May 8, 2013

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

Dear Ms. Walli:

Re: EB-2013-0109 - Union Gas Limited - 2012 Earnings Sharing & Disposition of Deferral Accounts and Other Balances

Enclosed is the application and evidence submitted by Union Gas Limited ("Union") concerning the final disposition and recovery of certain 2012 year-end deferral account and other balances and the calculation of its 2012 utility earnings for the purposes of earnings sharing.

Union notes that Section 36 (4.2) of the Ontario Energy Board Act, 1998 states that with respect to non-commodity related deferral accounts *"the Board shall at least once every 12 months, or such period as is prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates."* These deferral accounts were last disposed of by the Board in its EB-2012-0087 Rate Order dated February 28, 2013.

The Application is supported by evidence which is outlined below:

EXHIBIT A

Tab 1	2012 Deferral Account and Other Balances
Tab 2	2012 Utility Results, Earnings Sharing and Utility Financial Reporting Package
Tab 3	Allocation and Disposition of 2012 Deferral Account and Other Balances and 2012 Earnings Sharing
Tab 4	Incremental Transportation Contracting Analysis

The Board determined in EB-2012-0087 (Union's 2011 Deferral Account Disposition proceeding) that 2011 net FT-RAM related transportation exchange revenue should be recorded in the Upstream Transportation FT-RAM Optimization deferral account and treated as a gas cost reduction. Union proposes to include 2012 net FT-RAM related transportation exchange revenue in utility earnings subject to earnings sharing rather than as a gas cost reduction. Union's proposal is described in Exhibit B. Notwithstanding Union's proposal, Union has provided schedules in Exhibit A above to illustrate the effect of treating FT-RAM related transportation exchange revenue as a gas cost reduction, as per the treatment in 2011.

In addition, the Board directed Union in EB-2011-0210 to file an expert, independent review of its gas supply plan, its gas supply planning process, and gas supply planning methodology prior to its next rates proceeding. Union's response to the Board's directive is provided in Exhibit B, Tab 5. The expert reviews are provided in Exhibit C, Tab 2 and Exhibit C, Tab 3.

EXHIBIT B

Tab 1	Union's Proposed Treatment of FT-RAM Related Transportation Exchange Revenue for 2012
Tab 2	Transportation Exchange Services
Tab 3	Union's Gas Supply Planning Process
Tab 4	Rate Impacts of Union's Proposed Treatment of Transportation Exchange Revenue in 2012
Tab 5	Union's Response to the Board's EB-2011-0210 Directive to Review the Gas Supply Planning Process

EXHIBIT C

Tab 1	The Secondary Natural Gas Market in Ontario prepared by Stephen Acker
Tab 2	Union's Gas Supply Planning Review prepared by Sussex Economic Advisors
Tab 3	Review of Union's Gas Supply-Related Cost Allocation/Rate Design and Deferral Accounting prepared by Concentric Energy Advisors

Union proposes that the impacts which result from the disposition of 2012 deferral account and other balances and 2012 earnings sharing be implemented on October 1, 2013 to align with other rate changes implemented through the Quarterly Rate Adjustment Mechanism.

In accordance with the Board-approved Settlement Agreement in the EB-2005-0520 proceeding, Union agreed to report new upstream transportation contracts with a term of one year or longer that may form part of Union's "system" sales service in the future. Union has included in the evidence at Exhibit A, Tab 4 Incremental Transportation Contracting Analysis for six contracts.

The approved IR mechanism provides for the sharing (50/50 between Union and its customers) of actual utility earnings greater than 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan.

The approved IR mechanism also provides for the sharing (10/90 between Union and its customers, in the customers favour) of actual utility earnings greater than 300 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan.

Union's 2012 actual utility earnings exceeded the 200 basis point threshold. Union is, therefore, seeking an order or orders approving $6.748 million as the customer portion of earnings sharing in 2012 above the 200 basis point threshold and the proposed disposition of that amount to Union's customers.

Union's 2012 actual utility earnings exceeded the 300 basis point threshold by 40 basis points. Union is, therefore, seeking an order or orders approving $4.813 million as the customer portion of earnings sharing above the 300 basis point threshold in 2012 and the proposed disposition of that amount to Union's customers.

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

cc Crawford Smith (Torys)
EB-2012-0087 Intervenors

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-2011-0025, Union applied to the Ontario Energy Board (the "OEB") 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, 2012 through an incentive rate (IR) mechanism. The Board approved Union's request. In doing so, the OEB approved the continuation of certain deferral accounts.

4. The approved IR mechanism provides for the sharing (50/50 between Union and its customers) of actual utility earnings greater than 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan.

5. Union's 2012 actual utility earnings exceeded this threshold. The customer portion of earnings sharing above the 200 basis point threshold is $6.748 million.

6. The approved IR mechanism also provides for the sharing (90/10 between Union and its customers, in the customers' favour) of actual utility earnings greater than 300 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan.

7. Union's 2012 actual utility earnings exceeded this threshold. The customer portion of earnings sharing above the 300 basis point threshold is $4.813 million

8. Union applies for the:

    a) approval of final balances for all 2012 deferral accounts and an order for final disposition of those balances;

    b) approval of $15.730 million as the customer portion of earnings sharing in 2012 and the proposed disposition of that amount to Union's customers; and,

    c) approval to close Shared Savings Mechanism deferral account No. 179-115 effective January 1, 2013.

9. Union also applies to the OEB 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.

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

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

12. 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.

13. 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: May 8, 2013

UNION GAS LIMITED

By its Lawyers

Torys
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

Exhibit A

TAB 1

2012 DEFERRAL ACCOUNT BALANCES AND TAX CHANGES

2012 YEAR-END DEFERRAL ACCOUNT BALANCES

Union has classified the deferral accounts approved by the Board for use in 2012 into three groups:

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

The net balance in the above deferral accounts together with the Federal and Provincial Tax Changes at December 31, 2012, result in a $15.929 million debit from ratepayers. This is based on Union's proposal to include FT-RAM related transportation exchange revenues ("FT-RAM revenue") in utility earnings subject to earnings sharing. Refer to Exhibit B for evidence on the proposed treatment of FT-RAM revenue. Interest has been calculated on account balances according to the Board-approved accounting orders. The applicable short-term interest rate used was 1.47% for the months of January through December as prescribed by the Board in EB-2006-0117.

Tab 1, Appendix A, Schedule 1 provides a summary of the deferral account balances and tax changes.

GAS SUPPLY DEFERRAL ACCOUNTS

Account No. 179-108 Unabsorbed Demand Costs

The balance in Account No. 179-108 Unabsorbed Demand Cost ("UDC") Deferral 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 credit balance of $1.388 million in the UDC deferral account 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 targeted (planned) storage inventory levels at October 31, Union's 2012 approved rates included UDC of 4.4 PJ in Union North and 0.2 PJ in Union South.

In Union North, UDC is part of planned operations due to the requirement to hold sufficient TCPL firm transportation ("FT") capacity and other firm assets (both storage and transportation related) to meet both design day requirements as well as annual demand. Assets required to meet design day demands are greater than what is required to meet average daily demand, and therefore result in unutilized pipe and UDC. In a warmer than normal year, Union may incur UDC in Union South to rebalance supply with lower demands. Union manages its North and South transport portfolios on an integrated basis and will determine which pipeline to leave empty, if necessary, based on the least cost option. Consequently, UDC is managed on an integrated basis.

In 2012, Union's actual UDC was 24.4 PJ; Union South was 10.7 PJ, and Union North was 13.7 PJ. The level of UDC in excess of planned levels experienced in 2012 was largely due to significantly warmer than normal weather. The Actual Heating Degree Days ("HDD") were 14.9 % lower than Board Approved Normal HDD.

The UDC variance was offset, in part, by direct purchase customers returning to system supply in Union South. Union provides the default gas supply and, as such, manages return to system for bundled direct purchase arrangements. Therefore, when customers are on a bundled direct purchase arrangement and return to system (either due to the customer or Energy Marketer's initiative), Union manages the resulting default supply function to ensure supply is available for these customers by purchasing additional supplies it otherwise would not have required.

For 2012, Union's total UDC incurred was $5.427 million. Union collected $6.795 million in rates and recorded an associated interest credit of $0.020 million. The result is a credit in the UDC variance account of $1.388 million. Table 1 below provides the derivation of the UDC variance account balances by operating area.

Table 1
UDC Variance Account by Operational Area

Line No.	Particulars ($000's)	Union North	Union South	Total Franchise Area
1	UDC Recovery in Rates	6,657	138	6,795
2	UDC Costs Incurred	3,039	2,387	5,427
3	Variance (line 2 - line 1)	(3,618)	2,249	(1,368)
4	Interest	(53)	33	(20)
5	(Credit) / Debit to Operations Area	(3,671)	2,282	(1,388)

A description of each item follows:

UDC Recovery in Rates

2012 Board-approved rates include $7.330 million associated with planned UDC in Union North and $0.117 million associated with planned UDC in Union South. Union actually recovered $6.657 million in Union North and $0.138 million in Union South. The lower than expected recovery is a reflection of lower than expected demand.

UDC Costs Incurred

The costs reflected in the UDC variance account are the total demand charges for the unutilized capacity totaling $13.292 million partially offset by revenue generated from transportation releases totaling $7.865 million. This resulted in a net UDC cost of $5.427 million.

Unutilized upstream transportation capacity due to excess supply, is released and sold on the secondary market to minimize UDC. Revenues generated from the transportation releases are credited to the UDC variance account mitigating the overall UDC impact.

Consistent with past UDC variance account dispositions, Union proposes to assign the total cost of $5.427 million to each operating area in proportion to the actual excess supply. This results in UDC of $3.039 million for Union North and $2.387 for Union South.

Interest

Interest associated with UDC amounted to a credit of $0.053 million for Union North and a debit of $0.033 million for Union South for a net credit of $0.020 million.

(Credit)/Debit to Operations areas

The UDC variance account has a net total credit balance of $1.388 million. The balance applicable to customers in Union North is a credit of $3.671 million. The balance applicable to customers in Union South is a debit of $2.282 million.

Account No. 179-130 Upstream Transportation FT-RAM Optimization

There is no balance in this deferral account. This deferral account was approved by the Board in EB-2012-0087 (Union's 2011 Deferral Disposition proceeding) to include exchange revenues related to FT-RAM Optimization. As addressed in Exhibit B of this evidence, Union proposes to include 2012 FT-RAM revenues in utility earnings subject to earnings sharing, rather than gas cost reductions.

In EB-2012-0087, the Board determined that 2011 transportation exchange revenues related to FT-RAM should be treated as a gas cost reduction. Under the method approved in EB-2012-0087, the Upstream Transportation FT-RAM Optimization Deferral Account (179-130) would have a credit balance of $32.977 million (90% of the FT-RAM revenue), and the total deferral accounts would have a net credit balance of $17.048 million. Tab 1, Appendix B provides the schedules derived using the method approved in EB-2012-0087. The summary of deferral account balances schedule can be found at Tab 1, Appendix B, Schedule 1, the calculation of the amount in the FT-RAM Optimization Deferral Account can be found in Tab 1, Appendix B, Schedule 2, and the Compressor Fuel and UFG costs related to FT-RAM can be found at Tab 1, Appendix B, Schedule 3.

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, C1 Short-Term Firm Peak Storage, and C1 Firm Short-Term Deliverability. 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.

There is a debit balance in the Short-Term Storage and Other Balancing Services deferral account of $1.879 million. The balance is calculated by comparing $9.375 million (90% of the actual 2012 Short Term Storage and Other Balancing Services net revenue of $10.417 million) to the net revenue included in rates of $11.254 million in the EB-2011-0025 Rate Order. The result is a net deferral debit of $1.879 million. The details of the balance are found at Tab 1, Appendix A, Schedule 2.

Actual 2012 revenues from C1 Off Peak Storage, Gas Loans and all other Balancing services were $1.085 million lower than the 2007 Board approved forecast. The main driver for lower revenues continues to be the impact of shale gas production causing less seasonal volatility of natural gas prices.

The C1 Short Term Firm Peak Storage revenues were $3.237 million lower than the 2007 Board approved forecast. The Board approved forecast implied an annual average value of $1.75/GJ ($13.794 million/7.9 PJ), and the actual average annual C1 Short Term Peak Storage value in 2012 is $0.78/GJ. The market value for short-term peak storage has declined since the last Board approved forecast in 2007, as shown at Figure 1.

The decline in average annual value is partially offset by higher capacity available for sale of C1 Short Term Peak Storage for 2012/2013 winter (12.0 PJ) compared to the 2007 Board approved forecast (7.9 PJ).

