April 21, 2017

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

Dear Ms. Walli:

Re: EB-2017-0091 - Union Gas Limited - 2016 Disposition of Deferral Account Balances and 2016 Utility Earnings

Enclosed is the application and evidence submitted by Union Gas Limited ("Union") concerning the final disposition and recovery of certain 2016 deferral account balances and earnings sharing amount.

Union is not proposing to dispose of DSM related deferral account balances in this proceeding. Union will file its DSM deferral account evidence following the completion of the 2016 audit of program results.

The Application is supported by evidence which is outlined below:

EXHIBIT A

Tab 1	2016 Deferral Account Balances
Tab 2	2016 Utility Results and Earnings Sharing
Tab 3	Allocation and Disposition of 2016 Deferral Account Balances and 2016 Earnings Sharing Amount
Tab 4	Incremental Transportation Contracting Analysis
Tab 5	April 13, 2017 Stakeholder Presentation
Tab 6	Data Centre Consolidation

Union proposes that the impacts which result from the disposition of 2016 deferral account balances be implemented on October 1, 2017 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) 436-5473.

Yours truly,

[*Original Signed by*]

Karen Hockin
Manager, Regulatory Initiatives

c.c.: Crawford Smith (Torys)
EB-2016-0245 Intervenors (2017 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-2015-0116, 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, 2016. 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 2016 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 2016 deferral accounts as listed in Exhibit A, Tab 1, Appendix A, Schedule 1 and an order for final disposition of those balances.

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: Karen Hockin
Manager, Regulatory Initiatives

Telephone: (519) 436-5473
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: April 21, 2017

UNION GAS LIMITED

[Original signed by]

____

Karen Hockin
Manager, Regulatory Initiatives

2016 DEFERRAL ACCOUNT BALANCES

2016 YEAR-END DEFERRAL ACCOUNT BALANCES

Union has classified the deferral accounts approved by the Ontario Energy Board ("Board") for use in 2016 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 $45.771 million debit from ratepayers. This total includes balances as at December 31, 2016. Interest has been calculated on account balances according to the Board-approved accounting orders. The applicable short-term interest rate used was 1.10% as prescribed by the Board in EB-2006-0117.

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 EB-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")

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 the UDC Variance Account is a debit from ratepayers of $3.003 million, and 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 2016 approved rates included planned unutilized pipeline capacity of 6.3 PJ in Union North and 0 PJ in Union South. The UDC volumes included in rates are based on the Gas Supply Plan filed in Union's 2013 Cost of Service proceeding (EB-2011-0210), updated for the Normalized Average Consumption ("NAC") adjustment in 2014.

As discussed in the Gas Supply Memorandum in the 2017 rates proceeding[1], 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

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

requirements is less than the capacity to meet design day requirements and 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 rebalance 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 $5.475 million in rates for UDC during 2016 and recorded an associated interest debit of $0.012 million (see Table 1). Actual UDC costs in 2016 were $19.569 million offset by $10.451 million in released capacity value and a credit of $0.652 million related to a change in contracted capacity on Centra Transmission Holdings and Centra Pipeline Minnesota ("CTHI / CPMI"), resulting in a net cost of $8.466 million (see Table 2).

The variance between the UDC amount collected in rates and the actual UDC cost, including the interest debit of $0.012 million, is a net debit in the UDC Variance Account of $3.003 million.

The balance of $3.003 million is allocated to Union North and Union South in proportion to the actual excess supply and costs incurred for UDC for each respective area. The balance applicable to sales service and bundled Direct Purchase ("DP") customers in Union North is a debit of $1.836 million. A debit of $1.167 million is applicable to sales service customers in Union South.

Table 1 provides the derivation of the UDC Variance Account balances by operations area.

Table 1

UDC Variance Account by Operational Area

Line No.	Particulars ($000's)	Union North	Union South	Total Franchise Area
1	UDC Collected in Rates	(5,475)	-	(5,475)
2	Net UDC Costs Incurred (Table 2)	7,304	1,162	8,466
3	Variance (line 2 - line 1)	1,829	1,162	2,991
4	Interest	7	5	12
5	(Credit) / Debit to Operations Area	1,836	1,167	3,003

A description of each item follows:

UDC Collected in Rates

2016 Board-approved rates include $5.609 million of UDC associated with 6.3 PJ of planned unutilized pipeline capacity in Union North and no planned unutilized pipeline capacity in Union South. The total cost of UDC in rates assumes TransCanada final tolls effective January 1, 2016 including the TransCanada abandonment surcharge. On an actual basis in 2016, Union recovered $5.475 million in Union North (due to lower throughput than forecast) and $0 million in Union South.

UDC Costs Incurred

The actual unutilized capacity in 2016 was 31.5 PJ. The level of unutilized capacity experienced in 2016 was largely due to planned unutilized capacity and significantly warmer than normal weather that resulted in lower transportation throughput.

The costs reflected in the UDC Variance Account are the total demand charges for unutilized pipeline capacity totaling $19.569 million which are offset, in part, by value generated from pipeline transportation releases totaling $10.451 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.

In addition, consistent with the approach in prior periods, Union has reflected a credit of $0.652 million in the UDC Variance Account to capture a volume variance related to capacity contracted with CTHI / CPMI. In Union North, Union contracts for capacity on CTHI / CPMI to move gas into Union's Manitoba Delivery Area ("MDA"). Union's MDA is connected to the TransCanada Mainline at the Spruce interconnect, in the TransCanada Centra MDA, by CTHI / CPMI. In Union's 2013 Cost of Service filing (EB-2011-0210), Union reflected the then contracted capacity on CTHI / CPMI of 8,473 GJ/day. Union has since reduced the contracted capacity on these pipelines to 5,572 GJ/day. The reduction in costs for this contract is $0.652 million in 2016 and this amount has been recorded in the UDC Variance Account to pass through the benefit of this contract change to Union North sales service and bundled DP customers. As of January 1, 2017, Union has reflected the current contracted capacity in rates which will eliminate the variance going forward.

Table 2
UDC Costs Incurred

Line No.	Particulars ($000's)	Union North	Union South	Total Costs
1	UDC Costs Incurred	17,012	2,556	19,569
2	Released Capacity Value	(9,057)	(1,394)	(10,451)
3	CTHI / CPMI Contracted Capacity Credit	(652)	-	(652)
4	Net UDC Costs (Credit)/Debit	7,304	1,162	8,466

Account No. 179-128 Gas Supply Review Consultant Cost

There is no balance in this deferral account. In accordance with its EB-2016-0245 Decision, the Board has approved the closure of this account effective January 1, 2017.

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 $11.646 million.

In setting rates for 2016, the Board-approved a forecast of optimization revenue of $14.918 million[2]. Of that amount, 90%, or $13.426 million, was credited to ratepayers in the Board-approved 2016 rates[3]. On an actual basis, consistent with the method approved in its EB-2011-0210 Decision and Rate Order, Union credited $14.668 million in rates to ratepayers during 2016, $1.242 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.[4] The main driver of actual sales service volumes exceeding the forecasted amount is customer growth since 2013.

Union earned $3.358 million in net revenues from upstream transportation optimization during 2016. Per the Board-approved sharing methodology, 90% of this net revenue, or $3.022 million, is to be credited to customers. As stated above, $14.668 million has already been credited through rates; therefore, $11.646 million ($14.668 million less $3.022 million) is to be collected from ratepayers through this deferral account disposition.

Tab 1, Appendix A, Schedule 2 provides a summary of the calculation of the amount in this deferral account. Union's 2016 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); and,

[2] EB-2015-0116, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[3] EB-2015-0116, Draft Rate Order, Working Papers, Schedule 14, p. 1.
[4] EB-2011-0210, Decision and Rate Order, p. 16.

2) Warmer weather in 2016 created less demand and lower prices for exchange transactions.

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 the Short-Term Storage and Other Balancing Services Deferral Account is a credit to ratepayers of $2.226 million.

As shown in Table 3, the balance is calculated by comparing $6.777 million (90% of the actual 2016 Short-Term Storage and Other Balancing Services net revenue of $7.530 million) to the net revenue included in rates of $4.551 million in the EB-2011-0210 Rate Order. The details of the balance are found at Tab 1, Appendix A, Schedule 3.

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

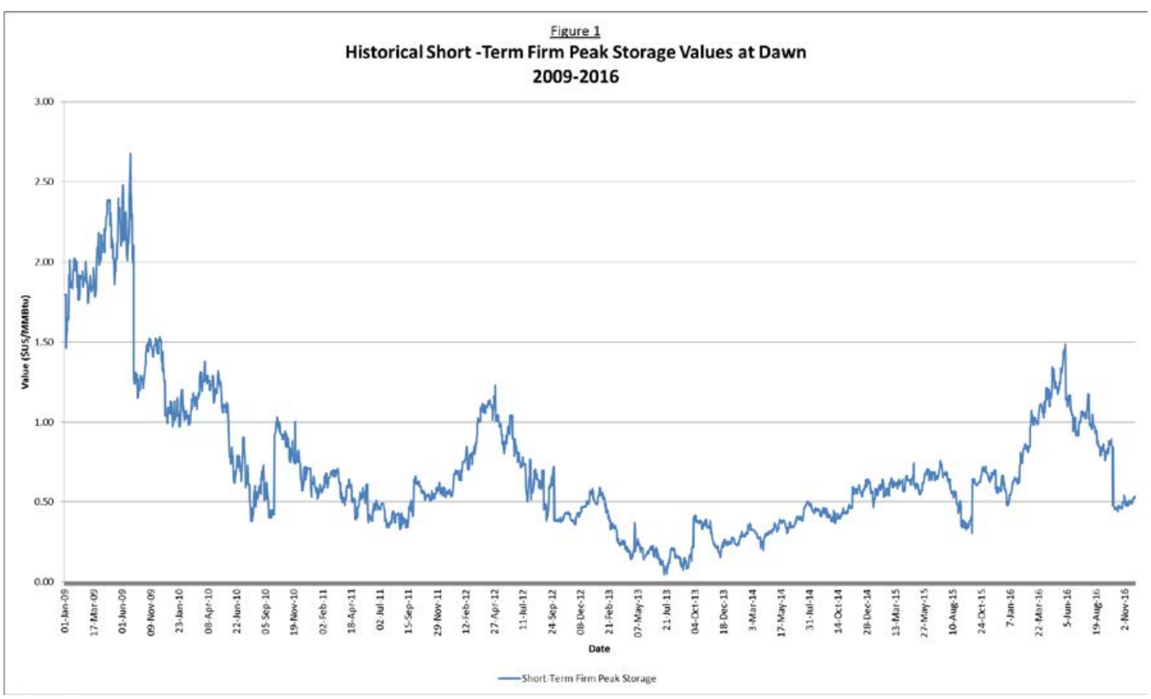
Line No.	Particulars ($000's)	Actual 2016
1	Net Revenue	7,530
2	Ratepayer Portion (90%)	6,777
3	Approved in Rates	4,551
4	Deferral Balance Payable to/(Collectable from) Ratepayers	2,226

Actual 2016 revenues from C1 Off-Peak Storage, Gas Loans and all other Balancing services of $5.102 million were $2.602 million higher than the 2013 Board-approved forecast of $2.500 million.

The C1 Short-Term Firm Peak Storage revenues of $5.627 million were $2.256 million lower than the 2013 Board-approved forecast of $7.883 million. Actual utility storage requirements for 2016 were 4.9 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 6.4 PJ in 2016). Union's customers received the value of storage directly through the use of the storage space, rather than indirectly through the sale of short-term storage.

Year-over-year, actual utility storage requirements for 2016 were 1.4 PJ lower than the requirement in 2015, resulting in an increase in the C1 Short-Term Peak Storage available for sale (from 5.0 PJ in 2015 to 6.4 PJ in 2016). This is a result of a decrease in storage requirement in the general service market, partially offset by an increase in the storage requirement of 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 using either the Board-approved aggregate excess methodology or the 15 times obligated Daily Contracted Quantity ("DCQ") storage methodology.

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 2016 was $0.88/GJ ($5.627 million/6.4 PJ). Please see Figure 1 for Short-Term Peak Storage values in US dollars.



Non-Utility Storage Balances for 2016

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.

Tab 1, Appendix A, Schedule 4 shows the non-utility inventory balances for October and November of 2016.

During the 2016 injection season, the non-utility storage balance peaked on October 10, 2016 at 96% of available space with a balance of 85.1 PJ compared to available space of 88.3 PJ. At October 31, 2016, the date to which Union manages its storage balance, the non-utility balance was 95% of available space. The balance stayed below the total non-utility available space of 100% for the rest of 2016.

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 2016 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, Decision and Order, pp. 116-117. 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 2016, Union sold a total of 6.4 PJ of short-term peak storage. The total 6.4 PJ was excess utility space, calculated by deducting 93.6 PJ of in-franchise utility requirement (as per Union's Gas Supply Plan) from the total 100 PJ of in-franchise utility storage. There was no sale of short-term peak storage from non-utility space.
Total revenue from the sale of C1 Short-Term Peak Storage (Utility) in 2016 was $5.627 million.

Details of the above sales are reflected in 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.

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 of the GDAR Deferral Account is a debit from ratepayers of $0.443 million.

The GDAR capital costs are made up of the costs associated with three separate Notice 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 Gas' 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	1130	258	459	1,847
3	Total Costs	$1,475	$278	$468	$2,221

Consistent with EB-2014-0145, Union's 2013 Deferrals Disposition, Union replaced the capital costs with the annual revenue requirement related to these capital costs. This is outlined in Table 5 below. Accordingly, the 2016 GDAR Deferral Account has a debit balance of $0.443 million. The revenue requirement will continue to be included in the respective future deferral disposition proceedings.

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. 179-117 Carbon Dioxide Offset Credits

There is no balance in this deferral account. In accordance with its EB-2016-0245 Decision, the Board has approved the closure of this account effective January 1, 2017.

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.

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

There is no balance in this deferral account. 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). In 2016 Union did not deliver any CDM programs on behalf of electric local distribution companies.

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 deferral account balance is a debit from ratepayers of $0.235 million plus interest of $0.002 million, for a total of $0.237 million. This balance represents an under-recovery of the Board-approved deferral account balances in EB-2015-0010 (Union's 2014 Deferral Account Disposition). Please see Tab 1, Appendix A, Schedule 6, p. 1 for a summary of the applicable deferral account balances by application.

Union's 2014 Deferral Account Disposition (EB-2015-0010)

In its EB-2015-0010 Decision, the Board-approved the prospective disposition to rate classes of the total balances in the approved deferral accounts through a temporary rate adjustment from October 1, 2015 to March 31, 2016. The total amount approved for prospective recovery from rate classes was $0.645 million. Please see Tab 1, Appendix A, Schedule 6, p. 2, Column (e), based on the forecasted volumes as noted at Tab 1, Appendix A, Schedule 6, p. 2, Column (a).

Actual volumes for the period October 1, 2015 to March 31, 2016 averaged approximately 12% 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 has recovered $0.410 million, or $0.235 million less than the final deferral account balances approved for disposition in EB-2015-0010. Please see Tab 1, Appendix A, Schedule 6, p. 2, Column (f) for the actual disposition of deferral accounts and Tab 1, Appendix A, Schedule 6, p. 2, Column (g) for the variance between forecast and actual disposition.

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

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

For 2016, the balance in the NAC Deferral Account is a debit from ratepayers of $23.506 million plus interest of $0.125 million for a total of $23.631 million.

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

Target and Actual NAC

The 2016 target NAC for each rate class was approved by the Board in Union's 2016 Rates proceeding (EB-2016-0116). The 2014 actual NAC, weather normalized using the 2016 weather normal, was used to determine the 2016 target NAC. Setting the 2016 target NAC based on the 2014 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 2016 actual NAC for each rate class is weather normalized using the 2016 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 2016 target and 2016 actual NAC by rate class.

Table 6

2016 Target and Actual NAC (m^3/customer)

Line No.		Rate 01	Rate 10	Rate M1	Rate M2
		(a)	(b)	(c)	(d)
1	2016 Target NAC	3,015	177,214	2,852	172,693
2	2016 Actual NAC	2,788	159,855	2,667	159,933
3	Change in NAC (Target - Actual NAC)	227	17,359	185	12,760

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 2016 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
2016 NAC Deferral Account: $000s

Line No.		Rate 01	Rate 10	Rate M1	Rate M2	All Rates
		(a)	(b)	(c)	(d)	(e)
1	Delivery Revenue Balances	6,157	1,912	7,409	3,357	18,835
2	Storage Revenue Balances	2,910	1,000	1,379	534	5,823
3	Storage Cost Balances	80	(199)	330	(1,363)	(1,152)
4	Interest	49	15	45	16	125
5	Total NAC Deferral Balance	9,196	2,728	9,163	2,544	23,631

Storage Costs

The storage costs recognize that variances between the 2016 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 (EB-2014-0145), p. 9, *"starting in 2014, the NAC Deferral Account, which replaces the Average Use Per Customer Deferral Account, will include storage related revenues and costs for general service rate classes."*

To determine the change in storage requirements for each general service rate class due to NAC variances, Union calculated the NAC volume variance per customer between its 2016/2017 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 2016/2017 Gas Supply Plan volumes represent the April 1, 2016 to March 31, 2017 period, which are used to determine the storage requirements for general service rate classes effective November 1, 2016. These general service rate class storage requirements are then used in the calculation of the total in-franchise utility storage space requirement at November 1, 2016. The difference between the total in-franchise utility storage requirement and the total 100 PJ of utility storage represents the excess utility storage capacity available for sale ("excess utility space") at November 1, 2016.

For Rate M1, the NAC volume variance between the 2016/2017 Gas Supply Plan and the 2013 Board-approved volumes was a decrease of 3.12 PJ. The majority of the NAC volume variance decrease occurred in the summer months, which increased the Rate M1 storage requirement by 0.47 PJ. This resulted in increased storage costs of $0.330 million (Table 7, Line 3).

For Rate M2, the NAC volume variance between the 2016/2017 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 5.05 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate M2 storage requirement by 1.95 PJ and resulted in decreased storage costs of $1.363 million (Table 7, Line 3).

For Rate 01, the NAC volume variance between the 2016/2017 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 0.41 PJ. The NAC volume variance increase was slightly higher in the winter months than the summer, which increased the Rate 01 storage requirement by 0.10 PJ and increased storage costs by $0.080 million (Table 7, Line 3).

For Rate 10, the NAC volume variance between the 2016/2017 Gas Supply Plan and the 2013 Board-approved volumes was an increase of 0.73 PJ. The majority of the NAC volume variance increase occurred in the summer months, which decreased the Rate 10 storage requirement by 0.24 PJ and resulted in decreased storage costs of $0.199 million (Table 7, Line 3).

Overall, the NAC volume variance between the 2016/2017 Gas Supply Plan and the 2013 Board-approved volumes resulted in a decrease in general service storage requirements of 1.62 PJ. Accordingly, Union has included a storage cost credit of $1.152 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)

	(PJ)		(PJ)
Rate M1	0.47	Rate 01	0.10
Rate M2	(1.95)	Rate 10	(0.24)
Total South	(1.48)	Total North	(0.14)

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

The 1.62 PJ reduction in general service storage requirements due to NAC volume variances forms part of the 6.4 PJ of excess utility space available for sale for winter 2016/2017. The revenue from the sale of the 6.4 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 Tab 1, Appendix A, Schedule 7.

For Rate M1, actual NAC is less than target NAC by 185 m^3/customer (Table 6, Line 3). As shown in Table 7, this results in a delivery and storage revenue charge of $8.788 million ($7.409 million and $1.379 million respectively). In addition, the NAC volume variance increases the

Rate M1 storage requirement by 0.47 PJ. Accordingly, Union must recover an additional $0.330 million (Table 7, Line 3) to recognize the increase in Rate M1 storage requirements.

For Rate M2, actual NAC is less than target NAC by 12,760 m^3/customer (Table 6, Line 3). As shown in Table 7, this results in a delivery and storage revenue charge of $3.891 million ($3.357 million and $0.534 million respectively). In addition, the NAC volume variance decreases the Rate M2 storage requirement by 1.95 PJ. Accordingly, Union must refund $1.363 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 227 m^3/customer (Table 6, Line 3). As shown in Table 7, this results in a delivery and storage revenue charge of $9.067 million ($6.157 million and $2.910 million respectively). In addition, the NAC volume variance increased the Rate 01 storage requirement by 0.10 PJ. Accordingly, Union must recover an additional $0.080 million (Table 7, Line 3) to recognize the increase in Rate 01 storage requirements.
For Rate 10, actual NAC is less than target NAC by 17,359 m^3/customer (Table 6, Line 3). As shown in Table 7, this results in a delivery and storage revenue charge of $2.912 million ($1.912 million and $1.000 million respectively). In addition, the NAC volume variance decreases the Rate 10 storage requirement by 0.24 PJ. Accordingly, Union must refund $0.199 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 the Tax Variance Deferral Account is a credit to ratepayers of $0.197 million plus interest of $0.001 million for a total of $0.198 million. The establishment of the Tax Variance Deferral Account was approved through the 2014-2018 Incentive Regulation (EB-2013-0202) Settlement Agreement. 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 2016, there is no impact related to income tax, however, there is a credit balance of $0.197 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.

Consistent with the 2015 Deferrals Disposition proceeding (EB-2016-0118), Union will continue to record 50% of the annual incremental savings in the Tax Variance Deferral Account until Union's next rebasing since Union's HST Deferral Account used for the 2010 implementation of HST is closed. The annual balance is expected to grow until rebasing in proportion to the timeline of tax changes above.

To calculate the 2016 Tax Variance Deferral Account balance related to HST changes, Union reviewed the transactions from January 1 to December 31, 2016 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 2016, the Tax Variance Deferral Account is a credit balance of $0.197 million. The calculation of the balance is provided in Table 9.

Table 9
50% of 2016 Net Savings from the Impact of HST Changes
to be Shared with Ratepayers

Line No.		Particulars ($000's)
1	Capital Savings	0.004
2	O&M Savings	0.193
3	Compressor Fuel Savings	0.000
4	Tax Variance Deferral Account Balance	$0.197

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

The balance in the UFG Volume Deferral Account is a debit from ratepayers of $5.184 million, plus interest of $0.005 million, for a total balance of $5.189 million.

The establishment of the UFG Volume Deferral Account was approved by the Board as part of the 2014-2018 Incentive Regulation Settlement Agreement. 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 $5.000 million. 2016 Board-approved rates included $11.676 million in UFG costs. Based on 2016 actual volumes Union only recovered $10.784 million in UFG costs for 2016. In comparison, Union's actual 2016 UFG costs were $20.969 million as a result of the actual UFG percentage of 0.427% being greater than the 2013 Board-approved UFG percentage of 0.219%.

Accordingly, the difference between the UFG costs recovered in rates of $10.784 million and Union's actual UFG expense of $20.969 million is $10.184 million. The difference of $10.184 million is in excess of the $5.0 million threshold established by the Board for the UFG Volume Deferral Account. A summary of this deferral account is shown in Table 10.

Table 10
2016 UFG Variances from Board-Approved
($ 000's)

		2016 Actual	Recovered in 2016 Rates	Variance
1	Total UFG Costs	20,969	10,784	10,184
2	$5M UFG Deferral Account Threshold			5,000
3	UFG Volume Deferral Receivable			5,184

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 the Parkway West Deferral Account is a credit to ratepayers of $1.412 million plus interest of $0.003 million for a total of $1.415 million. The credit of $1.412 million represents the difference between $16.457 million of costs included in 2016 rates (EB-2015-

0116) and the calculation of the actual revenue requirement for 2016 of $15.045 million as shown in Table 11.

Table 11
2016 Parkway West Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2016 Board-Approved (a)	2016 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	800	15,142	14,342
2	Average Investment	213,094	215,846	2,752
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses	1,615	455	(1,160)
4	Depreciation Expense (1)	5,094	5,185	91
5	Property Taxes	510	530	20
6	Total Operating Expenses	7,218	6,169	(1,049)
7	Required Return (2)	12,306	12,217	(89)
8	Total Operating Expense and Return	19,524	18,386	(1,138)
	Income Taxes:			
9	Income Taxes - Equity Return (3)	2,466	2,502	36
10	Income Taxes - Utility Timing Differences (4)	(5,534)	(5,843)	(309)
11	Total Income Taxes	(3,068)	(3,341)	(273)
12	Total Revenue Requirement	16,457	15,045	(1,412)

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 2016 required return calculation is as follows:
$215.846 million * 64% * 3.82% = $5.277 million plus
$215.846 million * 36% * 8.93% = $6.939 million for a total of $12.217 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 2016 in-service assets were higher by $14.342 million compared to the 2016 Board-approved as shown in Table 12.

Table 12
Parkway West Capital Expenditures

Line No.	Particulars ($000's)	2016 Board-Approved (a)	2016 Actuals (b)	Difference (c) = (b - a)
1	Station Infrastructure	286	5,076	4,790
2	Pipeline Replacement	-	8	8
3	Dawn-Parkway Valve Nest	-	630	630
4	Station Header	-	3,245	3,245
5	Enbridge Measurement	-	505	505
6	Interconnect/TransCanada Measurement	-	230	230
7	LCU Compressor	514	5,448	4,934
8	Total Capital Expenditures	800	15,142	14,342

Station infrastructure costs were $4.790 million higher than 2016 Board-approved rates. Increased labour and material costs were due to additional cleanup work, commissioning, third party engineering, environmental, permitting and timing of finalizing the contractor costs.

Dawn Parkway valve nest costs were $0.630 million higher than 2016 Board-approved rates mainly due to additional cleanup work, commissioning and timing of finalizing the contractor costs.

Station header costs were $3.245 million higher than 2016 Board-approved rates. Increased material and labour costs were mainly due to the blowdown recovery compressor and related equipment purchased in 2016 originally scheduled for 2015, additional cleanup work, commissioning and timing of finalizing the contractor costs.

Enbridge measurement station costs were $0.505 million higher than 2016 Board-approved rates. Increased labour and miscellaneous material costs were due to additional cleanup work, commissioning deferred from 2015 to 2016 to align with the Enbridge and TransCanada project completion and timing of finalizing the contractor costs.

Interconnect/TransCanada measurement costs were $0.230 million higher than 2016 Board-approved rates mainly due to additional cleanup work and timing of finalizing the contractor costs.

Loss of Critical Unit ("LCU") compressor costs were $4.934 million higher than 2016 Board-approved rates. Increased labour and material costs were due to the additional cleanup work, commissioning, and timing of finalizing the contractor costs.

Average Investment

The average investment has increased by $2.752 million over the costs included in the 2016 Board-approved rates due to capital expenditures being $14.342 million higher than the amount included in 2016 Board-approved rates.

Operating Expenses

Operating and maintenance expenses were $1.160 million lower than the costs included in the 2016 Board-approved rates. The decrease is a result of the Parkway C compressor experiencing lower than anticipated operational hours, including being out of service for approximately two months to remediate commissioning legacy issues, which lead to lower maintenance and utility costs.

The increase in depreciation expense of $0.091 million relates to the higher capital expenditures than included in 2016 Board-approved rates.

Required Return

The decrease in the required return of $0.089 million is the result of a decrease in the long term debt rate used in the calculation partially offset by an increase in the average investment. 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 2016 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 the 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 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 2015 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.036 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 $0.309 million "Income Taxes-Timing Differences" decrease relates to a higher Capital Cost Allowance due to higher actual capital expenditures than included in 2016 Board-approved rates.

Project-To-Date Capital Costs

In addition to reviewing the capital spending and variance explanations for calendar year 2016 related to the deferral balance calculations for this project, Union has included below Table 13 for additional reference only. The table summarizes capital spending for this project-to-date as at December 31, 2016 which exceeds the forecast by $8.571 million. Variance explanations are also provided. Project-to-date information is also provided in the Brantford-Kirkwall/Parkway D Project Deferral Account (No. 179-137) written evidence below, along with the combined total for the two 2015 Dawn Parkway projects. Providing the combined capital spend is reflective of the management of the projects, given the two compressors were constructed together on the same new compressor station site. Overall the capital spending for the combined projects at the end of 2016 is $1.523 million or less than 0.4 % over the original estimates.

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

Line No.	Year	Board Approved	Actual (as filed)	Variance
1	2014	73,978	80,929	6,951
2	2015	144,652	131,930	(12,722)
3	2016	800	15,142	14,342
4	Total	$219,430	$228,001	$8,571
	Brantford-Kirkwall/Parkway D (179-137)			
5	Total	$204,076	$197,028	($7,048)
	Combined 2015 Dawn Parkway Projects			
6	Total	$423,506	$425,029	$1,523

The Project-to-Date costs for the Parkway West project are higher than the Board-approved amount mainly due to contract and miscellaneous labour necessary to prepare the vacant land for the constructed facilities, as well as the permitting required at the site, and additional clean up and commissioning work. This was a greenfield site for building a major new compressor station and the extent of the work required at this location was much greater than anticipated at the time of Union's filing in 2012. Drawings were not finalized at this early date and therefore only a preliminary estimate was available from the Contractor. Once this was better defined, additional costs were identified, including contract labour which was utilized for the land development and involved soil movement for storm water management ponds, visual and noise abatement berms, top soil stripping, excavations and backfill. Additional studies, fees, permitting and site plan approvals added to these costs. Additional site preparation and development work also impacted the construction schedule resulting in additional clean-up work to be deferred into 2016. Re-mobilization of the contractor for 2016 clean-up work contributed to increased clean-up costs. These increased costs were 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 0.4 % 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 the Brantford-Kirkwall/Parkway D Deferral Account is a credit to ratepayers of $1.593 million plus interest of $0.005 million for a total of $1.598 million. The balance of $1.593 million includes a $1.545 million credit which represents the difference between the $14.720 million in costs included in 2016 rates (EB-2015-0116) and the calculation of the actual revenue requirement for 2016 of $13.175 million, as shown in Table 14. The remaining $0.048 million credit represents a true-up between the revenue requirement of a $0.502 million debit included in the 2015 deferral disposition (EB-2016-0118) and the actual 2015 revenue requirement of $0.454 million to reflect a property tax reassessment that occurred in 2016.

Table 14
2016 Brantford-Kirkwall Pipeline/Parkway D Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2016 Board-Approved (a)	2016 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	4,007	8,986	4,979
2	Average Investment	197,123	185,273	(11,850)
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses (1)	642	209	(433)
4	Depreciation Expense (2)	5,287	4,857	(430)
5	Property Taxes (3)	853	937	84
6	Total Operating Expenses	6,782	6,003	(779)
7	Required Return (4)	11,383	10,486	(897)
8	Total Operating Expense and Return	18,165	16,489	(1,676)
	Income Taxes:			
9	Income Taxes - Equity Return (5)	2,281	2,148	(133)
10	Income Taxes - Utility Timing Differences (6)	(5,726)	(5,462)	264
11	Total Income Taxes	(3,445)	(3,314)	131
12	Total Revenue Requirement (7)	14,720	13,175	(1,545)

Notes:

(1) 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) 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 2016 required return calculation is as follows:
$185.3million * 64% * 3.82% = $4.530 million plus
$185.3million * 36% * 8.93% = $5.956 million for a total of $10.486 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 capital expenditures on 2016 in-service assets increased by $4.979 million compared to the 2016 Board-approved as shown in Table 15.

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

Line No.	Particulars ($000's)	2016 Board-Approved	2016 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Brantford-Kirkwall Pipeline			
1	Land Rights	301	1	(300)
2	Pipelines	3,200	2,765	(435)
	Parkway D Compressor			-
3	Structures	-	128	128
4	Compressor Equipment	506	6,092	5,586
5	Total Capital Expenditures	4,007	8,986	4,979

Land rights costs were $0.300 million lower than the costs included in 2016 Board-approved rates due to Board-approved rates including a minor land purchase that did not materialize.

Pipelines costs were $0.435 million lower than the costs included in 2016 Board-approved rates. Main contractor clean-up costs were lower than anticipated but were offset by higher costs in categories such as environmental and material spend. Some negotiated land damages delayed in 2015 were realized in 2016. A minor amount of contingencies estimated for unforeseen costs was not required.

Structures costs were $0.128 million higher than 2016 Board-approved rates due to additional cleanup required in 2016.

Compressor equipment costs were $5.586 million higher than the costs included in 2016 Board-approved rates. Increased labour and material costs were due to the additional cleanup work, commissioning, and timing of finalizing the contractor costs.

Average Investment

The average investment has decreased by $11.850 million from the costs included in the 2016 Board-approved rates due to in-service timing and capital expenditure differences.

As noted in Union's 2015 Deferral Disposition proceeding (EB-2016-0118), capital expenditures for the Brantford-Kirkwall/Parkway D Project were $12.027 million lower in 2015 than the Board-approved capital expenditures. This has the effect of lowering the opening balance in 2016 for purposes of calculating the average investment.

This is partially offset by higher capital spend in 2016 compared to Board-approved capital expenditures.

Operating Expenses

Operating and maintenance expenses were $0.433 million lower than the costs included in 2016 Board-approved rates. The decrease is a result of the Parkway D compressor experiencing lower than anticipated operational hours, including being out of service for approximately two months to remediate commissioning legacy issues, which lead to lower maintenance costs.

The decrease in depreciation expense of $0.430 million relates to the average investment being $11.850 million lower than Board-approved.

The $0.084 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 $0.897 million is the result of a decrease in the average rate base investment from the Board-approved $197.123 million to $185.273 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 2016 actual required return calculation was derived using a capital structure of 64% long-term debt at 3.82%, and 36% equity at the Board-approved rate of return of 8.93%.

