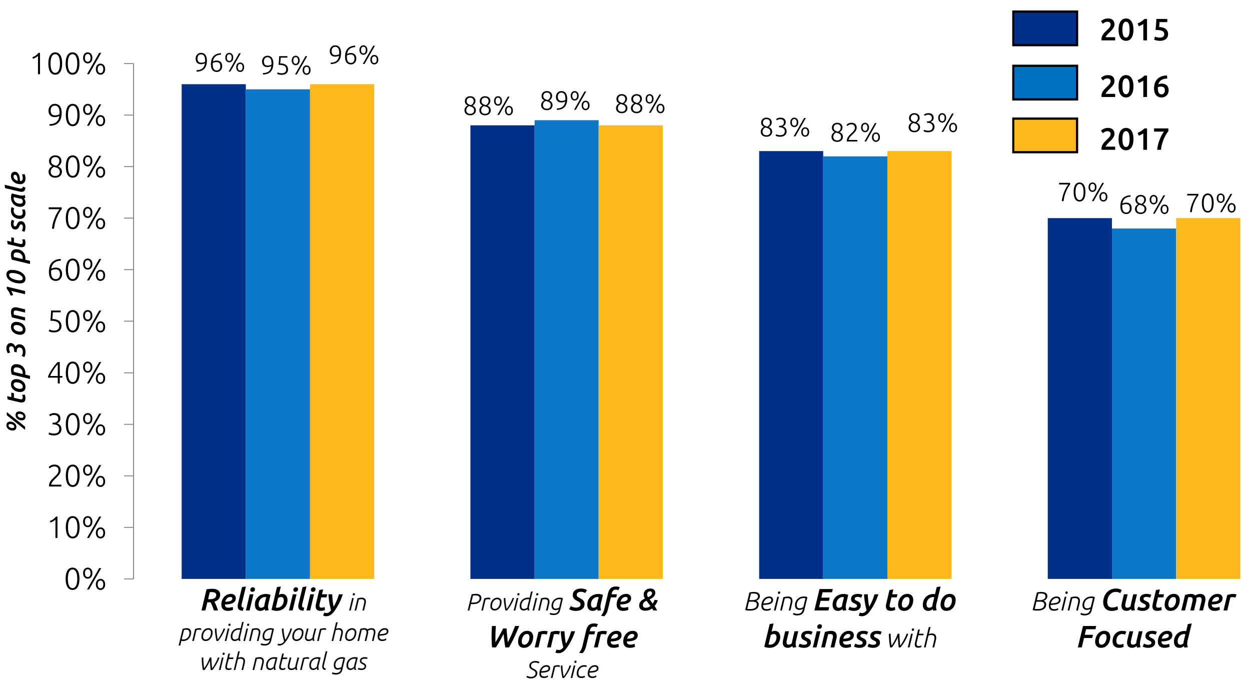
- ✓ Telephone Interviews are conducted weekly with a random sample of residential customers to achieve a total annual sample of 1200, providing a margin of error of 2.8% at the 95% confidence level
- ✓ For specific points of touch, such as the customer contacting Union Gas through the call centre or where a Utility Service Representative has performed meter-related work at the home, an additional telephone interview process is administered to measure customer satisfaction with the experience
- ✓ All telephone interviews are conducted by a third party research supplier, protecting the anonymity of the customer

uniongas
An Enbridge Company

Residential Customer Perceptions of Union Gas

Key Indicators

How would you rate Union Gas for each of the following … where 1 is poor and 10 is excellent?