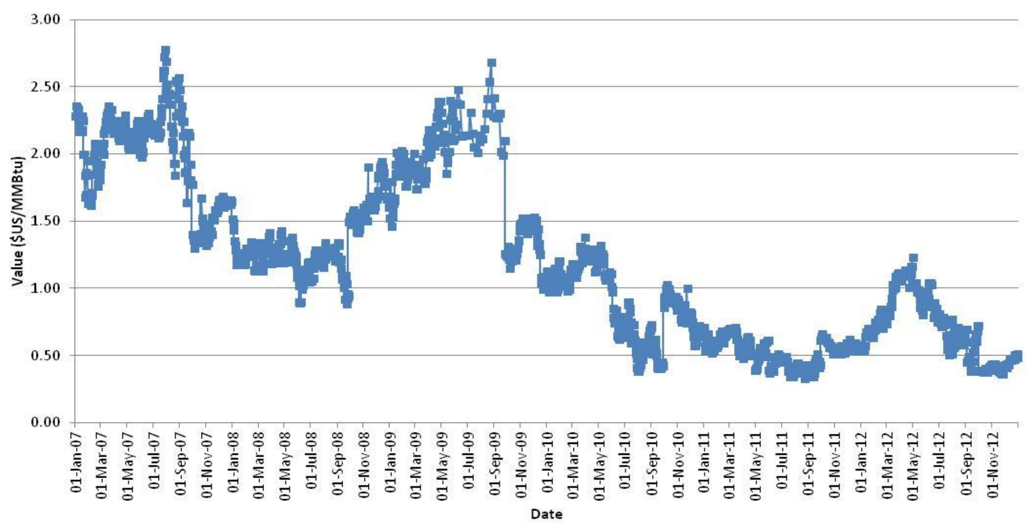

Figure 1
Historical Short -Term Firm Peak Storage Values at Dawn 2007-2012

Non-Utility Balances for 2012/Storage Encroachment Payment

The Board, on page 116 of its EB-2011-0210 Decision, directed Union to file a report similar to that ordered in EB-2011-0038 to monitor the inventory related to non-utility storage operations.

> *"The Board notes that pursuant to EB-2011-0038, Union must disclose to the Board when storage encroachment has occurred. That decision, however, only requires Union to file this information in conjunction with its rebasing applications.*
>
> *The Board therefore directs Union, at the time that the Short-Term Storage Account is to be disposed, to file a report similar to that ordered by the Board in EB-2011-0038."*

The report can be found at Tab 1, Appendix A, Schedule 3 showing the non-utility balances for October and November of 2012. As discussed in EB-2011-0038, October and November are the two critical months for peak storage.

During the 2012 injection season the non-utility storage balance peaked on October 5th at 97% of the entitlement with a balance of 77.6 PJ compared to an entitlement of 79.9 PJ. After October 5th, non-utility customers made withdrawals for the majority of the remaining days in October.

As discussed during the 2010 Deferral Proceeding, EB-2011-0038, Union manages its storage balance to the October 31 gas day. At October 31, 2012 the non-utility balance was 96% of entitlement and stayed below the total non-utility entitlement throughout November of 2012.

During EB-2011-0210, the Board further directed Union at page 116 to file a calculation for a storage encroachment payment from Union's non-utility business to Union's utility business if encroachment has occurred.

> *"If a storage encroachment has occurred, Union is further directed to file a calculation for the payment by Union's non-utility business to its utility business for storage encroachment. The Board believes that this payment should reflect the market value for the utility space that was subject to the encroachment. The Board notes that this finding only relates to any storage encroachment that occurs after the date of this Decision and will not apply retroactively to previous storage encroachments."*

There was no encroachment of utility space in 2012 and no calculation is required.

Sale of Non-Utility Storage Space

The Board in its Decision and Order under docket number EB-2011-0210 at page 117, issued at October 25, 2012, directed Union to identify how it will prioritize the sale of its utility storage and allocate short term peak storage margins.

> *"Finally, the Board directs Union to file sufficient evidence, at the time the balance in the Short-Term Storage Account is to be disposed, to allow the Board to confirm that Union has appropriately prioritized the sale of its utility storage space and calculated the balance in the account in accordance with this Decision."*

Union did not sell any non-utility storage on a short term basis in 2012. In the future, if there are sales of non-utility storage on a short term basis, Union will file evidence at the time the balance in the Short Term Storage Account is disposed of.

OTHER DEFERRAL ACCOUNTS

Account No.179-75 Lost Revenue Adjustment Mechanism ("LRAM")

The LRAM deferral account has a debit balance of $2.629 million. This balance includes volume variances related to 2011 audited versus unaudited Demand Side Management ("DSM") activities and the unaudited volumes related to 2012 DSM activities.

Tab 1, Appendix A, Schedule 4, page 1 provides the breakdown of the LRAM deferral account balance for 2011 and 2012. Tab 1, Appendix A, Schedule 4, pages 2 and 3 provide the LRAM volumes and the corresponding revenue impacts related to 2011 and 2012 DSM activities respectively. The calculation for lost revenues for the 2011 true-up reflects the Board's ruling in EB-2006-0021 Decision with Reasons (page 11) which states that the first year impact will be calculated as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

The calculation for lost revenues for 2012 reflects the Board’s ruling in EB-2011-0327 Settlement Agreement (page 34) which states that for each measure implemented in any given month, the volumetric reductions for that month and the remaining months of the year will be calculated on a rate class basis. The volumetric reductions will be multiplied by the volumetric distribution rate per m^3 for the rate class for that year. For example, the natural gas savings implemented in March 2012 have 10 months of LRAM calculated based on the average rate for that rate class for the year whereas natural gas savings implemented in November have two months of LRAM calculated based on the average rate for that rate class for the year.

The audit of 2011 DSM volumes is complete. The amount Union proposes to dispose of for 2011 is a debit balance of $1.612 million (Tab 1, Appendix A, Schedule 4, page 2, line 18, column (g)) which is composed of the following:

- 50% of the variance between lost revenues resulting from the audited 163,703 10^3 m^3 volumes savings and those resulting from the unaudited forecasted volumes savings of 163,766 10^3 m^3 at 2011 rates;
- lost revenues from audited 2011 volumes savings of 163,703 10^3 m^3 at 2012 rates.

In 2012, the variance is a debit balance of $1.017 million (Tab 1, Appendix A, Schedule 4, page 3, line 18, column (c)), comprising of total monthly forecasted volume savings of 109,246 10^3 m^3. The 2012 variance represents the volumetric reductions for the month the forecasted volume savings were realized and for the remaining months of the 2012 year.

There were no 2012 DSM volumes included in 2012 rates. The process to finalize DSM balances for 2012 includes preparation of Union’s DSM Annual Report, which is subsequently reviewed by a third party auditor and an Audit Committee, communicated to the DSM Consultative and filed with the Board.

Consistent with the approach taken related to activity in previous deferral disposition proceedings, Union is proposing to dispose of the LRAM balance related to unaudited 2012 DSM activities. Recognizing this balance may still change following the audit, any amount disposed of would be subject to a future true-up. Any true-up amount will be captured in the deferral account for future disposition.

Account No. 179-103 Unbundled Services Unauthorized Storage Overrun

No unauthorized storage overrun charges were incurred by customers electing unbundled service in 2012.

Account No.179-111 Demand Side Management Variance Account ("DSMVA")

This account records the difference between actual DSM costs incurred and the DSM budget included in rates. The debit balance of $0.368 million (Tab 1, Schedule 5, line 13, column (c)) represents the difference between actual 2012 DSM expenditures of $31.322 million and $30.954 million included in rates.

Union has followed the methodology filed in the Settlement Agreement approved by the Board in the EB-2011-0327 Decision and Order dated February 21, 2012 ("Settlement Agreement"). Union has tracked the variance between actual DSM spending by rate class relative to the DSM budget included in rates by rate class in the DSMVA. With the exception of Low-income costs, all program costs were allocated by program level and assigned by rate class based on the percentage allocation of the customer incentive costs. All portfolio-level costs were allocated to a rate class based on the percentage allocation of the program costs by rate class, as outlined on page 36 of the Settlement Agreement. The variance spent on Low-income DSM programming has been allocated in proportion to the most recent Board-approved distribution revenue by rate class, as outlined in Appendix C of the Settlement Agreement. The overall 2012 Low Income budget spend of $8.608 million, which includes the allocated portfolio costs, is allocated in proportion to the 2012 distribution revenue from the EB-2011-0025 Rate proceeding (EB-2011-0025 Rate Order Working papers, approved December 2011).

In addition, as per Section 10.2 of the Settlement Agreement, Union is eligible to recover up to an additional 15% above its annual Board-approved DSM budget through the DSMVA as long as Union has achieved its overall weighted scorecard target on a pre-audited basis for one or more of its scorecards, provided the funding was spent on program expenses.

The additional expenditure over the 2012 DSM Budget included in rates is $0.368 million. This expenditure was allocated to three of the four scorecards – the Resource Acquisition, Low-Income and Large Industrial Scorecards. All three Scorecards achieved pre-audit results above the weighted scorecard targets required for the 15% overspend to be accessed. The pre-audit, scorecard results are summarized below, in Table 2. Scorecards are provided in Tables 11 to 14 in the Demand Side Management Incentive Deferral Account section.

Table 2
DSM Scorecard Results

Scorecard	Total Scorecard Target Achieved
Resource Acquisition	124%
Low-Income	155%
Large Industrial Rate T1 and Rate 100	191%
Market Transformation	117%

The details of the 2012 DSM overspend are presented in Table 3 below.

Table 3
2012 DSM Budget vs. Actual Spend

Budget	DSM Budget		
	Board Approved Budget	Actual Results	Variance
RA - Residential	$3,253,364	$3,053,693	($199,671)
RA - C/I	$11,171,107	$11,314,294	$143,187
Total Resource Acquisition	$14,424,471	$14,367,987	($56,484)
Large Industrial T1/R100	$4,663,623	$5,043,295	$379,672
Low Income	$7,035,022	$7,702,047	$667,025
Market Transformation	$852,974	$434,823	($418,151)
Portfolio	$3,428,007	$3,296,922	($131,085)
DWHR - Sunset Funding	$550,000	$477,142	($72,858)
Total DSM budget	**$ 30,954,097**	**$ 31,322,216**	**$368,119**

Budget Transfers between Programs (DSM Guidelines for Natural Gas Utilities issued June 30, 2011, EB-2008-0346)

Union adhered to the provision on page 4 of the OEB's DSM Guidelines for Natural Gas Utilities EB-2008-0346 issued on June 30, 2011, ensuring the utilities inform the Board and stakeholders, in the event that cumulative fund transfers among Board approved DSM programs exceed 30% of the approved annual DSM budget for an individual natural gas DSM program. Union did not transfer more than 30% between programs.

Drain Water Heat Recovery ("DWHR") Program (Settlement Agreement Section 2.4)

The maximum budget attributable to the DWHR program is $0.550 million and was used to support commitments made to builders as Union exited the DWHR program. The DWHR budget was isolated and was not otherwise used for any other DSM Activity. The $0.073 million difference between the DWHR budget and the actual spend is credited to the DSMVA, as outlined in Section 2.4.

Evaluation Budget (Settlement Agreement Section 2.5)

The inflation evaluation budget of $1.129 million was used solely for Evaluation expenditures as outlined in Section 2.5 of the Settlement Agreement. The difference between the Evaluation budget and the actual $0.827 million spent on Evaluation, is credited to the DSMVA ($0.302 million).

Resource Acquisition Program – Integrated Energy Management Systems ("IEMS") (Settlement Agreement Section 6.1)

The $0.600 million budget associated with IEMS was allocated according to the provisions in section 6.1 of the Settlement Agreement. The actual spend for IEMS activities in 2012 was $0.178 million, or less than 50% of the 2012 IEMS budget. As

Union did not shift more than 50% or $0.300 million of the IEMS budget to other programs, the 2012 Resource Acquisition targets were not adjusted. The unspent $0.122 million of the IEMS budget is credited to ratepayers in the DSMVA.

Resource Acquisition Program – Restrictions on rate class allocations (Settlement Agreement Section 6.4)

Shifts in the Resource Acquisition budget did not result in increases of greater than 100% of the amount allocated to each rate class, as indicated in Tab 1, Appendix A, Schedule 5.

Large Industrial Rate T1 and Rate 100 Program (Settlement Agreement Section 7)

As outlined in Section 7 of the Settlement Agreement, Union transferred less than the maximum of $0.500 million allowable program budget between the Rate T1 and Rate 100 rate classes. In addition, as per the Agreement, Union did not transfer budget dollars from any other part of the overall DSM budget into Rate T1 or Rate 100 rate classes. The maximum allowable overspend of 15%, as set out in Section 7 of the Settlement Agreement for the Large Industrial Rate T1 and Rate 100 Program is $0.764 million. Union overspent by $0.542 million and the overspend claim has been debited to the DSMVA.

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

The Gas Distribution Access Rule (“GDAR”) Costs 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. Union incurred $1.753 million in capital costs related to GDAR.

The GDAR capital costs are made up of the costs associated with two 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 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.

1. Residential Customer Service Amendments to the GDAR

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. The amendments to the GDAR require each rate-regulated Gas Distributor to implement and publish a Customer Service Policy that is fair, transparent, and enforceable by the Board. The Board ordered that the amendments to the GDAR come into force on April 1, 2012. Union implemented GDAR amendments effective March 5, 2012

Union has incurred $1.475 million in capital costs in 2011 and 2012 to implement the amendments to the GDAR. The capital costs include the costs to modify Union's customer service information system to have the functionality required to implement Union's updated policies and practices. This involved the development of business and system design requirements, programming by the external Customer Service System provider and internal IT staff, testing and implementation. The capital costs also included the salaries and expenses of four temporary additional employees who were added to the Customer Care group in order to implement the amendments to the GDAR by April 1, 2012. A listing of the costs associated with implementation of the GDAR amendments is provided in Table 4 below. The costs include those associated with incremental internal resources and expenses as well as Contractor Services. Union Gas' retail CIS 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 Gas.