Income Taxes

Union's actual tax rate for 2015 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.133 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 $0.264 million "Income Taxes-Timing Differences" increase relates to a lower Capital Cost Allowance deduction due to a decrease in average investment.

Project-To-Date Capital Costs

In addition to reviewing the capital spending and variance explanations for calendar year 2016 related to the deferral balance calculations for this project, Union has included below Table 16 for additional reference only. The table summarizes capital spending for this project-to-date as at December 31, 2016 which is lower than the forecast by $7.048 million. Variance explanations are also provided. Similar information is provided in the Parkway West Project Deferral Account (No. 179-136) written evidence above, along with the combined total for the two 2015 Dawn Parkway projects. Providing the combined capital spend is reflective of the management of the projects, given the two compressors were constructed together on the same new compressor station site. Overall capital spending for the combined projects at the end of 2016 is $1.523 million or less than 0.4% over the original estimates.

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

Line No.	Year	Board Approved	Actual (as filed)	Variance
1	2015	200,069	188,042	(12,027)
2	2016	4,007	8,986	4,979
3	Total	$204,076	$197,028	($7,048)
	Parkway West Project (179-136)			
4	Total	$219,430	$228,001	$8,571
	Combined 2015 Dawn Parkway Projects			
5	Total	$423,506	$425,029	$1,523

The capital spending for this project-to-date as at December 31, 2016 is lower than the forecast by $7.048 million. The actual cost for the Parkway D compressor portion of this Project was lower than the Board-approved level as the contingencies included in the original estimate for unforeseen expenditures were not required. This more than offset higher actual costs of the Brantford-Kirkwall pipeline portion of the project. The actual cost for the prime contractor for the Brantford-Kirkwall pipeline was significantly higher than the original estimate. At the time of submission of the evidence to the Board in early 2013, Union had not yet completed its competitive bidding exercise to reflect current market contractor cost. It was found during the competitive bidding process that the pipeline contractor market cost had increased more than expected. In addition, the actual cost for easements was higher than the original estimate which was based upon historical land values from similar projects.

These increased costs were partially offset by material and equipment costs that were lower than original estimates. Estimates were based upon historical average unit costs, however steel costs were lower at the time of purchase than when estimates were completed. In addition to contingencies, other offsets were Interest During Construction which was significantly lower than estimated as the cost to borrow was lower than estimated (interest rates were lower) and actual expenditures were realized later than the cash flow used in the estimate.

Account No. 179-138 Parkway Obligation Rate Variance

The balance in the Parkway Obligation Rate Variance Deferral Account is a debit from ratepayers of $2.822 million. In the 2014 Rates (EB-2013-0365) Settlement Agreement, Union and intervenors agreed to permanently shift the Union South DP Parkway Delivery Obligation (“PDO”) to Dawn over time and agreed to the payment of a Parkway Delivery Commitment Incentive (“PDCI”) for any continuing obligated Daily Contract Quantity (“DCQ”) deliveries at Parkway beginning November 1, 2016. As part of the 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, 2017 to reflect the PDCI costs for obligated Parkway deliveries of 292 TJ/d for DP customers and 19 TJ/d for sales service customers. To account for the actual effective date of November 1, 2016, Union is proposing to recover $2.822 million from ratepayers for the November 1, 2016 to December 31, 2016 period in the Parkway Obligation Rate Variance Deferral Account. The $2.822 million includes $2.000 million of Dawn Parkway demand costs, $0.821 million of Dawn Parkway commodity (compressor fuel) costs and $0.001 million of interest.

To calculate the Dawn Parkway demand costs of $2.000 million, Union applied two months of the Board-approved 2016 daily M12 Dawn to Parkway transportation rate of $0.095/GJ/d to 350 TJ/d for the period November 1, 2016 to December 21, 2016 and 320 TJ/d for the period December 22, 2016 to December 31, 2016. The 350 TJ/d is comprised of 292 TJ/d for DP customers and 58 TJ/d for sales service customers. The 320 TJ/d is comprised of 292 TJ/d for DP customers and 28 TJ/d for sales service customers.

On December 22, 2016, TransCanada's Maple facilities were placed in-service reducing Parkway deliveries for the sales service supply portfolio from 58 TJ/d to 28 TJ/d. Effective January 1, 2017, Union's sales service portfolio was further reduced from the 28 TJ/d following the in-service of TransCanada's Maple facilities to 19 TJ/d which was included in Union's 2017 Rates proceeding (EB-2015-0245).

To calculate the Dawn Parkway commodity (compressor fuel) costs of $0.821 million, Union applied the October 2015 QRAM average M12 compressor fuel rate to 350 TJ/d for the period November 1, 2016 to December 21, 2016 and 320 TJ/d for the period December 22, 2016 to December 31, 2016.

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 EB-2013-0365 Settlement Agreement.

Account No. 179-139 Energy East Pipeline Consultation Costs

There is no balance in this deferral account. The Energy East Pipeline Consultation Costs Deferral Account was created in accordance with the Board's Decision in Union's 2015 Rates proceeding (EB-2014-0271) to record Union's consultation costs related to the Energy East Pipeline allocated by the Board.

Account No. 179-141 Unaccounted for Gas ("UFG") Price Variance Account

Consistent with the Board's Decision in EB-2015-0010, the UFG Price Variance Account will capture 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.   For 2016, the balance in the UFG Price Variance Account is a credit to ratepayers of $1.196 million plus interest of $0.003 million for a total of $1.199 million.

During 2016, Union purchased 31,169 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"), as shown in Table 17.

The actual monthly cost of the Union South gas portfolio in 2016 was $140.54/$10^3m^3$. Relative to Board-approved reference prices included in rates, the price variance is $38.38/$10^3m^3$ (see Tab 1, Appendix A, Schedule 9). The result is a payable balance of $1.196 million to be credited to ratepayers, as shown in see Table 17.

Table 17
Calculation of 2016 UFG Price Deferral

Line. No.		UFG Volumes (10^3m^3)
1	Planned UFG (1)	131,588
2	UFG Collected through T1, T2, T3 and ex-franchise CSF	100,419
3	UFG Volumes – Ratepayer (2)	31,169
		Deferral Calculation
4	UFG Volumes (10^3m^3) – Ratepayer (2)	31,169
5	Price Variance (3)	$38.38
		$1.196 (million)

(1) Converted using the following heat values (38.55 Jan-Mar) (38.81 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 as per Tab 1, Appendix A, Schedule 9

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

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

The balance in the Lobo C Compressor/Hamilton-Milton Pipeline Deferral Account is a debit from ratepayers of $1.698 million plus interest of $0.001 million for a total of $1.699 million. The $1.698 million includes a debit of $1.713 million, which represents the difference between the $0.683 million in costs included in 2016 rates (EB-2015-0116) and the calculation of the actual revenue requirement of $2.396 million as shown in Table 18. The remaining $0.015 million credit represents a true-up between the revenue requirement of a $0.334 million credit included in the 2015 deferral disposition (EB-2016-0118) and the recalculated 2015 revenue requirement of a credit of $0.349 million to adjust the long-term debt rate from the estimate of 4.40% to the actual of 3.36%. This rate will be used to calculate the debt portion of the utility required return through to and including 2018.

Table 18
2016 Lobo C Compressor/Hamilton-Milton Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2016 Board-Approved (a)	2016 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	378,233	314,154	(64,079)
2	Average Investment	44,292	64,092	19,800
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses	187	100	(87)
4	Depreciation Expense (1)	4,528	4,066	(462)
5	Property Taxes	191	175	(16)
6	Total Operating Expenses	4,906	4,341	(565)
7	Required Return (2)	2,671	3,442	771
8	Total Operating Expense and Return	7,577	7,783	206
	Income Taxes:			
9	Income Taxes - Equity Return (3)	487	744	257
10	Income Taxes - Utility Timing Differences (4)	(7,381)	(6,131)	1,250
11	Total Income Taxes	(6,894)	(5,387)	1,507
12	Total Revenue Requirement	683	2,396	1,713

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The 2016 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 2016 required return calculation is
$64.092 million * 64% * 3.36% = $1.378 million plus
$64.092 million * 36% * 8.93% = $2.064 million for a total of $3.442 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 2016 in-service assets decreased by $64.079 million compared to the 2016 Board-approved as shown in Table 19.

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

Line No.	Particulars ($000's)	2016 Board-Approved	2016 Actuals	Difference
		(a)	(b)	(c) = (b - a)
	Lobo C Compressor			
1	Land	-	3,273	3,273
2	Structures	21,819	19,997	(1,822)
3	Pipelines	8,195	4,080	(4,115)
4	Compressor Equipment	125,236	111,706	(13,530)
	Hamilton-Milton Pipeline			
5	Land	5,253	6,539	1,286
6	Land Rights	4,132	1,232	(2,900)
7	Pipelines	213,598	167,327	(46,271)
8	Total Capital Expenditures	378,233	314,154	(64,079)

Land costs for Lobo C were $3.273 million higher than the costs included in 2016 Board-approved rates due to the purchase of the land in 2016 that was originally planned for 2017.

Structures costs for Lobo C were $1.822 million lower than the costs included in 2016 Board-approved rates. Higher material costs were offset by lower labour costs and contingencies not being required.

Pipelines costs for Lobo C were $4.115 million lower than the costs included in 2016 Board-approved rates. Higher contractor costs were offset by lower material and labour costs, and contingencies not being required due to the Pipelines being put into service in 2015.

Lobo C compressor equipment costs were $13.530 million lower than the costs included in 2016 Board-approved rates. Higher contractor and material costs were offset by lower company labour costs and contingencies not being required. Some of the work has been re-scheduled from 2016 into 2017.

Hamilton-Milton Pipeline land costs were $1.286 million higher than the costs included in 2016 Board-approved rates due to the additional purchase of two properties. Higher Land costs were offset by lower Land Rights costs.

Land rights costs for Hamilton-Milton Pipeline were $2.900 million lower than the costs included in 2016 Board-approved rates due to some property being purchased rather than treated as easements. In addition, the estimate included in 2016 Board-approved rates allowed for overlapping easement which was later deemed as not required. A portion of easement spend has been re-scheduled from 2016 into 2017.

Pipelines costs for Hamilton-Milton Pipeline were $46.271 million lower than the costs included in 2016 Board-approved rates. A large portion of this was attributed to forecast risk items included in 2016 Board-approved rates being successfully mitigated. Key examples of identified risks that were mitigated include: potential Niagara Escarpment Commission delay (related to Limestone Creek), possible horizontal directional drilling of Kilbride Swamp, and additional watercourse crossings. Costs associated with temporary land costs and damages were incomplete at the time of the 2016 Board-approved rates and actual property values negotiated were somewhat lower than projected. As well, very few landowners utilized outside legal counsel and use of fewer consultants for property appraisals, tree evaluation, and other landowner related rights resulted in cost reductions. Increases associated with foreign exchange on materials, contractor costs, and environmental were offset by contingencies. Interest during construction was lower due to risk and lands reductions and timing of spend.

Average Investment

The average investment increase of $19.800 million over Board-approved is due to in-service timing of capital expenditures.

As noted in Union's 2015 Deferral Disposition proceeding (EB-2016-0118), capital expenditures for the Lobo C Compressor/Hamilton-Milton Pipeline Project were $14.058 million higher in 2015 than the Board-approved capital expenditures. This has the effect of raising the opening balance in 2016 for purposes of calculating the average investment.

Additionally, 2016 Board-approved rates are based on an in-service date of November 2016 whereas 2016 actual costs reflect work done throughout the year which raises the average investment. The main contributor is additional piping that went into service in early 2016.

Operating Expenses

Operating and maintenance expenses were $0.087 million lower than the costs included in 2016 Board-approved rates. The decrease is due to the inclusion of fleet costs and materials costs in 2016 rates that were not incurred in 2016 for the project.

The $0.462 million depreciation expense decrease relates to lower capital expenditures incurred in 2016 compared to Board-approved.

Required Return

The increase in the required return of $0.771 million is the result of the increase in the average rate base investment from the Board-approved $44.292 million to $64.092 million, 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 4.4% and 36% equity at the Board-approved rate of return of 8.93%. The 2016 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 2015 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.257 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 $1.250 million "Income Taxes-Timing Differences" increase relates to a lower Capital Cost Allowance deduction due to a decrease in capital expenditures.

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

In its 2016 Rates (EB-2015-0116) Decision and Order, the Board ordered Union to establish the Unauthorized Overrun Non-Compliance Account (No. 179-143) 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 for 2016 is a credit to ratepayers of $0.106 million plus interest of $0.001 million for a total of $0.107 million.

The charge was intentionally set to be a punitive charge to incent customers to comply as contracted during an interruption of distribution services. This balance will be refunded to ratepayers.

Account No. 179-144 Dawn H/Lobo D/Bright C Compressor Project Costs

In its 2017 Dawn Parkway Project (EB-2015-0116) Decision, the Board-approved the establishment of the Dawn H/Lobo D/Bright C Compressor Project Costs Deferral Account to track the differences between the actual revenue requirement related to costs for the Dawn H/Lobo D/Bright C Compressor Project and the revenue requirement included in rates.

The deferral account has a debit balance of $0.525 million, less an interest credit of $0.002 million for a total balance of $0.523 million. The $0.525 million represents the difference between the $1.716 million credit included in 2016 rates (EB-2015-0116) and the calculation of the actual revenue requirement for 2016 of a $1.191 million credit as shown in Table 20.

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 surplus capacity 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. As there was no surplus capacity in 2016, no actual revenue was earned and so no variances are included in Table 20.

Table 20
2016 Dawn H/Lobo D/Bright C Compressor Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2016 Board-Approved (a)	2016 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	107,400	91,342	(16,058)
2	Average Investment	11,432	18,368	6,936
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses	-	2	2
4	Depreciation Expense (1)	1,677	1,225	(452)
5	Property Taxes	-	-	-
6	Total Operating Expenses	1,677	1,227	(450)
7	Required Return (2)	660	1,060	400
8	Total Operating Expense and Return	2,337	2,287	(50)
	Income Taxes:			
9	Income Taxes - Equity Return (3)	126	213	87
10	Income Taxes - Utility Timing Differences (4)	(4,178)	(3,690)	488
11	Total Income Taxes	(4,053)	(3,478)	575
12	Total Revenue Requirement	(1,716)	(1,191)	525

Notes:
(1) Depreciation expense at 2013 Board-approved depreciation rates.
(2) The required return of 5.77% assumes a capital structure of 64% long-term debt at 4.0% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 * 0.04 + 0.36 * 0.0893)
The 2016 required return calculation is as follows:
$18.368 million * 64% * 4.0% = $0.470 million plus
$18.368 million * 36% * 8.93% = $0.590 million for a total of $1.060 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 2016 in-service assets decreased by $16.058 million compared to the 2016 Board-approved as shown in Table 21.

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

Line No.	Particulars ($000's)	2016 Board-Approved (a)	2016 Actuals (b)	Difference (c) = (b - a)
	Dawn H			
1	Compressor Equipment	33,776	27,745	(6,031)
2	Metering	13,607	11,744	(1,863)
	Bright C			
3	Structures	2,523	377	(2,146)
4	Pipelines	18,742	17,370	(1,372)
5	Compressor Equipment	38,752	34,106	(4,646)
6	Total Capital Expenditures	107,400	91,342	(16,058)

Dawn H compressor equipment costs were $6.031 million lower than the costs included in 2016 Board-approved rates. The difference was primarily due to some Dawn north yard tie-in work being re-scheduled from 2016 into 2017 due to logistics of installation timing.

Dawn H metering costs were $1.863 million lower than the costs included in 2016 Board-approved rates. There was a slight increase in design costs offset by a decrease in materials. Timing of spend had some impact in decreased 2016 actual costs. Contingencies for unforeseen costs included in 2016 Board-approved rates were not required.

Structures costs for Bright C were $2.146 million lower than the costs included in 2016 Board-approved rates. Costs for the modification of the Bright A and B Structure included in the 2016 Board-approved rates were not required as limitations of the original building design caused the modification work to be re-scheduled for 2017.

Pipelines costs for Bright C were $1.372 million lower than 2016 Board-approved rates due to the contingencies for unforeseen expenses not being required.

Compressor equipment costs for Bright C were $4.646 million lower than the costs included in 2016 Board-approved rates. Higher labour costs were offset by lower material costs and contingencies for unforeseen expenses were not required.

Average Investment

The average investment has increased by $6.936 million over the costs included in 2016 Board-approved rates due to in-service timing, even though capital expenditures for 2016 were below the Board-approved amount. 2016 Board-approved rates were based on an estimate of a November 2016 in-service date, compared to an actual in-service date of October, 2016 for related assets including approximately 50% of Dawn North yard tie-in work, all of Cuthbert Road measurement costs, all Bright A and B yard modifications, and all Trafalgar pipeline work.

Operating Expenses

The $0.452 million depreciation expense decrease relates to the decrease in in-service capital expenditures of $16.059 million in 2016.

There were no property taxes associated with the project in 2016.

Required Return

The $0.400 million required return increase relates to the average rate base investment in 2016 being $6.936 million greater than expected. The 2016 actual required return calculation was derived using a capital structure of 64% long term debt at 4.0% and 36% common equity at the Board-approved return of 8.93%. The required return calculation is consistent with that filed and approved in the 2017 Dawn Parkway Expansion Project (EB-2015-0200, Exhibit A, Tab 10, Schedule 1).

Income Taxes

Union's actual tax rate for 2016 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.087 million "Income Taxes – Equity Return" increase relates to the higher required return in 2016 versus Board-approved.

The $0.488 million "Income Taxes – Utility Timing Difference" decrease relates primarily to a lower actual Capital Cost Allowance versus the 2016 Board-approved amount due to the lower capital expenditures in 2016 versus Board-approved.

Account No. 179-149 Burlington Oakville Project Costs

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

The deferral account balance is a debit from ratepayers of $0.258 million, less an interest credit of $0.001 million for a total balance of $0.257 million. The $0.258 million represents the difference between the $0.077 million in costs included in 2016 rates (EB-2015-0116) and the calculation of the actual revenue requirement for 2016 of $0.355 million as shown in Table 22.

Table 22
Burlington Oakville Pipeline Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2016 Board-Approved (a)	2016 Actuals (b)	Difference (c) = (b - a)
	Rate Base Investment			
1	Capital Expenditures	117,710	79,120	(38,590)
2	Average Investment	13,584	15,902	2,318
	Revenue Requirement Calculation:			
	Operating Expenses:			
3	Operating and Maintenance Expenses	3	-	(3)
4	Depreciation Expense (1)	1,186	821	(365)
5	Property Taxes	20	14	(6)
6	Total Operating Expenses	1,208	835	(374)
7	Required Return (2)	819	854	35
8	Total Operating Expense and Return	2,027	1,689	(339)
	Income Taxes:			
9	Income Taxes - Equity Return (3)	149	185	36
10	Income Taxes - Utility Timing Differences (4)	(2,100)	(1,539)	561
11	Total Income Taxes	(1,951)	(1,354)	597
12	Total Revenue Requirement	77	335	258

Notes:

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

(2) The required return assumes a capital structure of 64% long-term debt at 3.36% and 36% common equity at the 2013 Board-approved return of 8.93% (0.64 * 0.0336 + 0.36 * 0.0893)
The 2016 required return calculation is as follows:
$15.902 million * 64% * 3.36% = $0.342 million plus
$15.902 million * 36% * 8.93% = $0.511 million for a total of $0.854 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 2016 in-service assets decreased by $38.590 million compared to the 2016 Board-approved as shown in Table 23.

Table 23
Burlington Oakville Pipeline Project Capital Expenditures

Line No.	Particulars ($000's)	2016 Board-Approved	2016 Actuals	Difference
		(a)	(b)	(c) = (b - a)
1	Land Rights	17,962	12,958	(5,004)
2	Structures	520	206	(314)
3	Pipelines	80,213	49,066	(31,147)
4	Station Equipment	19,015	16,890	(2,125)
5	Total Capital Expenditures	117,710	79,120	(38,590)

Land rights costs were $5.004 million lower than the costs included in 2016 Board-approved rates. 2016 Board-approved rates reflected that Infrastructure Ontario and Hydro-One land rights can be charged at up to 150% of the appraised value for land rights, while actual costs were less.

Structures costs were $0.314 million lower than the costs included in 2016 Board-approved rates because the existing Regulator Building at Bronte could be utilized, rather than requiring a new building. Instead, two smaller buildings (for telemetry and odorant) were erected at the Parkway site.

The NPS 20 pipeline costs were $31.147 million lower than the costs included in 2016 Board-approved rates. Temporary Land Use spend (along the pipeline for purposes of construction) was lower than estimated as noted above based on the appraised value. Interest during Construction was lower due to the above reductions in spend, as well as later timing of Lands spend. Wet weather shut down and change order allowance was not entirely utilized during construction. Risk allocations (horizontal directional drilling, station scope, etc.) were sufficient such that Contingency did not need to be utilized in 2016. Company labour spend was slightly less than expected.

Station equipment costs were $ 2.125 million lower than the costs included in 2016 Board-approved rates. Risk allocations were sufficient such that Contingency did not need to be utilized in 2016. Interest during Construction was lower due to overall reductions in spend.

Average Investment

The average investment has increased by $2.318 million over the costs included in 2016 Board-approved rates due to in-service timing, even though capital expenditures for 2016 were below the Board-approved amount. 2016 Board-approved rates included an estimate of a November 2016 in-service date, compared to an actual in-service date of October, 2016.

Operating Expenses

The $0.365 million depreciation expense decrease relates to the decrease in in-service capital expenditures of $38.590 million in 2016.

Required Return

The $0.035 million required return increase relates to the average rate base investment in 2016 being $2.318 million greater than expected, 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 4.4%, and 36% equity at the Board-approved rate of return of 8.93%. The 2016 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 or return of 8.93%.

When Union prepared the Burlington Oakville Pipeline Project application (EB-2014-0182) the long-term debt rate used was 4.4%. In 2016, the year the project was brought into service, Union issued long-term debt at an average rate of 3.36%. 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 2016 was 26.5% and was used in the calculation of income taxes for purposes of this deferral account.

The $0.036 million "Income Taxes – Equity Return" increase relates to the higher required return in 2016 versus Board-approved.

The $0.561 million "Income Taxes – Utility Timing Difference" decrease relates primarily to a lower actual Capital Cost Allowance versus the 2016 Board-approved amount due to the lower capital expenditures in 2016 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 $0.829 million plus interest of $0.003 million for a total of $0.832 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. Please see Tab 1, Appendix B, Schedule 1 for a copy of the February 9, 2016 letter.

Entries to the account are made on a quarterly basis, when the OEB's cost assessment invoice is received. In Union's Board-approved rates, there is $2.5 million in OEB cost assessment costs (which equals $0.625 million per quarter). In 2016, the actual amount of cost assessment invoices beginning at April 1, 2016 was $2.704 million. The breakdown showing how the

$0.829 variance is calculated is shown in Table 24 below.

Table 24
OEB Cost Assessment Variance (April 1 to December 31)

Date	Actual OEB Cost Assessment	2013 Board-approved OEB Cost Assessment in Rates[1]	Incremental OEB Cost Assessment, beg. April 1 2016
	($ millions)	($ millions)	($ millions)
	a	b	c = (a – b)
01-Apr-16	0.901	0.625	0.276
01-Jul-16	0.901	0.625	0.276
01-Oct-16	0.901	0.625	0.276
Total	2.704	1.875	0.829

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

Account No. 179-152 Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA")

The establishment of the Greenhouse Gas Emissions Impact Deferral Account (GGEIDA) was approved in EB-2015-0367. The purpose of the account is to record the cost impacts of government regulations related to greenhouse gas emissions requirements. The costs recorded in this account are outside the base upon which Union's rates were derived, as the costs will be incurred as a result of Union's compliance obligations under Ontario's Cap-and-Trade program. The balance in this deferral account is a debit from ratepayers of $2.225 million for 2016, plus interest of $0.007 million, for a total debit of $2.232 million.

As noted in EB-2015-0367, Union would "seek recovery of any costs recorded in the GGEIDA in a future deferral account disposition proceeding". The following evidence is consistent with Union's 2017 Compliance Plan (EB-2016-0296) and interrogatory responses.

On May 18, 2016, the Climate Change Mitigation and Low-carbon Economy Act, 2016 (Climate Change Act) received Royal Assent. On May 19, 2016, Ontario Regulation 144/16, The Cap-and-Trade Program (Cap-and-Trade Regulation) was issued, which provides details about Ontario's Cap-and-Trade program. In accordance with the April 7, 2016 Board Order (EB-2015-0367), Union has recorded costs in Account No. 179-152 Greenhouse Gas Emissions Impact Deferral Account (GGEIDA).

Union's 2016 GGEIDA balance includes costs incurred related to the Ontario Government's Cap-and-Trade program and the Climate Change Act; the costs are all incremental and administrative in nature for 2016 with some being unique to the initial setup of the program. Union expects to continue to incur program implementation costs as well as ongoing maintenance and program costs which will be tracked in this deferral account for 2017 and beyond.

To understand the nature of the requirements of Cap-and-Trade in 2016 and the resulting costs, it is important to review the context in which the program was introduced and implemented. First, the Cap-and-Trade program is new to Ontario, to the natural gas utilities, and to customers. In addition, the Cap-and-Trade program was implemented in Ontario more quickly than any other jurisdiction, including California and Quebec. Ontario's intention to adopt a Cap-and-Trade system was announced in Spring 2015, with program design options being shared with stakeholders in late fall of that same year. The draft regulations and legislation, issued in February 2016, gave participants the first glimpse around program design and timing, set for January 1, 2017. Through March and April 2016, stakeholders (including Union), filed submissions of comment regarding the draft regulations and legislation. In May 2016 the final regulations were issued and the Climate Change Act was passed. Soon after, in June, the province released the Climate Change Action Plan which laid out how Ontario plans to invest the proceeds from Cap-and-Trade to further reduce GHG emissions.

With the regulations in place, the focus then shifted to the Board process for the utilities. By the end of July 2016, the Board determined how customer charges would be reflected on customers' bills, and Union promptly began to implement billing system changes necessary for January 1, 2017. For the remainder of the summer, the Board worked to develop the Regulatory Framework for natural gas utilities, which was delivered at the end of September 2016. This required the utilities to file a comprehensive Compliance Plan by mid-November. This plan included elements such as Union's forecasted compliance obligation, strategy for achieving compliance, forecasted costs and rate impacts, and customer communication plans. By early December, Union had received an interim rate order which then reflected the Cap-and-Trade charges on customers' bills for January 1, 2017.

As the second largest participant in the Cap-and-Trade program, and the natural gas utility for more than 1.4 million customers in over 400 communities across the province, it was critical that Union dedicate sufficient resources in order to implement the program effectively, efficiently and on time. The consequence of not meeting the compliance obligations of the Cap-and-Trade program is very high, including penalties for non-compliance. In addition, a successful and seamless implementation of the billing system changes is expected by Union's customers. The accuracy of bills including these changes and proper communication is very important as it relates to overall customer satisfaction.

As outlined in Union's December 17, 2015 letter to the Board, examples of the types of costs for inclusion in the GGEIDA include, but are not limited to: emissions reporting compliance costs, external consultant costs, and implementation costs, including additional salaries and employee expenses. As shown in Table 25, Union incurred $2.225 million in 2016 related to Ontario's Cap-and-Trade program and the Climate Change Act.

Table 25:
Total GGEIDA Costs for the year ending December 31, 2016

Line No.	Particulars	2016 Cost ($000)
1	Salaries and Wages	1,682
2	Consulting and Market Research	484
3	Other	63
4	Revenue Requirement on Capital Costs	(4)
5	Total	**2,225**

Salaries and Consulting make up the majority of the costs included in the GGEIDA for 2016 and both are described in more detail in the following sections.

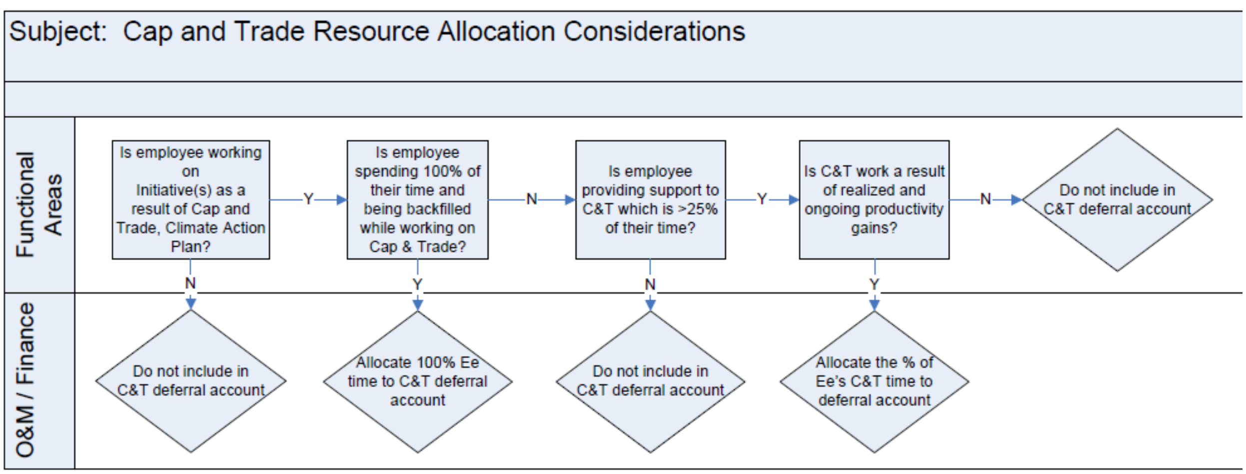
Salaries and Wages

Union has included the costs of 13.5 full time employees ('FTE') as of December 31, 2016 that were allocated to incremental work activities to support Cap-and-Trade and the Climate Change Act. These FTE are shown in Table 26. To properly support the incremental work from the implementation of the Cap-and-Trade program, Union has been required to increase administrative costs. These costs are comprised of 13 new roles and portions of existing roles totaling 0.5 FTE. In the case of existing roles, Union has reallocated work, refined processes and restructured support teams to drive productivity gains allowing for these roles to take on incremental Cap-and-Trade work. As shown in Figure 2, a decision tree was created to ensure that incremental administrative costs related to Cap-and-Trade obligations are properly accounted for. These costs are reviewed quarterly to ensure appropriateness and correct capture of administrative costs.

Table 26
GGEIDA FTE Breakdown by Activity

Activity Description	Number of FTEs
Compliance Plan development and implementation of Cap-and-Trade	5.0
GHG Reporting and Forecasting	3.0
Accounting and financial system impacts	1.0
Compliance purchase plan and execution	1.0
Business development (including renewable natural gas)	1.5
Technology, innovation and offsets	2.0
Total	13.5

Figure 2:
Decision Tree for Incremental GGEIDA Costs



The FTE count ramped up through the calendar year of 2016 as the Cap-and-Trade related responsibilities increased at Union and the requirements evolved.

Cap-and-Trade Implementation

Since the introduction of Ontario's Cap-and-Trade program in early 2016, Union has incurred incremental employee costs related to understanding and interpreting the program, working towards program implementation and completing a carbon market strategy.

Union established a Cap-and-Trade team to focus on the overall implementation of Cap-and-Trade regulations and development of Compliance Plans. This team was the project management office, which executed or lead activities such as establishment of process changes, governance structures, reporting and monitoring, researching other jurisdictions, reviewing and responding to draft proposals from ministries and the Board, ongoing dialogue with government regarding program structure and implementation, program registration, and communications with customers, employees and stakeholders.

GHG Reporting and Forecasting

Additional resources were required to ensure compliance with GHG emission measurement, verification and reporting requirements. This included the development of a new greenhouse gas reporting framework in order to meet new regulatory requirements in support of the implementation of the Cap-and-Trade program in Ontario and reporting of emissions under ON.400 – Natural Gas Distributor and ON.350 – Natural Gas Operations as required under the MOECC Greenhouse Gas Reporting Guideline. These resources were also responsible for the development of GHG forecasts in support of the Union Gas Compliance Plan, GHG forecast updates, ongoing technical support for the implementation of a Cap-and-Trade Program at Union Gas and consultations with MOECC on new GHG reporting regulations.

Finance

A Finance role was allocated to Cap-and-Trade implementation that was responsible for financial analyses, the development of business design requirements including billing and reporting changes and the financial tracking of a compliance instrument acquisition process.

Compliance Purchasing

Another area of incremental responsibility was covered by an allocated FTE from Gas Supply who was responsible for the development of Union's Compliance Instrument Purchasing Strategy and Cap-and-Trade Compliance Instrument Procurement Procedures as well as Union's compliance instrument procurement capabilities in preparation for Cap-and-Trade program implementation in 2017. This role was also responsible for the understanding of market fundamentals, development of buying processes and bidding strategies.

Business Development

These roles are accountable for developing the market approach for renewable natural gas and natural gas solutions related to Climate Change Action Plan initiatives. These roles identify opportunities, complete analyses, interface with government ministries and key stakeholders, and develop sustainable processes. The focus of these roles in 2016 was on renewable natural gas.

Technology and Innovation

Union has also established a Technology and Innovation group that is focused on the investigation, evaluation and potentially the pursuit of new technologies and innovations that could result in GHG emissions reductions in the province. Their responsibilities also include regulations development, offsets protocol development, and evaluation of offset markets and opportunities for purposes of compliance planning. This initial work and ongoing efforts in these areas will support Union's offsets program throughout implementation.