- ✓ *Residential customers continue to have positive perceptions of Union Gas*
- ✓ *The ratings have been stable over the 2015-2017 period (no statistically significant movements)*
- ✓ *Ratings continue to be supported by a positive customer experience at points of touch:*
  - *High responsiveness as indicated by 90% "first call resolution" (call centre)*
  - *84% customer satisfaction (top 3 box score on a 10 point scale) with utility service appointment experiences (home visit, such as a meter replacement)*

uniongas
An Enbridge Company

Community Expansion

Jeff Okrucky

Director, New Business

uniongas
An Enbridge Company

Community Expansion Projects: Status

- EB-2015-0179
  - OEB approvals granted August 10, 2017 and October 5, 2017
    - Lambton Shores/Kettle and Stony Point First Nation: *Entered service December 19, 2017*
    - Milverton/Rostock/Wartburg
      - Milverton: *Entered service December 20, 2017*
      - Rostock and Wartburg: *To be constructed in 2018*
    - Prince Township: *To be constructed in 2018*
    - Moraviantown First Nation: *To be constructed in 2018*
- EB-2016-0137/8/9
  - South Bruce Project awarded to EPCOR
- Future Projects
  - Applications for Chippewa of the Thames First Nation, North Bay (N. Shore and Peninsula Roads) and Saugeen First Nation
  - Filed May 7, 2018

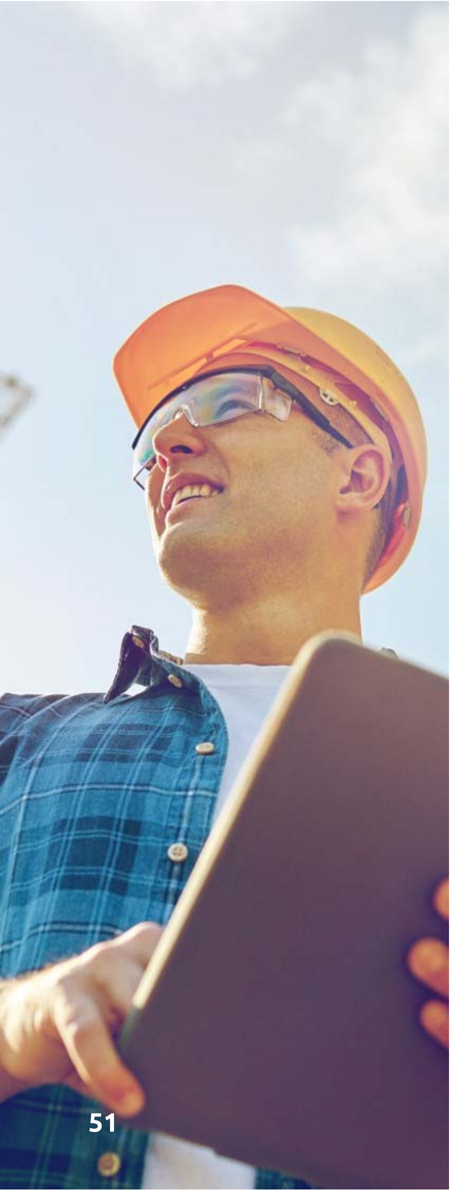
uniongas
An Enbridge Company

Results (as of April 30, 2018)

Project	Milverton/Rostock /Wartburg	Lambton Shores/ Kettle and Stony Pt. F.N.	Total
Year one capital cost forecast	$5.0 M	$1.8 M	$6.8 M
Actual capital costs to date	$6.1 M	$2.1 M	$8.2 M
Year one attachment forecast	185	158	343
Actual meters activated	149	104	253
Services installed	191	150	341

- Year one attachments (by mid-December 2018) are expected to exceed forecast
    - 31 further requests in queue
- Additional attachments over forecast period required to mitigate increased costs

unionigas
An Enbridge Company



Wrap-Up

Mark Kitchen

Director, Regulatory Affairs

unionGas
An Enbridge Company

Future Regulatory Applications

- 2017 Deferrals
- DSM 2016 Deferrals
- 2019-2020 Cap-and-Trade Compliance Plan
- 2019 Rates Application
- Distribution Expansion LTCs

uniongas
An Enbridge Company

Connect with us

uniongas.com

uniongas
An Enbridge Company