2. *Low Income Customer Service Amendments to the GDAR*

On September 6, 2012, the Board issued a Notice of Amendment to a Rule – Eligible Low-Income Customer Service Amendments to the GDAR also under docket number EB-2010-0280. The Board ordered that these amendments to the GDAR come into force as of January 1, 2013. Union implemented these GDAR amendments prior to the end of 2012 in order to be able to implement the GDAR requirements on January 1, 2013. Union has incurred $0.278 million in capital costs in 2012 to implement the eligible Low-income customer service amendments to the GDAR. Modifications were made to the system to identify low income customers, track payment arrangements, and to waive late payment charges while active payment arrangements are in place. Refer to Table 4 below for a breakdown of the Low Income GDAR costs.

A listing of the customer service standards policies and practices implemented, per the GDAR amendments as well as the associated system changes required, is provided at Tab 1, Appendix A, Schedule 6.

Table 4

GDAR Costs

Line No.	Particulars ($000's)	Residential Customer Service Amendments 2011 Costs	Residential Customer Service Amendments 2012 Costs	Low Income Amendments 2012 Costs	Deferral Total
1	Resources (Salary & Expenses)	93	252	20	365
2	Contractor Services	502	628	258	1388
3	**Total Costs**	**$595**	**$880**	**$278**	**$1,753**

Union proposes to replace the capital costs with the annual revenue requirement related to the capital costs as outlined in Table 5 below. Accordingly, the 2012 GDAR deferral account has a debit balance of $0.194 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	TOTAL
1	Depreciation	219	438	438	438	219	1,753
2	Interest	80	64	43	21	5	213
3	Return	51	40	27	13	3	135
4	Current Tax	(156)	(102)	126	121	59	49
5	**TOTAL**	**$194**	$441	$634	$594	$287	$2,149

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. The annual reporting requirements include supplying data (e.g. disconnections, arrears, write-offs, security deposits, billing and payment plans etc.), detailed complaint reporting, enquiries reporting and baseline data for 2011, 2012 and the first six months of 2013. If there are costs associated with these amendments, Union will apply for the costs within the GDAR Costs Deferral Account as part of the 2013 non commodity deferral account disposition.

Account No. 179-113 Late Payment Penalty ("LPP") Litigation

The LPP Litigation deferral account has no balance as the final payment to the Winter Warmth Fund per the settlement approved by the Ontario Superior Court on February 10, 2009 was made in 2011. This account was closed effective January 1, 2013 per the Board's EB-2011-0210 Decision.

Account No. 179-115 Shared Savings Mechanism ("SSM") Variance Account

There is no SSM balance for 2012. The account was established in 2006, in accordance with the mechanism approved by the Board in the EB-2005-0507 proceeding, to record any shareholder incentive earned by Union related to DSM activities. A new DSM Incentive Deferral Account ("DSMIDA") No. 179-126 was approved in EB-2011-0025, reflecting all incentive amounts for 2012. See page 32 for the description of the DSMIDA.

The SSM account has an overall zero balance related to the 2011 audit true-up for DSM activity in 2011. Tab 1, Appendix A, Schedule 7 provides the breakdown of the SSM variance account by rate class. Union has completed the audit of 2011 DSM activity and there is no overall change in the resulting SSM incentive payout variance (Tab 1, Appendix A, Schedule 7, line 13, column (c)). There are small changes identified to individual rate classes, as indicated in the schedule. The auditor's report was filed with the Board on June 29, 2012 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements. Upon completion of the audit of Union's 2011 DSM activity, the maximum SSM of $9.243 million was confirmed and adjustments to individual rate classes were allocated based on the audited results. No true-up is required for either the 2011 Market Transformation Incentive or the 2011 Incremental Low Income Incentive. As this deferral account has been replaced by the DSMIDA, Union requests Board approval to close this deferral account effective January 1, 2013.

Account No. 179-117 Carbon Dioxide Offset Credits

This account has no balance. The account was created in accordance with the Board's Decision in the EB-2006-0021 proceeding to record the amounts representing proceeds from the sale of or other dealings in carbon dioxide offset credits earned as a result of Union's DSM activities.

Account No. 179-118 Average Use Per Customer

The Average Use Per Customer deferral account is a credit of $3.656 million and interest of $0.009 million, for a total deferral balance credit of $3.665 million.

The credit balance of $3.656 million is the margin variance resulting from the difference between the actual rate of decline in use-per-customer for 2012 and the forecast rate of decline in use-per-customer included in 2012 Board-approved rates. Actual and forecast rates of decline in use-per-customer were calculated on a percentage and rate class specific basis for rate classes M1, M2, Rate 01 and Rate 10. The rates of decline were normalized for weather and excluded the volume impacts attributed to DSM. The details of the Average Use per Customer Deferral Account balance can be found at Tab 1, Appendix A, Schedule 8.

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

In accordance with the Board-approved Settlement Agreement in EB-2010-0039 Union agreed to remove from the deferral account the capital costs associated with upgrading Union's accounting system to report results under IFRS. These capital costs were replaced by the annual revenue requirement related to those capital costs as outlined in Table 6, and are to be included in the respective future deferral account disposition proceedings.

Accordingly, the 2012 IFRS Conversion Costs deferral account has a debit balance of $0.538 million.

Table 6

IFRS Conversion Costs by Year

Line No.	Particulars ($ Millions)	2008 (a)	2009 (b)	2010 (c)	2011 (d)	2012 (e)	2013 (f)	2014 (g)	Total (h)
1	Proposed by Union	1.918	2.071						3.989
2	Less capital expenditures	0.953	0.459						1.412
3	O&M	0.965	1.612						2.577
4	Revenue requirement	-	-	0.124	0.335	0.538	0.505	0.244	1.747
5		0.965	1.612	0.124	0.335	**0.538**	0.505	0.244	4.324

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

In its EB-2010-0055 Decision and Order which granted approval for Union's 2011 DSM plan, the Board ordered Union to establish a deferral account to track net revenues associated with CDM activities to share 50% with ratepayers. The Board approved the accounting order for Union's CDM deferral account on November 29, 2010 through the Board's Decision and Rate Order for Union's 2011 rates application (EB-2010-0148).

For 2012, there are no net revenues for sharing. The balance in the CDM deferral account for 2012 is zero since the actual cost of delivering these programs exceeded the revenue. In 2012 Union Gas delivered four CDM programs on behalf of various electric local distribution companies ("LDCs") including:

1) High Performance New Construction Generation 2 (“HPNC2”),

2) Key Account Management (“KAM”),

3) Commercial Conservation Account Management (“CCAM”) and

4) Home Assistance Program (“HAP”) for Low Income Customers.

HPNC2 is an Ontario Power Authority (“OPA”) funded program to encourage builders of commercial, industrial, institutional and agricultural facilities to reduce electricity demand and/or consumption by designing and building new buildings or major renovations with higher energy efficient equipment and systems (i.e. lighting, space cooling, ventilation etc.) than required by the building code. Union Gas provides sales and technical support services to Enbridge in their delivery of HPNC2 for designated LDCs within Union’s franchise area. Union contracted with Enbridge to deliver this program until Dec 31, 2014. Union began delivering the HPNC2 program to 13 electric LDCs in 2012.

KAM is an OPA funded CDM program to assist major industrial customers (average monthly peak demand greater than 5MW) develop capital projects that support industrial energy management and electricity efficiency. Union has contracted with four electric LDCs; (Hydro One Networks Inc, Veridian Connections, Utilities Kingston and Hydro One Brampton) to deliver the KAM services until December 31, 2012. The contract term may be extended by one year, two times at the purchaser’s sole discretion. This contract has been extended for one year until December 31, 2013.

The CCAM program supports capital investments in equipment that reduces electrical demand and energy consumption for commercial and industrial electricity customers with average monthly electricity demand of less than 5MW. Union contracted with Hydro One Networks Inc. to deliver the CCAM program in their service area until December 31, 2012. The contract term may be extended by one year, two times at the purchaser's sole discretion. This contract has been extended for one year until December 31, 2013.

The Home Assistance Program (HAP) is an OPA funded program to offer free installation of energy efficiency measures to qualifying low income households to reduce electricity and peak demand savings. Union contracted with Halton Hills Hydro and Burlington Hydro to deliver this program in their service area until December 31, 2014.

Overall results for CDM, broken down by individual programs can be found in Table 7 below.

Table 7

CDM Net Revenues by Program

Line No.	Particulars ($000's)	HPNC	KAM	CCAM	HAP	Total
1	Revenues	319	239	417	26	1001
2	Costs	339	242	422	10	1013
3	**Net Revenues**	**-20**	**-3**	**-5**	**16**	**-12**

Account No. 179-124 Harmonized Sales Tax

On July 1, 2010, Harmonized Sales Tax ("HST") came into effect in Ontario, combining provincial and federal taxes. The impact of HST resulted in both savings and additional costs to Union related to the provincial component of the tax.

In its EB-2010-0148 Decision, the Board ordered Union to establish a deferral account to record as a credit the amount of Provincial Sales Tax ("PST") previously paid and collected in approved rates that is now subject to HST tax credits (i.e. the savings to Union). Additionally, the Board ordered Union to record in the deferral account as a debit the amount of HST paid on taxable items for which no tax credits are received (i.e. the additional costs to Union). Union will share the net impact 50/50 between the ratepayers and the shareholders.

To calculate the 2012 HST deferral balance, Union reviewed the 2012 transactions for: a) Capital and O&M purchases that were subject to PST but are now subject to a tax credit; and, b) Compressor Fuel costs that are now subject to PST with no tax credit.

For 2012 the HST deferral account is a credit balance of $1.167 million which represents a balance of $1.160 million and interest of $0.007 million. The credit balance of $1.160 million, by component, Capital, Operations & Maintenance, and Compressor Fuel Costs is provided in Table 8. A discussion of each component is also provided below.

Table 8

50% of Net Savings (Costs) from the impact of HST
to be shared with Ratepayers
($ Millions)

Line No.		2012
1	Capital Savings	0.717
2	Operations and Maintenance Savings	0.564
3	Compressor Fuel Costs	(0.121)
4		1.160

Capital

Prior to July 2010, PST paid on capital purchases was included in capital costs. With the introduction of HST in July 2010, a tax credit was created for the provincial component of HST paid on capital purchases. As a result, Union is collecting PST in rates for which it now can claim a tax credit. This generates a savings to ratepayers.

The revenue requirement associated with Capital expenditures is recovered through rates. Consistent with this approach, the HST impact related to Capital is also calculated based on revenue requirement. In 2012, Union had a tax savings of an estimated $4.266 million related to Capital additions, including $0.079 million of O&M overhead Capitalization, for the year. After applying the half-year rule, Union applied depreciation, interest, return and income taxes to calculate the revenue requirement impact for Capital. The revenue requirement impact is a credit of $0.258 million, of which 50% or $0.129 million is the ratepayer portion. In 2010 and 2011 Union had a tax savings of $3.330 million and

$6.395 million respectively related to capital additions, including $0.032 million and $0.082 million of O&M overhead capitalization. The revenue requirement impact for the 2010 and 2011 Capital additions in 2012 is a credit of $0.402 million and $0.773 million, of which 50% or $0.201 million and $0.387 million is the ratepayer portion. The combined revenue requirement impact for 2012 is $1.433 million, of which 50% or $0.717 million is the ratepayer portion. The calculation of this balance is provided in Table 9 below. The HST impact on capital expenditures has been included in rate base through the EB-2011-0210 rebasing proceeding.

Table 9

HST Capital Summary
($ Millions)

Line No			2010-2011	2012	Total
	Capital Additions				
1	Capital PST Savings Estimate		9.725	4.266	13.991
2	1/2 year rule		N/A	0.5	
			9.725	2.133	11.858
3	Depreciation	3.30%	0.321	0.070	0.391
4	Interest	4.61%	0.448	0.098	0.546
5	Return	3.07%	0.298	0.066	0.364
6	Income Taxes	26.5%	0.108	0.024	0.132
7	Revenue Requirement Impact		1.175	0.258	1.433

Operations & Maintenance ("O&M")

Prior to July 2010, PST paid on O&M purchases was included as an expense in rates. As a result of the introduction of the HST in July 2010, except where restricted by the

Canada Revenue Agency, the provincial component of the HST is subject to tax credit. This results in a 2012 tax savings of $1.656 million.

Where Union pays HST on O&M purchases that were previously exempt and tax credits are now restricted, Union incurs additional costs not included in rates. This results in a 2012 tax cost of $0.449 million.

Certain O&M costs are related to Overhead Capitalization and must be removed from the O&M HST impact calculations and included in the Capital HST impacts. For 2012, Union transferred costs of $0.079 million to Capital.

The net impact to Union in 2012 is a savings of $1.128 million, of which 50%, or $0.564 million is attributable to ratepayers.