To fulfil all of the above incremental activities in support of overall compliance with and implementation of Ontario's Cap-and-Trade program and Climate Change, Union has included the appropriate salaries and expenses associated with 13.5 FTE's for the relevant months of 2016.

Consulting and Market Research

As described above, the Cap-and-Trade program in Ontario was a new concept until late, 2015 and was not familiar to many in Ontario's natural gas or energy industry. Considering the magnitude and criticality of Union's compliance obligation, Union needed to adapt quickly in the dynamic and uncertain environment as the Cap-and-Trade program took shape. Union had to quickly develop internal expertise on the program and its impacts, and relied heavily on external consultants who had some familiarity with Cap-and-Trade programs in other jurisdictions (eg. California, Quebec, Europe) to assist. In addition, these consultants provided specialized knowledge and experience that Union did not have internally, and was critical to program implementation and compliance. Union's consulting costs for 2016 totaled $484,000, as outlined below in Table 27.

Table 27
Consulting and Market Research Costs for the year ending December 31, 2016

Line No.	Particulars	2016 Cost ($000)
1	Legal	135
2	Carbon Strategy and Analysis	152
3	Compliance Planning, Implementation and Customer Communication/Research	162
4	GHG Reporting and Forecasting	35
5	**Total**	**484**

Union spent approximately $135,000 for external legal support throughout 2016. Legal interpretation and review was critical to implementation and interpretation of Cap-and-Trade regulations and the Climate Change Act, operationalizing Union's Cap-and-Trade program and ensuring Union's GHG compliance obligation is consistent with applicable regulations.

Carbon Strategy and Analysis consulting services of approximately $152,000 included third party analysis of draft and final C&T regulations, the Climate Change Action Plan and analysis to support the Long-term Energy Plan. This cost also includes Union's subscription with a carbon market data provider, which supported Union's preparation for the development of

Ontario's carbon market.

Union engaged a consultant to assist with the development of its 2017 Compliance Plan, as well as to provide carbon market expertise to advise Union on its process and strategy development related to Cap-and-Trade. This expertise formed the basis of Union's 2017 Compliance Plan which was filed with the Board on November 15, 2016 (EB-2016-0296). Union also received training and documentation that has been included in this category of costs.

Union's Climate Change customer research consulting received in 2016 is comprised of two specific research studies. First, Union held focus group sessions in June, 2016 to assess general awareness of the government's Cap-and-Trade plan, reactions to the plan and to Cap-and-Trade costs, and preferences related to how Cap-and-Trade costs might appear on natural gas bills. The final report, titled "Natural Gas Consumer Reaction to Ontario Government Reported Cap-and-Trade Plan", was filed with the Board on July 6, 2016 (EB-2015-0363). Second, as part of Union's customer outreach efforts, Union engaged a consultant to conduct two customer research surveys among residential and general service business customers to evaluate the effectiveness of Union Gas' Cap-and-Trade customer communications. The surveys were conducted over the October 7, 2016 to October 17, 2016 period, and the December 7, 2016 to December 14, 2016 period. The results of these surveys were filed with the Board on March 17, 2017 (EB-2016-0296, Exhibit B.BOMA.32). In addition to identifying whether customers had seen and read Union's bill inserts and other communications, the study gauged overall awareness of the Cap-and-Trade program, as well as knowledge regarding the timing and impact of the program. Results were used to refine subsequent communications about Union's Cap-and-Trade program.

Union utilized the services of a consultant to design and produce content for the new Cap-and-Trade section on www.uniongas.com, to serve as a central source of up-to-date Cap-and-Trade related information for customers. Union also utilized consultant resources to help develop communication material including an overview of the program and its impacts on customers. Union incurred costs of approximately $162,000 for Compliance Planning and Customer Communications and Research consulting services in 2016.

Union incurred costs of approximately $35,000 in GHG Reporting and Forecasting consultant costs in 2016. Union received ongoing technical assistance from an environmental consultant in order to meet new regulatory GHG emissions reporting requirements associated with the implementation of Cap-and-Trade in Ontario, including O.Reg. 452. This includes the development of new reporting tools to facilitate the reporting and forecasting of GHG emissions for a natural gas distributor, critical review of calculation methodologies, and assistance with submissions in response to the Greenhouse Gas Reporting Guideline.

Other

Union has incurred miscellaneous costs that represent employee expenses for travel to meetings with the Board and consultants, IT expenses and office supplies. For these items, Union incurred costs of approximately $63,000 in 2016.

Revenue Requirement on Capital Costs

Union was required to make changes to its IT billing systems for both general service and contract customers. Union has incurred capital costs of $454,000 as at December 31, 2016. Consistent with similar capital costs, these costs will be depreciated over the appropriate number of years dependent on the category. These systems were available for use in mid-December 2016. Union has recorded a credit of $4,000 in the GGEIDA, as a result of the CCA exceeding the provision of book depreciation during 2016.

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.

UNION GAS LIMITED
Deferral Account Balances
Year Ending December 31, 2016

Line No.	Account Number	Account Name	Filed Balance [1] ($000's)
	Gas Supply Accounts:		
1	179-107	Spot Gas Variance Account	-
2	179-108	Unabsorbed Demand Costs (UDC) Variance Account	3,003
3	179-128	Gas Supply Review Consultant Costs	-
4	179-131	Upstream Transportation Optimization	11,646
5	179-132	Deferral Clearing Variance Account - Supply	293 [3]
6	179-132	Deferral Clearing Variance Account - Transport	23 [3]
7	Total Gas Supply Accounts (Lines 1 through 6)		14,965 [2]
	Storage Accounts:		
8	179-70	Short-Term Storage and Other Balancing Services	(2,226)
	Other:		
9	179-103	Unbundled Services Unauthorized Storage Overrun	-
10	179-112	Gas Distribution Access Rule (GDAR) Costs	443
11	179-117	Carbon Dioxide Offset Credits	-
12	179-120	IFRS Conversion Cost	-
13	179-123	Conservation Demand Management (CDM)	-
14	179-132	Deferral Clearing Variance Account	(79) [3]
15	179-133	Normalized Average Consumption	23,631
16	179-134	Tax Variance	(198)
17	179-135	Unaccounted for Gas (UFG) Volume Variance Account	5,189
18	179-136	Parkway West Project Costs	(1,415)
19	179-137	Brantford-Kirkwall/Parkway D Project Costs	(1,598)
20	179-138	Parkway Obligation Rate Variance	2,822
21	179-139	Energy East Pipeline Consultation Costs	-
22	179-141	Unaccounted for Gas (UFG) Price Variance Account	(1,199)
23	179-142	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	1,699
24	179-143	Unauthorized Overrun Non-Compliance Account	(107)
25	179-144	Lobo D/Bright C/Dawn H Compressor Project Costs	523
26	179-149	Burlington-Oakville Project Costs	257
27	179-151	OEB Cost Assessment Variance Account	832
28	179-152	Greenhouse Gas Emission Impact Deferral Account	2,232
29	179-153	Base Service North T-Service TransCanada Capacity	-
30	Total Other Accounts (Lines 9 through 29)		33,032
31	**Total Deferral Account Balances (Lines 7 + 8 + 30)**		**45,771**

Notes:

[1] Account balances include interest to December 31, 2016.

[2] With the exception of UDC (No. 179-108), Gas Supply Review Consultant Costs (No. 179-128), 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 $237 ($293 + $23 - $79)

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

Line No.	Particulars ($000's)	2013 Board Approved	2015 Actual Total	2016 Actual Total
		(a)	(b)	(c)
1	Base Exchange Revenue	9,118	7,739	3,358
2	FT RAM Exchange Revenue	5,800	-	-
3	Total Exchange Revenue	14,918	7,739	3,358
4	Exchange Revenue Subject to Deferral		7,739	3,358
5	Ratepayer portion - 90%	13,426	6,965	3,022
6	10% Union Incentive Payment		774	336
7	Less: Gas Supply Optimization Margin in Rates	13,426	15,565	14,668
8	2016 Deferral Account Balance receivable from Ratepayers		(8,600)	(11,646)

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 2015	Actual 2016
		(a)	(b)	(c)
	Revenue			
1	C1 Off-Peak Storage	500	603	2,749
2	Supplemental Balancing Services	2,000	1,001	1,367
3	Gas Loans	-	38	19
4	Enbridge LBA	-	282	968
5		2,500	1,925	5,102
6	C1 ST Firm Peak Storage	7,883	4,935	5,627
7	Total Revenue (1)	10,383	6,860	10,729
	Costs			
8	O&M (2)	3,810	1,684	2,156
9	UFG (3)	316	278	514
10	Compressor Fuel (4)	1,201	405	530
11	Total Costs	5,327	2,367	3,199
12	Net Revenue (line 7 - 11)	5,056	4,493	7,530
13	Less Shareholder Portion (10%)	505	449	753
14	Ratepayer Portion	4,551	4,043	6,777
15	Approved in Rates	4,551	4,551	4,551
16	Deferral balance payable to/(collectable from) ratepayers	-	(508)	2,226

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-16	88.3	84.6	96%	1-Nov-16	89.2	83.3	93%
2-Oct-16	88.3	84.7	96%	2-Nov-16	89.2	83.2	93%
3-Oct-16	88.3	84.8	96%	3-Nov-16	89.2	83.1	93%
4-Oct-16	88.3	84.8	96%	4-Nov-16	89.2	83.1	93%
5-Oct-16	88.3	84.9	96%	5-Nov-16	89.2	83.1	93%
6-Oct-16	88.3	84.9	96%	6-Nov-16	89.2	83.1	93%
7-Oct-16	88.3	84.9	96%	7-Nov-16	89.2	82.9	93%
8-Oct-16	88.3	85.1	96%	8-Nov-16	89.2	83.0	93%
9-Oct-16	88.3	85.1	96%	9-Nov-16	89.2	82.9	93%
10-Oct-16	88.3	85.1	96%	10-Nov-16	89.2	83.1	93%
11-Oct-16	88.3	85.1	96%	11-Nov-16	89.2	83.1	93%
12-Oct-16	88.3	85.1	96%	12-Nov-16	89.2	83.2	93%
13-Oct-16	88.3	85.0	96%	13-Nov-16	89.2	83.2	93%
14-Oct-16	88.3	85.0	96%	14-Nov-16	89.2	83.3	93%
15-Oct-16	88.3	85.0	96%	15-Nov-16	89.2	83.1	93%
16-Oct-16	88.3	84.9	96%	16-Nov-16	89.2	83.1	93%
17-Oct-16	88.3	84.8	96%	17-Nov-16	89.2	83.2	93%
18-Oct-16	88.3	84.8	96%	18-Nov-16	89.2	83.2	93%
19-Oct-16	88.3	84.7	96%	19-Nov-16	89.2	83.2	93%
20-Oct-16	88.3	84.7	96%	20-Nov-16	89.2	83.0	93%
21-Oct-16	88.3	84.6	96%	21-Nov-16	89.2	82.7	93%
22-Oct-16	88.3	84.7	96%	22-Nov-16	89.2	82.2	92%
23-Oct-16	88.3	84.7	96%	23-Nov-16	89.2	82.0	92%
24-Oct-16	88.3	84.5	96%	24-Nov-16	89.2	82.1	92%
25-Oct-16	88.3	84.5	96%	25-Nov-16	89.2	82.3	92%
26-Oct-16	88.3	84.2	95%	26-Nov-16	89.2	82.6	93%
27-Oct-16	88.3	83.9	95%	27-Nov-16	89.2	82.8	93%
28-Oct-16	88.3	83.9	95%	28-Nov-16	89.2	82.8	93%
29-Oct-16	88.3	83.9	95%	29-Nov-16	89.2	83.2	93%
30-Oct-16	88.3	83.7	95%	30-Nov-16	89.2	83.7	94%
31-Oct-16	88.3	83.4	95%				

UNION GAS LIMITED
Southern Operations Area
Allocation of Short-Term Peak Storage Revenues Between Utility and Non Utility

Line No.	Particulars	Utility Storage Space (PJs)	Short-Term Peak Storage Sold (PJs)	Revenue from Short-Term Peak Storage ($ millions)
1	Net Revenues from Short-Term Peak Storage			5.6
2	Total Short-Term Peak Storage Sales		6.4	
3	Storage Space reserved for Utility	100.0		
4	Utility Space Requirement	93.6		
5	Excess Utility Storage Space (line 3 - line 4)	6.4		
6	Total Utility Short-Term Peak Storage Sales (line 2)		6.4	
7	Total Non Utility Short-Term Peak Storage Sales		0.0	
8	Short-Term Peak Storage Net Revenues - Utility (line 6 / line 2 * line 1)			5.6
9	Short-Term Peak Storage Net Revenues - Non Utility (line 7 / line 2 * line 1)			0.0

UNION GAS LIMITED
179-132 Deferral Clearing Variance Account
2014 Deferral Disposition (EB-2015-0010)
2016 Deferral Account Dispositions

Line No.	Particulars ($000's)	2016: 2014 Deferral Disposition EB-2015-0010 ($000)	2016: Interest ($000)	2016: Total Variance With Interest ($000)
		(a)	(b)	(c) = (a) + (b)
1	Total General Service for Prospective Recovery (Refund) - Delivery	(79)	-	(79)
2	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation	23	-	23
3	Total Prospective Recovery (Refund) - Gas Supply Commodity	291	2	293
4	Total	235	2	237

UNION GAS LIMITED
179-132 Deferral Variance Account
2014 Deferral Disposition (EB-2015-0010)
Disposition Period - October 1, 2015 to March 31, 2016

			2016							
Line No.	Particulars	Rate Class	Forecast Volume (10^3m^3) (1)	Actual Volume (10^3m^3)	Volume Variance (10^3m^3)	Unit Rate for Prospective Recovery/(Refund) (cents/m³)	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	756,529	679,252	77,277	(0.2304)	(1,743)	(1,565)	(178)
2	Large Volume General Service	10	244,726	238,600	6,126	(0.3351)	(820)	(800)	(21)
3	Small Volume General Service	M1	2,308,240	2,007,071	301,169	0.0629	1,451	1,261	189
4	Large Volume General Service	M2	884,479	811,178	73,302	(0.0946)	(836)	(767)	(69)
5	Total General Service for Prospective Recovery (Refund) - Delivery		4,193,975	3,736,100	457,874		(1,948)	(1,870)	(79)
	General Service for Prospective Recovery(Refund) - Gas Supply Transportation								
6	Small Volume General Service	01	756,529	679,252	77,277	0.0301	227	204	23
7	Large Volume General Service	10	243,229	236,323	6,906	(0.0094)	(23)	(22)	(1)
8	Total General Service for Prospective Recovery (Refund) - Gas Supply Transportation		999,758	915,575	84,183		205	182	23
	Prospective Recovery/(Refund) - Gas Supply Commodity								
9	Small Volume General Service	M1	2,030,085	1,816,850	213,235	0.0935	2,067	1,699	368
10	Large Volume General Service	M2	495,823	394,651	101,172	0.0935	297	369	(72)
11	Firm Com/Ind Contract	M4	19,586	17,540	2,046	0.0935	14	16	(2)
12	Interruptible Com/Ind Contract	M5	7,869	5,175	2,694	0.0935	18	5	13
13	Special Large Volume Contract	M7	-	8,673	(8,673)	0.0935	(8)	8	(16)
14	Small Wholesale	M10	232	195	37	0.0935	(0)	0	(0)
15	Total Prospective Recovery (Refund) - Gas Supply Commodity		2,553,595	2,243,085	310,510		2,389	2,097	291
16	Total						645	410	235

Under Collected from Rate Payers

Notes:
(1) Forecast volume for the period October 1, 2015 to March 31, 2016

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

Line No.	Particulars (m^3)		Rate 01	Rate 10	Rate M1	Rate M2	Net Account Balance
			(a)	(b)	(c)	(d)	(e)
1	2016 Target NAC: m³		3,015	177,214	2,852	172,693	
2	2016 Actual NAC: m³		2,788	159,855	2,667	159,933	
3	Actual change in NAC (line 1 - line 2)		227	17,359	185	12,760	
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)	72,628	35,614	196,287	86,739	391,268
6	2016 Net Annual Average Delivery Rate ($/m^3)	(2)	$0.085	$0.054	$0.038	$0.039	
7	2016 Net Annual Storage Rate ($/m^3)	(3)	$0.040	$0.028	$0.007	$0.006	
8	Delivery Rate Annual Balance Amount ($ 000)	(4)	$6,157	$1,912	$7,409	$3,357	$18,835
9	Storage Rate Annual Balance Amount ($ 000) (line 5 x line 7)	(4)	$2,910	$1,000	$1,379	$534	$5,823
10	Storage Cost Annual Balance Amount ($ 000)		$80	($199)	$330	($1,363)	($1,152)
11	Interest ($ 000)	(5)	$49	$15	$45	16	$125
12	Total Deferral Account Amounts ($ 000) (line 8+9+10+11)		$9,196	$2,728	$9,163	$2,544	$23,631

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
2016 Parkway Obligation Rate Variance Summary
Based on the Parkway Delivery Commitment Incentive for DP and Sales Service Customers
From November 1, 2016 to December 31, 2016

Line No.	Rate Class ($000's)	Dawn-Parkway Demand Costs (1)	Compressor Fuel Costs (2)	Interest (3)	Total Costs
		(a)	(b)	(c)	(d) = (a + b + c)
1	Rate M1	1,015	292	0	1,307
2	Rate M2	341	103	0	444
3	Rate M4	99	47	0	146
4	Rate M5 - Firm	1	1	0	2
5	Rate M5 - Interruptible	-	33	0	33
6	Rate M7 - Firm	46	19	0	65
7	Rate M7 - Interruptible	-	-	-	-
8	Rate M9	16	10	0	26
9	Rate M10	1	0	0	1
10	Rate T1 - Firm	49	43	0	92
11	Rate T1 - Interruptible	-	5	0	5
12	Rate T2 - Firm	318	221	0	539
13	Rate T2 - Interruptible	-	5	0	5
14	Rate T3	115	44	0	159
15	Total	2,000	821	1	2,822

Note:
(1) Tab 1, Appendix A, Schedule 8, p. 2, column (b) + Tab 1, Appendix A, Schedule 8, p. 3 columns (b) + column (c).
(2) Tab 1, Appendix A, Schedule 8, p. 2, column (d) + Tab 1, Appendix A, Schedule 8, p. 3 columns (e) + column (f).
(3) Simple interest computed monthly on the opening balance of the Parkway Obligation deferral account at a rate of 1.10%. Allocated to rate classes in proportion to Dawn-Parkway demand and compressor fuel costs column (a) and column (b).

UNION GAS LIMITED
Derivation of the 2016 Direct Purchase (DP) PDCI Costs

		Demand Costs		Commodity Costs		
Line No.	Particulars	2013 Approved Design Day Demands (1) ($10^3m^3/d$)	292 TJ DP Demand Costs (2) ($000's)	2013 Approved Delivery Volumes East of Dawn (4) (10^3m^3)	292 TJ DP Fuel and UFG Costs (5) ($000's)	Total DP PDCI Costs ($000's)
		(a)	(b)	(c)	(d)	(e) = (b + d)
1	Rate M1	22,132	858	1,823,853	247	1,105
2	Rate M2	7,435	288	645,259	87	376
3	Rate M4	2,162	84	294,126	40	124
4	Rate M5 Firm	20	1	7,501	1	2
5	Rate M5 Interruptible	-	-	203,891	28	28
6	Rate M7 Firm	997	39	118,324	16	55
7	Rate M7 Interruptible	-	-	-	-	-
8	Rate M9	356	14	60,750	8	22
9	Rate M10	11	0	189	0	0
10	Rate T1 Firm	1,068	41	267,950	36	78
11	Rate T1 Interruptible	-	-	28,552	4	4
12	Rate T2 Firm	6,931	269	1,380,265	187	456
13	Rate T2 Interruptible	-	-	32,431	4	4
14	Rate T3	2,511	97	272,712	37	134
15	Total	43,624	1,692 (3)	5,135,803	695 (6)	2,387

Notes:
(1) Union South In-franchise Design Day Demand Allocation Factor per EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, p. 7, line 2, Updated for Board Decision.
(2) Allocated in proportion to column (a).
(3) Calculated as 292 TJ x $0.095/GJ/d x 61 = $1.692 million. Rate represents the M12 Dawn to Parkway demand rate per EB-2016-0296.
(4) Union South in-franchise volumes east of Dawn per EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, pp. 13 & 14, Updated for Board Decision.
(5) Allocated in proportion to column (c).
(6) Calculated as 292 TJ x $0.039/GJ/d x 61 = $0.695 million. Rate represents the average Dawn to Parkway (TCPL, EGT) fuel and commodity rate per EB-2016-0296 Rate M12 Schedule 'C'.

UNION GAS LIMITED
Derivation of the 2016 Sales Service PDCI Costs

Line No.	Particulars	Demand Costs: 2013 Approved Design Day Demands (1) ($10^3m^3/d$)	Demand Costs: 58 TJ Sales Service Demand Costs (2) ($000's)	Demand Costs: 28 TJ Sales Service Demand Costs (2) ($000's)	Commodity Costs: 2013 Approved Delivery Volumes East of Dawn (5) (10^3m^3)	Commodity Costs: 58 TJ Sales Service Fuel and UFG Costs (5) ($000's)	Commodity Costs: 28 TJ Sales Service Fuel and UFG Costs (5) ($000's)	Total Sales Service PDCI Costs ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (b+c+e+f)
1	Rate M1	22,132	143	13	1,823,853	41	4	201
2	Rate M2	7,435	48	5	645,259	14	1	68
3	Rate M4	2,162	14	1	294,126	7	1	22
4	Rate M5 Firm	20	0	0	7,501	0	0	0
5	Rate M5 Interruptible	-	-	-	203,891	5	0	5
6	Rate M7 Firm	997	6	1	118,324	3	0	10
7	Rate M7 Interruptible	-	-	-	-	-	-	-
8	Rate M9	356	2	0	60,750	1	0	4
9	Rate M10	11	0	0	189	0	0	0
10	Rate T1 Firm	1,068	7	1	267,950	6	1	14
11	Rate T1 Interruptible	-	-	-	28,552	1	0	1
12	Rate T2 Firm	6,931	45	4	1,380,265	31	3	83
13	Rate T2 Interruptible	-	-	-	32,431	1	0	1
14	Rate T3	2,511	16	2	272,712	6	1	24
15	Total	43,624	281 (3)	27 (4)	5,135,803	115 (6)	11 (7)	434

Notes:
(1) Union South In-franchise Design Day Demand allocation factor per EB-2011-0210, Exhibit G3, Tab 5, Schedule 23, p. 7, line 2, Updated for Board Decision.
(2) Allocated in proportion to column (a).
(3) Calculated as 58 TJ x $0.095/GJ/d x 51 = $0.281 million. Rate represents the M12 Dawn to Parkway demand rate per EB-2016-0296.
(4) Calculated as 28 TJ x $0.095/GJ/d x 10 = $0.027 million. Rate represents the M12 Dawn to Parkway demand rate per EB-2016-0296.
(5) Union South in-franchise volumes east of Dawn per EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, pp. 13 & 14, Updated for Board Decision.
(5) Allocated in proportion to column (d).
(6) Calculated as 58 TJ x $0.039/GJ/d x 51 = $0.115 million. Rate represents the average Dawn to Parkway (TCPL, EGT) fuel and commodity rate per EB-2016-0296 Rate M12 Schedule 'C'.
(7) Calculated as 28 TJ x $0.039/GJ/d x 10 = $0.011 million. Rate represents the average Dawn to Parkway (TCPL, EGT) fuel and commodity rate per EB-2016-0296 Rate M12 Schedule 'C'.

UNION GAS LIMITED
Calculation of 2016 UFG Price Variance

	January	February	March	April	May	June	July	August	September	October	November	December	Total	
Actual UFG (GJ)	424,945	424,945	424,945	424,945	424,945	424,945	424,945	424,945	424,945	424,945	424,945	424,945	5,099,338	
less: UFG collected through T1, T2, T3 and exfranchise CSF (GJ	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(324,290)	(3,891,475)	
UFG - Utility Ratepayer (GJ)	100,655	100,655	100,655	100,655	100,655	100,655	100,655	100,655	100,655	100,655	100,655	100,655	**1,207,863**	(1)
Reference Price ($CDN/GJ)	$ 4.691	$ 4.691	$ 4.691	$ 4.379	$ 4.379	$ 4.379	$ 4.519	$ 4.519	$ 4.519	$ 4.881	$ 4.881	$ 4.881	**$ 4.675**	
Total SPGVA Purchases - (GJ)	11,176,665	10,454,899	10,486,801	6,115,431	7,161,674	10,158,570	11,302,786	9,838,250	11,465,810	6,978,750	9,898,848	12,291,637	**117,330,121**	
UFG Related Spot Purchase			-										-	
SPGVA Purchase (GJ)	11,176,665	10,454,899	10,486,801	6,115,431	7,161,674	10,158,570	11,302,786	9,838,250	11,465,810	6,978,750	9,898,848	12,291,637	117,330,121	(2)
SPGVA Portfolio Cost ($CDN/GJ)	$ 43,735,960	$ 38,681,347	$ 28,864,709	$ 17,330,509	$ 20,752,392	$ 28,884,654	$ 44,045,252	$ 36,038,105	$ 44,274,955	$ 28,971,829	$ 41,444,714	$ 59,297,439	$ 432,321,864	(2)
Average SPGVA Purchase Cost (CDN$/GJ)	$ 3.913	$ 3.700	$ 2.752	$ 2.834	$ 2.898	$ 2.843	$ 3.897	$ 3.663	$ 3.861	$ 4.151	$ 4.187	$ 4.824	**$ 3.685**	(2)
Price Variance ($CDN/GJ)	$ 0.778	$ 0.991	$ 1.939	$ 1.545	$ 1.481	$ 1.536	$ 0.622	$ 0.856	$ 0.658	$ 0.730	$ 0.694	$ 0.057	**$ 0.990**	(3)
Price Variance ($CDN)	$ 78,294.75	$ 99,766.47	$ 195,122.21	$ 155,522.59	$ 149,100.49	$ 154,568.42	$ 62,622.75	$ 86,154.80	$ 66,183.20	$ 73,434.52	$ 69,872.66	$ 5,716.20	**$ 1,196,359**	

UFG Volumes (10^3m^3)	**31,169**	(4)
Average Price Variance (CDN$/$10^3m^3$) $	**38.383**	(5)

Notes:

(1) Required Utility ratepayer purchase of gas associated with UFG that is not collected through customer supplied fuel.

(2) Total purchase of gas for the South portfolio (as detailed in the 2016 QRAM submissions); includes the purchase

for Utility UFG purposes as noted above in (1).

(3) Net price variance for 2016 representing difference between actual purchase cost versus Board-approved reference prices.

(4) UFG total GJ from note 1 multiplied by approved heat values (Jan-Mar @ 38.55; Apr-Dec @ 38.81)

(5) Average price variance in GJ converted to volumetric rate by dividing total price variance of $1,196,359 over the UFG volumes determined in note 4.

Ontario Energy Board

P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4
Telephone: 416-481-1967
Facsimile: 416-440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario

C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4
Téléphone: 416-481-1967
Télécopieur: 416-440-7656
Numéro sans frais: 1-888-632-6273

Ontario

February 9, 2016

To: Regulated Entities subject to the OEB's Cost Assessment

Re: Revisions to the Ontario Energy Board Cost Assessment Model

Please be advised that the Ontario Energy Board (OEB) has revised its Cost Assessment Model (CAM), the methodology used to apportion its costs under section 26 of the *Ontario Energy Board Act, 1998* (Act). The persons or classes of persons that are liable to pay the OEB's costs under section 26(1) of the Act are set out in Ontario Regulation 16/08.

The consulting firm MNP LLP was engaged to undertake a review of the CAM, to ensure alignment with the OEB's current mandate and best practices. The model was last reviewed in its entirety in 2006.

Material changes include:

1. Updating the OEB's direct cost allocations (staff time and Market Surveillance Panel cost) to align with the OEB's mandate.

2. Updating of electricity distribution and gas distribution intra-class allocations from a revenue based allocation to a customer number based allocation, resulting in increased stability and predictability.

The OEB has adopted all of MNP's recommendations effective April 1, 2016. A summary report of MNP's recommendations is posted on the OEB's website.

These changes to the CAM may result in material shifts in the allocation of costs.

It is worth noting that as outlined in the OEB's letter dated January 4, 2016, the OEB's budget has increased for the first time since 2011, to accommodate an expanded mandate and priorities. The budget increase was not a consideration during MNP's analysis of the CAM. The 2015-18 Business Plan and budget is also located on the OEB website.

New Variance Account

The OEB has established the following variance account for electricity distributors and transmitters 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:

- *Account 1508 Other Regulatory Assets, Sub-account OEB Cost Assessment Variance*
- Note: the offsetting entry to this account shall be to Account 5655, Regulatory Expenses.

The OEB has also authorized the establishment of a similar variance account by natural gas distributors, OPG and the IESO.

Entries into the variance accounts are to be made on a quarterly basis when the OEB's cost assessment invoice is received. Amounts should be prorated to take into account the effective date of rebased/reset rates, payment amounts or fees (as applicable). Regulated entities are to cease recording amounts in these accounts when their rates, payment amounts or fees (as applicable) are rebased/reset (cost of service or custom IR) incorporating an updated forecast of cost assessments.

Carrying charges at the OEB-prescribed rate are to be calculated using simple interest applied to the monthly opening balances in the accounts (exclusive of accumulated interest) and recorded in a separate sub-account.

Regulated entities are expected to seek disposition of the variance account balances when their rates, payment amounts or fees, as applicable, are next rebased/reset, and the accounts will be closed to any further entries at that time.

Regulated entities are reminded that, in the normal course, any disposition of deferral and variance account balances must meet any OEB default or company-specific materiality thresholds.

Any questions can be directed to John Moon at john.moon@ontarioenergyboard.ca or 416-440-7748.

Yours truly,

Original signed by

Julie Mitchell
Vice President
People, Culture & Business Solutions| Ontario Energy Board

2016 UTILITY RESULTS AND EARNINGS SHARING

2016 UTILITY RESULTS

For the year ended December 31, 2016 Union's actual revenue sufficiency from utility operations is $7.3 million, which is $12.6 million lower than the 2015 revenue sufficiency of $19.9 million. Table 1 provides the results from Union's actual utility operations for 2016.

Table 1

Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31, 2016

Line No.	Particulars ($ Millions)	Board Approved 2013	Actual 2015	Actual 2016	Increase/ (decrease) 2016 vs. 2015
		(a)	(b)	(c)	(d) = (c) - (b)
1	Gas sales and distribution revenue	1,448.8	1,659.2	1,514.5	
2	Cost of gas	701.4	856.8	700.4	
3	Gas distribution margin	747.4	802.4	814.1	11.7
4	Transportation	157.0	156.2	182.7	26.5
5	Storage	10.4	7.4	8.5	1.1
6	Other revenue	20.2	19.9	16.5	(3.4)
7	Expenses	643.8	662.3	695.6	33.3
8	Income taxes	17.1	15.7	4.4	(11.3)
9	Utility income	274.1	307.9	321.8	13.9
10	Cost of Capital	272.6	292.4	315.6	23.2
11	Revenue deficiency / (sufficiency) after tax	(1.5)	(15.5)	(6.2)	9.3
12	Provision for income taxes on deficiency / (sufficiency)	(0.5)	(5.6)	(2.2)	3.4
13	Distribution revenue deficiency/(sufficiency)	(2.0)	(21.1)	(8.4)	12.7
14	Shareholder portion of short-term storage revenue	0.5	0.4	0.8	0.4
15	Shareholder portion of optimization activity	1.5	0.8	0.3	(0.5)
16	Total revenue deficiency/(sufficiency)	-	(19.9)	(7.3)	12.6

The primary drivers of Union's 2016 financial results relative to 2015 are provided below.

Gas Distribution Margin

The increase in gas distribution margin of $11.7 million relative to 2015 was mainly driven by rate increases and growth in the number of customers being serviced by Union (and related natural gas usage), partially offset by a decrease in customer usage of natural gas due to weather that was 8% warmer than the previous year.

Transportation Revenue

The increase in transportation revenue of $26.5 million relative to 2015 was mainly driven by increased M12 rates due to capital pass-through projects being included in rates, partially offset by decreased C1 short-term transportation. The decrease in C1 short-term transportation was due to less incremental market opportunities.

Other Revenue

The decrease in other revenue of $3.4 million relative to 2015 was mainly driven by a decrease in delayed payment charges. The decrease was a result of warmer weather in 2016 which reduced customer bills and the number of accounts falling into arrears.

Expenses

The increase in expenses of $33.3 million relative to 2015 was mainly driven by higher depreciation and O&M expenses. The increase in depreciation of $16.2 million relative to 2015 was mainly driven by new projects placed into service. The increase in O&M of $14.9 million relative to 2015 was mainly driven by increased 2016 DSM program costs as approved by the Board in its EB-2015-0029 Decision, partially offset by lower pension expense.

Income Taxes

The decrease in income taxes relative to 2015 of $11.3 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 and 2016.

2016 EARNINGS SHARING

The benchmark return on equity ("ROE") for 2016 was 8.93%. Union's actual ROE from utility operations in 2016 was 9.24% or 31 basis points above the 2016 benchmark ROE.