Compressor Fuel Costs

Prior to July 2010, Union did not assess PST on the gas used in its own operations. As a result of the introduction of the HST in July 2010, Union is required to assess HST on its own use of gas. No tax credit exists for the provincial component of HST on own-use compressor fuel, resulting in additional compressor fuel costs to Union. In 2012, the increased compressor fuel cost to Union was $0.242 million, of which 50%, or $0.121 million is attributable to ratepayers. This account was closed effective January 1, 2013 per the Board's EB-2011-0210 Decision.

Account No. 179-126 Demand Side Management Incentive Deferral Account (“DSMIDA”)

DSM Scorecard Results for all Programs

This account has a debit balance of $8.598 million related to the 2012 pre-audit DSM activity. Tab 1, Appendix A, Schedule 9 provides the breakdown of the Demand Side Management Incentive Deferral Account by rate class.

The account was established in 2012, in accordance with the mechanism approved by the Board in the EB-2011-0327 proceeding, to record any shareholder incentive earned by Union related to DSM activities, including Resource Acquisition, Low Income, Large Industrial and Market Transformation. This replaces incentives previously captured in the SSM deferral account and through Market Transformation and Incremental Low Income Incentives.

The pre-audit 2012 DSM Incentive Union has achieved for each scorecard is presented in Table 10 below.

Table 10

Summary of Incentive Results by Scorecard

Scorecard	DSM Incentives		
	Plan (100% Target)	Actual Results	Max Payout
Resource Acquisition	$2,235,101	$3,868,403	$5,587,753
Large Industrial T1/R100	$722,638	$1,806,595	$1,806,595
Low Income	$1,090,091	$2,725,227	$2,725,227
Market Transformation	$132,170	$198,255	$330,425
Total	**$ 4,180,000**	**$ 8,598,480**	**$ 10,450,000**

A. *Resource Acquisition Scorecard*

Resource Acquisition programs seek to achieve direct, measurable savings customer by customer, via the installation of energy efficient equipment.

The Resource Acquisition Scorecard included three performance metrics that support and incentivize technologies that drive deeper and longer savings for all customers. Union achieved 124% on the overall Resource Acquisition Scorecard and achieved a $3.868 million incentive based on the 2012 scorecard targets[1] and corresponding incentives. The 2012 Resource Acquisition Scorecard is presented below in Table 11.

[1] EB-2011-0327, Settlement Agreement, Section 6, p.16

Table 11

2012 Resource Acquisition Scorecard Pre-Audit Results

Metrics	Metric Target Levels: Lower Band	Metric Target Levels: Target	Metric Target Levels: Upper Band	Weight	Achievement	% of Metric Achieved	Weighted % of Metric Achieved
Cumulative Natural Gas Savings (m^3)	619,500,000	826,000,000	1,032,500,000	90%	900,443,984	118%	*106%*
Deep Savings – Residential	120	160	200	5%	73	-9%	*-0.4%*
Deep Savings - C/I	4%	5%	6%	5%	10.43%	371%	*19%*
						Total Scorecard Target Achieved	*124%*
						Scorecard Incentive Achieved	*$ 3,868,403*
						% of Maximum Incentive Achieved	*69%*

B. *Large Industrial Rate T1 and Rate 100 Scorecard*

The Large Industrial scorecard measures the cumulative m3 savings of participants within the Rate T1 and Rate 100 rate classes.

The 2012 Large Industrial Rate T1/Rate 100 program achieved the maximum DSM incentive of $1.807 million. This incentive amount is based upon achieving the upper band level on the overall scorecard[2] approved by the Board. The 2012 Large Industrial Scorecard results are provided below in Table 12.

[2] EB-2011-0327, Settlement Agreement, Section 7, p.24

Table 12

2012 Large Industrial Scorecard Pre-Audit Results

Metrics	Metric Target Levels			Weight	Achievement	% of Metric Achieved	Weighted % of Metric Achieved
	Lower Band	Target	Upper Band				
Cumulative Natural Gas Savings (m^3)	750,000,000	1,000,000,000	1,250,000,000	100%	**1,456,247,081**	191%	*191%*
				Total Scorecard Target Achieved			***191%***
				Scorecard Incentive Achieved			***$ 1,806,595***
				% of Maximum Incentive Achieved			***100%***

C. *Low-Income Scorecard*

Similar to the Resource Acquisition program, the Low-Income program seeks to achieve direct measurable savings by the installation of energy efficient equipment focusing on the needs of the low-income market segment. The 2012 Low-Income program achieved the maximum DSM incentive of $2.725 million. This incentive amount is based upon exceeding the performance goals as outlined by the approved Low-Income Scorecard[3]. As outlined in the Settlement Agreement, Union claimed the maximum 7.7 million cumulative m^3 savings from the Helping Homes Conserve offering, included in the Cumulative Natural Gas Savings from Single Family metric. The remaining 36.3 million cumulative m^3 savings in this metric resulted from the Home Retrofit offering. The overall 2012 Low-Income Scorecard results are provided below in Table 13.

[3] EB-2011-0327, Settlement Agreement, Section 8, p.28

Table 13

2012 Low Income Scorecard Pre-Audit Results

Metrics	Metric Target Levels: Lower Band	Metric Target Levels: Target	Metric Target Levels: Upper Band	Weight	Achievement	% of Metric Achieved	Weighted % of Metric Achieved
Cumulative Natural Gas Savings from Single Family (m^3)	20,600,000	30,000,000	37,500,000	65%	**44,042,693**	194%	*126%*
Cumulative Natural Gas Savings from Multi-Family (m^3)	9,750,000	13,000,000	16,250,000	35%	**11,860,409**	82%	*29%*
				Total Scorecard Target Achieved			***155%***
				Scorecard Incentive Achieved			***$ 2,725,227***
				% of Maximum Incentive Achieved			***100%***

D. *Market Transformation Scorecard*

In 2012, Union shifted its Market Transformation focus from Drain Water Heat Recovery (DWHR) to the New Home Efficiency offering, which was branded as Optimum Home.

Union achieved 117% on the overall 2012 Market Transformation scorecard[4] resulting in a $0.198 million incentive for the Market Transformation program. The 2012 Market Transformation results are provided in Table 14.

[4] EB-2011-0327, Settlement Agreement, Section 9, p.32

Table 14

2012 Market Transformation Scorecard Pre-Audit Results

Metrics	Metric Target Levels: Lower Band	Metric Target Levels: Target	Metric Target Levels: Upper Band	Weight	Achievement	% of Metric Achieved	Weighted % of Metric Achieved
Residential New Build - Top 10 Builders Participating	1	2	4	50%	**4**	150%	*75%*
Residential New Build - Top 50 Builders Participating	5	8	15	50%	**7**	83%	*42%*
				Total Scorecard Target Achieved			***117%***
				Scorecard Incentive Achieved			***$ 198,255***
				% of Maximum Incentive Achieved			***60%***

The process to finalize DSMIDA balances includes an external audit of Union's DSM Annual Report, review by the Audit Committee and communication to the DSM Consultative as outlined in the Joint Terms of Reference on Stakeholder Engagement for DSM Activities dated November 4, 2011[5]. Similar to the approach taken for LRAM and the DSMVA, and in an effort to dispose of deferral account balances in a timely manner, Union is applying for disposition of the balance in the DSMIDA related to unaudited 2012 DSM Incentive activities as measured by the four DSM scorecards at this time. The variances between the payout balances calculated based on audited and unaudited results would be subject to a future true-up. Any true-up amount will be captured in the deferral account for future disposition. The SSM account addresses true-up for the DSM activity in 2011.

[5] EB-2011-0327, Joint Terms of Reference on Stakeholder Engagement for DSM Activities by Enbridge Gas Distribution Inc. and Union Gas Limited, Attachment A.

Account No. 179-127 Pension Charge on Transition to U.S. GAAP

Union transitioned its accounting and reporting standards to U.S. GAAP beginning January 1, 2012. The U.S. GAAP standard for reporting on pensions is ASC 715 *Compensation – Retirement Benefits* and results in a different pension expense than the Canadian GAAP standard CICA 3461 *Employee Future Benefits*. On transition to U.S. GAAP, a charge to retained earnings would have resulted due to amounts that would have been previously recognized through pension expense had Union been reporting in U.S. GAAP historically. The charge is made up of two components: a change in measurement date from September 30 to December 31, and a write off of unrecognized actuarial losses that were established upon the implementation of CICA 3461. At the time of transition to CICA 3461, unrecognized actuarial losses were established and amortized over the expected average remaining service life of the plan employees at the time. These unrecognized actuarial losses would have been fully amortized under U.S. GAAP. In its EB-2011-0025 decision the Board approved the establishment of the Pension Charge on Transition to U.S. GAAP Deferral Account.

The deferral account is a debit of $7.811 million. The debit balance breakdown by component is provided in Table 15. Union has proposed the entire balance for recovery in this proceeding. Disposing of the amount on a basis established by Canadian GAAP Accounting Standards is no longer appropriate since the Board has approved 2013 rates to be set under U.S. GAAP.

Table 15

Pension Charge on Transition to U.S.GAAP Breakdown
($ Millions)

Change in the Measurement Date	($0.096)
Transitional Obligation	$7.907
	$7.811

OTHER ITEMS

Federal and Provincial Tax Changes

In accordance with the Board's EB-2007-0606 decision, 50% of the impact of the tax increase/decrease became subject to annual deferral account treatment. Union recorded a debit of $0.132 million in 2012, which represents 50% of the tax cost arising from the elimination of the previously enacted 0.5% decrease in the Ontario corporate tax rate. The decrease was scheduled to occur on July 1, 2012. The elimination of the decrease was not reflected in 2012 rates.

Account No. 179-132 Deferral Clearing Variance Account

As a result of the increased risk of variance outlined below, Union is requesting this deferral account be approved by the Board effective April 1, 2013. Union submitted an application on April 22, 2013 requesting approval of the deferral account noting that supporting evidence would be filed in this proceeding.

During the 2008 Deferral Disposition proceeding (EB-2009-0052) the Board had requested Union investigate the possibility of implementing a true-up mechanism to capture any volume variance related to the disposition of deferral accounts. Union determined in a response to an interrogatory in the 2009 Deferral Disposition proceeding (EB-2010-0039, Exhibit B2.01), that the average variance of deferral disposition from 2005 through 2007 was approximately $0.025 million per year, which did not represent a material amount to warrant a true-up mechanism.

During the 2011 Deferral Disposition proceeding (EB-2012-0087) Union was asked to revisit the need for a true-up mechanism by updating the information supplied in the 2009 Deferral Disposition proceeding to include the years 2008 and 2009. The investigation found that the average impact from 2005 to 2009 of not truing-up the disposition of deferral account balances was approximately $0.003 million per year. Consistent with the response during the 2009 proceeding, Union determined that no true-up mechanism was required.

In 2013, upon completion of the disposition of 2010 deferral account balances, Union determined that due to variances from forecasted volumes, approximately $1.3 million had been refunded to ratepayers in excess of the final deferral balances approved for disposition in EB-2011-0038.

There were two major drivers of the large variance between actual and forecast volumes used to refund the 2010 deferral balances:

i.) Differences in the new M1 and M2 rate classes where the combined variance was not significant. This had a significant impact because there was a planned recovery from the M1 class where actual volumes were below the forecast and a planned refund to the M2 class where the actual results were above the forecast. The brief history for the new M1 and M2 rate classes made the forecast split uncertain.

ii.) Lower volume refund period resulted in higher unit rates and more variability. The disposition occurred over the six month period starting April 1 rather than the traditional October 1 to March 31 period that was used for the 2005 to 2009 deferral proceedings. In Rate 10, the small forecast volume in this period resulted in a large unit rate for refund that, when applied to additional volume in this rate class, resulted in a significant over refund.

In addition to the 2010 factors outlined above, for the 2011 Deferral Disposition Union has additional volume risk. This results from the uncertainty in the forecast of sales service versus bundled direct purchase volumes which will affect the actual amount of the refund. Using current forecast assumptions for system sales volumes, the actual refund could be approximately $1.7 million above the amount approved by the Board in EB-2012-0087, which is a material variance. For these reasons Union has requested approval of this new deferral account effective April 1, 2013.

APPENDIX A

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 1
Appendix A
Schedule 1

UNION GAS LIMITED

Deferral Account Balances

Year Ending December 31, 2012

Line No.	Account Number	Account Name	Balance ($000's)	(1)
	Gas Supply Accounts:			
1	179-108	Unabsorbed Demand Costs (UDC) Variance Account	(1,388)	(2)
2	179-130	Upstream Transportation FT-RAM Optimization	-	(2)
3	Total Gas Supply Accounts (Lines 1 + 2)		(1,388)	
	Storage Accounts:			
4	179-70	Short-Term Storage and Other Balancing Services	1,879	
	Other:			
5	179-75	Lost Revenue Adjustment Mechanism	2,629	
6	179-103	Unbundled Services Unauthorized Storage Overrun	-	
7	179-111	Demand Side Management Variance Account	368	
8	179-112	Gas Distribution Access Rule (GDAR) Costs	194	
9	179-113	Late Payment Penalty Litigation	-	
10	179-115	Shared Savings Mechanism	-	
11	179-117	Carbon Dioxide Offset Credits	-	
12	179-118	Average Use Per Customer	(3,665)	
13	179-120	IFRS Conversion Cost	538	
14	179-123	Conservation Demand Management	-	
15	179-124	Harmonized Sales Tax	(1,167)	
16	179-126	Demand Side Management Incentive	8,598	
17	179-127	Pension Charge on Transition to US GAAP	7,811	
18	Total Other Accounts (Lines 5 through 17)		15,306	
19	Total Deferral Account Balances (Lines 3 + 4 + 18)		15,797	
20		Federal & Provincial Tax Changes	132	
21	**Total Deferral Account Balances (Lines 3 + 4 + 18 + 20)**		15,929	

Notes:
(1) Account balances include interest to December 31, 2012.