The calculation of ROE for 2016 is found at 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; 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 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 (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 DSM Incentive of $4.237 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 $3.089 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 $0.985 million have been added to operating expenses and foreign exchange loss on bank balances of $0.394 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 $14.668 million has been shown as a cost of gas reduction.

Amounts relating to the Conservation Demand Management ("CDM") program of $0.139 million have been removed from operating and maintenance expenses. These expenses relate to closing the CDM program with Hydro One Networks at the end of 2015 and were reflected in the 2015 CDM deferral balance, as filed in EB-2016-0118. There is no balance in the CDM deferral account for 2016 as Union was not successful in the request for proposal ("RFP") process to continue contract services into 2016 with Hydro One Networks.

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 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 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 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 $0.553 million, net of tax, has been removed from the earnings sharing calculation.

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 $0.247 million, net of tax, has been removed from the earnings sharing calculation.

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 2016 ROE is 9.24% (Please see 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 2016, the difference is 31 basis points and therefore there is no earnings sharing (please see Tab 2, Appendix B, Schedule 1, column (d), line 35).

2016 UNREGULATED STORAGE

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

SERVICE QUALITY RESULTS

As set out in Union's 2014-2018 IR Mechanism Settlement Agreement, p. 40, Union has provided the service quality indicator results at Tab 2, Appendix D, Schedule 1.

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

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2015	Actual 2016
		(a)	(b)	(c)
1	Operating revenue	1,636,340	1,842,717	1,722,253
2	Cost of service	1,362,212	1,534,839	1,400,491
3	Utility income	274,128	307,878	321,762
4	Requested return	272,639	292,359	315,580
5	Revenue deficiency / (sufficiency) after tax	(1,489)	(15,519)	(6,182)
6	Provision for income taxes on deficiency / (sufficiency)	(509)	(5,595)	(2,229)
7	Distribution revenue deficiency / (sufficiency)	(1,998)	(21,114)	(8,411)
8	Shareholder portion of short-term storage revenue	506	449	753
9	Shareholder portion of optimization activity	1,492	774	336
10	Total revenue deficiency/ (sufficiency)	$ -	$ (19,891)	$ (7,322)

UNION GAS LIMITED
Statement of Utility Income
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2013	Actual 2015	Actual 2016
		(a)	(b)	(c)
	Operating Revenues:			
1	Gas sales and distribution	1,448,762	1,659,203	1,514,537
2	Transportation	156,997	156,244	182,683
3	Storage	10,383	7,368	8,503
4	Other	20,198	19,902	16,530
5		1,636,340	1,842,717	1,722,253
	Operating Expenses:			
6	Cost of gas	701,427	856,842	700,444
7	Operating and maintenance expenses	383,132	382,984	397,858
8	Depreciation	196,091	212,219	228,401
9	Other financing	1,179	820	985
10	Property and capital taxes	63,272	65,848	69,564
11		1,345,101	1,518,713	1,397,252
	Other Income (Expense)			
12	Gain/(Loss) on sale of assets	-	-	-
13	Gain/(Loss) on foreign exchange	-	(442)	1,159
14		-	(442)	1,159
15	Utility income before income taxes	291,239	323,562	326,160
16	Income taxes	17,111	15,684	4,398
17	Total utility income	$ 274,128	$ 307,878	$ 321,762

UNION GAS LIMITED
Statement of Earnings Before Interest and Taxes
Year Ended December 31

Line No.	Particulars ($000s)	2013 Board-Approved				2015 Actual				2016 Actual			
		Corporate	Unregulated Storage	Adjustments	Utility	Corporate	Unregulated Storage	Adjustments	Utility	Corporate	Unregulated Storage	Adjustments	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	1,674,769	-	(15,565)	1,659,203	1,529,204	-	(14,668) (i)	1,514,537
2	Transportation	156,641	(356)	-	156,997	155,775	(469)	-	156,244	182,195	(488)	-	182,683
3	Storage	96,441	86,059	-	10,383	83,162	75,794	-	7,368	95,598	87,095	-	8,503
4	Other	24,498	-	(4,300)	20,198	25,819	-	(5,917)	19,902	20,768	-	(4,237) (ii)	16,530
5		1,726,343	85,703	(4,300)	1,636,340	1,939,524	75,325	(21,483)	1,842,717	1,827,765	86,607	(18,905)	1,722,253
	Operating Expenses:												
6	Cost of gas	701,966	539	-	701,427	874,628	2,221	(15,565)	856,842	716,827	1,715	(14,668) (i)	700,444
7	Operating and maintenance expenses	397,112	12,986	(993)	383,132	399,070	14,771	(1,315)	382,984	414,496	13,410	(3,228) (iii)	397,858
8	Depreciation	205,804	9,713	-	196,091	223,796	11,577	-	212,219	239,080	10,679	-	228,401
9	Other financing	-	-	1,179	1,179	-	-	820	820	-	-	985 (iv)	985
10	Property and other taxes	64,674	1,402	-	63,272	67,468	1,620	-	65,848	71,199	1,635	-	69,564
11		1,369,556	24,640	186	1,345,101	1,564,962	30,189	(16,060)	1,518,713	1,441,601	27,439	(16,910)	1,397,252
	Other Income (Expense)												
12	Gain/(Loss) on sale of assets	-	-	-	-	(4)	(4)	-	-	(624)	(624)	-	-
13	Other	-	-	-	-	(691)	(691)	-	-	-	-	-	-
14	Gain/(Loss) on foreign exchange	-	-	-	-	(1,614)	(18)	1,154	(442)	1,592	39	(394) (v)	1,159
15		-	-	-	-	(2,309)	(713)	1,154	(442)	967	(585)	(394)	1,159
16	Earnings Before Interest and Taxes	$ 356,787	$ 61,063	$ (4,486)	$ 291,239	$ 372,254	$ 44,423	$ (4,269)	$ 323,562	$ 387,132	$ 58,583	$ (2,389)	$ 326,160

Notes:

i) Reclassification of optimization revenue as cost of gas

ii) Demand Side Management Incentive

iii) Charitable donations 3,089
CDM Program 139
3,228

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				2015 Actual				2016 Actual			
Line		Utility Capital Structure		Cost Rate	Return	Utility Capital Structure		Cost Rate	Return	Utility Capital Structure		Cost Rate	Return
No.	Particulars	($000s)	(%)	%	($000s)	($000s)	(%)	%	($000s)	($000s)	(%)	%	($000s)
1	Long-term debt	2,289,139	61.30%	6.53%	149,481	2,746,659	64.96%	5.64%	154,972	3,161,476	66.44%	5.12%	161,809
2	Unfunded short-term debt	(1,287)	(0.03%)	1.31%	(17)	(143,529)	(3.39%)	0.84%	(1,206)	(219,473)	(4.61%)	0.82%	(1,800)
3	Total debt	2,287,852	61.26%		149,464	2,603,130	61.56%		153,766	2,942,003	61.83%		160,009
4	Preference shares	102,248	2.74%	3.05%	3,117	103,043	2.44%	2.58%	2,659	103,384	2.17%	2.51%	2,597
5	Common equity	1,344,432	36.00%	8.93%	120,058	1,522,222	36.00%	8.93%	135,934	1,713,030	36.00%	8.93%	152,974
6	Total rate base	$ 3,734,532	100.00%		$ 272,639	$ 4,228,395	100.00%		$ 292,359	$ 4,758,418	100.00%		$ 315,580

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

Board Approved 2013

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

Actual 2015

Line No.	Volumes in 10^3m^3	System Sales (g)	ABC-T (h)	ABC-Unbundled (i)	Bundled-T (j)	T-Service (k)	Total (l)
	General Service						
1	Rate M1 Firm	2,583,548	255,785	32,406	17,127	-	2,888,866
2	Rate M2 Firm	579,474	326,911	5,562	277,278	-	1,189,225
3	Rate 01 Firm	826,618	101,871	-	10,455	-	938,944
4	Rate 10 Firm	172,559	74,364	-	93,077	3,625	343,625
5	Total General Service	4,162,199	758,930	37,968	397,938	3,625	5,360,660
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	66,583	-	66,583
7	Rate M10 Firm	300	-	-	-	-	300
8	Total Wholesale - Utility	300	-	-	66,583	-	66,882
	Contract						
9	Rate M4	31,119	19,047	-	407,162	-	457,328
10	Rate M7	21,253	2,937	-	403,517	-	427,707
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	10,943	-	-	90,848	439,048	540,839
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,398,114	1,398,114
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	442,947	442,947
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,368,501	4,368,501
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	263,235	263,235
21	Rate M5	8,026	2,881	-	197,724	-	208,631
22	Rate 25	93,474	-	-	-	50,839	144,313
23	Rate 30	-	-	-	-	-	-
24	Total Contract	164,815	24,864	-	1,099,251	6,962,684	8,251,614
25	Total Throughput Volume	4,327,314	783,795	37,968	1,563,771	6,966,309	13,679,156

Actual 2016

Line No.	Volumes in 10^3m^3	System Sales (m)	ABC-T (n)	ABC-Unbundled (o)	Bundled-T (p)	T-Service (q)	Total (r)
	General Service						
1	Rate M1 Firm	2,656,511	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 Volume	4,403,593	758,395	17,487	1,624,029	6,808,655	13,612,159

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

Board Approved 2013

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

Actual 2015

Line No.	Volumes in 10^3m^3	System Sales (g)	ABC-T (h)	ABC-Unbundled (i)	Bundled-T (j)	T-Service (k)	Total (l)
	General Service						
1	Rate M1 Firm	2,701,384	267,452	33,884	17,908	-	3,020,628
2	Rate M2 Firm	597,640	337,159	5,737	285,971	-	1,226,506
3	Rate 01 Firm	846,945	104,376	-	10,712	-	962,033
4	Rate 10 Firm	176,638	76,121	-	95,277	3,710	351,747
5	Total General Service	4,322,607	785,108	39,621	409,868	3,710	5,560,914
	Wholesale - Utility						
6	Rate M9 Firm	-	-	-	66,583	-	66,583
7	Rate M10 Firm	300	-	-	-	-	300
8	Total Wholesale - Utility	300	-	-	66,583	-	66,882
	Contract						
9	Rate M4	31,119	19,047	-	407,162	-	457,328
10	Rate M7	21,253	2,937	-	403,517	-	427,707
11	Rate 20 Storage	-	-	-	-	-	-
12	Rate 20 Transportation	10,943	-	-	90,848	439,048	540,839
13	Rate 100 Storage	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	1,398,114	1,398,114
15	Rate T-1 Storage	-	-	-	-	-	-
16	Rate T-1 Transportation	-	-	-	-	442,947	442,947
17	Rate T-2 Storage	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	4,368,501	4,368,501
19	Rate T-3 Storage	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	263,235	263,235
21	Rate M5	8,026	2,881	-	197,724	-	208,631
22	Rate 25	93,474	-	-	-	50,839	144,313
23	Rate 30	-	-	-	-	-	-
24	Total Contract	164,815	24,864	-	1,099,251	6,962,684	8,251,614
25	Total Throughput Volume	4,487,722	809,972	39,621	1,575,701	6,966,395	13,879,411

Actual 2016

Line No.	Volumes in 10^3m^3	System Sales (m)	ABC-T (n)	ABC-Unbundled (o)	Bundled-T (p)	T-Service (q)	Total (r)
	General Service						
1	Rate M1 Firm	2,533,596	218,389	12,565	14,614	-	2,779,165
2	Rate M2 Firm	568,260	322,466	4,130	280,107	-	1,174,963
3	Rate 01 Firm	815,697	82,619	-	10,131	-	908,447
4	Rate 10 Firm	164,705	76,374	-	97,516	4,289	342,884
5	Total General Service	4,082,258	699,848	16,695	402,368	4,289	5,205,459
	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 Volume	4,214,935	727,565	16,695	1,607,438	6,808,519	13,375,153

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

Line No.	Particulars ($000's)	Board Approved 2013						Actual 2015						Actual 2016					
		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	799,970	30,778	4,564	1,004	-	836,316	758,382	26,931	1,824	888	-	788,025
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	124,182	15,439	222	11,700	310	151,853	116,762	16,501	179	12,871	160	146,472
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	344,837	27,644	-	2,096	-	374,577	333,261	23,100	-	2,138	-	358,499
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	48,374	11,048	-	12,778	176	72,375	43,966	11,765	-	13,966	270	69,967
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,317,362	84,909	4,786	27,577	486	1,435,120	1,252,371	78,297	2,002	29,863	429	1,362,963
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	-	-	-	805	-	805	962	-	-	817	-	1,779
7	Rate M10 Firm	11	-	-	7	-	18	69	-	-	-	-	69	50	-	-	-	-	50
8	Total Wholesale - Utility	11	-	-	734	-	745	69	-	-	805	-	874	1,012	-	-	817	-	1,829
	Contract																		
9	Rate M4	3,407	-	-	11,786	-	15,193	6,352	602	-	13,022	-	19,976	6,945	708	-	15,088	-	22,742
10	Rate M7	-	-	-	4,127	-	4,127	6,582	256	-	8,961	-	15,798	3,850	267	-	9,903	-	14,020
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	1,819	1,819	-	-	-	-	1,854	1,854
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	2,634	-	-	8,895	11,902	23,430	3,103	-	-	9,098	11,137	23,337
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	89	89	-	-	-	-	304	304
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	12,423	12,423	-	-	-	-	12,626	12,626
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,367	1,367	-	-	-	-	1,368	1,368
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,695	8,695	464	-	-	-	8,791	9,255
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,769	7,769	-	-	-	-	7,700	7,700
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	43,299	43,299	3,930	-	-	-	45,868	49,798
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,420	1,420	-	-	-	-	1,344	1,344
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,426	3,426	-	-	-	-	3,721	3,721
21	Rate M5	2,801	-	-	12,913	-	15,713	1,626	92	-	5,767	-	7,485	1,643	154	-	5,965	-	7,762
22	Rate 25	10,172	-	-	-	3,273	13,445	19,543	-	-	-	1,609	21,152	8,838	-	-	-	2,173	11,011
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610	36,736	950	-	36,645	93,820	168,151	28,773	1,129	-	40,053	96,887	166,842
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,354,168	85,859	4,786	65,026	94,306	1,604,145	1,282,157	79,426	2,002	70,733	97,316	1,531,634
26	LRAM						-						(872)						538
27	Average Use / Normalized Average Consumption						-						10,204						23,278
28	Parkway Obligation Rate Variance						-						(1)						2,861
29	Capital Pass Through						-						553						2,539
30	Total Revenue					$	1,448,762						1,614,029						1,560,850

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 2015						Actual 2016					
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	830,046	30,973	4,593	1,010	-	866,622	732,935	26,717	1,809	881	-	762,342
2	Rate M2 Firm	84,792	17,612	2,631	11,466	-	116,501	129,532	15,585	224	11,810	313	157,464	110,940	16,242	176	12,670	157	140,185
3	Rate 01 Firm	268,545	66,665	-	1,993	-	337,202	351,890	28,014	-	2,130	-	382,034	321,839	22,469	-	2,067	-	346,375
4	Rate 10 Firm	43,957	13,251	-	12,874	-	70,083	49,738	11,243	-	13,017	177	74,175	42,469	11,445	-	13,565	268	67,747
5	Total General Service	1,090,412	156,472	27,301	27,222	-	1,301,407	1,361,206	85,815	4,817	27,967	490	1,480,295	1,208,183	76,874	1,985	29,183	425	1,316,649
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	-	-	-	805	-	805	962	-	-	817	-	1,779
7	Rate M10 Firm	11	-	-	7	-	18	69	-	-	-	-	69	50	-	-		-	50
8	Total Wholesale - Utility	11	-	-	734	-	745	69	-	-	805	-	874	1,012	-	-	817	-	1,829
	Contract																		
9	Rate M4	3,407	-	-	11,786	-	15,193	6,352	602	-	13,022	-	19,976	6,945	708	-	15,088	-	22,742
10	Rate M7	-	-	-	4,127	-	4,127	6,582	256	-	8,961	-	15,798	3,850	267	-	9,903	-	14,020
11	Rate 20 Storage	-	-	-	-	1,057	1,057	-	-	-	-	1,819	1,819	-	-	-	-	1,854	1,854
12	Rate 20 Transportation	3,304	-	-	10,277	10,637	24,219	2,634	-	-	8,895	11,902	23,430	3,103	-	-	9,098	11,137	23,337
13	Rate 100 Storage	-	-	-	-	166	166	-	-	-	-	89	89	-	-	-	-	304	304
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	12,423	12,423	-	-	-	-	12,626	12,626
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,367	1,367	-	-	-	-	1,368	1,368
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,695	8,695	464	-	-	-	8,791	9,255
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,769	7,769	-	-	-	-	7,700	7,700
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	43,299	43,299	3,930	-	-	-	45,868	49,798
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,420	1,420	-	-	-	-	1,344	1,344
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,426	3,426	-	-	-	-	3,721	3,721
21	Rate M5	2,801	-	-	12,913	-	15,713	1,626	92	-	5,767	-	7,485	1,643	154	-	5,965	-	7,762
22	Rate 25	10,172	-	-	-	3,273	13,445	19,543	-	-	-	1,609	21,152	8,838	-	-	-	2,173	11,011
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	19,684	-	-	39,102	87,824	146,610	36,736	950	-	36,645	93,820	168,151	28,773	1,129	-	40,053	96,887	166,842
25	Subtotal	1,110,107	156,472	27,301	67,058	87,824	1,448,762	1,398,011	86,765	4,817	65,416	94,310	1,649,319	1,237,968	78,003	1,985	70,053	97,311	1,485,321
26	LRAM						-						(872)						538
27	Average Use / Normalized Average Consumption						-						10,204						23,278
28	Parkway Obligation Rate Variance						-						(1)						2,861
29	Capital Pass Through						-						553						2,539
30	Total Revenue					$	1,448,762						1,659,203						1,514,537

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 2015						Actual 2016					
		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	363,403	30,973	4,593	1,010	-	399,979	368,263	26,717	1,809	881	-	397,671
2	Rate M2 Firm	19,898	17,612	2,631	11,466	-	51,607	27,470	15,585	224	11,810	313	55,402	28,868	16,242	176	12,670	157	58,112
3	Rate 01 Firm	118,812	41,509	-	928	-	161,249	148,300	17,109	-	1,024	-	166,432	147,414	13,505	-	965	-	161,884
4	Rate 10 Firm	9,524	5,578	-	4,876	-	19,979	10,190	4,636	-	4,714	177	19,717	9,882	4,659	-	4,882	268	19,691
5	Total General Service	451,532	123,643	27,301	18,159	-	620,636	549,363	68,302	4,817	18,559	490	641,531	554,427	61,124	1,985	19,398	425	637,358
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	727	-	727	-	-	-	805	-	805	73	-	-	817	-	889
7	Rate M10 Firm	2	-	-	7	-	10	16	-	-	-	-	16	15	-	-		-	15
8	Total Wholesale - Utility	2	-	-	734	-	736	16	-	-	805	-	821	87	-	-	817	-	904
	Contract																		
9	Rate M4	514	-	-	11,786	-	12,300	1,114	602	-	13,022	-	14,738	1,510	708	-	15,088	-	17,306
10	Rate M7	-	-	-	4,127	-	4,127	2,964	256	-	8,961	-	12,180	841	267	-	9,903	-	11,011
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	434	-	-	2,425	10,637	13,496	335	-	-	2,013	11,902	14,250	462	-	-	2,117	11,125	13,705
13	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Rate 100 Transportation	-	-	-	-	15,481	15,481	-	-	-	-	12,423	12,423	-	-	-	-	12,626	12,626
15	Rate T-1 Storage	-	-	-	-	1,400	1,400	-	-	-	-	1,367	1,367	-	-	-	-	1,368	1,368
16	Rate T-1 Transportation	-	-	-	-	9,241	9,241	-	-	-	-	8,697	8,697	-	-	-	-	8,773	8,773
17	Rate T-2 Storage	-	-	-	-	5,976	5,976	-	-	-	-	7,769	7,769	-	-	-	-	7,700	7,700
18	Rate T-2 Transportation	-	-	-	-	36,193	36,193	-	-	-	-	43,278	43,278	-	-	-	-	45,839	45,839
19	Rate T-3 Storage	-	-	-	-	1,345	1,345	-	-	-	-	1,420	1,420	-	-	-	-	1,344	1,344
20	Rate T-3 Transportation	-	-	-	-	3,054	3,054	-	-	-	-	3,426	3,426	-	-	-	-	3,721	3,721
21	Rate M5	375	-	-	12,913	-	13,288	275	92	-	5,767	-	6,134	351	154	-	5,965	-	6,470
22	Rate 25	1,200	-	-	-	3,273	4,473	2,315	-	-	-	1,609	3,924	1,398	-	-	-	2,173	3,571
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	2,524	-	-	31,250	86,601	120,375	7,003	950	-	29,763	91,892	129,607	4,563	1,129	-	33,073	94,671	133,436
25	Subtotal	454,058	123,643	27,301	50,143	86,601	741,747	556,382	69,252	4,817	49,126	92,381	771,959	559,077	62,253	1,985	53,288	95,096	771,698
26	LRAM						-						(872)						538
27	Average Use / Normlalized Average Consumption						-						8,478						19,442
28	Parkway Obligation Rate Variance						-						(1)						2,861
29	Capital Pass Through						-						553						2,539
30	Total Revenue						$ 741,747						780,117						797,079

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

		Board Apprroved 2013						Actual 2015						Actual 2016					
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	1,003,873	74,656	9,991	1,113	-	1,089,633	1,037,178	64,868	2,388	1,063	-	1,105,497
2	Rate M2 Firm	3,172	2,594	241	771	-	6,778	4,429	2,457	29	837	-	7,752	4,371	2,382	22	833	-	7,608
3	Rate 01 Firm	242,644	80,300	-	343	-	323,287	305,931	30,287	-	639	-	336,857	318,440	23,853	-	653	-	342,946
4	Rate 10 Firm	930	845	-	289	-	2,064	1,312	579	-	324	5	2,220	1,283	570	-	332	5	2,190
5	Total General Service	1,084,047	240,904	72,630	2,305	-	1,399,886	1,315,545	107,979	10,020	2,913	5	1,436,462	1,361,272	91,673	2,410	2,881	5	1,458,241
	Wholesale - Utility																		
6	Rate M9 Firm	-	-	-	3	-	3	-	-	-	2	-	2	1	-	-	2	-	3
7	Rate M10 Firm	1	-	-	1	-	2	2	-	-	-	-	2	2	-	-		-	2
8	Total Wholesale - Utility	1	-	-	4	-	5	2	-	-	2	-	4	3	-	-	2	-	5
	Contract																		
9	Rate M4	11	-	-	104	-	115	18	9	-	132	-	159	23	10	-	145	-	178
10	Rate M7	-	-	-	4	-	4	2	1	-	25	-	28	2	1	-	27	-	30
11	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rate 20 Transportation	4	-	-	20	39	63	3	-	-	16	28	47	4	-	-	16	27	47
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	-	-	-	-	37	37
17	Rate T-2 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Rate T-2 Transportation	-	-	-	-	29	29	-	-	-	-	22	22	-	-	-	-	23	23
19	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Rate T-3 Transportation	-	-	-	-	1	1	-	-	-	-	1	1	-	-	-	-	1	1
21	Rate M5	5	-	-	139	-	144	6	2	-	67	-	75	7	2	-	54	-	63
22	Rate 25	50	-	-	-	42	92	31	-	-	-	47	78	39	-	-	-	45	84
23	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Contract	70	-	-	267	163	500	60	12	-	240	146	458	75	13	-	242	144	474
25	Total Number of Customers	1,084,118	240,904	72,630	2,576	163	1,400,391	1,315,607	107,991	10,020	3,155	151	1,436,924	1,361,350	91,686	2,410	3,125	149	1,458,720

*Customer count for storage is included within transportation

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

Line No.	Particulars ($000s)	2013 Board-Approved	2015 Actual	2016 Actual
		(a)	(b)	(c)
	Revenue from Regulated Storage Services:			
1	C1 Off-Peak Storage	500	603	2,749
2	Supplemental Balancing Services	2,000	1,283	2,335
3	Gas Loans	-	38	19
4	C1 Short Term Firm Peak Storage	7,883	4,935	5,627
5	Short Term Storage and Balancing Services Deferral	-	508	(2,226)
6	Total Regulated Storage Revenue Net of Deferral	$ 10,383	$ 7,368	$ 8,503
	Revenue from Regulated Transportation Services:			
7	M12 Transportation	120,963	120,975	145,913
8	M12-X Transportation	13,896	15,445	17,130
9	C1 Long Term Transportation	7,039	6,807	9,154
10	C1 Short Term Transportation	11,067	10,007	7,923
11	Gross Exchange Revenue	14,918	7,739	3,358
12	Ratepayer Portion of Exchange Revenue	(13,426)	(6,965)	(3,022)
13	M13 Local Production	424	346	359
14	M16 Transportation	694	578	599
15	Other S&T Revenue	1,423	1,311	1,270
16	Total Regulated Transportation Revenue Net of Deferral	$ 156,997	$ 156,244	$ 182,683

UNION GAS LIMITED
Other Revenue
Year Ended December 31

Line No.	Particulars ($000's)	2013 Board Approved	2015 Actual	2016 Actual
1	Delayed payment charges	6,467	8,091	5,147
2	Account opening charges	7,000	6,953	6,817
3	Billing revenue	3,453	1,873	1,652
4	Mid market transactions	2,000	955	1,139
5	Other operating revenue	1,278	2,030	1,775
6	Total other revenue	$ 20,198	$ 19,902	$ 16,530

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

Line No.	Particulars ($000s)	2013 Board-Approved	2015 Actual	2016 Actual
		(a)	(b)	(c)
1	Salaries/Wages	192,786	210,164	209,763
2	Benefits	81,083	67,939	63,498
3	Materials	9,958	8,852	8,757
4	Employee Training	14,330	12,962	13,189
5	Contract Services	66,376	70,933	68,775
6	Consulting	8,172	8,226	9,566
7	General	18,890	25,380	25,927
8	Transportation and Maintenance	9,761	9,817	9,676
9	Company Used Gas	2,611	2,689	2,048
10	Utility Costs	4,682	5,102	6,007
11	Communications	6,380	5,900	6,054
12	Demand Side Management Programs	24,031	24,593	45,960
13	Advertising	2,386	2,843	3,106
14	Insurance	9,056	8,548	8,126
15	Donations	788	1,713	3,207
16	Financial	1,871	2,307	2,626
17	Lease	4,191	4,705	4,627
18	Cost Recovery from Third Parties	(2,549)	(5,105)	(4,898)
19	Computers	6,465	8,109	10,867
20	Regulatory Hearing & OEB Cost Assessment	4,300	3,467	3,964
21	Outbound Affiliate Services	(13,706)	(15,454)	(15,905)
22	Inbound Affiliate Services	11,888	19,949	22,008
23	Bad Debt	6,250	5,700	3,650
24	Other	139		-
25	Total	470,139	489,339	510,596
26	Indirect Capitalization	(51,376)	(67,343)	(71,964)
27	Direct Capitalization	(21,652)	(22,926)	(24,136)
28	Total	397,111	399,070	414,496
29	Unregulated Storage	(12,883)	(14,771)	(13,410)
30	Non Utility Earnings Adjustments	(1,096)	(1,315)	(3,227)
31	Total Non Utility Costs	(13,979)	(16,086)	(16,637)
32	Total Net Utility Operating and Maintenance Expense	$ 383,132	$ 382,984	$ 397,858

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

Line No.	Particulars ($000s)	2013 Board-Approved	2015 Actual	2016 Actual
		(a)	(b)	(c)
	Determination of Taxable Income			
1	Utility income before interest and income taxes	291,239	323,562	326,160
	Adjustments required to arrive at taxable utility income:			
2	Interest expense	(149,464)	(153,766)	(160,009)
3	Utility permanent differences	4,693	3,468	3,857
4		146,468	173,264	170,008
	Utility timing differences			
5	Capital Cost Allowance	(185,314)	(222,048)	(270,300)
6	Depreciation	196,091	212,219	228,401
7	Depreciation through clearing	2,265	2,586	3,044
8	Other	(32,921)	(58,463)	(66,185)
9	Gas Cost Deferrals and Other (current)	-	114,807	(78,363)
10		(19,879)	49,101	(183,403)
11	Taxable income	$ 126,589	$ 222,365	$ (13,395)
	Calculation of Utility Income Taxes			
12	Income taxes (line 11 * line 18)	32,280	58,927	(3,550)
13	Deferred tax on Gas Cost Deferrals	-	(30,424)	20,766
14	Deferred tax drawdown	(15,169)	(12,819)	(12,819)
15	Total taxes	$ 17,111	$ 15,684	$ 4,398
	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)	Rate (%) (b)	CCA (c)	2015 Actual Depreciable UCC Balance (d)	Rate (%) (e)	CCA (f)	2016 Actual Depreciable UCC Balance (g)	Rate (%) (h)	CCA (i)
	Class										
1	1	Buildings, structures and improvements, services, meters, mains	1,259,974	4%	50,399	1,201,975	4%	48,079	1,171,075	4%	46,843
2	1	Non-residential building acquired after March 19, 2007	83,527	6%	5,012	103,367	6%	6,202	110,417	6%	6,625
3	2	Mains acquired before 1988	147,495	6%	8,850	130,333	6%	7,820	122,500	6%	7,350
4	3	Buildings acquired before 1988	4,279	5%	214	3,860	5%	193	3,660	5%	183
5	6	Other buildings	173	10%	17	140	10%	14	130	10%	13
6	7	Compression equipment acquired after February 22, 2005	165,697	15%	24,855	207,713	15%	31,157	358,627	15%	53,794
7	8	Compression assets, office furniture, equipment	79,640	20%	15,928	133,160	20%	26,632	162,925	20%	32,585
8	10	Transportation, computer equipment	18,611	30%	5,583	19,913	30%	5,974	16,963	30%	5,089
9	12	Computer software, small tools	7,701	100%	7,701	9,307	100%	9,307	4,696	100%	4,696
10	13	Leasehold improvements (1)	332	N/A	113	2,164	N/A	787	2,396	N/A	628
11	17	Roads, sidewalk, parking lot or storage areas	946	8%	76	800	8%	64	738	8%	59
12	38	Heavy work equipment	6,878	30%	2,063	4,197	30%	1,259	3,340	30%	1,002
13	41	Storage assets	8,019	25%	2,005	4,112	25%	1,028	4,152	25%	1,038
14	45	Computers - Hardware acquired after March 22, 2004	246	45%	111	73	45%	33	40	45%	18
15	49	Transmission pipeline additions acquired after February 23, 2005	204,628	8%	16,370	302,425	8%	24,194	485,350	8%	38,828
16	50	Computers hardware acquired after March 18, 2007	22,934	55%	12,614	18,905	55%	10,398	23,156	55%	12,736
17	51	Distribution pipelines acquired after March 18, 2007	556,733	6%	33,404	815,117	6%	48,907	980,217	6%	58,813
18		Total	$ 2,567,813		$ 185,314	$ 2,957,562		$ 222,048	$ 3,450,381		$ 270,300

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	2015 Actual	2016 Actual
1	Total provision for depreciation and amortization before adjustments (per page 3)	-	215,174	231,445
2	Adjustments: vehicle depreciation through clearing	-	2,955	3,044
3	Provision for depreciation amortization and depletion	$ -	$ 212,219	$ 228,401

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

		2013 Board-Approved			2015 Actual			2016 Actual		
Line No.	Particulars ($000s)	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Intangible plant:									
1	Franchises and consents	-		-	$ 1,237	Amortized	63	1,211	Amortized	62
2	Intangible plant - Other	-		-	6,347	Amortized	122	6,347	Amortized	122
3		-		-	7,583		185	7,558		184
	Local Storage Plant									
4	Structures and improvements	-	2.85%	-	3,938	2.85%	112	4,123	2.85%	118
5	Gas holders - storage	-	2.54%	-	4,574	2.54%	116	4,586	2.54%	116
6	Gas holders - equipment	-	3.54%	-	16,065	3.54%	569	16,805	3.54%	595
7		-		-	24,577		797	25,515		829
	Storage:									
8	Land rights	-	2.10%	-	31,984	2.10%	672	31,985	2.10%	672
9	Structures and improvements	-	2.50%	-	61,652	2.50%	1,541	62,159	2.50%	1,554
10	Wells and lines	-	2.48%	-	89,863	2.48%	2,229	90,391	2.48%	2,242
11	Compressor equipment	-	2.68%	-	239,963	2.68%	6,431	255,366	2.68%	6,844
12	Measuring & regulating equipment	-	3.11%	-	56,603	3.11%	1,760	58,272	3.11%	1,812
13	Other equipment	-			2,394		474	1,197		0
14		-		-	482,460		13,107	499,370		13,123
	Transmission:									
15	Land rights	-	1.76%	-	41,023	1.76%	722	49,754	1.76%	876
16	Structures and improvements	-	2.03%	-	86,725	2.03%	1,761	115,799	2.03%	2,351
17	Mains	-	1.98%	-	1,215,369	1.98%	24,064	1,421,508	1.98%	28,146
18	Compressor equipment	-	3.23%	-	431,172	3.23%	13,927	597,214	3.23%	19,290
19	Measuring & regulating equipment	-	2.60%	-	193,205	2.60%	5,023	223,081	2.60%	5,800
20		-		-	1,967,494		45,497	2,407,357		56,463
	Distribution - Southern Operations:									
21	Land rights	-	1.65%	-	6,592	1.65%	109	7,040	1.65%	116
22	Structures and improvements	-	2.22%	-	129,494	2.22%	2,901	131,482	2.22%	2,934
23	Services - metallic	-	2.81%	-	119,504	2.81%	3,358	121,858	2.81%	3,424
24	Services - plastic	-	2.51%	-	816,547	2.51%	20,495	838,168	2.51%	21,038
25	Regulators	-	5.00%	-	66,525	5.00%	3,385	72,811	5.00%	3,641
26	Regulator and meter installations	-	2.80%	-	70,457	2.80%	1,940	71,295	2.80%	1,996
27	Mains - metallic	-	2.83%	-	448,560	2.83%	12,694	466,282	2.83%	13,196
28	Mains - plastic	-	2.31%	-	566,435	2.31%	13,085	585,316	2.31%	13,521
29	Measuring & regulating equipment	-	3.66%	-	36,098	3.66%	1,321	39,378	3.66%	1,441
30	Meters	-	3.82%	-	258,217	3.82%	9,864	276,539	3.82%	10,564
31	Other equipment	-		-	-		-	-		-
32		-		-	$ 2,518,431		$ 69,152	$ 2,610,170		$ 71,871

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

		2013 Board-Approved			2015 Actual			2016 Actual		
Line No.	Particulars ($000s)	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision	Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Distribution plant - Northern & Eastern Operations:									
1	Land rights	-	1.71%	-	$ 9,666	1.71%	165	9,804	1.71%	168
2	Structures & improvements	-	2.41%	-	64,478	2.41%	1,554	64,866	2.41%	1,563
3	Services - metallic	-	3.22%	-	101,243	3.22%	3,260	103,044	3.22%	3,318
4	Services - plastic	-	2.60%	-	417,625	2.60%	10,858	433,331	2.60%	11,267
5	Regulators	-	5.00%	-	26,959	5.00%	1,348	28,454	5.00%	1,423
6	Regulator and meter installations	-	2.92%	-	30,413	2.92%	888	30,490	2.92%	890
7	Mains - metallic	-	3.02%	-	421,221	3.02%	12,721	445,850	3.02%	13,465
8	Mains - plastic	-	2.38%	-	217,028	2.38%	5,165	220,854	2.38%	5,256
9	Compressor equipment	-		-	-	-	-	-	-	-
10	Measuring & regulating equipment	-	3.77%	-	125,249	3.77%	4,722	128,996	3.77%	4,863
11	Meters	-	4.03%	-	67,927	4.03%	2,737	74,225	4.03%	2,991
12	Other distribution equipment	-		-	-	-	-	-	-	-
13		-		-	1,481,810		43,419	1,539,913		45,204
	General:									
14	Structures and improvements	-	1.92%		53,555	1.92%	1,927	58,734	1.92%	2,068
15	Office furniture and equipment	-	6.67%	-	11,773	6.67%	780	11,000	6.67%	726
16	Office equipment - computers	-	25.00%	-	76,413	25.00%	18,117	72,901	25.00%	16,252
17	Transportation equipment	-	13.27%	-	53,310	13.27%	7,132	54,218	13.27%	7,182
18	Heavy work equipment	-	6.92%	-	14,940	6.92%	1,043	14,867	6.92%	1,028
19	Tools and other equipment	-	6.67%	-	33,424	6.67%	2,213	33,618	6.67%	2,237
20	Communications equipment & structures	-	6.67%	-	15,517	6.67%	1,026	14,899	6.67%	982
21	Other equipment	-		-	-	-	-	-	-	-
22		-		-	258,933		32,239	260,238		30,475
23	Regulatory Assets	-		-	321,738		10,779	397,634		13,296
24	Sub-total	-		-	7,063,026		215,174	7,747,753		231,445
25	Total provision for depreciation and amortization			-			215,174			231,445
26	Depreciation through clearing			-			2,955			3,044
27		-		-	$ 7,063,026		$ 212,219	$ 7,747,753		$ 228,401

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	2015 Actual	2016 Actual
		(a)	(b)	(c)
1	Storage	11,562	19,699	158,941
2	Transmission	113,795	381,068	583,285
3	Distribution	131,797	172,968	182,522
4	General	37,215	44,508	30,432
5	Other	53,333	73,106	78,778
6	Total	$ 347,702	$ 691,349	$ 1,033,958
	Less: Parkway West Reliability, and Brantford-Kirkwall/Parkway D Project	80,000	206,233	24,128
		$ 267,702	$ 485,116	$ 1,009,830

Notes:

(1) 2015 Dawn H capital costs of $13,783 reclassified from Transmission to Storage in accordance with the OEB system of accounts

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

Line No.	Particulars ($000s)	2013 Board-Approved (a)	2015 Actual (b)	2016 Actual (c)
	Gas Utility Plant			
1	Gross plant at cost	6,361,532	7,029,496	7,682,951
2	Less: accumulated depreciation	(2,754,070)	(2,994,815)	(3,149,165)
3	Net utility plant	3,607,462	4,034,681	4,533,786
	Working Capital and Other Components			
4	Cash working capital	20,007	20,688	21,205
5	Gas in storage and line pack gas	163,109	180,264	184,471
6	Balancing gas	72,963	68,895	67,090
7	ABC receivable (gas in storage)	(44,901)	(27,915)	(12,985)
8	Inventory of stores, spare equipment	29,618	26,773	28,974
9	Prepaid and deferred expenses	4,955	5,603	4,857
10	Customer deposits	(48,231)	(38,584)	(39,380)
11	Customer interest	(764)	(179)	(107)
12	Total working capital and other components	196,757	235,545	254,125
13	Total rate base before deduction of accumulated deferred income taxes	3,804,218	4,270,226	4,787,911
14	Accumulated deferred income taxes	(69,686)	(41,831)	(29,493)
15	Total rate base	$ 3,734,532	$ 4,228,395	$ 4,758,418

UNION GAS LIMITED
Allocation of Fuel

Line No.	Particulars (GJ)	Board-Approved	%	2016 Actual	%	2015 Actual	%	2014 Actual	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	M12	3,616,843	77%	1,746,256	85%	2,115,225	62%	1,862,928	63%
2	Other	1,057,714	23%	314,761	15%	1,286,425	38%	1,093,774	37%
3	Total Fuel	4,674,557	100%	2,061,017	100%	3,401,650	100%	2,956,702	100%

UNION GAS LIMITED
Earnings Sharing Calculation
Calendar Year Ending December 31, 2016

Line No.	Particulars ($000s)	2016 (a)	Unregulated Storage (b)	Adjustments (c)		2016 Utility (d)=(a)-(b)+(c)
	Operating Revenues					
1	Gas Sales	1,529,204	-	(14,668)	i	1,514,537
2	Transportation	182,195	(488)	-		182,683
3	Storage	95,598	87,095	-		8,503
4	Other	20,768	-	(4,237)	ii	16,530
5		1,827,765	86,607	(18,905)		1,722,253
	Operating Expenses					
6	Cost of gas	716,827	1,715	(14,668)	i	700,444
7	Operating and maintenance expenses	414,496	13,410	(3,228)	iii	397,858
8	Depreciation	239,080	10,679	-		228,401
9	Other financing	-	-	985	iv	985
10	Property and other taxes	71,199	1,635	-		69,564
11		1,441,601	27,439	(16,910)		1,397,252
	Other					
12	Gain / (Loss) on sale of assets	(624)	(624)	-		-
13	Other / Huron Tipperary	-	-	-		-
14	Gain / (Loss) on foreign exchange	1,592	39	(394)	v	1,159
15		967	(585)	(394)		1,159
16	Earnings before interest and taxes	387,132	58,583	(2,389)		326,160
17	Income taxes					4,398
18	Total utility income subject to earnings sharing					321,762
	Less debt and preference share return components					
19	Long-term debt					161,809
20	Unfunded short-term debt					(1,800)
21	Preferred dividend requirements					2,597
22						162,606
	Less shareholder portions of:					
23	Net short-term storage revenue (after tax)					553
24	Net optimization activity (after tax)					247
25						800
26	Earnings subject to sharing					158,356
27	Common equity					1,713,030
28	Return on common equity (line 26 / line 27)					9.24%
29	Benchmark return on common equity + 100 basis points					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	3,089
	CDM program	139
		3,228

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, 2016

Line No.	Particulars ($000's)	Balance Dec. 31/15 (a)	Capital Additions (b)	Transfers (c)	Retirements (d)	Balance Dec. 31/16 (e)
	Unregulated Gas Plant in Service:					
	Underground storage plant:					
1	Land	$ 2,129	28	-	-	$ 2,156
2	Land rights	29,930	-	-	-	29,930
3	Structures and improvements	25,675	61	(2)	-	25,733
4	Wells and lines	118,390	1,092	49	(515)	119,016
5	Compressor equipment	162,826	589	297	(0)	163,711
6	Measuring & regulating equipment	24,368	588	15	-	24,971
7	Base pressure gas	27,702	1,778	-	-	29,481
8	Other equipment	-	-	-	-	-
9		$ 391,021	4,135	358	(515)	$ 394,999
	General plant:					
10	Land	$ 17	-	-	-	$ 17
11	Structures & improvements	2,041	25	-	(7)	2,058
12	Office furniture & equipment	411	0	-	(45)	367
13	Office equipment - computers	7,020	551	-	(4,421)	3,150
14	Transportation equipment	2,355	117	0	(107)	2,365
15	Heavy work equipment	669	2	(0)	(13)	658
16	Tools & work equipment	1,139	133	-	(75)	1,197
17	Communication equipment	547	15	-	(102)	460
18	Other general equipment	-	-	-	-	-
19		$ 14,199	844	-	(4,771)	$ 10,271
20	Total gas plant in service	$ 405,220	4,979	358	(5,287)	$ 405,270
21	Gas plant under construction	8,708	5,701			14,409
22	Total unregulated property plant and equipment	$ 413,928	10,680	358	(5,287)	$ 419,679

UNION GAS LIMITED
Continuity of Accumulated Depreciation
Calendar Year Ending December 31, 2016

Line No.	Particulars ($000's)	Balance Dec. 31/15	Transfers	Provisions	Retirements	Net Salvage /(Costs)	Balance Dec. 31/16
		(a)	(b)	(c)	(d)	(e)	(f)
	Unregulated Gas Plant in Service:						
	Underground storage plant:						
1	Land rights	$ 9,328	-	613	-	-	$ 9,941
2	Structures & improvements	10,011	(2)	775	-	-	10,783
3	Wells and lines	33,224	41	2,493	(309)	-	35,450
4	Compressor equipment	52,723	164	4,420	(0)	-	57,307
5	Measuring & regulating equipment	11,842	16	519	-	-	12,377
6		$ 117,128	218	8,820	(309)	-	$ 125,858
	General plant:						
7	Structures & improvements	356	-	94	(7)	-	442
8	Office furniture & equipment	183	-	33	(45)	-	171
9	Office equipment - computers	5,275		1,211	(4,421)	-	2,065
10	Transportation equipment	996	0	326	(107)	11	1,226
11	Heavy work equipment	73	(0)	47	(13)	-	106
12	Tools and other equipment	562	-	83	(75)	-	570
13	Communication equipment	309	-	45	(102)	-	252
14		$ 7,754	-	1,837	(4,770)	11	$ 4,831
15	Total unregulated gas plant in service	$ 124,882	218	10,657	(5,079)	11	$ 130,689

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2016

Line No.	Particulars ($000's)	UNREGULATED
1	Total unregulated provision for depreciation and amortization before adjustments (per page 2)	10,657
	Adjustments:	
2	Vehicle depreciation through clearing	(17)
3	Asset Retirement Obligation expense for Unregulated storage wells	39
4	Unregulated provision for depreciation amortization and depletion	**10,679**

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2016

Line No.	Particulars ($000's)	Average Plant (1) (a)	Rate (%) (b)	Total Provision
	Storage:			
1	Land rights	$ 29,930	Allocation	$ 613
2	Structures and improvements	24,083	Allocation	775
3	Wells and lines	116,083	Allocation	2,493
4	Compressor equipment	159,252	Allocation	4,420
5	Measuring & regulating equipment	22,773	Allocation	519
6	Other equipment	-		
7		$ 352,120		$ 8,820
	General:			
8	Structures & improvements	$ 2,050	Allocation	$ 94
9	Office furniture and equipment	389	Allocation	33
10	Office equipment - computers	5,085	Allocation	1,211
11	Transportation equipment	2,360	Allocation	326
12	Heavy work equipment	664	Allocation	47
13	Tools and other equipment	1,169	Allocation	83
14	Communications equipment	503	Allocation	45
15	Other equipment	-		
16		$ 12,219		$ 1,837
17	Sub-total	364,340		10,657
18	Total unregulated provision for depreciation and amortization before adjustments			$ 10,657
19	Vehicle depreciation through clearing			(17)
20	Asset Retirement Obligation expense for Unregulated storage wells			39
21	Unregulated provision for depreciation amortization and depletion	364,340		$ **10,679**

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-16	80,039	88,889	90.0
Feb-16	66,267	72,835	91.0
Mar-16	64,608	78,866	81.9
Apr-16	95,951	125,246	76.6
May-16	71,094	91,052	78.1
Jun-16	68,195	85,551	79.7
Jul-16	83,973	107,817	77.9
Aug-16	66,102	82,687	79.9
Sep-16	71,813	90,056	79.7
Oct-16	79,307	119,441	66.4
Nov-16	71,854	84,662	84.9
Dec-16	70,743	83,791	84.4
Total	889,946	1,110,893	80.1

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-16	1,157	70,799	1.6
Feb-16	847	57,963	1.5
Mar-16	1,934	62,577	3.1
Apr-16	4,094	100,122	4.1
May-16	2,822	73,826	3.8
Jun-16	2,155	70,885	3.0
Jul-16	4,992	86,903	5.7
Aug-16	2,482	67,617	3.7
Sep-16	2,529	72,531	3.5
Oct-16	5,818	98,554	5.9
Nov-16	1,905	69,907	2.7
Dec-16	1,431	67,755	2.1
Total	32,166	899,439	3.6

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.B - BILLING PERFORMANCE
S.2.1.9.B - Billing Performance
Measurement Calculation: The billing performance standard is a quality assurance standard. The standard requires gas distributors to have a verifiable quality assurance program in place. No specific metric is attached to this requirement.
OEB Approved Standard: Manual checks must be done to validate data when meter reads fall outside criteria, as set out in the quality assurance program, for excessively high or low usage.

Month	**Total Number of Billings** (1)	**Total Number of Manual Checks Done as per QAP** (2)	**Total Number of Manual Checks Done When Meter Reads Show Excessively High Usage as per QAP Criteria** (3)	**Brief Explanation for Excessively High Usage (In 100 Words or less)** (4)	**Total Number of Manual Checks Done When Meter Reads Show Excessively Low Usage as per QAP Criteria** (5)	**Brief Explanation for Excessively Low Usage (In 100 Words or less)** (6)
January	1,445,655	13,167	3,628	Change in load, previously low	5,335	Vacant, seasonal use (crop
February	1,445,502	14,457	5,031	estimate/read, previous vacant,	6,069	dryer), stopped meter,
March	1,446,216	12,153	6,449	seasonal use.	2,402	previous high estimate/read.
April	1,448,331	11,672	9,189		77	
May	1,451,710	13,201	10,070		1,257	
June	1,443,138	16,959	12,085		3,156	
July	1,455,945	15,834	13,356		206	
August	1,457,528	19,634	17,240		200	
September	1,458,378	17,055	13,701		943	
October	1,483,931	14,873	11,990		549	
November	1,461,654	12,337	9,242		57	
December	1,466,852	10,039	6,430		114	
Total	17,464,840	171,381	118,411		20,365	

S.2.1.9 SERVICE QUALITY REQUIREMENTS (SQR) FORM
S.2.1.9.C – METER READING PERFORMANCE
S.2.1.9.C.1 Meter Reading Performance Measurement (MRPM)
Measurement Calculation: MRPM = Number of meters with no read for 4 consecutive months of more divided by the total number of active meters to be read (MRPM should be rounded to the first decimal number, e.g. 0.45% becomes 0.5%)
OEB Approved Standard: Measurement shall not exceed 0.5% on a yearly basis

Month	Number of meters with no read for consecutive 4 months or more (1)	Total number of active meters to be read (2)	Meter reading performance measurement (%) (3 = 1 / 2 * 100)
Jan-16	1,021	1,432,064	0.1
Feb-16	1,410	1,433,076	0.1
Mar-16	2,773	1,433,398	0.2
Apr-16	2,814	1,433,830	0.2
May-16	1,624	1,433,852	0.1
Jun-16	1,018	1,433,921	0.1
Jul-16	1,200	1,434,395	0.1
Aug-16	1,165	1,435,331	0.1
Sep-16	1,801	1,437,477	0.1
Oct-16	2,263	1,441,081	0.2
Nov-16	1,474	1,445,361	0.1
Dec-16	2,184	1,448,236	0.2
Total	20,747	17,242,022	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-2016	13,995	14,170	98.8%
Feb-2016	15,604	15,723	99.2%
Mar-2016	17,824	17,987	99.1%
Apr-2016	15,451	15,549	99.4%
May-2016	15,524	15,697	98.9%
Jun-2016	15,511	15,749	98.5%
Jul-2016	13,260	13,439	98.7%
Aug-2016	14,558	14,754	98.7%
Sep-2016	16,504	16,734	98.6%
Oct-2016	18,341	18,564	98.8%
Nov-2016	18,515	18,742	98.8%
Dec-2016	12,223	12,341	99.0%
TOTAL	187,310	189,449	98.9%

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-2016	175	175		100.0%
Feb-2016	119	119		100.0%
Mar-2016	163	162	The Rep had responded to an emergency and the dispatcher said they would take care of the order. It was forgotten and not handled in the AM. Customer was not contacted.	99.4%
Apr-2016	98	98		100.0%
May-2016	173	173		100.0%
Jun-2016	238	238		100.0%
Jul-2016	179	179		100.0%
Aug-2016	196	196		100.0%
Sep-2016	230	229	Assigned to "dummy" WAD by planner, contact centre booked and didn't ask for order to be unassigned.	99.6%
Oct-2016	223	223		100.0%
Nov-2016	227	226	USR went home sick at 1 p.m. Poor communication to dispatcher. Didn't contact customer informing them that we were late, arrived at 2:42 p.m.	99.6%
Dec-2016	118	117	USR thought dispatcher was going to rebook. Dispatcher did not catch AM timeslot.	99.2%
TOTAL	2139	2135		99.8%

S.2.1.9 SERVICE QUALITY REQUIREMENTS FOR (SQR) FORM
S.2.1.9.E - GAS EMERGENCY RESPONSE
S.2.1.9.E.1 - Percentage of Emergency Calls Responded Within One Hour (ECRWOH)
Measurement Calculation: ECRWOH - Number of emergency calls responded to within 60 minutes divided by total number of emergency calls in the year.
OEB Approved Standard: The minimum performance standard shall be that 90% of customers have received a response within 60 minutes of their call reaching a live person. The standard shall be calculated on an annual basis.

	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-2016	1,264	1,274	99.2%
Feb-2016	1,063	1,077	98.7%
Mar-2016	988	995	99.3%
Apr-2016	962	972	99.0%
May-2016	1,083	1,095	98.9%
Jun-2016	1,067	1,082	98.6%
Jul-2016	1,013	1,025	98.8%
Aug-2016	1,174	1,200	97.8%
Sep-2016	1,101	1,113	98.9%
Oct-2016	1,235	1,244	99.3%
Nov-2016	1,256	1,264	99.4%
Dec-2016	1,080	1,106	97.6%
TOTAL	13,286	13,447	98.8%

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-16	240	240	100.0
Feb-16	366	366	100.0
Mar-16	399	399	100.0
Apr-16	605	605	100.0
May-16	503	503	100.0
Jun-16	470	470	100.0
Jul-16	395	395	100.0
Aug-16	443	443	100.0
Sep-16	429	429	100.0
Oct-16	440	440	100.0
Nov-16	425	425	100.0
Dec-16	356	356	100.0
Total	5,071	5,071	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-2016	221	272	81.3%
Feb-2016	53	75	70.7%
Mar-2016	58	65	89.2%
Apr-2016	587	609	96.4%
May-2016	1,125	1,268	88.7%
Jun-2016	802	847	94.7%
Jul-2016	664	779	85.2%
Aug-2016	629	727	86.5%
Sep-2016	945	1,133	83.4%
Oct-2016	1,198	1,445	82.9%
Nov-2016	590	740	79.7%
Dec-2016	267	321	83.2%
TOTAL	7,139	8,281	86.2%

ALLOCATION AND DISPOSITION OF 2016 DEFERRAL ACCOUNT BALANCES AND 2016 EARNINGS SHARING AMOUNT

The purpose of this evidence is to address the allocation and disposition of 2016 deferral account balances identified at Tab 1, Appendix A, Schedule 1. There are no 2016 earnings sharing to allocate to rate classes, as described at Tab 2.

The allocation of 2016 deferral account balances to rate classes appears at Tab 3, Appendix A, Schedule 1. 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. Tab 3, Appendix A, Schedule 3, provides the estimated bill impacts of the proposed disposition for general service customers in Union South and Union North.

With the exception of the Unaccounted for Gas (UFG) Volume Variance Account (179-135), Unauthorized Overrun Non-Compliance Account (179-143), Lobo D/Bright C/ Dawn H Compressor Project Costs (179-144), Burlington-Oakville Project Costs (179-149), OEB Cost Assessment Variance Account (179-151), Greenhouse Gas Emission Impact Account (179-152), and Base Service North T-Service TransCanada Capacity (179-153) the allocation of 2016 deferral account balances to rate classes is consistent with the allocation methodologies approved by the Board in EB-2016-0118 (Union's 2015 Deferral Account Disposition proceeding) or in EB-2011-0210 (Union's 2013 Cost of Service proceeding).

2015 GAS SUPPLY RELATED DEFERRAL ACCOUNTS

The gas supply related deferral accounts include: the Spot Gas Variance Account (179-107), the Unabsorbed Demand Cost ("UDC") Variance Account (179-108), the Gas Supply Review Account (179-128), the Upstream Transportation Optimization Account (179-131), and the gas supply commodity and gas supply transportation-related balances in the Deferral Clearing Variance Account (179-132).

Spot Gas Variance Account

There is no balance in the Spot Gas Variance Account (179-107) at December 31, 2016.

Unabsorbed Demand Cost Variance Account

Union proposes that the balance in the UDC Variance Account (179-108) related to Union North be allocated to the firm Rate 01, Rate 10 and Rate 20 sales service and bundled DP customers in proportion to 2013 Board-approved excess of peak day demands over average annual demands. This allocation is consistent with the allocation of UDC in approved 2016 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 (179-108) related to Union South be allocated to sales service customers only based on forecast sales service volumes.

Gas Supply Review Consultant Costs

There is no balance in the Gas Supply Review Consultant Costs Deferral Account (179-128) at December 31, 2016.

Upstream Transportation Optimization

Union proposes to allocate the balance in the Upstream Transportation Optimization Deferral Account (179-131) between Union North and Union South rate classes based on the upstream transportation contracts used to serve each delivery area. Transportation optimization net revenues generated using upstream transportation and STS contracts designed to serve Union North (with delivery points of Centrat MDA, Union WDA, Union SSMDA, Union NDA, Union NCDA and Union EDA) have been allocated to Union North. Transportation optimization net revenues generated using upstream transportation contracts designed to serve Union South have been allocated to Union South. Specifically, with respect to capacity assignments, the net revenue from each capacity assignment has been attributed to either the Union North or Union South based on the delivery point.

Union proposes that the portion of the balance related to Union North be allocated to rate classes in proportion to the allocation of 2013 Board-approved TransCanada FT transportation demand costs. This approach ensures that transportation optimization margin is allocated to Union North sales service and bundled DP customers consistent with the manner in which this margin is included in Board-approved gas supply transportation rates.

Union proposes that the portion of the balance related to Union South be allocated to sales service customers only based on forecast sales service volumes. This approach is consistent with the manner in which this margin is included in approved gas supply transportation rates.

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 (179-132) to rate classes based on the differences between the forecast and actual volumes associated with the disposition of deferral account balances for each rate class, per Tab 1, Appendix A, Schedule 6.

2015 NON- GAS SUPPLY RELATED DEFERRAL ACCOUNTS

Non-gas supply related deferral accounts can be divided into two groups: storage-related deferral accounts and other deferral accounts.

STORAGE-RELATED DEFERRAL ACCOUNTS

Union proposes to allocate the balance in the Short-Term Storage and Other Balancing Services Deferral Account (179-70) 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 and Rate 20 in proportion to the 2013 Board-approved excess of peak day demands over average day demands. This approach is consistent with the 2013 Board-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 Union's 2016 Rates.

OTHER DEFERRAL ACCOUNTS

There is no balance in the Unbundled Services Unauthorized Storage Overrun Deferral Account (179-103) at December 31, 2016.

Union proposes to allocate the balance in the Gas Distribution Access Rule (GDAR) Costs Deferral Account (179-112) in proportion to the 2013 Board-approved average number of customers in Rate 01 and Rate M1.

There is no balance in the Carbon Dioxide Offset Credits Deferral Account (179-117) at December 31, 2016.

There is no balance in the IFRS Conversion Costs Account (179-120) at December 31, 2016.

There is no balance in the Conservation Demand Management Deferral Account (179-123) at December 31, 2016.

Union proposes to allocate the delivery-related balance in the Deferral Clearing Variance Account (179-132) to rate classes based on the differences between the forecast and actual volumes associated with the disposition of deferral account balances for each rate class, per Tab 1, Appendix A, Schedule 6.

Union proposes to allocate the balance in the Normalized Average Consumption (NAC) Deferral Account (179-133) to General Service rate classes in proportion to the margin variances by rate class resulting from the difference between the actual NAC and the forecast NAC included in approved rates.

Union is proposing to allocate the balance in the Tax Variance Deferral Account (179-134) 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.

Union is proposing to allocate the balance in the Unaccounted for Gas (UFG) Volume Variance Account (179-135) to rate classes in proportion to the 2013 Board-approved allocation of UFG volumes.

Union proposes to allocate the balance in the Parkway West Project Costs Deferral Account (179-136) to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2016 Rates (EB-2015-0116). Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2016 Parkway West Project costs.

Union proposes to allocate the balance in the Brantford-Kirkwall/Parkway D Project Costs Deferral Account (179-137) to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2016 Rates (EB-2015-0116). Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2016 Brantford-Kirkwall/Parkway D Project costs.

Union proposes to allocate the balance in the Parkway Obligation Rate Variance Account (179-138) to rate classes in accordance with the EB-2013-0365 Settlement Agreement. 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.

There is no balance in the Energy East Pipeline Consultation Costs Deferral Account (179-

139) at December 31, 2016.

Union is proposing to allocate the balance in the Unaccounted for Gas (UFG) Price Variance Account (179-141) to rate classes in proportion to the 2013 Board-approved allocation of UFG costs to customers for which Union provides fuel.

Union proposes to allocate the balance in the Lobo C Compressor/Hamilton-Milton Pipeline Project Costs Deferral Account (179-142) to rate classes in proportion to the difference between the actual project costs and the forecasted project costs included in 2016 Rates (EB-2015-0116). Union determined the actual project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2016 Lobo C Compressor/Hamilton-Milton Pipeline Project costs.

Union is proposing to allocate the balance in the Unauthorized Overrun Non-Compliance Account (179-143) 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.

Union proposes to allocate the balance in the Lobo D/Bright C/Dawn H Compressor Project Costs Deferral Account (179-144) to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2016 Rates (EB-2015-0116).

Consistent with the methodology described in EB-2015-0200 (Union's 2017 Dawn Parkway Expansion Project application), Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2016 Lobo D/Bright C/Dawn H Compressor Project costs.

Union proposes to allocate the balance in the Burlington-Oakville Project Costs Deferral Account (179-149) to rate classes in proportion to the difference between the actual Project costs and the forecasted Project costs included in 2016 Rates (EB-2015-0116). Consistent with the methodology described in EB-2014-0182 (Union's Burlington Oakville Pipeline Project application), Union determined the actual Project costs by rate class by updating the 2013 Board-approved cost allocation study to include the actual 2016 Burlington-Oakville Project costs.

Union is proposing to allocate the balance in the OEB Cost Assessment Variance Account (179-151) 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.

Union is proposing to allocate the balance in the Greenhouse Gas Emission Impact Deferral Account (179-152) 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. This allocation is consistent with the Board's Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities (EB-2015-0363).

There is no balance in the Base Service North T-Service TransCanada Capacity Account (179-153) at December 31, 2016.

DISPOSITION OF 2016 DEFERRAL ACCOUNT BALANCES

For General Service Rate M1, Rate M2, Rate 01 and Rate 10 customers Union proposes to dispose of the net 2016 deferral account balances prospectively, over the October 1, 2017 to March 31, 2018 time period. The prospective refund / recovery approach over six months is consistent with how Union disposed of 2015 deferral account balances in EB-2016-0118.

For in-franchise contract and ex-franchise rate classes, Union is proposing to dispose of the net 2016 delivery-related deferral account balances as a one-time adjustment with October 2017 bills customers receive in November 2017. This approach is consistent with the methodology used for the disposition of 2015 deferral account balances in EB-2016-0118.

GENERAL SERVICE BILL IMPACTS

General Service bill impacts are presented at 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 October 1, 2017 to March 31, 2018 is $13.34. This $13.34 charge consists of a delivery-related charge of \$9.39 (line 13, column (c)) and a commodity-related charge of \$3.95 (line 14, column (c)). For a bundled direct purchase residential customer the charge is \$9.39.

For a Rate 01 sales service residential customer in Union North with annual consumption of 2,200 m^3, the charge for the period October 1, 2017 to March 31, 2018 is \$35.06. This \$35.06 charge consists of a delivery-related charge of \$21.87 (line 1, column (c)) and a gas transportation-related charge of \$13.19 (line 3, column (c)). For a bundled direct purchase residential customer the charge is \$35.06.