(2) With the exception of UDC (No. 179-108) and Upstream Transportation FT-RAM Optimization (No. 179-130), all gas supply-related deferral account balances are disposed of through the QRAM process. In 2012, the Board issued final orders in respect of Union's gas supply-related deferral accounts in EB-2011-0382, EB-2012-0070, EB-2012-0249 and EB-2012-0345.

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 1
Appendix A
Schedule 2

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 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
	Revenue			
1	C1 Off-Peak Storage	1,000	342	1,351
2	Supplemental Balancing Services	2,000	1,461	1,620
3	Gas Loans	1,000	57	18
4	Enbridge LBA	75	68	93
5	C1 ST Firm Peak Storage	13,794	9,036	10,557
6	C1 Firm ST Deliverability	92	-	-
7	Total Revenue(1)	17,961	10,964	13,639
	Costs			
8	O&M(2)	673	2,261	2,261
9	UFG(3)	751	342	582
10	Compressor Fuel (4)	707	462	379
11	Total Costs	2,131	3,065	3,222
12	Net Revenue (line 7 - 11)	15,829	7,899	10,417
13	Less Shareholder Portion (10%)	4,575	790	1,042
14	Ratepayer Portion	11,254	7,109	9,375
15	Approved in Rates	11,254	11,254	11,254
16	Deferral account balance payable to/ (collectible from) ratepayers		(4,145)	(1,879)

Notes:
(1) Based on short-term storage services provided.
(2) Revenue requirement on 7.9 PJs of 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.

Filed:2013-05-08
EB-2013-0109
Exhibit A
Tab 1
Appendix A
Schedule 3

UNION GAS LIMITED
Southern Operations Area
Summary of Non-Utility Storage Balances

Date	Entitlement (PJs)	Balance (PJs)	% Full (%)	Date	Entitlement (PJs)	Balance (PJs)	% Full (%)
01-Oct-12	79.9	77.2	97%	01-Nov-12	79.9	76.3	95%
02-Oct-12	79.9	77.3	97%	02-Nov-12	79.9	75.9	95%
03-Oct-12	79.9	77.4	97%	03-Nov-12	79.9	75.4	94%
04-Oct-12	79.9	77.5	97%	04-Nov-12	79.9	75.0	94%
05-Oct-12	79.9	77.6	97%	05-Nov-12	79.9	74.4	93%
06-Oct-12	79.9	77.5	97%	06-Nov-12	79.9	74.0	93%
07-Oct-12	79.9	77.3	97%	07-Nov-12	79.9	73.6	92%
08-Oct-12	79.9	77.1	96%	08-Nov-12	79.9	73.3	92%
09-Oct-12	79.9	76.8	96%	09-Nov-12	79.9	73.2	92%
10-Oct-12	79.9	76.2	95%	10-Nov-12	79.9	72.9	91%
11-Oct-12	79.9	76.0	95%	11-Nov-12	79.9	72.8	91%
12-Oct-12	79.9	75.8	95%	12-Nov-12	79.9	72.6	91%
13-Oct-12	79.9	75.7	95%	13-Nov-12	79.9	72.4	91%
14-Oct-12	79.9	75.9	95%	14-Nov-12	79.9	71.7	90%
15-Oct-12	79.9	75.7	95%	15-Nov-12	79.9	71.2	89%
16-Oct-12	79.9	75.4	94%	16-Nov-12	79.9	71.0	89%
17-Oct-12	79.9	75.3	94%	17-Nov-12	79.9	70.7	88%
18-Oct-12	79.9	75.4	94%	18-Nov-12	79.9	70.4	88%
19-Oct-12	79.9	75.4	94%	19-Nov-12	79.9	70.0	88%
20-Oct-12	79.9	75.5	94%	20-Nov-12	79.9	69.8	87%
21-Oct-12	79.9	75.6	95%	21-Nov-12	79.9	69.7	87%
22-Oct-12	79.9	75.7	95%	22-Nov-12	79.9	69.8	87%
23-Oct-12	79.9	75.7	95%	23-Nov-12	79.9	69.8	87%
24-Oct-12	79.9	75.9	95%	24-Nov-12	79.9	69.9	87%
25-Oct-12	79.9	76.1	95%	25-Nov-12	79.9	69.8	87%
26-Oct-12	79.9	76.2	95%	26-Nov-12	79.9	69.5	87%
27-Oct-12	79.9	76.0	95%	27-Nov-12	79.9	69.0	86%
28-Oct-12	79.9	75.7	95%	28-Nov-12	79.9	68.6	86%
29-Oct-12	79.9	75.4	94%	29-Nov-12	79.9	68.0	85%
30-Oct-12	79.9	75.9	95%	30-Nov-12	79.9	67.6	85%
31-Oct-12	79.9	76.7	96%				

Note : same format at Exhibit C1, Tab 6, Appendix A EB-2011-0210

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
Breakdown of 2012 LRAM Deferral Account Balance

Line No.	Particulars ($)	Amounts by DSM Plan Year 2011[1]	2012 [2]	Total Amount in LRAM Deferral Account
		(a)	(b)	(c)
	South			
1	M1 Residential	205,574	85,858	291,432
2	M1 Commercial	170,713	99,183	269,896
3	M1 Industrial	47,770	1,708	49,478
4	M2 Commercial	249,371	171,709	421,080
5	M2 Industrial	128,723	86,156	214,879
	Industrial			
6	M4	44,170	59,831	104,001
7	M5	262,735	154,170	416,905
8	M7	8,473	1,566	10,038
9	T1	97,678	61,366	159,043
10		1,215,206	721,547	1,936,753
	North			
11	Residential 01	146,891	42,969	189,860
12	Commercial 01	104,603	60,146	164,750
13	Commercial 10	88,428	100,200	188,628
14	Industrial 10	25,365	57,943	83,308
	Industrial			
15	Rate 20	11,967	14,569	26,536
16	Rate 100	19,168	19,685	38,853
17		396,422	295,513	691,935
18	Total	1,611,628	1,017,060	2,628,688

Notes:
(1) EB-2013-0109, Exhibit A, Tab 1, Schedule 2, page 2 of 3, column (g).
(2) EB-2013-0109, Exhibit A, Tab 1, Schedule 2, page 3 of 3, column (c).

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2011 - Audited

Line No.	Particulars	2011 Audited Volumes (1) $10^3 m^3$	2011 Unaudited Volumes (2) $10^3 m^3$	Delivery Rates: 2011 Rates $\$/10^3 m^3$	Delivery Rates: 2012 Rates $\$/10^3 m^3$	Net Revenue Impact: 2011 (3) ($)	Net Revenue Impact: 2012 ($)	Net LRAM Deferral Account Balance Proposed for Disposition ($)
		(a)	(b)	(c)	(d)	(e) = [(a)-(b)]x (c) x 50%	(f) = (a) x (d)	(g) = (e) + (f)
	South							
1	M1 Residential	5,387	5,438	40.757	38.350	(1,025)	206,599	205,574
2	M1 Commercial	4,447	4,438	40.757	38.350	176	170,536	170,713
3	M1 Industrial	1,246	1,246	40.757	38.350	(2)	47,772	47,770
4	M2 Commercial	6,064	6,070	40.763	41.147	(130)	249,501	249,371
5	M2 Industrial	3,129	3,130	40.763	41.147	(21)	128,743	128,723
	Industrial							
6	M4	7,981	7,981	8.764	5.534	-	44,170	44,170
7	M5	14,414	14,414	14.574	18.227	-	262,735	262,735
8	M7	12,780	12,780	2.418	0.663	-	8,473	8,473
9	T1	86,670	86,670	0.913	1.127	-	97,678	97,678
10		142,117	142,167			(1,001)	1,216,207	1,215,206
	North							
11	Residential 01	1,653	1,668	91.828	89.288	(695)	147,586	146,891
12	Commercial 01	1,256	1,253	85.583	83.211	115	104,488	104,603
13	Commercial 10	1,549	1,550	62.162	57.093	(25)	88,453	88,428
14	Industrial 10	484	484	57.001	52.469	(19)	25,385	25,365
	Industrial							
15	Rate 20	4,577	4,577	3.683	2.615	-	11,967	11,967
16	Rate 100	12,067	12,067	2.065	1.588	-	19,168	19,168
17		21,586	21,600			(624)	397,046	396,422
18	Total	163,703	163,766			(1,626)	1,613,254	1,611,628

Notes:
(1) Audited Demand Side Management 2011 Annual Report, page 82 (submitted by Union to the OEB Secretary on June 29, 2012 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements).
(2) EB-2012-0087, Exhibit A, Tab 1, Schedule 2, page 3 of 3, column (a).
(3) The 50% factor reflects the Board's ruling in EB-2006-0021 Decision with Reasons (page 11) which states that the first year impact will be calculated as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2012 - Unaudited

Line No.	Particulars	2012 - Monthly Unaudited Volumes (1) 10^3 m^3	2012 Delivery Rates $\$/10^3$ m^3	Revenue Impact ($)
		(a)	(b)	(c) = (a) x (b)
	South			
1	M1 Residential	2,239	38.350	85,858
2	M1 Commercial	2,586	38.350	99,183
3	M1 Industrial	45	38.350	1,708
4	M2 Commercial	4,173	41.147	171,709
5	M2 Industrial	2,094	41.147	86,156
	Industrial			
6	M4	10,811	5.534	59,831
7	M5	8,458	18.227	154,170
8	M7	2,362	0.663	1,566
9	T1	54,451	1.127	61,366
10		87,218		721,547
	North			
11	Residential 01	481	89.288	42,969
12	Commercial 01	723	83.211	60,146
13	Commercial 10	1,755	57.093	100,200
14	Industrial 10	1,104	52.469	57,943
	Industrial			
15	Rate 20	5,572	2.615	14,569
16	Rate 100	12,393	1.588	19,685
17		22,028		295,513
18	Total	109,246		1,017,060

Notes:
(1) Based on unaudited 2012 DSM evaluation results. The monthly volumetric reductions for the month the measure is implemented and the remaining months of the year is calculated based on the Settlement Agreement in EB-2011-0327 (page 34).

UNION GAS LIMITED
Demand Side Management Variance Account

Line No.	Particulars ($000's)	2012 DSM Costs in 2012 Rates[1]	Actual DSM Costs [2]	Account Balance	Variance
		(a)	(b)	(c) = (b) - (a)	
	South				
1	M1	10,223,670	9,928,224	(295,446)	-2.9%
2	M2	3,811,036	3,740,320	(70,715)	-1.9%
3	M4	1,572,104	2,708,435	1,136,331	72.3%
4	M5	2,624,378	2,089,944	(534,434)	-20.4%
5	M7	885,953	453,765	(432,188)	-48.8%
6	T1	4,313,703	4,758,916	445,213	10.3%
7		23,430,843	23,679,604	248,760.39	1.1%
	North				
8	Rate 01	3,650,512	3,016,785	(633,726)	-17.4%
9	Rate 10	1,160,460	1,516,814	356,354	30.7%
10	Rate 20	953,332	1,326,339	373,007	39.1%
11	Rate 100	1,758,951	1,782,675	23,724	1.3%
12		7,523,254	7,642,613	119,358.91	1.6%
13	Total	30,954,097	31,322,217	368,119	1.2%

Notes:
(1) Based on Revised settled DSM budgets included in Settlement Agreement EB-2011-0327 filed January 31, 2012.
(2) Allocated as per the Settlement Agreement filed January 31, 2012 and the Decision and Order on the Settlement Agreement EB-2011-0327 issued on February 21, 2012

UNION GAS LIMITED
GDAR Amendments and Associated System Changes Required (No. 179-112)

Area/Topic	Update to policy and practice	System change required
Bill Issuance and Payment		
	Union Gas will now accept credit cards for bill payments.	• Required the set-up of the Union Gas web portal through Paymentus corporation, as well as modifications to the Union Gas website and IVR.
	Union Gas will provide customers requiring emergency financial assistance a total of 21 days to secure social assistance before a collection action is initiated for non-payment.	• Process change that did not require any functionality changes.
	Union Gas has extended the bill payment period for the Late Payment Charge to be applied from 16 to 20 days.	• Modified rules applied to account charges within the Customer Service Information System.
Correction of Billing Errors		
	In the rare event that an adjustment must be made to the charges that have been billed to a customer’s account, Union Gas will provide additional explanations on the customer’s bill as to the reasons for the adjustment.	• Required modifications to our customer service system to identify those adjustments considered significant. • Changes also made to Union’s bill print functionality.
Equal Billing Plan		
	Customers can now join the Equal Billing Plan (“EBP”) during any month of the year.	• Modifications to the customer service information system functionality for EBP to extend the eligibility of the program to every month of the year. • Significant changes to the EBP algorithm to ensure an accurate calculation of a customer’s EBP amount at any time of the year and also to account for unique circumstances such as new housing when insufficient usage history is available. • Modifications to Union Gas’ website and IVR system.
Disconnection for		