UNION GAS LIMITED
Allocation of 2016 Deferral Account Balances

Line No.	Particulars ($000's)	Acct No.	Union North Rate 01	Rate 10	Rate 20	Rate 100	Rate 25	Union South M1	M2	M4	M5A	M7	M9	M10	T1	T2	T3	M12	M13	Excess Utility	C1	M16	Total (1)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
	Gas Supply Related Deferrals:																						
1	Spot Gas Variance Account	179-107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Unabsorbed Demand Cost (UDC) Variance Account	179-108	1,222	453	161	-	-	965	187	9	1	4	-	0	-	-	-	-	-	-	-	-	3,003
3	Gas Supply Review Consultant Costs	179-128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Upstream Transportation Optimization	179-131	4,681	1,610	558	-	139	3,947	657	29	25	-	-	0	-	-	-	-	-	-	-	-	11,646
5	Deferral Clearing Variance Account - Supply (2)	179-132	-	-	-	-	-	371	(72)	(2)	13	(16)	-	(0)	-	-	-	-	-	-	-	-	293
6	Deferral Clearing Variance Account - Transport (2)	179-132	23	(1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23
7	Total Gas Supply Related Deferrals		5,927	2,062	719	-	139	5,284	772	36	39	(12)	-	(0)	-	-	-	-	-	-	-	-	14,965
	Storage Related Deferrals:																						
8	Short-Term Storage and Other Balancing Services	179-70	(333)	(87)	(23)	(2)	-	(755)	(254)	(82)	(1)	(30)	(10)	(0)	(70)	(514)	(66)	-	-	-	-	-	(2,226)
	Delivery Related Deferrals:																						
9	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Distribution Access Rule (GDAR) Costs	179-112	103	-	-	-	-	340	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443
11	Carbon Dioxide Offset Credits	179-117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	IFRS Conversion Costs	179-120	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Conservation Demand Management	179-123	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Deferral Clearing Variance Account - Delivery (2)	179-132	(178)	(21)	-	-	-	189	(69)	-	-	-	-	-	-	-	-	-	-	-	-	-	(79)
15	Normalized Average Consumption (NAC)	179-133	9,196	2,728	-	-	-	9,163	2,544	-	-	-	-	-	-	-	-	-	-	-	-	-	23,631
16	Tax Variance	179-134	(35)	(5)	(4)	(3)	(1)	(77)	(12)	(3)	(2)	(1)	(0)	(0)	(2)	(9)	(1)	(41)	(0)	(1)	(0)	(0)	(198)
17	Unaccounted for Gas (UFG) Volume Variance Account	179-135	143	48	18	0	-	612	203	83	111	31	13	0	86	655	54	2,352	20	-	718	41	5,189
18	Parkway West Project Costs	179-136	75	(17)	4	12	5	530	51	21	19	5	0	0	22	107	1	(2,264)	0	3	10	0	(1,415)
19	Brantford-Kirkwall/Parkway D Project Costs	179-137	72	(10)	8	13	6	361	17	7	17	0	(1)	0	9	23	(8)	(2,120)	0	4	4	0	(1,598)
20	Parkway Obligation Rate Variance	179-138	-	-	-	-	-	1,307	444	146	35	65	26	1	96	544	159	-	-	-	-	-	2,822
21	Energy East Pipeline Consultation Costs	179-139	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Unaccounted for Gas (UFG) Price Variance Account	179-141	(136)	(43)	(15)	(0)	-	(567)	(188)	(77)	(103)	(28)	(12)	-	-	-	-	-	(17)	-	-	(11)	(1,199)
23	Lobo C Compressor/Hamilton-Milton Pipeline Project Costs	179-142	321	48	35	27	10	731	113	29	23	10	2	0	21	102	11	196	0	11	7	1	1,699
24	Unauthorized Overrun Non-Compliance Account	179-143	-	-	-	-	-	(45)	(15)	(5)	(0)	(2)	(1)	(0)	(4)	(31)	(4)	-	-	-	-	-	(107)
25	Lobo D/Bright C/ Dawn H Compressor Project Costs	179-144	87	14	9	7	2	190	31	8	6	3	1	0	6	26	4	124	0	4	1	0	523
26	Burlington-Oakville Project Costs	179-149	119	19	13	10	4	76	(22)	(10)	8	(4)	(2)	(0)	(10)	(94)	(12)	157	(1)	4	1	0	257
27	OEB Cost Assessment Variance Account	179-151	167	14	12	11	5	420	39	15	16	4	1	0	11	29	3	78	0	3	2	0	832
28	Greenhouse Gas Emission Impact Deferral Account	179-152	448	39	33	29	13	1,128	106	39	44	11	2	0	29	79	9	210	0	8	5	0	2,232
29	Base Service North T-Service TransCanada Capacity Account	179-153	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Total Delivery-Related Deferrals		10,382	2,815	114	107	44	14,358	3,243	253	173	93	28	1	263	1,431	216	(1,308)	2	36	747	32	33,032
31	Total 2016 Storage and Delivery Disposition (Line 8 + Line 30)		10,048	2,727	91	105	44	13,603	2,989	171	172	64	19	1	193	918	150	(1,308)	2	36	747	32	30,806
32	Total 2016 Deferral Account Disposition (Line 7 + Line 31)		15,975	4,790	810	105	183	18,887	3,761	207	211	52	19	1	193	918	150	(1,308)	2	36	747	32	45,771
33	2016 Earnings Sharing (3)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Grand Total (Line 32 + Line 33)		15,975	4,790	810	105	183	18,887	3,761	207	211	52	19	1	193	918	150	(1,308)	2	36	747	32	45,771

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

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2016 Deferral Account Disposition

Line No.	Particulars	Rate Class	2016 Deferral Balances ($000's)	2016 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	10,048	-	10,048	778,223	1.2912
2	Large Volume General Service	10	2,727	-	2,727	248,400	1.0980
3	Small Volume General Service	M1	13,603	-	13,603	2,363,019	0.5757
4	Large Volume General Service	M2	2,989	-	2,989	852,358	0.3507

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

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2016 Deferral Account Disposition

Line No.	Particulars	Rate Class	2016 Deferral Balances ($000's)	2016 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c) = (a+b)	(d)	(e) = (c/d)*100
1	Small Volume General Service	01	5,927	-	5,927	778,223	0.7615
2	Large Volume General Service	10	2,062	-	2,062	246,354	0.8371

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

UNION GAS LIMITED
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2016 Deferral Account Disposition

Line No.	Particulars	Rate Class	2016 Deferral Balances ($000's)	2016 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	5,284	-	5,284	2,152,071	0.2352
2	Large Volume General Service	M2	772	-	772	416,626	0.2352
3	Firm Com/Ind Contract	M4	36	-	36	20,331	0.2352
4	Interruptible Com/Ind Contract	M5	39	-	39	3,023	0.2352
5	Special Large Volume Contract	M7	(12)	-	(12)	9,670	0.2352
6	Small Wholesale	M10	(0)	-	(0)	272	0.2352
7	Total				6,118	2,601,993	0.2352

Notes:
(1) Forecast sales service volumes for the period October 1, 2017 to March 31, 2018.
(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
2016 Deferral Account Disposition

Line No.	Particulars	Rate Class	2016 Deferral Balances ($000's)	2016 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2016 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	22	-	22	107,771	0.0202
2	Medium Volume Firm Service (2)	20T	93	-	93	457,698	0.0202
3	Large Volume High Load Factor (2)	100T	107	-	107	1,365,541	0.0078
4	Large Volume Interruptible	25	44	-	44	116,389	0.0379
	Union South						
5	Firm Com/Ind Contract	M4	171	-	171	472,042	0.0363
6	Interruptible Com/Ind Contract	M5	172	-	172	194,586	0.0884
7	Special Large Volume Contract	M7	64	-	64	475,225	0.0134
8	Large Wholesale	M9	19	-	19	72,275	0.0261
9	Small Wholesale	M10	1	-	1	247	0.4121
10	Contract Carriage Service	T1	193	-	193	447,213	0.0432
11	Contract Carriage Service	T2	918	-	918	4,213,980	0.0218
12	Contract Carriage- Wholesale	T3	150	-	150	250,167	0.0601

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
2016 Deferral Account Disposition

Line No.	Particulars	Rate Class	2016 Deferral Balances ($000's)	2016 Earnings Sharing Mechanism ($000's)	Deferral Balance for Disposition ($000's)	2016 Actual Volume/ Demand	Billing Units	Unit Volumetric/ Demand Rate
			(a)	(b)	(c) = (a+b)	(d)		(e) = (c/d)*100
	Gas Supply Transportation (cents/m^3)							
1	Medium Volume Firm Service	20	719	-	719	5,945	$10^3m^3/d$	12.0868
2	Large Volume Interruptible	25	139	-	139	44,633	10^3m^3	0.3114
	Storage ($/GJ)							
3	Bundled-T Storage Service	20T/100T	(25)	-	(25)	155,904	GJ/d	(0.160)

UNION GAS LIMITED
Storage and Transportation Service Amounts for Disposition
2016 Deferral Account Disposition

Line No.	Particulars ($000's) (1)	Rate Class	2016 Deferral Balances	2016 Earnings Sharing Mechanism	Deferral Balance for Disposition
			(a)	(b)	(c)
1	Storage and Transportation	M12	(1,308)	-	(1,308)
2	Local Production	M13	2	-	2
3	Short-Term Cross Franchise	C1	747	-	747
4	Storage Transportation Service	M16	32	-	32

Notes:
(1) Exfranchise 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	Rate Component	Unit Rate for Prospective Recovery/(Refund) (cents/m^3) (1)	Volume (m^3) (2)	Bill Impact ($)
			(a)	(b)	(c) = (a x b) / 100
1	Rate 01	Delivery	1.2912	1,733	22.37
2		Commodity	-	1,733	-
3		Transportation	0.7615	1,733	13.19
4			2.0527		35.56
5	Sales Service				35.56
6	Direct Purchase Bundled T				35.56
7	Rate 10	Delivery	1.0980	66,961	735.23
8		Commodity	-	66,961	-
9		Transportation	0.8371	66,961	560.53
10			1.9351		1,295.75
11	Sales Service				1,295.75
12	Direct Purchase Bundled T				1,295.75
13	Rate M1	Delivery	0.5757	1,679	9.66
14		Commodity	0.2352	1,679	3.95
15			0.8109		13.61
16	Sales Service				13.61
17	Direct Purchase				9.66
18	Rate M2	Delivery	0.3507	55,772	195.59
19		Commodity	0.2352	55,772	131.18
20			0.5859		326.77
21	Sales Service				326.77
22	Direct Purchase				195.59

Notes:
(1) Exhibit A, Tab 3, Appendix A, Schedule 2, pages 1-3, column (e).
(2) Average consumption, per customer, for the period October 1, 2017 to March 31, 2018.
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 AND ANNUAL STAKEHOLDER MEETING

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 firm transportation capacity on the following contracts:

1. Panhandle Eastern (1 year) Transportation Contract Renewal (10,000 Dth/day)
2. TransCanada (1 year) Empress to Union EDA (2,291 GJ/day)
3. Contracts resulting from the TransCanada Settlement Agreement RH-001-2014
    a. TransCanada (15 year) contracts from 2015 New Capacity Open Season
        - 75,000 GJ/day Union Parkway Belt to Union EDA – FT (Firm Transportation)
        - 25,000 GJ/day Union Parkway Belt to Union EDA – EMB (EMB Enhanced Market Balancing)
        - 10,000 GJ/day Union Parkway Belt to Union NDA – FT (Firm Transportation)
    b. TransCanada (15 year) contracts from 2016 New Capacity Open Season
        - 100,000 GJ/day Union Parkway Belt to Union NDA – FT (Firm Transportation)

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

- 135,000 GJ/day Kirkwall to Union CDA – FT (Firm Transportation)

4. Vector Contract Extension (80,000 Dth/day)
5. Vector (1 year) contracts (20,000 Dth/day)
6. Vector Winter 2016-2017 contracts (26,030 Dth/day - 86,030 Dth/day)

1. PANHANDLE EASTERN (1 YEAR) TRANSPORTATION CONTRACT RENEWAL

Capacity History

Union holds 27,000 Dth/day (28,487 GJ/day) of firm transportation on Panhandle Eastern Pipeline Company, LP ("Panhandle Eastern") from the Panhandle Field Zone to Union's pipeline system at Ojibway through to October 31, 2017. There were no changes to these contracts.

In addition, Union held a contract for 10,000 Dth/day (10,551 GJ/d) of incremental firm transportation on Panhandle Eastern (Panhandle Field Zone to Ojibway) with a one-year term that expired on October 31, 2015. In 2015, Union extended this 10,000 Dth/day (10,551 GJ/day) contract to an October 31, 2016 expiry date. Union provided the landed cost analysis for this renewal as part of the 2015 Disposition of Deferral Account Balances evidence.[2]

[2] EB-2016-0118 Exhibit A Tab 4 Page 19 to 21

Renewed Capacity

Union has exercised its Right of First Refusal ("ROFR") on its existing contract for 10,000 Dth/day (10,551 GJ/day) at the current 100% load factor rate of US$0.4687/Dth/day, for a one-year term commencing November 1, 2016 and expiring October 31, 2017.

Contract Parameters

- Transportation provider: Panhandle Eastern Pipe Line Company, LP
- Service: Firm Transportation
- Term: November 1, 2016 through October 31, 2017
- Capacity: 10,000 Dth/day (10,551 GJ/day)
- 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: ROFR

Rationale for Transportation Capacity

Union's Gas Supply Plan supports the Panhandle Eastern capacity to meet forecasted demand for Union South sales service customers. The landed cost of this gas arriving at Dawn is forecast to be competitive with supply flowing on alternative upstream pipelines.

The benefits of this capacity are:

i. The firm transportation capacity is consistent with the gas supply principal of ensuring secure and reliable gas supply to Union's service territory at a reasonable cost;
ii. Supports the acquisition of secure supply from the Panhandle Field Zone gas supply basin, maintaining Union's supply diversity of contract terms and supply basins;
iii. Lands gas at Ojibway to support diversity of deliveries and support system integrity. Deliveries to the Ojibway interconnect are required to support Design Day deliveries into the Windsor area market and supplement Union transmission capabilities from Dawn;
iv. Provides Union with both receipt and delivery flexibility within the path; and
v. Contract has renewal provisions (ROFR) which provides contractual rights for Union to retain access to this capacity in future years if required.

Incremental Contracting Analysis Form

Tab 4, Appendix A, Schedule 1 shows a comparison of landed costs for the Panhandle Eastern contract relative to the alternatives reviewed by Union. Schedule 1 is in the format agreed upon in the EB-2005-0520 Settlement Agreement.

2. TRANSCANADA EMPRESS TO UNION EDA (1 YEAR) TRANSPORTATION CONTRACT

New Capacity

Union entered into a one-year, firm transportation long-haul contract with TransCanada for capacity of 2,291 GJ/day from Empress to the Union EDA.

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service (FT-NR)
- Term: November 1, 2016 through October 31, 2017
- Capacity: 2,291 GJ/day
- Current Rate: C$2.1284/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Union EDA
- Renewal Rights: None

Rationale for Transportation Capacity

The Gas Supply Plan identified a winter of 2017/2018 design day shortfall of 2,291 GJ/day in the Union EDA. TransCanada was offering capacity to the Union EDA through Daily Existing Capacity Open seasons. This capacity was offered on a non-renewable basis, available for a minimum term of one year, not to exceed October 31, 2019. In September 2016 Union bid for and was awarded the required capacity.

The benefits of this capacity are:

i. Provides firm transportation capacity to meet the firm design day loads within the Union EDA to cover the design day shortfall;
ii. Contract is one year in duration which aligns with the gas year and provides opportunity to recalculate needs in future years; and,
iii. Firm transportation contract is consistent with the gas supply principal of ensuring secure and reliable gas supply to Union's service territory.

Incremental Contracting Analysis Form

The only firm transportation capacity available to the Union EDA was TransCanada Empress to Union EDA. Thus, a landed cost comparison is not applicable.

3. CONTRACTS CHANGES RESULTING FROM THE TRANSCANADA PIPELINES LIMITED MAINLINE SETTLEMENT AGREEMENT RH-001-2014

Capacity History

Union has been working to better diversify supply for customers in the Northern delivery areas, and due to their geographical location, could only be served by the TransCanada Mainline. Further system and capacity constraints on TransCanada Mainline require new contracted capacity to be underpinned by infrastructure builds. The TransCanada contracts listed below are directly linked to the long haul transportation to short haul transportation conversion which has been discussed extensively in numerous proceedings[3]. Specific contract parameters are provided below.

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service (FT)
- Term: November 1, 2016 through October 31, 2031
- Capacity: 75,000 GJ/day
- Current Rate: C$0.412/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Union Parkway Belt
- Delivery Point: Union EDA
- Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice required)

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Enhanced Market Balancing (EMB)
- Term: November 1, 2016 through October 31, 2031
- Capacity: 25,000 GJ/day

[3] EB-2013-0074, RH-001-2014, EB-2014-0145, EB-2015-0010, EB-2015-0116, EB-2015-0181, and EB-2016-0245

- Current Rate: C$0.45096/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Union Parkway Belt
- Delivery Point: Union EDA
- Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice required)

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service (FT)
- Term: November 1, 2016 through October 31, 2031
- Capacity: 10,000 GJ/day
- Current Rate: C$0.5932/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Union Parkway Belt
- Delivery Point: Union NDA
- Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice required)

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service (FT)
- Term: December 15, 2016 through October 31, 2031
- Capacity: 100,000 GJ/day

- Current Rate: C$0.5932/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Union Parkway Belt
- Delivery Point: Union NDA
- Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice required)

Contract Parameters

- Transportation provider: TransCanada PipeLines Limited
- Service: Firm Gas Transportation Service (FT)
- Term: November 1, 2016 through October 31, 2032
- Capacity: 135,000 GJ/day
- Current Rate: C$0.1623/GJ/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Point: Kirkwall
- Delivery Point: Union CDA
- Renewal Rights: Per TransCanada Firm Transport Tariff (24 month notice required)

Rationale for Transportation Capacity

The goal in acquiring this capacity was to allow Union's North East customer base to gain access to capacity sourced from Dawn or upstream of Dawn. To date customers in these delivery areas have been served exclusively from Empress by Western Canadian Sedimentary Basin ("WCSB") sourced supplies.[4]

Union also filed to contract for service from Parkway to Union's North East as part of a larger project (EB-2013-0074) which included requests for Leave to Construct approval of facilities tied to the contracts.[5] A key milestone in securing this capacity was the Board's desire for TransCanada, Enbridge and Union to work together cooperatively to efficiently manage the development of new facilities in the Parkway area.[6]

TransCanada PipeLines Limited, Enbridge Gas Distribution Inc., Union Gas Limited, and Gaz Métro Limited Partnership worked together to ultimately agree to the "TransCanada PipeLines Mainline Settlement Agreement". This agreement contained commitments from each party, including an agreement from TransCanada to build facilities to underpin capacity requests from Parkway, including the 2015 and 2016 New Capacity Open Season contracts as outlined above.

The benefits of this capacity are:

i. Firm Transportation contracts provide Union's North East customers the benefits of diversity and security of supply by sourcing supply at or upstream of Dawn;
ii. Supports Union's objective of structuring a portfolio with diversity of contract terms and supply basins;

[4] EB-2010-0300 Exhibit A Page 12 of 14
[5] EB-2013-0074 Section 7 Page 14 of 14
[6] EB-2011-0210 Decision (pages 126-127)

iii. Provides firm transportation capacity to meet the firm design day and average day needs of the Union North East; and,

iv. The right to renew this capacity ensures secure access to this transportation in the future.

4. Vector Contract Extension

Capacity History

Union holds contracts for 80,000 Dth/day (84,405 GJ/day) of capacity on Vector. These contracts include extension rights that can be exercised before November 30th of each year. As stated in EB-2015-0010, Union has previously exercised its right to extend this contract for one-year periods, and most recently extended the contract to November 30, 2018 at the existing US$0.2518/Dth/day 100% load factor rate.[7]

Renewed Capacity

In late 2015, Union accepted a firm transportation contract renewal offer from Vector that provided a reduction in tolls to US$0.18/Dth/day from the existing US$0.25/Dth/day rate; the rate reduction is effective December 1, 2017. In order to secure the rate reduction, Union agreed to renew the existing contract to October 31, 2022 and also to contract for an additional 20,000 Dth/day of capacity November 1, 2016 through May 31, 2017 at US$0.18/Dth/day. Details regarding the 20,000 Dth/day of incremental contracted

[7] EB-2015-0010 Exhibit A Tab 4 Page 2 to 4

capacity for November 1, 2016 through May 31, 2017 is referenced in the "Vector Short Term Contracts" section.

Contract Parameters

- Transportation provider: Vector Pipeline L.P. / Vector Pipeline Limited Partnership
- Service: Firm Transportation (FT-1)
- Extension Term: December 1, 2018 through October 31, 2022
- Capacity: 80,000 Dth/day (84,405 GJ/day)
- Existing Rate (through Nov 30, 2017): US$0.2516/Dth/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Negotiated Rate (December 1, 2017 through October 31, 2022): US$0.1816/Dth/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Points: Chicago (Alliance/Guardian/Northern Border Interconnects)
- Delivery Point: Dawn
- Renewal Rights: Can extend this agreement four times for three year increments for a potential total of twelve years ("Initial Extended Terms") with a minimum one year written notice prior to the applicable contract expiration date. After the initial twelve years Union can extend the agreement in three year increments with one year written notice.

Rationale for Transportation Capacity

Union's Gas Supply Plan supports the extension of Vector capacity in order for Union to meet forecasted demand within the Sales Service customer base. The landed cost of this gas arriving at Dawn is forecasted to be competitive with supply flowing on alternative upstream pipelines.

The benefits of this capacity are:

i. The landed cost of gas flowing to Union along this route is competitively priced;
ii. The extended term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
iii. A reduction in the demand charge on the original contracted capacity results in cost savings for Sales Service customers;
iv. Access to the Chicago market hub that receives competing gas supplies from the WCSB, the U.S. Midwest, Marcellus/Utica, Gulf and Rockies basins which supports Union's objective of diversity of supply basins;
v. Firm Transportation contract maintains and supports the acquisition of secure supply from a liquid market hub with many gas suppliers accessing multiple gas supply basins;
vi. Provides Union with both receipt and delivery flexibility within the path;
vii. Lands gas at Dawn to support diversity of deliveries and system integrity; and,
viii. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation in the future.

Incremental Contracting Analysis Form

Tab 4, Appendix A, Schedule 2 shows a comparison of landed costs for the Long Term contract relative to the other alternatives reviewed by Union; this schedule is in the format agreed upon in the EB-2005-0520 Settlement Agreement.

5. VECTOR SHORT TERM CONTRACTS

Capacity History

As referenced in the "Vector Contract Extension" above, Union accepted a contract renewal offer from Vector that provided for a reduction in the tolls on an existing contract in exchange for Union extending the original contract and contracting for incremental capacity of 20,000 Dth/day November 1, 2016 through May 31, 2017 at US$0.18/Dth/day.

New Capacity

The incremental 20,000 Dth/day of Vector capacity was offered for the term of November 1, 2016 through May 31, 2017. At the time of the negotiation, a significant amount of capacity on the Vector system was reserved for the Rover and NEXUS Pipeline Projects which limited the term available.

In a subsequent Vector open season, in late April 2016 Vector was able to offer capacity for June 2017 through October 2017 due to a delay in the start date of contracts underpinning their Rover/NEXUS projects. This capacity offering enabled Union to contract for 20,000 Dth/day of capacity from June 1, 2017 through October 31, 2017 which would effectively extend the capacity to a full 1 year contract.

Contract Parameters

- Transportation provider: Vector Pipeline L.P. / Vector Pipeline Limited Partnership
- Service: Firm Transportation (FT-1)
- Term: November 1, 2016 through October 31, 2017
- Capacity: 20,000 Dth/day (21,101 GJ/day)
- Rate :
  - November 1, 2016 through May 31, 2017 US$0.1816/Dth/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
  - June 1, 2017 through October 31, 2017 US$0.1516/Dth/day at 100% load factor (includes abandonment surcharge, exclusive of fuel)
- Primary Receipt Points: Chicago (Alliance/Guardian /Northern Border Interconnects)
- Delivery Point: Dawn
- Renewal Rights: ROFR for capacity was not available due to the reservation of future capacity for the Rover and NEXUS Pipeline Projects

Rationale for Transportation Capacity

Union's Gas Supply Plan supports the capacity to meet forecasted demand for Union sales service customers.

The benefits of this capacity are:

i. The landed cost of gas flowing to Union along this route is competitively priced;
ii. The one-year term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
iii. Supports Union's objective of diversity of supply basins with access to the Chicago market hub that receives competing gas supplies from: the WCSB, the U.S. Midwest, Appalachia (Marcellus/Utica), Gulf and the Rockies basins;
iv. Firm Transportation contract maintains and supports the acquisition of secure supply from a liquid market hub with many gas suppliers accessing multiple gas supply basins;
v. Low unabsorbed demand charge ("UDC") exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
vi. Provides Union with both receipt and delivery flexibility within the path; and,
vii. Lands gas at Dawn to support diversity of deliveries and system integrity.

Incremental Contracting Analysis Form

Tab 4, Appendix A, Schedule 1 shows a comparison of landed costs for a 1 year Vector contract relative to the alternatives reviewed by Union; this schedule is in the format agreed upon in the EB-2005-0520 Settlement Agreement.

6. VECTOR WINTER 2016-2017 CONTRACTS

Capacity History

As Union evaluated the portfolio requirements for the winter of 2016/2017 there was considerable uncertainty in the market. As outlined above in the "Contract changes resulting from the TransCanada Settlement Agreement RH-001-2104" TransCanada was building facilities that would allow significant conversion of longhaul contracts originating at Empress to shorthaul contracts originating at Dawn and Parkway. These contract changes had the potential to materially impact the flows of supply into Dawn and increase the need for supply at Dawn. This could have resulted in price volatility at Dawn for the winter period. In addition, most transportation options into Dawn were already sold out including Panhandle Eastern Pipe Line, DTE/Michcon, and TransCanada at Niagara/Chippewa. The Vector capacity was the last remaining economic option to secure firm transportation into Dawn for the 2016/2017 gas year.

New Contracts

Union acquired Vector capacity for winter 2016/2017 to mitigate Dawn price exposure while minimizing the potential risk of surplus capacity should the TransCanada facilities be significantly delayed beyond November 1, 2016.

Contract Parameters

- Transportation provider: Vector Pipeline L.P. / Vector Pipeline Limited Partnership
- Service: Firm Transportation (FT-1)
- Term: November 1, 2016 through March 31, 2017
- Capacity:
  - November 1, 2016 through November 30, 2016 - 26,030 Dth/day (27,463 GJ/day)
  - December 1, 2016 through March 31, 2017, 2016 - 86,030 Dth/day (90,766 GJ/day)
- Rate : US$0.1816/Dth/day at 100% load factor (includes abandonment surcharge)
- Primary Receipt Points: Chicago (Alliance/Guardian/Northern Border Interconnects)
- Delivery Point: Dawn
- Renewal Rights: Not Included

Rationale for Transportation Capacity

The benefits of this capacity are:

i. The landed cost of gas flowing to Union along this route is competitively priced;
ii. Supports Union's objective of diversity of supply basins with access to the Chicago market hub that receives competing gas supplies from: the WCSB, the U.S. Midwest, Appalachia (Marcellus/Utica), Gulf and the Rockies basins;
iii. Firm Transportation contract maintains and supports the acquisition of secure supply from a liquid market hub with many gas suppliers accessing multiple gas supply basins;
iv. Low unabsorbed demand charge ("UDC") exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
v. Provides Union with both receipt and delivery flexibility within the path; and,
vi. Lands gas at Dawn to support diversity of deliveries and system integrity.

Incremental Contracting Analysis Form

Tab 4, Appendix A, Schedule 1 shows a comparison of landed costs for a 1 year Vector contract relative to the alternatives reviewed by Union; this schedule is in the format agreed upon in the EB-2005-0520 Settlement Agreement

Union Gas Limited
2016-2017 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	-0.455	2.2910	0.1845	0.0000	0.0060	0.1905	$2.48	$3.07	Kirkwall
	Dawn	Dawn	0.095	2.8410	0.0000	0.0000	0.0000	0.0000	$2.84	$3.52	Dawn
(2)	DTE/Michcon to St. Clair	SE Michigan	0.024	2.7702	0.0781	0.0000	0.0516	0.1297	$2.90	$3.59	Dawn
(3) *	Vector (2016 - 2017 One Year Contract)	Chicago	-0.021	2.7254	0.1675	0.0017	0.0298	0.1990	$2.92	$3.62	Dawn
*	Vector (2016 - 2017 Winter Only)	Chicago	-0.021	2.7254	0.1797	0.0017	0.0298	0.2112	$2.94	$3.64	Dawn
(2)	Vector (2014 - 2017)	Chicago	-0.021	2.7254	0.1884	0.0017	0.0298	0.2199	$2.95	$3.65	Dawn
(2) (3)	Vector (Extension to 2022)	Chicago	-0.021	2.7254	0.1926	0.0017	0.0298	0.2242	$2.95	$3.65	Dawn
(2)	PEPL (2012 - 2017)	Panhandle Field Zone	-0.241	2.5058	0.3492	0.0442	0.1039	0.4973	$3.00	$3.72	Dawn
(2)	Trunkline/Panhandle	Trunkline Field Zone 1A	-0.067	2.6795	0.2203	0.0267	0.1090	0.3560	$3.04	$3.76	Dawn
(2)	PEPL (2010 - 2017)	Panhandle Field Zone	-0.241	2.5058	0.4541	0.0439	0.1039	0.6018	$3.11	$3.85	Dawn
(2) *	PEPL (2015 - 2016) (Extension to 2017)	Panhandle Field Zone	-0.241	2.5058	0.4541	0.0439	0.1039	0.6018	$3.11	$3.85	Dawn
	ANR-Michcon-Union	Fayetteville	-0.059	2.6875	0.3461	0.0143	0.1054	0.4657	$3.15	$3.91	Dawn
	GLGT to TCPL	Northern Michigan	0.072	2.8185	0.3126	0.0056	0.0316	0.3498	$3.17	$3.93	Dawn
	ANR-Michcon-Union	ANR South East	-0.083	2.6637	0.4047	0.0143	0.1121	0.5310	$3.19	$3.96	Dawn
	ANR-GLGT-TCPL	Fayetteville	-0.059	2.6875	0.5786	0.0198	0.0851	0.6834	$3.37	$4.18	Dawn
	ANR-GLGT-TCPL	ANR South East	-0.083	2.6637	0.6367	0.0198	0.0918	0.7484	$3.41	$4.23	Dawn
(1)	TCPL SWDA	Empress	-0.611	2.1357	1.4494	0.0000	0.0849	1.5343	$3.67	$4.55	Dawn
(2)	TCPL CDA	Empress	-0.611	2.1357	1.5730	0.0000	0.0878	1.6608	$3.80	$4.70	Union CDA

(1) For Reference Only
(2) Existing Union Gas Contract
(3) Average toll over the term of the analysis
* 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 2016 - Oct 2017	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub (NYMEX)	Henry Hub	$2.75	$2.75	
	TCPL Niagara	Niagara	$2.29	$2.29	0.26%
	Dawn	Dawn	$2.84	$2.84	0.00%
	DTE/Michcon to St. Clair	SE Michigan	$2.77	$2.77	1.86%
	Vector (2016 - 2017 One Year Contract)	Chicago	$2.73	$2.73	1.09%
	Vector (2016 - 2017 Winter Only)	Chicago	$2.73	$2.73	1.09%
	Vector (2014 - 2017)	Chicago	$2.73	$2.73	1.09%
	Vector (Extension to 2022)	Chicago	$2.73	$2.73	1.09%
	PEPL (2012 - 2017)	Panhandle Field Zone	$2.51	$2.51	4.15%
	Trunkline/Panhandle	Trunkline Field Zone 1A	$2.68	$2.68	4.07%
	PEPL (2010 - 2017)	Panhandle Field Zone	$2.51	$2.51	4.15%
	PEPL (2015 - 2016) (Extension to 2017)	Panhandle Field Zone	$2.51	$2.51	4.15%
	ANR-Michcon-Union	Fayetteville	$2.69	$2.69	3.92%
	GLGT to TCPL	Northern Michigan	$2.82	$2.82	1.12%
	ANR-Michcon-Union	ANR South East	$2.66	$2.66	4.21%
	ANR-GLGT-TCPL	Fayetteville	$2.69	$2.69	3.16%
	ANR-GLGT-TCPL	ANR South East	$2.66	$2.66	3.45%
	TCPL SWDA	Empress	$2.14	$2.14	3.98%
	TCPL CDA	Empress	$2.14	$2.14	4.11%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICE April 4, 2016		
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 =	$1.307 CDN	From Bank of Canada Closing Rate April 4, 2016
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	April 2016		

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

Union Gas Limited
2016-2022 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	-0.347	4.1478	0.1816	0.0000	0.0106	0.1923	$4.34	$5.45	Kirkwall
	Dawn	Dawn	0.060	4.5549	0.0000	0.0000	0.0000	0.0000	$4.55	$5.72	Dawn
(2)	DTE/MichCon to St. Clair	SE Michigan	-0.083	4.4116	0.0780	0.0000	0.0821	0.1601	$4.57	$5.74	Dawn
	Vector (2014 - 2017)	Chicago	-0.150	4.3441	0.1883	0.0017	0.0470	0.2369	$4.58	$5.76	Dawn
* (3)	Vector (2008 - 2019) (Extension to 2022)	Chicago	-0.150	4.3441	0.1926	0.0017	0.0470	0.2413	$4.59	$5.76	Dawn
* (2)	Vector (2008 - 2019)	Chicago	-0.150	4.3441	0.2500	0.0017	0.0470	0.2987	$4.64	$5.83	Dawn
	GLGT to TCPL	Northern Michigan	-0.092	4.4028	0.3108	0.0056	0.0376	0.3540	$4.76	$5.98	Dawn
(2)	PEPL (2012 - 2017)	Panhandle Field Zone	-0.356	4.1386	0.3490	0.0439	0.2569	0.6498	$4.79	$6.02	Dawn
	ANR-Michcon-Union	Fayetteville	-0.186	4.3083	0.3459	0.0143	0.1689	0.5291	$4.84	$6.08	Dawn
(2)	Trunkline/Panhandle	Trunkline Field Zone - ELA	-0.073	4.4220	0.2209	0.0268	0.1969	0.4446	$4.87	$6.11	Dawn
(2)	Panhandle Longhaul (2010 - 2017)	Panhandle Field Zone	-0.356	4.1386	0.4545	0.0439	0.2569	0.7553	$4.89	$6.15	Dawn
	PEPL (2015 - 2016)	Panhandle Field Zone	-0.356	4.1386	0.4545	0.0439	0.2569	0.7553	$4.89	$6.15	Dawn
	ANR-GLGT-TCPL	Fayetteville	-0.186	4.3083	0.5761	0.0197	0.1246	0.7204	$5.03	$6.32	Dawn
	ANR-Michcon-Union	ANR South East	0.030	4.5243	0.4046	0.0143	0.1903	0.6091	$5.13	$6.45	Dawn
(1)	TCPL SWDA	Empress	-0.772	3.7223	1.4220	0.0000	0.1570	1.5790	$5.30	$6.66	Dawn
	ANR-GLGT-TCPL	ANR South East	0.030	4.5243	0.6341	0.0197	0.1436	0.7975	$5.32	$6.69	Dawn
(2)	TCPL CDA	Empress	-0.772	3.7223	1.5432	0.0000	0.1629	1.7061	$5.43	$6.82	Union CDA

(1) For Reference Only
(2) Existing Union Gas Contract
(3) Average toll over the term of the analysis
* 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 2016 - Oct 2017	Nov 2017 - Oct 2018	Nov 2018 - Oct 2019	Nov 2019 - Oct 2020	Nov 2020 - Oct 2021	Nov 2021 - Oct 2022	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub (NYMEX)	Henry Hub	$3.55	$3.56	$4.42	$4.89	$5.20	$5.36	$4.49	
	TCPL Niagara	Niagara	$3.23	$3.52	$4.19	$4.52	$4.70	$4.74	$4.15	0.26%
	Dawn	Dawn	$3.77	$3.74	$4.48	$4.88	$5.13	$5.32	$4.55	0.00%
	DTE/MichCon to St. Clair	SE Michigan	$3.65	$3.60	$4.34	$4.73	$4.98	$5.17	$4.41	1.86%
	Vector (2014 - 2017)	Chicago	$3.58	$3.54	$4.28	$4.67	$4.91	$5.09	$4.34	1.08%
	Vector (2008 - 2019) (Extension to 2022)	Chicago	$3.58	$3.54	$4.28	$4.67	$4.91	$5.09	$4.34	1.08%
	Vector (2008 - 2019)	Chicago	$3.58	$3.54	$4.28	$4.67	$4.91	$5.09	$4.34	1.08%
	GLGT to TCPL	Northern Michigan	$3.64	$3.59	$4.33	$4.72	$4.97	$5.16	$4.40	0.85%
	PEPL (2012 - 2017)	Panhandle Field Zone	$3.35	$3.34	$4.08	$4.47	$4.71	$4.89	$4.14	6.21%
	ANR-Michcon-Union	Fayetteville	$3.48	$3.49	$4.25	$4.66	$4.90	$5.07	$4.31	3.92%
	Trunkline/Panhandle	Trunkline Field Zone - ELA	$3.49	$3.50	$4.35	$4.81	$5.11	$5.27	$4.42	4.45%
	Panhandle Longhaul (2010 - 2017)	Panhandle Field Zone	$3.35	$3.34	$4.08	$4.47	$4.71	$4.89	$4.14	6.21%
	PEPL (2015 - 2016)	Panhandle Field Zone	$3.35	$3.34	$4.08	$4.47	$4.71	$4.89	$4.14	6.21%
	ANR-GLGT-TCPL	Fayetteville	$3.48	$3.49	$4.25	$4.66	$4.90	$5.07	$4.31	2.89%
	ANR-Michcon-Union	ANR South East	$3.60	$3.60	$4.44	$4.91	$5.22	$5.38	$4.52	4.21%
	TCPL SWDA	Empress	$3.04	$2.97	$3.65	$4.01	$4.24	$4.42	$3.72	4.22%
	ANR-GLGT-TCPL	ANR South East	$3.60	$3.60	$4.44	$4.91	$5.22	$5.38	$4.52	3.17%
	TCPL CDA	Empress	$3.04	$2.97	$3.65	$4.01	$4.24	$4.42	$3.72	4.38%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF Q3 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 =	$1.326 CDN	From Bank of Canada Closing Rate Oct 1, 2015
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	October 2015		

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

uniongas
An Enbridge Company

2017 Annual Stakeholder Meeting

April 13, 2017

Agenda

Opening Comments	**Mark Kitchen** *Director, Regulatory Affairs*
2016 Financial Results	**Greg Tetreault** *Manager, Accounting & Finance Support*
Facilities Expansion Projects	**Chris Shorts** *Director, Business Development & Upstream Regulation*
Gas Supply Update	**Cheryl Newbury** *Director, Gas Supply & Customer Support*
Residential Customer Perceptions of Union Gas	**Tracy Lynch** *Director, Distribution Marketing*
Wrap-up	**Mark Kitchen** *Director, Regulatory Affairs*

An Enbridge Company

2016 Financial Results

Greg Tetreault
Manager, Accounting & Finance Support

Agenda

- 2016 Utility Financial Results
- Capital Spend
- Deferral Accounts
  - Summary of 2016 Deferral Accounts
  - Normalized Average Consumption (“NAC”)
  - Transportation Optimization
  - Unaccounted for Gas (“UFG”) Volume
  - Greenhouse Gas Emission Impact Deferral Account
  - Capital Pass-Through Project Accounts
- 2017 Trends and Cost Pressures
- Service Quality Requirements and Billing Performance

2016 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%
2015 Actual			
Weather normalized	314.6	4,228.4	9.46%
Weather	9.0		
2015 Total	323.6	4,228.4	9.89%
2016 Actual			
Weather normalized	338. 6	4,758.4	9.78%
Weather	(12.4)		
2016 Total	326.2	4,758.4	9.24%

2016 Utility Financial Results – Cont'd

2016 vs 2015 Actuals - $2.6 million increase

- Transportation Revenue - $26 million increase
  - M12 rates / capital pass-through projects
- Distribution Margin - $12 million increase
  - Rate increases and growth partially offset by warmer weather
- Operating Expenses - $33 million increase
  - Higher 2016 DSM program charges and depreciation
- Other Items - $2 million decrease

2016 Utility Financial Results – Cont'd

unionGas
An Enbridge Company

2016 Actuals vs 2013 Board-approved - <u>$34.9 million increase</u>

- Distribution Margin - $67 million increase
  - Growth, rate increases and lower compressor fuel partially offset by warmer weather
- Transportation Revenue - $26 million increase
  - M12 rates / capital pass-through projects
- Operating Expenses - $52 million increase
  - Higher depreciation and DSM program charges
- Other Items - $6 million decrease

Capital Spend

Particulars ($ millions)	2015 Actual	2016 Actual	Variance
Storage	19.7	158.9	139.2
Transmission	381.1	583.3	202.2
Distribution	173.0	182.5	9.5
General	44.5	30.4	(14.1)
Other	73.1	78.8	5.7
Total	**691.4**	**1,033.9**	**342.5**

- Capital pass-through project spend:
  - 2015 - $353 million
  - 2016 - $684 million
- Storage & Transmission variance primarily driven by capital pass-through projects:
  - Storage - Dawn H Compression (2017 Dawn-Parkway)
  - Transmission - 2016/2017 Dawn-Parkway and Burlington-Oakville

uniongas
An Enbridge Company

Deferral Accounts

Summary of 2016 Deferral Accounts

unıongas
An Enbridge Company

Account Number	Account Name	Balance ($ millions)*
179-133	Normalized Average Consumption	23.6
179-131	Upstream Transportation Optimization	11.6
179-135	Unaccounted for Gas (UFG) Volume Variance Account	5.2
179-152	Greenhouse Gas Emission Impact Deferral Account	2.2
**	Combined Capital Pass-Through Project Accounts	(0.5)
**	Other	3.6
	Total Deferral Account Balances at Dec. 31, 2016	**45.7**

Notes:

***** Account balances include interest to Dec 31, 2016

****** Combination of various deferral accounts

NAC

Union Gas, An Enbridge Company

Table 1: 2016 NAC Deferral Account ($ millions)					
	Rate 01	Rate 10	Rate M1	Rate M2	All Rates
Total NAC Deferral Balance	**9.2**	**2.7**	**9.2**	**2.5**	**23.6**

Table 2: 2016 Target and Actual NAC (m3/customer)				
	Rate 01	Rate 10	Rate M1	Rate M2
2016 Target NAC	3,015	177,214	2,852	172,693
2016 Actual NAC	2,788	159,855	2,667	159,933
Change in NAC (Target - Actual NAC)	227	17,359	185	12,760
% Change in NAC	**7.53%**	**9.80%**	**6.49%**	**7.39%**

- 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 target NAC (based on 2014 actual NAC) exceeds the actual NAC for 2016

Transportation Optimization

Particulars ($ millions)	Board-approved	Actuals	Variance
Base exchanges	9.2	3.4	(5.8)
FT-RAM exchanges	5.8	-	(5.8)
Total exchanges revenue (pre-tax)	15.0	3.4	(11.6)
Less: Shareholder portion (10%)	(1.5)	(0.3)	1.2
Ratepayer portion (90%)	13.5	3.1	(10.4)
Less: Subsidy in rates	(13.5)	(14.7)	(1.2)
Deferral Balance Receivable	**-**	**11.6**	**(11.6)**

- Lower Total Exchange Revenue in 2016 than included in 2016 Board-approved rates primarily due to:
  - Elimination of TransCanada FT-RAM program
  - Warmer weather created less demand and lower prices for exchanges

UFG Volume Variance Account

- **Deferral Balance -** $5.2 million receivable
  - Purpose of the account is to capture the difference between UFG costs recovered in Board-approved rates and the actual cost of UFG, in excess of $5.0 million dead-band
  - 2016 Actual UFG expense of $21.0 million, less $10.8 million recovered in Board-approved rates results in a variance of $10.2 million, less the $5.0 million dead-band
  - 2016 Actual UFG percentage (.427%) **>** 2013 Board-approved percentage (.219%)

Greenhouse Gas Emission Impact Deferral Account

- **Deferral Balance -** $2.2 million receivable
  - Filed for the first time in the 2016 Deferrals proceeding
  - 2016 deferral account contains the following:
    - Salaries & Wages - $1.7 million
    - Consulting & Market Research - $0.5 million

Capital Pass-Through Project Accounts

- **Total Deferral Balance** - $0.5 million payable
  - Parkway West - $1.4 million payable
  - Brantford-Kirkwall/Parkway D - $1.6 million payable
  - Lobo C Compressor/Hamilton-Milton - $1.7 million receivable
  - Dawn H/Lobo D/Bright C Compressor - $0.5 million receivable
  - Burlington-Oakville - $0.3 million receivable

2017 Trends & Cost Pressures

- Salaries and wages
- Costs increases exceeding inflation:
  - Postage
  - Facility operating costs (leases, hydro)
- Incremental program costs:
  - Integrity
  - 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

Service Quality Requirements and Billing Performance

unionqas
An Enbridge Company

Service Quality Requirements	Target	Actual
Call Answering Service Level - Annual	75.0%	80.1%
Call Answering Service Level - Monthly	40.0%	>60.0% each month
Abandon Rate	<10%	3.6%
Meter Reading Performance Measurement	<0.5%	0.1%
Appointments Met Within the Designated Time Period	85.0%	98.9%
Time to Reschedule a Missed Appointment	100.0%	99.8%
Percentage of Emergency Calls Responded Within One Hour	90.0%	98.8%
Number of Days to Provide a Written Response	80.0%	100.0%
Number of Days to Reconnect a Customer	85.0%	86.2%

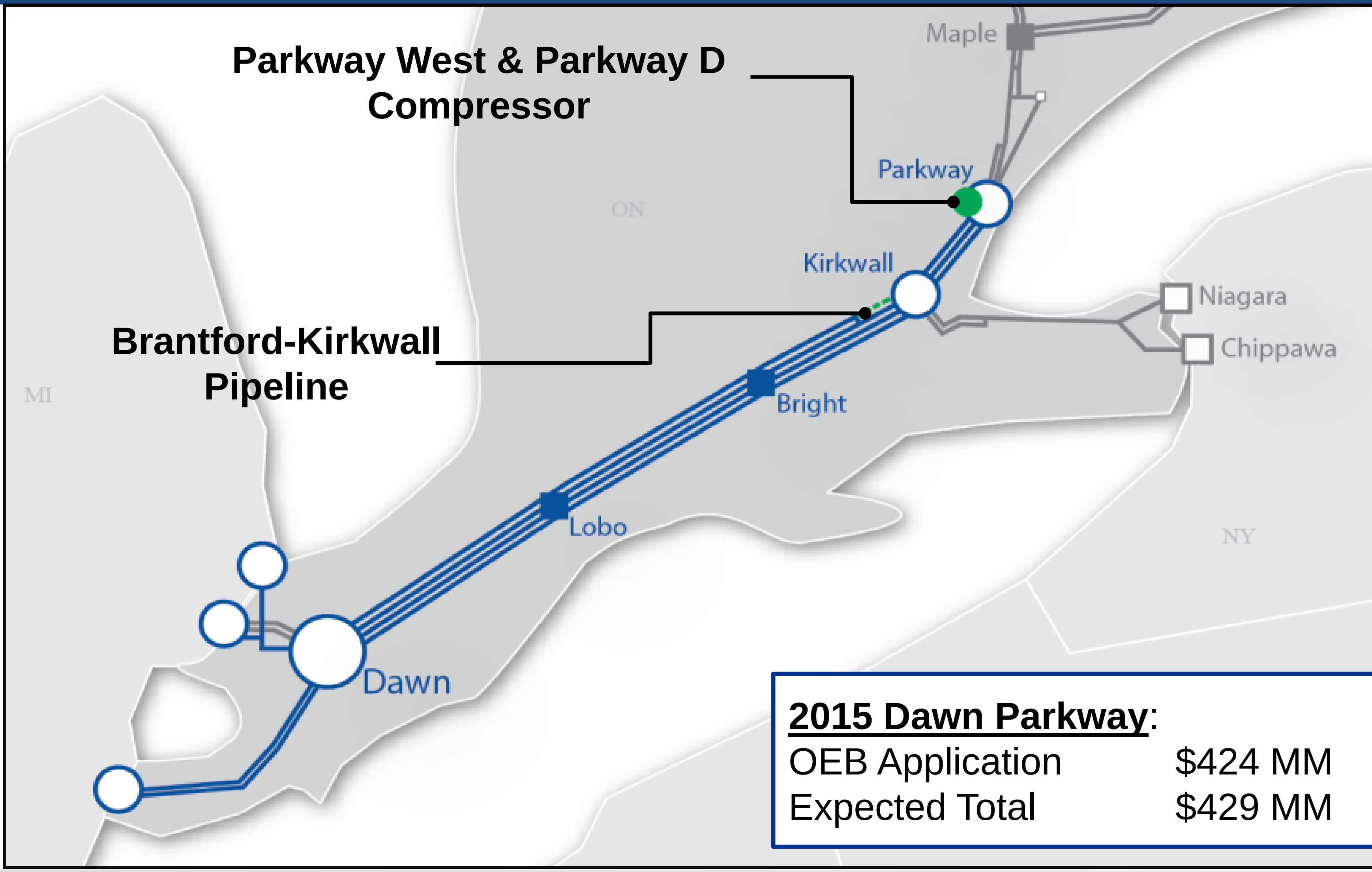
Billing Performance	Actual
Total Number of Billings	17,464,840
Total Number of Manual Checks Done as per QAP	171,381
Total Number of Manual Checks Done when Meter Reads Show Excessively High Usage as per QAP Criteria	118,411
Total Number of Manual Checks Done when Meter Reads Show Excessively Low Usage as per QAP Criteria	20,365

Facilities Expansion Projects

Chris Shorts
Director, Business Development &
Upstream Regulation

2015 Dawn Parkway Expansion

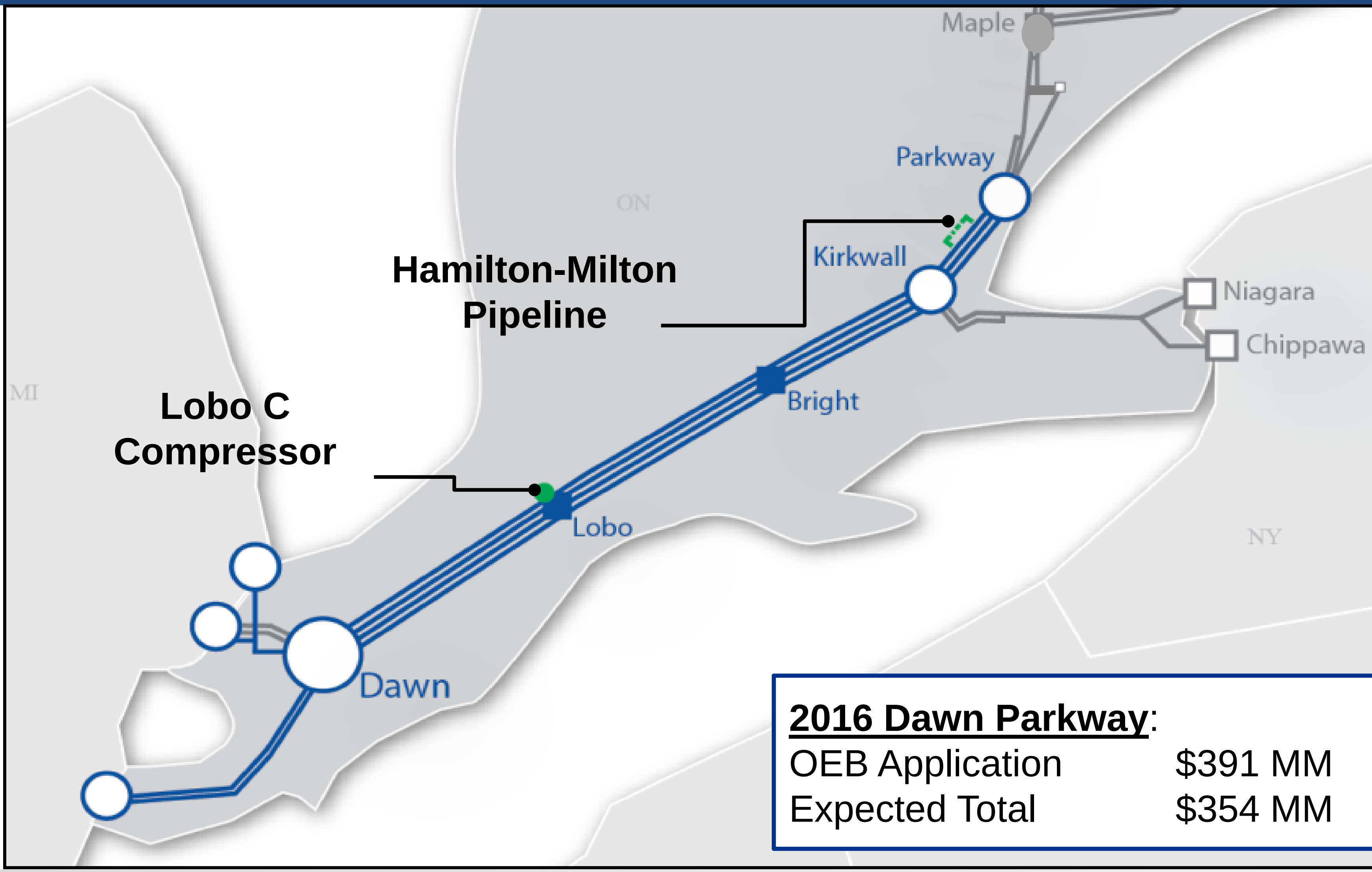
uniongas
An Enbridge Company



<u>2015 Dawn Parkway</u>:

OEB Application	$424 MM
Expected Total	$429 MM

2016 Dawn Parkway Expansion



<u>2016 Dawn Parkway</u>:

OEB Application	$391 MM
Expected Total	$354 MM

2016 Dawn Parkway Projects
Hamilton Milton Pipeline

uniongas
An Enbridge Company

2016 Burlington Oakville Project

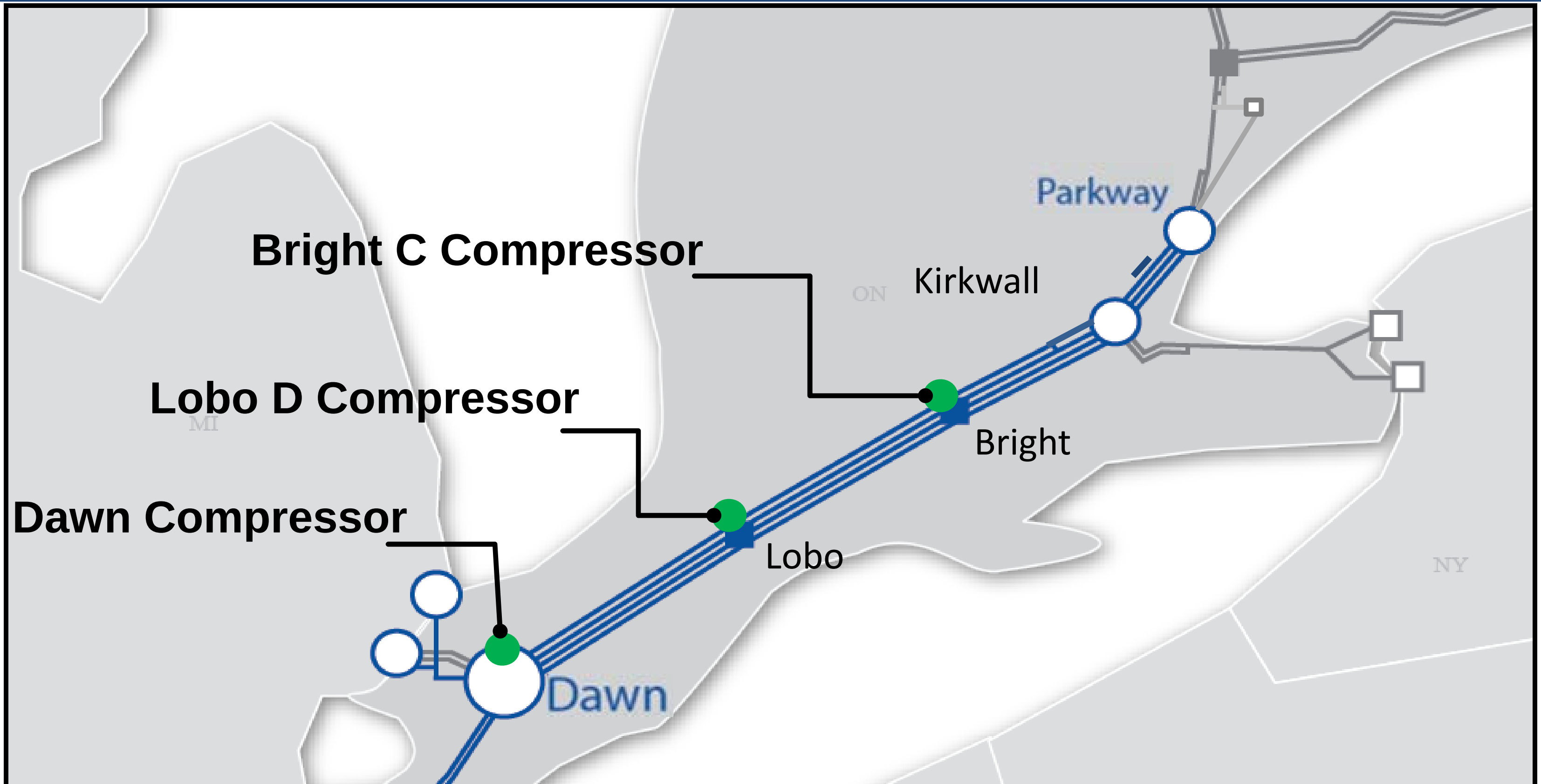
uniongas
An Enbridge Company

<u>2016 Burlington-Oakville</u>

OEB Application	$120 MM
Expected Total	$85 MM

2017 Dawn Parkway Expansion

uniongas
An Enbridge Company



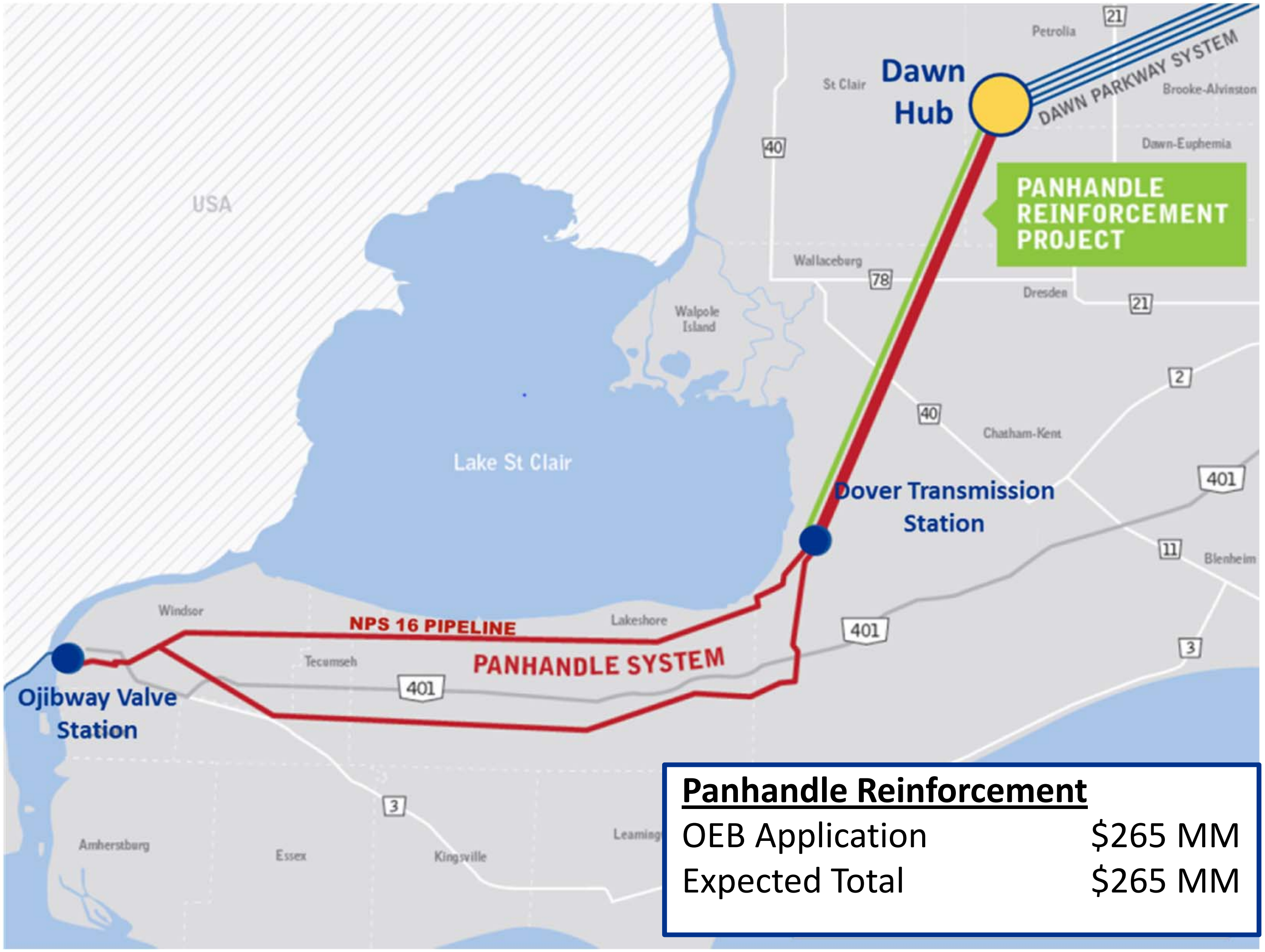
2017 Dawn Parkway	
OEB Settlement	$623 MM
Expected Total	$623 MM

2017 Dawn Parkway Projects
Dawn H

uniongas
An Enbridge Company

2017 Dawn Parkway Projects Bright C

2017 Panhandle Reinforcement Project



Panhandle Reinforcement	
OEB Application	$265 MM
Expected Total	$265 MM

2017 Panhandle Reinforcement Project

unionGas
An Enbridge Company

2019 Open Season Results

- Open Season Closed – February 2, 2017
- Union received 132 TJ/d of bids with a 15 year term starting November 1, 2019.
- Signed contracts of 75 TJ/d.

unionGas
An Enbridge Company

Gas Supply Update

Cheryl Newbury
Director, Gas Supply & Customer Support

Gas Supply Plan Agenda

- 2016/2017 Winter Experience
- Gas Supply Plan Recap
  - 2016/17 Plan
  - Future Trends

2016/2017 Winter Experience

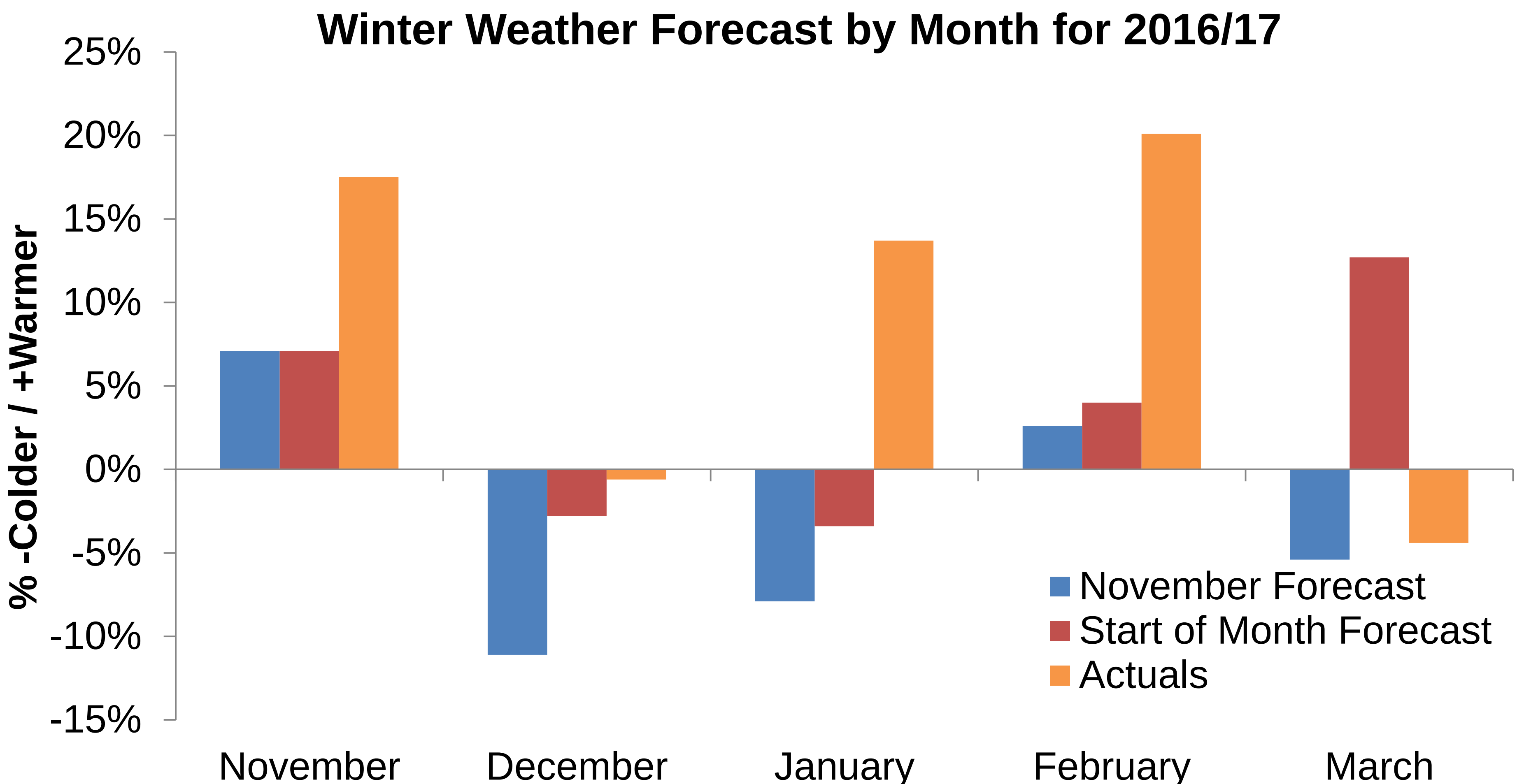
- Winter 2016/2017 Actual vs Normal (Union Merged)

Month	% Warmer than Normal	% Colder than Normal
November	17.5%	
December		0.6%
January	13.7%	
February	20.1%	
March		4.4%

- Winter 2015/2016 was 12.8% warmer than normal

9.3% warmer than normal in Winter 2016/17

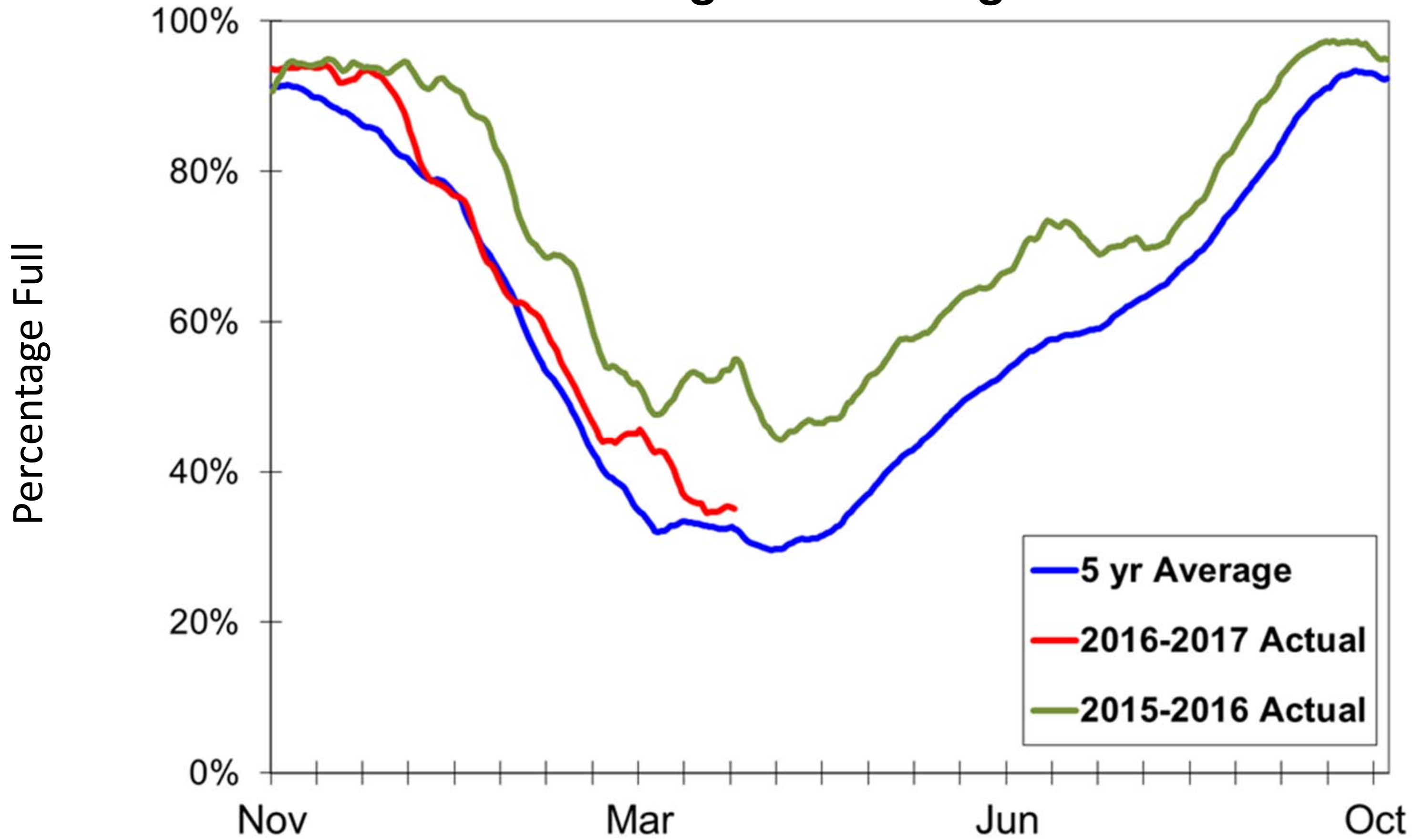
Weather Forecast Variability



Operating flexibility is critical to respond to fluctuations in weather

Storage Operation

Union Storage Percentage Full



Storage activity reflects the warmer than normal weather pattern

Winter Operational Update

- 2016 Dawn Parkway expansion facilities in service adding 0.46 PJ/d of capability
- Parkway discharge sets new record, over 3 PJ/d for 5 days, 4 of which were consecutive
- Seven days of net injections into storage in February