Non-Payment		
	Union Gas will provide 10 days written notice of a pending disconnection for non-payment of gas charges. The notification will also describe payment options to avoid the disconnection of gas services.	• Significant modifications to the CIS system, as well as field operations systems to issue a disconnection notice and to issue as well as cancel a disconnection order if customer payments or payment arrangements are received.
	Low-income Standard Disconnection suspended for 21 days if gas distributor is notified that the customer is being assessed for Emergency Financial Assistance by a social service or government agency.	• Process change only. No functionality changes required.
Security Deposits		
	Customers who are required to pay a security deposit will now be given the choice to pay the deposit in installments of up to six months duration. Union Gas will continue to provide customers the choice of waiving the required security deposit if they enrol in both the Equal Billing Plan and the Automatic Payment Plan.	• Modifications involved extensive changes to the customer service information system to calculate a security deposit using a two month average rather than the two highest months and to introduce installment functionality to allow the security deposit to be billed over six months. • Modifications to the website, the IVR and bill print functionality.
	Low-income Standard: Waived for Low-income customers who do not have an account with a financial institution and are moving residences provided that the customer: (i) has been qualified as a Low-income customer by a Social Agency and (ii) has enrolled in an Equal Billing Plan. Note: A Low-income eligible customer who has been disconnected for non-payment during the preceding two years, would require a security deposit at the discretion of the distributor.	• Modifications completed to track and identify eligible low-income customers in the CIS system and to ensure customers are made aware of their eligibility time period and when their eligibility is about to expire. Changes were also required to waive security deposits for low income customers who enrol in the EBP plan only.

Arrears Management Programs		
	Customers who have entered into a payment arrangement for an overdue account will be notified in advance when payments are due. Customers will also be given 10 days notice of disconnection if they fail to meet the obligations of the arrangement.	• Adjustments were made to the collection processes that occur within the customer service information system as well as our outbound collection system.
	Customers who have security deposits on their accounts may receive additional opportunities to pay their arrears before Union issues a notice of disconnection for non-payment.	• Modifications to the collection processes within the customer service information system.
	Low-income Standard: Late Payment charges are waived for Low-income customers who have entered into a payment agreement. Note: In the event that a Low-income eligible customer defaults on a payment agreement, then the option to have late payment charges waived with any future payment agreements will no longer be available for that customer.	• Modifications required to track payment arrangements for eligible low income customers and to waive late payment charges while active payment arrangements are in place.

UNION GAS LIMITED
Shared Savings Mechanism
Based on 2011 Audited Results

		2011 Amount		
Line No.	Particulars ($)	Amount Based on 2011 Audited Results[(1) (2)]	Amount Disposed of in EB-2012-0087 [(3)]	Net Amount
		(a)	(b)	(c) = (a) - (b)
	South			
1	M1	883,881	886,587	(2,706)
2	M2	497,753	497,955	(202)
3	M4	512,983	512,717	266
4	M5	980,927	980,419	508
5	M7	610,676	610,360	316
6	T1	4,404,013	4,401,731	2,282
7		7,890,233	7,889,769	464
	North			
8	Rate 01	251,804	252,721	(917)
9	Rate 10	104,232	104,296	(64)
10	Rate 20	291,511	291,360	151
11	Rate 100	705,587	705,221	366
12		1,353,134	1,353,598	(464)
13	Total	9,243,367	9,243,367	(0)

Notes:

(1) The SSM incentives for 2011 are calculated and allocated among rate classes using the mechanism approved by the Board in EB-2006-0021.

(2) Audited Demand Side Management 2011 Annual Report, page 85 (submitted by Union to the OEB Secretary on June 29, 2012 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements).

(3) EB-2012-0087 Exhibit A, Tab 1 Schedule 4, Column (d).

Calculation of Balances by Rate Class in Average Use Per Customer Deferral Account (No. 179-118)

Line No.	Particulars (m^3)		Rate 01 (a)	Rate 01 (b)	Rate 10 (c)	Rate 10 (d)	Rate M1/M2 (e)	Rate M1/M2 (f)	Net Account Balance (g)
1	2011 Target Average Use		3,128	0.0%	159,570	7.2%	4,179	(1.4%)	
2	2011 Actual Average Use	(1)	3,190	0.5%	180,325	5.0%	4,209	2.6%	
3	2012 Target Average Use		3,109	(0.6%)	170,899	7.1%	4,096	(2.0%)	
4	2012 Actual Average Use		3,186	(0.1%)	189,164	4.9%	4,090	(2.8%)	
5	Forecast decline in Average Use per customer (line 3 - line 2)	(2)	-81		-9,426		-114		
6	Actual decline in Average Use per customer (line 4 - line 2)		-4		8,839		-120		
7	Change in Average Use - Forecast vs. Actual (line 5 - line 6)	(3)	-77		-18,264		6		
8	2007 Board Approved Number of Customers		295,672		2,966		987,063		
9	Annual Volume Impact (10^3m^3) (line 7 x line 8)	(4)	-22,871		-54,044		5,448		
10	2012 Net Annual Average Delivery Rate ($/$10^3m^3$)	(5)	$68.703		$41.417		$28.217		
11	Average Use Deferral: Annual Amount ($ millions)		-1,571,314		-2,238,305		153,740		-3,655,879

Notes:
(1) Updated for 2011 audited DSM results
(2) Calculated volume variance by rate class after applying the Average Use percentage identified in Board-approved Accounting Order for Deferral Account No. 179-118
(3) Change in Average Use is calculated as the year-over-year volume variance after actual volumes are weather normalized and DSM adjusted for 2012 un-audited LRAM Volume Savings
(4) Volume obtained from monthly calculation
(5) The Net Annual Average Delivery Rate is the result of applying the quarterly Board Approved Delivery Rates to the monthly volumes both positive and negative

UNION GAS LIMITED
DSM Incentive Deferrral Account
Based on 2012 Un-Audited Results

Line No.	Particulars ($)	2012 Amount Amount Based on 2012 Un-Audited Results(1)
		(a)
	South	
1	M1	3,508,972
2	M2	1,058,073
3	M4	615,794
4	M5	477,542
5	M7	91,521
6	T1	1,300,316
7		7,052,217
	North	
8	Rate 01	441,257
9	Rate 10	302,710
10	Rate 20	296,016
11	Rate 100	506,279
12		1,546,263
13	Total	8,598,480

Notes:
(1) The DSM incentives for 2012 are calculated and allocated among rate classes using the mechanism approved by the Board in EB-2011-0327

APPENDIX B

UNION GAS LIMITED

Deferral Account Balances

Year Ending December 31, 2012

Line No.	Account Number	Account Name	Balance ($000's)	(1)
	Gas Supply Accounts:			
1	179-108	Unabsorbed Demand Costs (UDC) Variance Account	(1,388)	(2)
2	179-130	Upstream Transportation FT-RAM Optimization	(32,977)	(2)
3	Total Gas Supply Accounts (Lines 1 + 2)		(34,365)	
	Storage Accounts:			
4	179-70	Short-Term Storage and Other Balancing Services	1,879	
	Other:			
5	179-75	Lost Revenue Adjustment Mechanism	2,629	
6	179-103	Unbundled Services Unauthorized Storage Overrun	-	
7	179-111	Demand Side Management Variance Account	368	
8	179-112	Gas Distribution Access Rule (GDAR) Costs	194	
9	179-113	Late Payment Penalty Litigation	-	
10	179-115	Shared Savings Mechanism	-	
11	179-117	Carbon Dioxide Offset Credits	-	
12	179-118	Average Use Per Customer	(3,665)	
13	179-120	IFRS Conversion Cost	538	
14	179-123	Conservation Demand Management	-	
15	179-124	Harmonized Sales Tax	(1,167)	
16	179-126	Demand Side Management Incentive	8,598	
17	179-127	Pension Charge on Transition to US GAAP	7,811	
18	Total Other Accounts (Lines 5 through 17)		15,306	
19	Total Deferral Account Balances (Lines 3 + 4 + 18)		(17,180)	
20		Federal & Provincial Tax Changes	132	
21	**Total Deferral Account Balances (Lines 3 + 4 + 18 + 20)**		(17,048)	

Notes:

(1) Account balances include interest to December 31, 2012.

(2) With the exception of UDC (No. 179-108) and Upstream Transportation FT-RAM Optimization (No. 179-130), all gas supply-related deferral account balances are disposed of through the QRAM process. In 2012, the Board issued final orders in respect of Union's gas supply-related deferral accounts in EB-2011-0382, EB-2012-0070, EB-2012-0249 and EB-2012-0345.

UNION GAS LIMITED
Upstream Transportation FT-RAM Optimization Deferral Account (No. 179-130)

Line No.	Particulars ($000's)	2011	2012	Difference
		(a)	(b)	(c)
1	FT-RAM Revenues	25,300	40,004	14,704
2	Less:			
3	UFG	308	215	(93)
4	Compressor Fuel	640	421	(219)
5	3rd Party Upstream Costs	3,300	2,727	(573)
6		4,248	3,363	(885)
7	Net revenue (line 1 - line 6)	21,052	36,641	15,589
8	Less: 10% Union Incentive Payment	(2,105)	(3,664)	(1,559)
9	Deferral Account Balance payable to Ratepayers	18,947	32,977	14,030

Union Gas Limited
Summary of Compressor Fuel and UFG Costs Related to FT-RAM Optimization
For the Year Ended December 31, 2012

Line No.	Particulars	Jan (a)	Feb (b)	Mar (c)	Apr (d)	May (e)	Jun (f)	Jul (g)	Aug (h)	Sep (i)	Oct (j)	Nov (k)	Dec (l)	Total (m)
	FT-RAM Exchange Volumes (GJ's)													
	Paths With FT-RAM Related Compressor Fuel and UFG:													
1	Dawn to Iroquois	1,641,269	1,127,784	1,356,131	64,753	106,244	240,000	183,019	12,959	72,061	244,629	2,004,500	1,416,466	8,469,815
2	Dawn to Niagara	269,767	24,054	2,954	-	-	7,280	-	-	-	-	1,287	-	305,342
3	Dawn to Enbridge CDA	1,456,959	1,524,497	1,258,455	1,459,481	1,457,715	1,385,335	1,436,613	1,426,062	1,380,060	1,429,579	410,117	149,968	14,774,841
4	Dawn to Enbridge EDA	35,497	49,870	-	-	-	-	-	-	-	-	336	682	86,385
5	Dawn to East Hereford	-	-	37,554	265,868	21,207	243,921	365,580	146,955	84,052	11,307	17,000	-	1,193,444
6	Dawn to Chippawa	-	-	-	-	-	-	-	-	-	-	10,860	-	10,860
7	Dawn to Napierville	140,401	346,229	124,881	64,648	30,549	204,065	478,709	246,105	147,117	187,204	189,786	374,286	2,533,980
8	Total Volume Prior to Adjustments	3,543,893	3,072,434	2,779,975	1,854,750	1,615,715	2,080,601	2,463,921	1,832,081	1,683,290	1,872,719	2,633,886	1,941,402	27,374,667
9	Dawn to Iroquois Adjustment	(687,081)	(455,979)	(413,081)	-	-	-	-	-	-	-	(450,000)	(465,000)	(2,471,141)
10	Dawn to TCPL Niagara Adjustment	(269,767)	-	-	-	-	-	-	-	-	-	-	-	(269,767)
11	Dawn to Enbridge CDA Adjustment	(400,000)	(768,000)	(631,000)	(1,459,481)	(1,457,715)	(1,385,335)	(1,436,613)	(1,426,062)	(1,380,060)	(1,429,579)	(53,322)	-	(11,827,167)
12	Total Adjustments	(1,356,848)	(1,223,979)	(1,044,081)	(1,459,481)	(1,457,715)	(1,385,335)	(1,436,613)	(1,426,062)	(1,380,060)	(1,429,579)	(503,322)	(465,000)	(14,568,075)
13	Total Volume Subject to Compressor Fuel and UFG	2,187,045	1,848,455	1,735,894	395,269	158,000	695,266	1,027,308	406,019	303,230	443,140	2,130,564	1,476,402	12,806,592
	Dawn to Parkway Actual Fuel Rates:													
14	Compressor Fuel	0.746%	0.613%	0.690%	0.625%	0.538%	0.631%	0.515%	0.501%	0.499%	0.559%	0.641%	0.639%	
15	UFG	0.328%	0.328%	0.328%	0.328%	0.328%	0.328%	0.328%	0.328%	0.328%	0.328%	0.328%	0.328%	
16	Compressor Fuel (Line 14 x Line 18)	16,312	11,333	11,977	2,470	850	4,385	5,291	2,036	1,512	2,476	13,654	9,431	81,726
17	UFG ((Line 14 + Line 15) x Line 19)	7,174	6,063	5,694	1,296	518	2,280	3,370	1,332	995	1,453	6,988	4,843	42,006
18	Total Fuel Volumes	23,485	17,396	17,671	3,767	1,369	6,666	8,660	3,367	2,506	3,929	20,642	14,273	123,732
	Approved WACOG ($/GJ)	$ 5.386	$ 5.386	$ 5.386	$ 4.665	$ 4.665	$ 4.665	$ 4.823	$ 4.823	$ 4.823	$ 5.025	$ 5.025	$ 5.025	
	Total Fuel Costs (Line 16 x Line 17)	$ 126,491	$ 93,694	$ 95,174	$ 17,572	$ 6,385	$ 31,095	$ 41,768	$ 16,241	$ 12,088	$ 19,745	$ 103,725	$ 71,724	$ 635,704

TAB 2

2012 UTILITY RESULTS AND EARNINGS SHARING

2012 UTILITY RESULTS

For the year ended December 31, 2012, Union's actual revenue sufficiency from utility operations is $21.4 million higher relative to 2011. Table 1 below provides the results from Union's actual utility operations for 2012.