New facilities placed in service resulting in record throughput

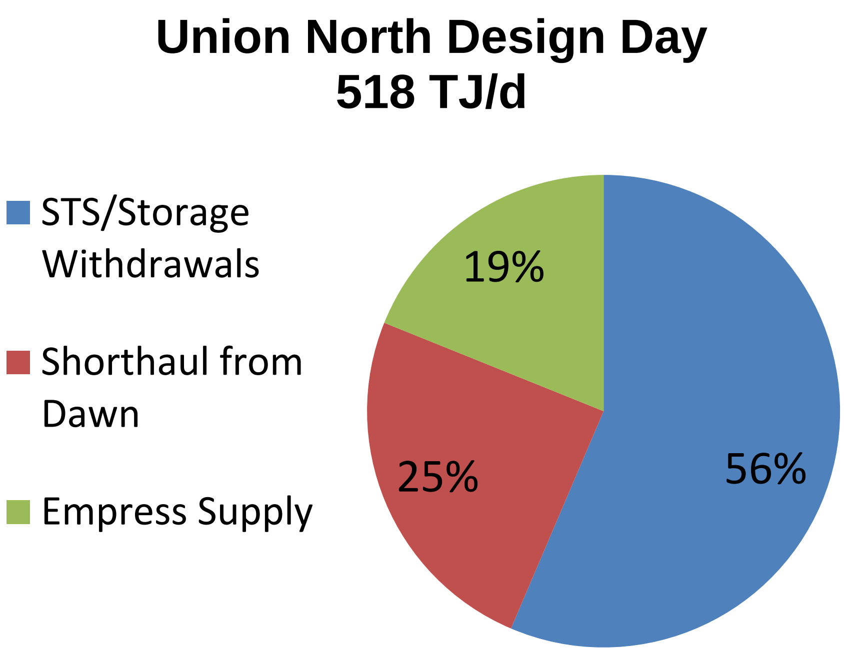
Gas Supply Plan Outlook

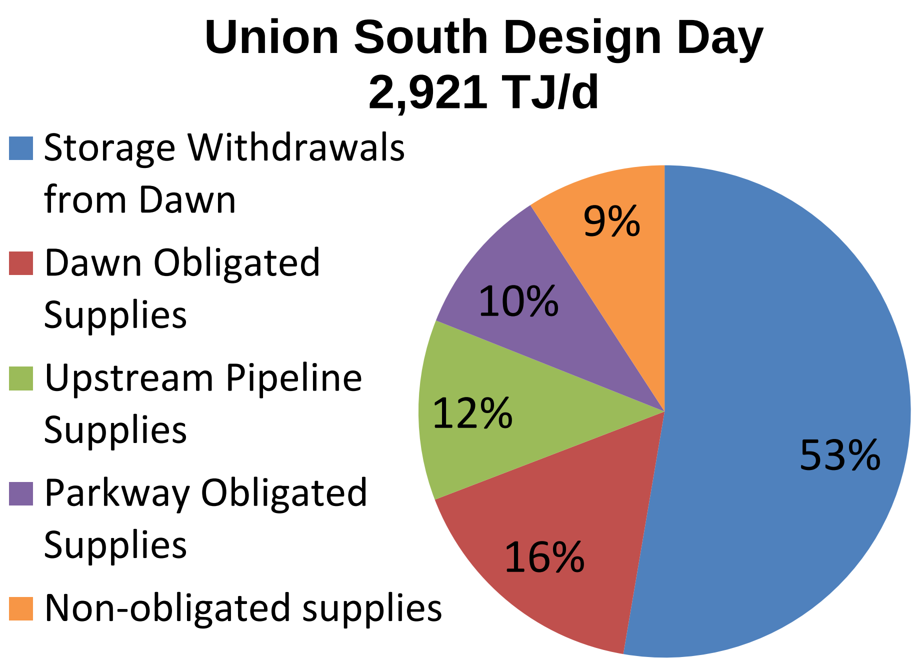
2016/2017 Plan

Gas Supply Plan Key Messages

- Plan period covers November 1, 2016 to October 31, 2017
- The corresponding Gas Supply Memorandum was filed as part of Union's 2017 Rates Application (EB-2016-0245)
- TransCanada long-haul to short-haul contract conversion in the North East planned for November 1, 2016; was fully phased-in by January 1, 2017
- Total supply required for system sales service is 181 PJ for 2016/17; an increase of 3 PJ over the 2015/16 plan
- In-franchise storage allocation at November 2016 is 93.6 PJ; a decrease of 1.4 PJ from the 2015/16 plan
- The Gas Supply Plan identified additional transportation capacity of approximately 3 TJ/d to meet design day requirements in the North

Union Design Day Supplies



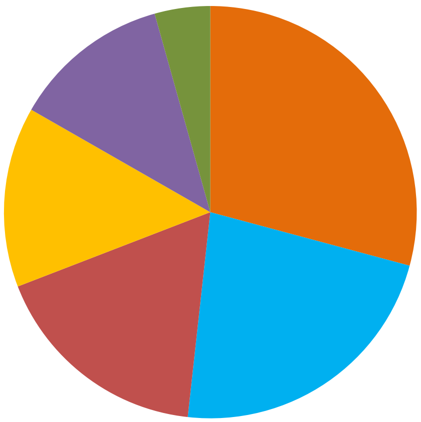


- Increase in Design Day requirement
  - Union North – 3 TJ/d
  - Union South – 21 TJ/d

Change in Supply Portfolio

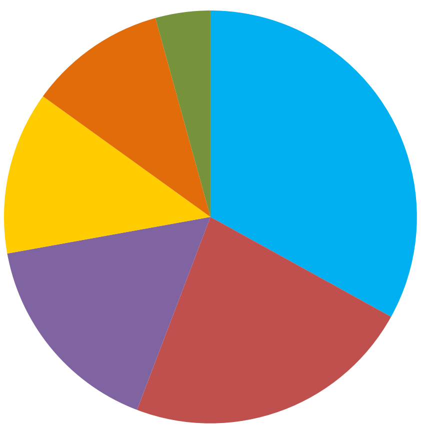
unıongas
An Enbridge Company

2015/2016 Plan



	Pipeline (Supply Point)	%	Avg. Daily Qty. (TJ/d)
	TransCanada (WCSB)	29.2%	142
	Vector (Chicago)	22.6%	110
	Dawn/Other	17.4%	85
	DTE (MichCon)	14.1%	69
	Panhandle/Trunkline (F.Z./Gulf)	12.4%	60
	TransCanada (Niagara)	4.3%	21

2016/2017 Plan



	Pipeline (Supply Point)	%	Avg. Daily Qty. (TJ/d)
	Vector (Chicago)	33.1%	164
	Dawn/Other	22.8%	113
	Panhandle/Trunkline(F.Z./Gulf/Ojib.)	16.4%	81
	DTE (MichCon)	12.8%	63
	TransCanada (WCSB)	10.8%	53
	TransCanada (Niagara)	4.3%	21

Upstream Transportation Portfolio Summary

Union South Changes

- Contract renewals
- Bridging contracts
- Contract expiries

Union North Changes

- Conversion from long-haul to short-haul
- Design Day requirements

Future Trends

Areas Being Monitored

- NEXUS and Other Projects Bringing Supply to Dawn
- TransCanada 2018-2020 Tolls Review
- Framework for the Assessment of Distributor Gas Supply Plans
- Climate Change Act

Residential Customer Perceptions of Union Gas

Tracy Lynch
Director, Distribution Marketing

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 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.

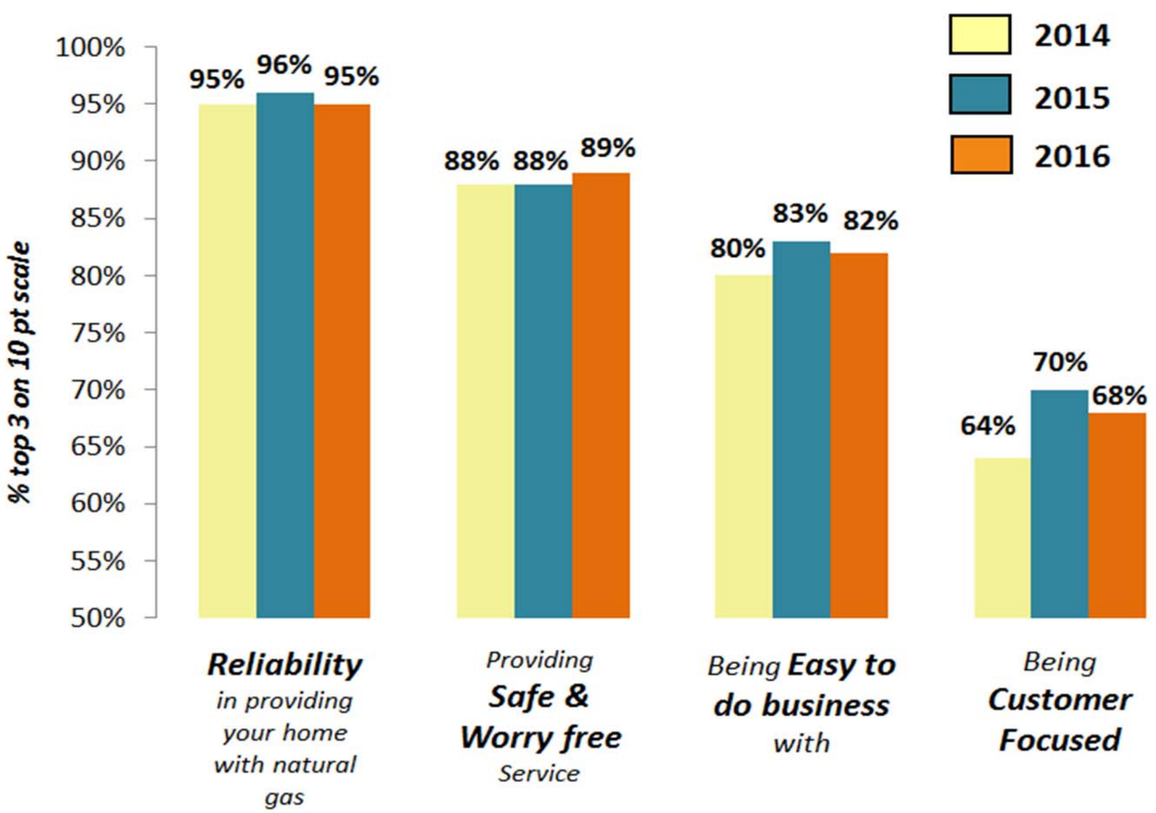
- All telephone interviews are conducted by a third party research supplier, protecting the anonymity of the customer feedback.

Residential Customer Perceptions of Union Gas

unionqas
An Enbridge Company

Key Indicators

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



- Winter of 2013/14 and subsequent price increases reflected in less positive view of Union in 2014 ("easy to do business" and "customer focus").
- Ratings rebounded in 2015 as prices decreased and remained stable in 2016.
- Ratings continue to be supported by positive customer experience at points of touch:
  - High responsiveness as indicated by 88% first call resolution (call centre)
  - 93% customer satisfaction (top 3 box score on a 10 point scale) with experience when utility service reps visit homes

Wrap-Up

Mark Kitchen
Director, Regulatory Affairs

Future Applications

- 2016 Deferrals
- Community Expansion
- DSM Mid-term Review
- DSM 2015 Deferrals
- 2018 Compliance Plan
- 2018 Rates Application

An Enbridge Company

Canada's Top 100 Employers 2017

www.uniongas.com

DATA CENTRE CONSOLIDATION

This section of evidence fulfills the commitment Union made in the Disposition of 2015 Deferral Account Balances and Earnings Sharing (EB-2016-0118) Settlement Proposal to file evidence as part of its 2016 non-commodity and earnings sharing application to explain the data centre co-location decision, its rationale and implementation, including the costs and benefit impacts to Union and its ratepayers.

Background

Summary

During 2015, Union, in conjunction with a Spectra Energy ("Spectra") enterprise-wide initiative moved its data centres from company owned facilities in Chatham and at Dawn to third party hosted data centres owned by Cyrus One in Lebanon, Ohio and Carrollton (Dallas), Texas.

The decision was made to retain ownership of the infrastructure in the data centre - servers, storage and network. One of the benefits of consolidating data centres across Spectra was that it created the "critical mass" necessary to be able to consider state-of-the-art VCE vBlock and IBM PureFlex converged infrastructure technology. This technology was leased and placed in the two new data centres.

What is a Data Centre?

A data centre is a facility (physical building, power, air cooling, security and fire suppression) used to house computer systems and the associated components (storage, servers, and network). Given their criticality to the operation of systems needed to provide safe, reliable service to customers, data centres typically have numerous layers of redundancy for power, network communications and security. Constant temperature and humidity levels need to be maintained in data centres at all times for the safety of the equipment.

Union uses approximately 130 systems that operate on infrastructure in the data centres. They include systems critical to the operation of the business such as:

i. Unionline: the web based system used by customers for nominations and reporting
ii. CARE: used to receive, confirm, schedule, reconcile and report shipper nominations on Union's storage, transportation and distribution system
iii. ConTrax: contract to cash for large in-franchise, ex-franchise and direct purchase customers
iv. Gas Measurement Accounting System ("GMAS"): gathers meter reads from large customers, interconnecting pipelines, storage, local producers and company used gas
v. Service Suite: provides work management functionality to the Distribution Operations field workforce
vi. ELocate: Ontario One Call Locate Ticket Application that creates work orders for line locates
vii. AUTOSOL: makes calls to telemeters from large customers and receives measurement information that is passed to GMAS
viii. Forecaster: predicts load on the system for volume planning and gas control purposes
ix. FOCUS: uses historical trends to predict how assets will be utilized in the future
x. Interruptions: facilitates notifications to manage gas usage

xi. Construction Administration Records System ("CARS"): Manages construction work orders related to new customer service lateral attachments

xii. ITRONFCS: Supports residential meter reading. It interfaces with the Banner system to enable the billing of residential meters

xiii. SAP: Used for financial reporting, procurement, asset management, accounts payable

As can be seen by a review of the functionality provided by Union's critical systems it is important that they are stable and reliable and available for clients to use. Many have Recovery Time Objectives ("RTOs") in the event of a disaster that are four hours or less; meaning that if there was a catastrophic event impacting the operation of a data centre, these systems need to be recovered and put back into operation in four hours or less. RTOs vary from system to system and are calibrated to align with how long the users of a system can reasonably manage without having the system available for them to use. The more critical the system is to business operations, the shorter the RTO.

Trends in the Marketplace

The trend has been for large companies to either co-locate or outsource their data centre functions. To co-locate, a vendor provides a building, cooling, power and physical security. The customer continues to provide their own hardware (storage, servers, and network). Companies do this for a variety of reasons:

i. They recognize that operating a data centre is not their core competency and as such should not be where they spend their time, effort and money

ii. To improve redundancy/reliability (e.g. power and cooling), flexibility (scalability) and security of their systems

iii. To reduce the risks of natural disasters (floods, tornadoes, earthquakes and hurricanes)

iv. To control escalating costs of physical security, cooling, connectivity, management and maintenance

Data centres periodically need to be scaled up to accommodate growth (organic business growth or the growth in data). The amount of data companies collect and analyze continues to grow exponentially. Data centres can be scaled down if need be to reflect trends in technology. An example of this occurs when systems are moved into the cloud. Data centre technologies evolve rapidly. The power intensity of devices has been increasing: they are getting smaller but use more power. Internally hosted data centres are difficult to scale up or down.

Description of Union's Existing Facilities

For many years Union operated two data centres. The primary data centre was located on the ground floor at 50 Keil, Union's Head Office. It occupied a 3,200 sq. ft. room and was built at the same time as the building, approximately 50 years ago. Lately, space in the 50 Keil data centre was significantly underutilized. Union experienced a 50% reduction in the floor space needed over the previous 15 years. Given the layout of the data centre and its physical attributes/requirements this floor space could not be used for other purposes. Storage and server growth had been averaging approximately 20% per year. The need for computing capability was increasing but the equipment needed to meet these needs was getting smaller, requiring less floor space.

The secondary or backup data centre was located at the Dawn compressor station. It occupied 1,200 sq. ft. of floor space in the building. The primary purpose of the Dawn compressor station is to support Dawn storage and transportation operations. The back-up data centre had been located at Dawn as this was a location where Union had office space available that was close enough to Chatham to provide reasonably quick and convenient access by staff in the event that a disaster affected the operation of the data centre at 50 Keil, and far enough away from Chatham to minimize the risk of the disaster having a similar negative effect on the Dawn facility. Data centre floor space was significantly constrained at Dawn.

The data centre at Dawn contained enough storage, servers, and network equipment to continue to operate the 15 to 20 key systems covered by Union's Disaster Recovery Plan in the event of a disaster. That is, there were fewer storage, servers, and network equipment at the Dawn back-up site than at the primary data centre at 50 Keil.

Need for a Change

Union's 50 Keil office building and the Dawn compressor station were built to provide office space and to support compressor operations, not to be modern day data centres. As a result of their primary functional purpose and their age, they are not well suited to be data centres in today's environment which places much more reliance on the availability of systems to provide safe, reliable service to customers than when the data centres were originally established.

The 50 Keil office building and the related electricity feed are situated meters from the Thames River. In the spring, ice dams on the Thames River can create significant risk of the Thames

River flooding. The risk of spring flooding in 2014 was particularly great. For weeks, ice conditions on the Thames River had to be monitored very closely. If the threat of flooding became high enough, the electricity supply to the 50 Keil building would have to be interrupted. If this occurred, the data centre would need to be shut down until power could be restored. This was narrowly avoided when rainfall was less than forecast during peak ice thawing conditions.

In May 2015, there was a significant leak in a water pipe in close proximity to the data centre at 50 Keil. The raised floor required replacement.. There had also been challenges keeping the equipment cool enough to operate safely during extremely hot weather conditions. A significant investment would have been required to maintain current service levels.

As a result of the above, the two existing data centres were not meeting Union's existing or future business requirements. Union had been looking for a long-term data centre solution for many years, at least as far back as 2011.

During 2013 Spectra identified an opportunity to consolidate data centres to realize the benefits that a co-location data centre service provider could provide and take advantage of the economies of scale and scope created by a combined entity the size of Spectra. These benefits would not be available to any Spectra business unit acting on their own as they would not be big enough to obtain favourable commercial terms from the best co-location data centre service providers.

Co-location and Managed Service Vendor Selection Process

The evaluation of alternatives and selection of data centre vendors (co-location and managed services) took place over the January to August 2014 time period. The process started with a scan of the marketplace. Twenty-six potential vendors were identified[1]. Service providers were filtered using the following selection criteria:

i. Does the vendor provide colocation services and managed services,
ii. Can the vendor drive transformation,
iii. Does the vendor have a good reputation for client satisfaction, and
iv. Does the vendor have a strong presence with mid-size clients (Spectra is considered a mid-size customer in the data centre space).

Briefing sessions were held with eight of the twenty-six potential vendors; AT&T, Bell Canada, Cyrus One, HCL, HP, Savvis, Sunguard and T-Systems.

The eight vendors were reduced to five to receive the Request for Proposal (RFP) that was sent out on February 20, 2014. The response deadline was March 10, 2014. Three of the eight vendors identified above were not sent the RFP as they either did not respond to inquiries or did not meet the selection criteria. These were Bell Canada, Sunguard and T-Systems. The selection criteria that determined whether a vendor would be sent the RFP included:

[1] By IT consultant firms Booz & Company, Forrester Research and Gartner

i. Basic service provisions: Did the vendor have strong capabilities in colocation and managed services?

ii. Operational considerations: This relates primarily to location. How close were the vendor's data centers relative to each other, relative to Spectra Energy's office locations, relative to areas prone to natural disasters and what telecommunication companies operated in the area? (The potential to have the redundancy that would result from receiving service from multiple telecom vendors was considered very favourable.)

iii. Strategic Considerations: Future vendor services offerings, how easy would the vendor be to work with, and the long-term viability of the vendor?

AT&T, Cyrus One (with Accudata or HCL providing managed services within the data centre) and HP responded to the RFP. These vendors went through a rigorous selection process that included responding to the RFP, RFP follow-up meetings, site visits, customer reference interviews and an internal scoring matrix. The scoring matrix included considerations related to Strategic Fit (capability, expertise, quality of team/responses), Solution Quality (facility design, facility location and security), and Competitive Pricing/Contractual Terms.

The vendor selected to provide co-location data centre services was Cyrus One. Cyrus One offered the highest service guarantee (100% uptime on power and cooling) and the best security model. The core business model of Cyrus One is to own and operate data centres. HCL was the vendor selected to provide managed services within the data centres.

The process was managed as a Spectra process. All Spectra business units were represented on the selection/steering committee. The project manager was a Union employee. Booz & Company was engaged to provide assistance and guidance to the selection process.

Equipment Leasing Decision

Converged infrastructure technology allows customers to select a pre-configured and integrated solution. It delivers improved performance, lower operating costs relative to technologies that are not integrated, and greater IT optimization, increased automation and faster implementation. The use of integrated technologies pushes much of the effort to configure and support to the manufacturer. Further, the management tools provided as part of the integrated solution enable more cost effective operations.

After reviewing the leading integrated technologies available in the marketplace (HP, IBM and VCE), two separate integrated technology platforms were selected. The VCE VBlock technology to run Windows based applications and the IBM PureFlex technology to run AIX based applications.

The VBlock technology from VCE is an integrated best of breed solution (CISCO, VMware, EMC Storage). VCE technologies have proven success across major global enterprises in banking, retail, healthcare and marketing. Much of the technology was currently in use at Union. Company staff were familiar with the technology which reduced the amount of training required. There was a higher level of certainty that Union applications would perform well on the VBlock technology.

The IBM PureFlex technology has the same benefits as other integrated technologies including improved performance, lower operating costs, increased automation and faster implementation over separate multi-vendor solutions. It was the only integrated technology that Union applications running on the IBM AIX platform could use. The key drivers for using a converged platform were:

i. Improved performance
ii. Low operating costs
iii. Increased automation
iv. Simplified sourcing and support
v. Simplified vendor relationship (single vendor)
vi. Smaller physical footprint which results in lower co-location space costs
vii. All parts are designed and built to work as a whole system

Sizing the Environment

To determine what hardware was required in the new data centres a detailed understanding of the existing resource requirements was needed. This step was necessary to ensure what was installed was correctly sized. To determine the existing computing usage, specialized tools were used to monitor and record the resource utilization on each server. The data captured from the monitoring tools was totaled to understand the total computing requirements. The resources tracked were CPU utilization, memory utilization, input/output to disk (I/O) and inter system network traffic.

Tools provided by VCE were installed on existing servers and storage systems. All activity was monitored for a period of time. The data captured provided a detailed analysis of the necessary system requirements (IO, CPU, memory and network) which was used to establish the size of the converged solution. In addition, a 20% growth factor (based on Union's historical average growth rate) was included to provide some time before more hardware would be required. No additional disk space, CPU, memory or network was needed in 2015 or 2016. It is anticipated that additions will be needed in 2017.

New Data Centre Costs

In 2016 (first full year following implementation of the consolidated data centre) Union paid the following data centre related costs:

From Third Parties:	**USD**	**CAD**
AT&T/Sprint/Level 3/Crystal (telecommunication)	314,025	412,079
Cyrus One (co-location, space, power)	359,008	470,077
Cisco/Citrix/IBM/KC Salley/KC Office/Logisticals[1]	1,045,189	1,412,260
Total	**$1,718,222**	**$2,294,416**
From Spectra Energy:	**USD**	**CAD**
Equipment Lease	1,429,212	1,893,134
Internal Labour	589,840	781,302
Cost to Implement[2]	530,568	702,790
Total	**$2,549,620**	**$3,377,226**
Union Gas:		**CAD**
Internal Labour		1,110,434
Internal Labour charged to Spectra (including loadings)		(1,312,827)
Total		**($202,393)**
Total Data Centre Costs in 2016		**$5,469,249**
[1] Software and equipment maintenance.		
[2] Represents ½ year impact. This cost will be eliminated in 5 years.		

The acquisition of the vBlock and PureFlex equipment was structured as a 5 year lease that started in 2015. The cost to implement includes the cost of consulting services (44%), internal labour (17%), licenses (10%), equipment leases (10%), contract/outside services (8%), circuits/hardware/software purchases (7%), and other (4%) incurred to configure and test the new vBlock and PureFlex hardware and migrate data and systems into the new data centres. These costs will be amortized over 5 years starting in 2016 (half year in 2016).

Union's proportionate share of data centre costs of 32% for 2016 was derived by examining Union's utilization of data centre components (storage, servers, and network) during the year. This factor will be updated yearly to reflect Union's utilization of the data centre. Prior to implementation, it was estimated that Union would utilize 35% of the data centres based on the infrastructure requirements that existed at the time. The following table shows the derivation of the 2016 factor.

	Storage		RISC\6000		Wintel Servers		Network Equipment / Telecom	
Devices	TB Allocated	TB %	Cores	% Core	Cores	% Cores	USER ID	User ID %
Union Gas	286.1	27.38%	211	62.24%	1,907	32.39%	2,989	36.17%
Total	1,045.0	100.00%	339	100.00%	5,888	100.00%	8,263	100.00%

	Annual Cost				
	Storage	RISC\6000	Wintel	Network/Telecom	Total
Total Cost	$ 4,434,550	$ 474,070	$ 1,169,470	$ 1,364,237	$ 7,442,327
Percentage	27.38%	62.24%	32.39%	36.17%	
Union Gas	$ 1,214,074	$ 295,070	$ 378,767	$ 493,490	$ 2,381,401
				% of Total Costs	32.00%

Cost of Storage: has been allocated in proportion to the number of Terabytes (TB) of storage used by each business unit within Spectra.

Cost of Servers: has been allocated in proportion to the number of server cores used by each business unit within Spectra. Two types of servers are used: RISC\6000 and Wintel. They have been allocated separately.

Cost of Network equipment and Telecom: has been allocated in proportion to the number of network IDs used by each business unit within Spectra.

Storage, servers, and network components are then weighted by the annual cost associated with each item to derive an overall allocation factor to be applied against data centre related costs.

Old Data Centre Costs

Union had been looking for a long-term data centre solution for a number of years. As a result, Union delayed purchasing new equipment in the old data centres as long as possible. As a result, capital spending in recent years was understated relative to a normalized steady state as expenditures had been deferred in anticipation of a decision on a long term strategy.

When the decision was made to proceed with the data centre consolidation project, Union's 2014 data centre costs were expected to be as follows:

	CAD
Hardware Maintenance	$1.2 million
Internal Labour	$1.1 million
Managed Services	$0.5 million
Power	$0.2 million
Total O&M	$3.0 million
Depreciation	$2.2 million
Capital	$2.0 million

RAKI was selected as the vendor to dispose of the equipment in the old data centres through an RFP process. They agreed to absorb the labour costs incurred to remove the equipment and pay approximately $13,000.

Benefits to Ratepayers

The main benefits to ratepayers resulting from moving to the new data centres are that the new data centres:

i. Lower operational risk and improve the reliability of the key systems needed to serve customer's needs in a safe and reliable manner (see chart below)
ii. Provide modern technology (i.e. vBlock and PureFlex)
iii. Improve physical security
iv. Allow for quicker server/storage installations
v. Are scalable
vi. Avoid the need to make costly upgrades at existing data centres and/or estimating infrastructure needs for next 20 to 30 years and sizing new "owned" data centres
vii. Make office space in Chatham and at Dawn available for other purposes
viii. Reduces the capital that would otherwise be spent at Union on servers, storage and network
ix. The modest cost increase disappears after the costs to implement have been amortized (in 5 years)

The following chart compares the old and new data centres.

Old Chatham Data Centre (back-up at Dawn)	New Lebanon and Carrolton Data Centres
Power: • Power delivered by a single electrical feed • Single backup generator • Single UPS system (battery) • Limited overall failure redundancy • Outages required for maintenance • Inefficient power utilization • Spring flooding of Thames River presents risk of power supply interruption	Power: • Power delivered by two independent and separate electrical feeds • 8 back-up generators configured to provide 3 layers of failure redundancy • 40,000 gallon fuel reserve with priority access to re-supply • Multiple UPS systems to ensure high level of redundancy • High frequency of redundancy testing • 100% available power guarantee • Reduces power consumption by over 50% compared to current use
Cooling: • 30" raised floor • Risk of water damage from piping • Limited and inefficient cooling capabilities	Cooling: • 48" raised floor • No cooling water in data centre – liquid cooling systems chill from outside data centre perimeter with cool air blown in • Multiple cooling systems to ensure redundancy • High frequency of redundancy testing • 100% available cooling guarantee • State-of-the-art cooling design requiring less power consumption
Security: • 2 layers of access security • 24 X 7 onsite security personnel (Chatham only), with limited video surveillance and pass-card access controls • No internal perimeter protection within data centre for computing equipment • Building not specifically designed for data centre use (water pipe leak could seriously damage data centre equipment) • No external facility perimeter fencing	Security: • 6 layers of access security • 24 X 7 onsite security personnel, with extensive video surveillance and pass-card access controls • Internal perimeter cage surrounds computing equipment, including overhead and underfloor protection • Reinforced building structure – built specifically for purpose as a data centre • Full external facility perimeter fencing

Fire Protection: • Older fire suppression system	Fire Protection: • Advanced technology using Very Early Smoke Detection Apparatus (VESDA) coupled with zone controlled, multi stage fire suppression system • Dry-pipe system with focused sprinkler heads to localize/minimize any damage
Telecommunications: • Single points of failure • Services obtained through one telecommunications provider • Limited ability to grow bandwidth	Telecommunications: • No single point of failure • Services obtained through multiple telecommunications providers – data centre is carrier neutral to maximize flexibility • Tremendous opportunity for bandwidth growth
Growth Opportunities: • Space is available within the existing Chatham data centre; the space being utilized is not optimized for efficient operation • Limited growth opportunities at Dawn • Power and cooling environmental systems need to be enhanced to support any growth – requires capital • Raised floor needs to be replaced	Growth Opportunities: • Highly scalable – expansion space is readily available in both data centres • No capital costs for growth in power and cooling environmental systems

Benchmarking

The costs Union is paying for data centre services were benchmarked in December 2016 against two cloud based service providers in the marketplace. During the investigation it was clear that not all of Union's requirements are readily available from cloud service providers. For example, AIX (used to deliver database services) and network security (firewall, cybersecurity) are not supported by cloud service providers. As not all of Union's internal computing requirements are readily available from cloud service providers the benchmark analysis was limited to Windows based systems (the largest internal computing footprint).

The cost for just Windows based servers is estimated to be $5.1 million at Microsoft Azure and $5.6 million at Amazon Web Services. This is compared to Union's cost of $2.4 million for Cyrus One co-location and the equipment lease cost which includes both the Windows and the IBM PureFlex technology. In both cases the costs of cloud provided Windows based systems greatly exceeds the costs Union is incurring.

In order to provide a high level total cost comparison, the current costs for the systems not included in the cloud analysis referenced above (AIX, security systems, labour) were added to the estimated cloud costs. The resulting totals were $7.5 million at Microsoft Azure and $8.0 million at Amazon Web Services, compared to Union's data centre costs of $5.5 million in 2016.

Conclusions

In 2015 Union moved its data centres from company owned facilities to third party hosted data centres owned by Cyrus One in conjunction with a Spectra enterprise-wide initiative. This was consistent with marketplace trends to co-locate or outsource data centre functions and allowed Union to take advantage of the economies of scale and scope available to entities the size of Spectra.

Union has approximately 130 systems that operate in these data centres. They include systems critical to the operation of the business. The data centres that Union previously operated at 50

Keil and at the Dawn compressor station were not meeting Union's existing or future business requirements.

The new data centres provide improved redundancy/reliability, scalability and security and eliminate single points of failure in power and the network. They significantly reduce the risk of natural disasters such as flooding of the Thames River and eliminate the inherent risks associated with being in a 50 year old building.

The cost Union pays to use the new data centres compares very favourably to services available in the marketplace.