Table 1

Calculation of Revenue Deficiency/(Sufficiency) from Utility Operations
For the Year Ended December 31, 2012

Line No.	Particulars ($ Millions)	Board Approved 2007	Actual 2011	Actual 2012	Increase/ (decrease) 2012 vs. 2011
		(a)	(b)	(c)	(d) = (c)-(b)
1	Gas sales and distribution revenue	1,796.8	1,482.7	1,348.5	
2	Cost of gas	1,134.3	754.2	636.6	
3	Gas distribution margin	662.5	728.5	711.9	(16.6)
4	Transportation	127.4	171.6	210.3	38.7
5	Other revenue	24.4	23.1	19.9	(3.2)
6	Expenses	567.4	625.3	628.7	3.4
7	Income taxes	8.7	25.2	24.1	(1.1)
8	Utility income	238.1	272.7	289.3	16.6
9	Cost of Capital	259.5	251.4	251.7	0.3
10	Revenue deficiency/(sufficiency) after tax	21.4	(21.3)	(37.6)	(16.3)
11	Provision for income taxes on deficiency/(sufficiency)	12.1	(8.4)	(13.5)	(5.1)
12	Distribution revenue deficiency/(sufficiency)	33.5	(29.7)	(51.1)	(21.4)
13	Storage premium adjustment	33.5	11.3	11.3	-
14	Total revenue deficiency/(sufficiency)	-	(41.0)	(62.4)	(21.4)

The primary drivers of Union's 2012 financial results relative to 2011 are provided below.

Gas Distribution Margin

The decrease in gas distribution margin of $16.6 million relative to 2011 was mainly driven by a decrease in customer usage of natural gas primarily due to weather that was more than 10% warmer than in 2011, partially offset by an increase from growth in the number of customers.

Transportation Revenue

The increase in transportation revenue of $38.7 million relative to 2011 was mainly driven by the FT-RAM optimization revenue in the prior year being subject to deferral per EB-2012-0087 and an increase in short-term transportation exchange service revenue.

2012 EARNINGS SHARING

The benchmark return on equity ("ROE") for 2012 was 7.67%. Union's actual ROE from utility operations in 2012 was 11.07% or 340 basis points above the 2012 benchmark ROE. This results in earnings sharing for 2012 of $15.730 million (Tab 2, Appendix B, Schedule 1, column (d), line 35).

The calculation of earnings sharing for 2012 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 unregulated storage operations; column (c) makes adjustments that would normally be made under cost of service to arrive at utility earnings for ratemaking before interest and income taxes. To arrive at utility earnings for the purposes of earnings sharing, deemed interest, income taxes and preferred dividends are calculated and deducted from utility earnings before interest and income taxes. The adjustments are discussed in more detail below.

Unregulated Storage Operations

The revenues and costs for Union's unregulated storage operations are shown in Tab 2, Appendix B, Schedule 1, column (b). The regulated and unregulated financial information was allocated using the methodology approved in EB-2011-0038.

Other Adjustments

Consistent with Section 10.1 of the EB-2007-0606 Settlement Agreement, Union is making the following adjustments (Tab 2, Appendix B, Schedule 1, column (c)):

a) Impact of Removing St. Clair Transmission Line from rates
b) Reversal of Upstream Transportation FT-RAM Optimization Deferral

c) Demand Side Management Incentive

d) Charitable donations

e) Interest on customer deposits

f) Other

Impact of Removing St. Clair Transmission Line from rates

On December 20, 2011 Union advised the Board that the sale of the St. Clair Transmission Line to Dawn Gateway LP was cancelled. In EB-2010-0039 the Board approved the return of the St. Clair Transmission Line to rate base but not until January 1, 2013.

Since the asset is not included in rate base for 2012, the amounts included in rates for the St. Clair Transmission Line should also be removed from utility earnings. The amounts removed from utility earnings include, $1.072 million of Distribution revenue, $0.101 million in Transportation revenue, depreciation of $0.540 million and transportation costs of $0.342 million.

Reversal of Upstream Transportation FT-RAM Optimization Deferral

In EB-2012-0087 the Board ordered Union to remove 90% of the net revenues related to 2011 transportation exchange transactions associated with the FT-RAM program from the 2011 earnings sharing calculation. The decision was rendered in 2012 and had the effect of reducing 2012 corporate earnings by $19.8 million. Union has reversed this impact in its calculation of 2012 utility earnings subject to sharing.

Based on the Board's decision in EB-2012-0087, and in accordance with Generally Accepted Accounting Principles in the United States ("U.S. GAAP"), Union recorded a provision of $33.771 million to similarly remove 90% of the 2012 net revenues related to transportation exchange transactions associated with the FT-RAM program from 2012 corporate earnings. Union describes in Exhibit B why the net revenues should be included in utility earnings subject to sharing. As a result, the provision has been reversed from 2012 utility earnings.

Under the method approved for 2011 in EB-2012-0087 whereby 90% of the FT-RAM revenues are included in a deferral account as a gas cost reduction, there are zero earnings sharing. Refer to Tab 2, Appendix D, Schedule 19 for the Earnings Sharing schedule under this treatment as well as related financial schedules (1-18).

Demand Side Management Incentive

Other revenue includes the revenue recorded from the 2012 Demand Side Management Incentive (DSMI) of $8.787 million. The DSMI payment is an incentive to the company to encourage it to actively pursue DSM activities. To ensure that the full amount of the DSMI accrues to the company and that the incentive is maintained, the DSMI revenue is removed from the earnings sharing calculation. This treatment is in accordance with the EB-2007-0606 Settlement Agreement and with past earnings sharing calculations.

Charitable Donations

Charitable donations are costs incurred by the utility that are not recovered from customers in rates. The reduction in costs of $0.689 million follows the treatment of charitable donations under cost of service ratemaking and the EB-2007-0606 Settlement Agreement.

Interest on Customer Deposits

Interest on customer deposits of $0.243 million paid out during the year (recorded in the company's accounts as interest expense) is included in the expenses allowable as deductions from earnings consistent with the treatment under cost of service ratemaking and the EB-2007-0606 Settlement Agreement.

Other

Amounts relating to the Conservation Demand Management (CDM) program of $0.032 million, have been removed from operating and maintenance expenses because of a separate deferral mechanism in place.

Amounts relating to the cancellation of a proposed decrease in the Ontario corporate tax rate of which 50% of the proposed reduction was included in 2012 rates. The amount included in rates has been proposed for recovery and therefore Distribution revenue and Storage & Transportation revenue have been increased by $0.103 and $0.029 million respectively.

Depreciation of $0.034 million related to capital costs incurred on the Customer Service Standards – Low Income GDAR related project have been added back because they are included in the GDAR Deferral Account (179-112).

As a result of the Board's decision in EB-2011-0210, Union reversed the accounting to record as revenue, fuel costs that would have been incurred ($0.676 million) had Union not entered into a separate exchange transaction.

Calculation of Earnings

Determining the amount of earnings for sharing requires a calculation of interest, dividends and income taxes based on the utility rate base to arrive at utility earnings to common shareholder. The amount of the storage premium is then added to earnings to calculate the ROE to compare to the threshold return. These calculations and amounts are discussed further below:

Interest, Income Taxes and Preferred Dividends

The approach used to calculate interest and income taxes to determine earnings subject to sharing is the same approach used for rate making under cost of service.

Utility interest expense of $145.109 million is calculated using actual utility rate base, deemed capital structure, and actual average interest rates adjusted for fees and other costs. The calculation can be found at Tab 2, Appendix A, Schedule 4.

Current utility income taxes are calculated using utility income before interest and taxes, less deemed interest costs, 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.

Preferred share dividend requirements are based on deemed capital structure and cost of capital. The calculation can be found at Tab 2, Appendix A, Schedule 4.

Storage Premium Adjustment

Earnings from utility operations are increased by the portion of the storage premium reflected in approved rates to determine utility earnings subject to sharing. In 2012, the amount of the ratepayer benefit comprised of revenue excess generated from short-term storage services is $11.254 million pre-tax or 71% of the $15.829 million forecast revenue excess on short-term storage services (EB-2007-0606, Rate Order Working Papers, Schedule 16). The after tax earnings impact of the premium in 2012 is $8.272 million for short-term storage.

Return on Equity ("ROE")

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 2012 ROE is 11.07% (Tab 2, Appendix B, Schedule 1, column (d), line 28).

Earnings Subject to Sharing

The actual ROE is compared to the ROE generated by applying the Board's approved ROE formula. If the difference between the actual ROE and the benchmark ROE is greater than 200 basis points but less than 300 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 exceeded 300 basis points then that excess over 300 basis points is shared 90/10 to the benefit of the ratepayers. For 2012, the difference is 340 basis points or $11.562 million, after tax (Tab 2, Appendix B, Schedule 1, column (d), line 34). The amount attributed to 50/50 sharing is $6.748 million and 90/10 sharing is $4.813 million. When grossed up for income taxes, the amount of the earnings sharing is $15.730 million (Tab 2, Appendix B, Schedule 1, column (d), line 35).

2012 NON UTILITY

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

APPENDIX A

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	Operating revenue	1,948,549	1,677,423	1,578,597
2	Cost of service	1,710,465	1,404,667	1,289,289
3	Utility income	238,084	272,756	289,308
4	Requested return	259,490	251,384	251,741
5	Revenue deficiency / (sufficiency) after tax	21,407	(21,372)	(37,567)
6	Provision for income taxes on deficiency / (sufficiency)	12,104	(8,415)	(13,546)
7	Distribution revenue deficiency / (sufficiency)	$ 33,511	$ (29,787)	$ (51,113)
8	Storage premium adjustment	33,511	11,254	11,254
9	Total revenue deficiency/ (sufficiency)	-	(41,041)	(62,367)

UNION GAS LIMITED
Statement of Utility Income
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
	Operating Revenues:			
1	Gas sales and distribution	1,796,757	1,482,738	1,348,519
2	Transportation	127,358	171,605	210,188
3	Other	24,434	23,080	19,890
4		1,948,549	1,677,423	1,578,597
	Operating Expenses:			
5	Cost of gas	1,134,293	754,190	636,555
6	Operating and maintenance expenses	325,623	369,470	364,942
7	Depreciation	173,780	195,477	200,864
8	Other financing	315	343	243
9	Property and capital taxes	67,709	60,699	61,407
10		1,701,720	1,380,179	1,264,011
	Other Income (Expense)			
11	Gain/(Loss) on sale of assets	-	35	9
12	Gain/(Loss) on foreign exchange	-	674	(1,196)
13			709	(1,187)
14	Utility income before income taxes	246,829	297,953	313,399
15	Income taxes	8,745	25,197	24,091
16	Total utility income	$ 238,084	$ 272,756	$ 289,308

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

Line No.	Particulars ($000s)	2007 Board-Approved Corporate (a)	2007 Board-Approved Non-Utility Storage (b)	2007 Board-Approved Adjustments (c)	2007 Board-Approved Utility (d)=(a)-(b)+(c)	2011 Actual Corporate (e)	2011 Actual Non-Utility Storage (f)	2011 Actual Adjustments (g)	2011 Actual Utility (h)=(e)-(f)+(g)	2012 Actual Corporate (i)	2012 Actual Non-Utility Storage (j)	2012 Actual Adjustments (k)	2012 Actual Utility (l)= (i)-(j)+(k)
	Operating Revenues:												
1	Gas sales and distribution	1,796,757	-	-	1,796,757	1,484,768	-	(2,030)	1,482,738	1,349,488	-	(969) i	1,348,519
2	Storage & Transportation	191,444	60,019	(4,067)	127,358	310,109	116,314	(22,190)	171,605	268,590	111,225	52,823 ii	210,188
3	Other	24,434	-	-	24,434	34,226	-	(11,146)	23,080	28,677	-	(8,787) iii	19,890
4	Earnings Sharing	-	-	-	-	-	-	-	-	-	-	-	-
5		2,012,635	60,019	(4,067)	1,948,549	1,829,103	116,314	(35,366)	1,677,423	1,646,755	111,225	43,067	1,578,597
	Operating Expenses:												
6	Cost of gas	1,135,842	1,549	-	1,134,293	755,265	- 215	(1,290)	754,190	637,755	182	(1,018) vii	636,555
7	Operating and maintenance expenses	333,029	7,002	(404)	325,623	384,773	14,716	(587)	369,470	380,114	14,451	(721) iv	364,942
8	Depreciation	178,502	4,722	-	173,780	204,344	8,731	(136)	195,477	211,794	10,357	(574) v	200,864
9	Other financing	-	-	315	315	-	-	343	343	-	-	243 vi	243
10	Property and capital taxes	68,671	962	-	67,709	62,057	1,358	-	60,699	62,819	1,412	-	61,407
11		1,716,044	14,235	(89)	1,701,720	1,406,439	24,590	(1,670)	1,380,179	1,292,482	26,402	(2,070)	1,264,011
	Other Income (Expense)												
12	Gain/(Loss) on sale of assets	-	-	-	-	6,322	(115)	(6,402)	35	(500)	(509)	-	9
13	Other	-	-	-	-	(1,165)	(1,165)	-	-	(986)	(986)	-	-
14	Gain/(Loss) on foreign exchange	-	-	-	-	701	27	-	674	(1,243)	(47)	-	(1,196)
15						5,858	(1,253)	(6,402)	709	(2,729)	(1,542)	-	(1,187)
16	Earnings Before Interest and Taxes	$ 296,591	$ 45,784	$ (3,978)	$ 246,829	$ 428,522	$ 90,471	$ (40,098)	$ 297,953	$ 351,544	$ 83,281	$ 45,137	$ 313,399

Notes:

i)	Impact of removing St. Clair Transmission Line from rates	(1,072)
	Tax rate change	103
		(969)
ii)	Impact of removing St. Clair Transmission Line from rates	(101)
	Reversal of 2011 Upstream Transportation FT-RAM Optimization Deferral	19,800
	Reversal of 2012 Upstream Transportation FT-RAM Optimization Provision	33,771
	Reversal of avoided costs	(676)
	Tax rate change	29
		52,823
iii)	Demand Side Management Incentive	
iv)	Charitable Donations	(689)
	CDM program	(32)
		(721)
v)	Impact of removing St. Clair Transmission Line from rates	(540)
	Customer Service Standards - Low Income	(34)
		(574)
vi)	Interest on Customer Deposits	
vii)	Impact of removing St. Clair Transmission Line from rates	(342)
	Reversal of avoided costs	(676)
		(1,018)

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

Line No.	Particulars	2007 Board-Approved Utility Capital Structure ($000s)	2007 Board-Approved Utility Capital Structure (%)	2007 Board-Approved Cost Rate %	2007 Board-Approved Return ($000s)	2011 Actual Utility Capital Structure ($000s)	2011 Actual Utility Capital Structure (%)	2011 Actual Cost Rate %	2011 Actual Return ($000s)	2012 Actual Utility Capital Structure ($000s)	2012 Actual Utility Capital Structure (%)	2012 Actual Cost Rate %	2012 Actual Return ($000s)
1	Long-term debt	2,016,833	61.66	7.66%	154,389	2,109,129	58.86	6.76%	142,509	2,151,082	57.38%	6.65%	142,999
2	Unfunded short-term debt	(28,980)	(0.89)	1.58%	(457)	81,473	2.27	1.61%	1,312	145,623	3.88%	1.45%	2,110
3	Total debt	1,987,853	60.77	7.74%	153,932	2,190,602	61.13		143,821	2,296,705	61.26%		145,109
4	Preference shares	105,519	3.23	4.74%	4,998	102,683	2.87	2.99%	3,075	102,725	2.74%	3.03%	3,112
5	Common equity	1,177,522	36.00	8.54%	100,560	1,289,973	36.00	8.10%	104,488	1,349,679	36.00%	7.67%	103,520
6	Total rate base	$ 3,270,894	100.00		$ 259,490	$ 3,583,258	100.00		$ 251,384	$ 3,749,109	100.00%		$ 251,741

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

		2007 Board Approved						2011 Actual						2012 Actual					
Line No.	Particulars (10^3m^3)	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	-	-	-	-	-	-	2,329,600	444,445	159,056	15,303	-	2,948,404	2,452,544	353,475	93,729	15,677	-	2,915,425
2	Rate M2 Firm	2,249,002	1,377,551	105,414	230,800	-	3,962,767	489,179	354,059	29,065	269,983	-	1,142,286	515,928	312,812	19,001	265,777	-	1,113,518
3	Rate 01 Firm	502,613	400,625	-	2,073	-	905,311	703,936	215,011	-	7,631	-	926,578	762,494	159,987	-	7,533	-	930,014
4	Rate 10 Firm	135,308	139,784	-	106,277	-	381,369	161,653	88,660	-	95,251	1,635.00	347,199	175,518	80,357	-	95,182	2,460	353,517
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Total General Service	2,886,923	1,917,960	105,414	339,150	-	5,249,447	3,684,368	1,102,175	188,121	388,168	1,635.00	5,364,467	3,906,484	906,631	112,730	384,169	2,460	5,312,474
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	24,506	-	24,506	-	-	-	60,129	-	60,129	-	-	-	57,798	-	57,798
8	Rate M10 Firm	202	-	-	-	-	202	39	153	-	-	-	192	99	79	-	-	-	178
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
10	Total Wholesale - Utility	202	-	-	24,506	-	24,708	39	153	-	60,129	-	60,321	99	79	-	57,798	-	57,976
	Contract																		
11	Rate M4	23,609	-	-	429,418	-	453,027	17,744	4,174	-	420,265	-	442,183	20,328	10,773	-	397,699	-	428,800
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	277,546	-	277,546	-	-	-	257,671	-	257,671	-	-	-	141,853	-	141,853
14	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Rate 20 Transportation	24,982	-	-	146,571	354,035	525,588	13,034	-	-	98,449	533,322	644,805	6,727	-	-	95,123	551,437	653,287
16	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Rate 100 Transportation	-	-	-	-	2,275,112	2,275,112	-	-	-	-	1,892,180	1,892,180	-	-	-	-	1,912,745	1,912,745
18	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Rate T-1 Transportation	-	-	-	-	4,889,989	4,889,989	-	-	-	-	4,607,226	4,607,226	-	-	-	-	5,024,870	5,024,870
20	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Rate T-3 Transportation	-	-	-	-	321,455	321,455	-	-	-	-	264,032	264,032	-	-	-	-	239,361	239,361
22	Rate M5	-	-	-	404,634	-	404,634	16,360	1,437	-	493,002	-	510,799	19,048	1,109	-	448,934	-	469,091
23	Rate 25	41,048	-	-	-	63,597	104,645	40,515	-	-	-	117,269	157,784	44,159	-	-	-	163,136	207,295
24	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Contract	89,639	-	-	1,258,169	7,904,188	9,251,996	87,653	5,611		1,269,387	7,414,029	8,776,680	90,262	11,882	-	1,083,609	7,891,549	9,077,302
26	Total Throughput Volume	2,976,764	1,917,960	105,414	1,621,825	7,904,188	14,526,151	3,772,060	1,107,939	188,121	1,717,684	7,415,664	14,201,468	3,996,845	918,592	112,730	1,525,576	7,894,009	14,447,752

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

Line No.	Particulars (10^3m^3)	2007 Board-Approved						2011 Actual						2012 Actual					
		System	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	-	-	-	-	-	-	2,308,386	440,398	157,607	15,164	-	2,921,555	2,166,173	312,202	82,784	13,847	-	2,575,006
2	Rate M2 Firm	2,249,002	1,377,551	105,414	230,800	-	3,962,767	484,725	350,835	28,801	267,525	-	1,131,886	470,418	285,219	17,325	242,333	-	1,015,295
3	Rate 01 Firm	502,613	400,625	-	2,073	-	905,311	688,496	210,295	-	7,463	-	906,254	695,192	145,865	-	6,868	-	847,925
4	Rate 10 Firm	135,308	139,784	-	106,277	-	381,369	158,487	86,923	-	93,386	1,635.00	340,431	162,477	74,386	-	88,110	2,277	327,250
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total General Service	2,886,923	1,917,960	105,414	339,150	-	5,249,447	3,640,094	1,088,451	186,408	383,538	1,635.00	5,300,126	3,494,260	817,672	100,109	351,158	2,277	4,765,476
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	24,506	-	24,506	-	-	-	60,129	-	60,129	-	-	-	57,798	-	57,798
8	Rate M10 Firm	202	-	-	-	-	202	39	153	-	-	-	192	99	79	-	-	-	178
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utility	202	-	-	24,506	-	24,708	39	153	-	60,129	-	60,321	99	79	-	57,798	-	57,976
	Contract																		
11	Rate M4	23,609	-	-	429,418	-	453,027	17,744	4,174	-	420,265	-	442,183	20,328	10,773	-	397,699	-	428,800
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	277,546	-	277,546	-	-	-	257,671	-	257,671	-	-	-	141,853	-	141,853
14	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Rate 20 Transportation	24,982	-	-	146,571	354,035	525,588	13,034	-	-	98,449	533,322	644,805	6,727	-	-	95,123	551,437	653,287
16	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Rate 100 Transportation	-	-	-	-	2,275,112	2,275,112	-	-	-	-	1,892,180	1,892,180	-	-	-	-	1,912,745	1,912,745
18	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Rate T-1 Transportation	-	-	-	-	4,889,989	4,889,989	-	-	-	-	4,607,226	4,607,226	-	-	-	-	5,024,870	5,024,870
20	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Rate T-3 Transportation	-	-	-	-	321,455	321,455	-	-	-	-	264,032	264,032	-	-	-	-	239,361	239,361
22	Rate M5	-	-	-	404,634	-	404,634	16,360	1,437	-	493,002	-	510,799	19,048	1,109	-	448,934	-	469,091
23	Rate 25	41,048	-	-	-	63,597	104,645	40,515	-	-	-	117,269	157,784	44,159	-	-	-	163,136	207,295
24	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Contract	89,639	-	-	1,258,169	7,904,188	9,251,996	87,653	5,611	-	1,269,387	7,414,029	8,776,680	90,262	11,882	-	1,083,609	7,891,549	9,077,302
26	Total Throughput Volume	2,976,764	1,917,960	105,414	1,621,825	7,904,188	14,526,151	3,727,786	1,094,215	186,408	1,713,054	7,415,664	14,137,127	3,584,621	829,633	100,109	1,492,565	7,893,826	13,900,754

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

Line No.	Particulars ($000s)	2011 Actual System Sales (a)	2011 Actual ABC-T (b)	2011 Actual ABC Unbundled (c)	2011 Actual Bundled-T (d)	2011 Actual T-Service (e)	2011 Actual Total (f)	2012 Actual System Sales (g)	2012 Actual ABC-T (h)	2012 Actual ABC Unbundled (i)	2012 Actual Bundled-T (j)	2012 Actual T-Service (k)	2012 Actual Total (l)
	General Service												
1	Rate M1 Firm	737,279	53,723	19,715	853	-	811,570	675,894	42,684	12,573	781	-	731,932
2	Rate M2 Firm	114,776	16,632	2,230	11,448	-	145,086	100,998	14,162	1,456	10,739	-	127,355
3	Rate 01 Firm	266,915	51,216	-	1,252	-	319,383	265,967	39,030	-	1,238	-	306,235
4	Rate 10 Firm	44,133	12,154	-	12,144	70	68,501	41,261	10,835	-	11,831	90	64,017
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-
6	Total General Service	1,163,103	133,725	21,945	25,697	70	1,344,540	1,084,120	106,711	14,029	24,589	90	1,229,539
	Wholesale - Utility												
7	Rate M9 Firm	-	-	-	833	-	833	-	-	-	796	-	796
8	Rate M10 Firm	8	4	-	-	-	12	18	2	-	-	-	20
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	
10	Total Wholesale - Utility	8	4	-	833	-	845	18	2	-	796	-	816
	Contract												
11	Rate M4	3,963	119	-	11,363	-	15,445	3,898	330	-	10,107	-	14,335
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	
13	Rate M7	-	-	-	5,890	-	5,890	-	-	-	3,909	-	3,909
14	Rate 20 Storage	-	-	-	-	1,701	1,701	-	-	-	-	1,784	1,784
15	Rate 20 Transportation	3,282	-	-	9,151	7,617	20,050	1,488	-	-	9,076	6,848	17,412
16	Rate 100 Storage	-	-	-	-	186	186	-	-	-	-	174	174
17	Rate 100 Transportation	-	-	-	-	12,823	12,823	-	-	-	-	11,866	11,866
18	Rate T-1 Storage	-	-	-	-	9,555	9,555	-	-	-	-	8,622	8,622
19	Rate T-1 Transportation	-	-	-	-	52,202	52,202	-	-	-	-	55,411	55,411
20	Rate T-3 Storage	-	-	-	-	1,310	1,310	-	-	-	-	1,200	1,200
21	Rate T-3 Transportation	-	-	-	-	3,397	3,397	-	-	-	-	3,243	3,243
22	Rate M5	3,422	34	-	8,556	-	12,012	3,463	33	-	9,267	-	12,763
23	Rate 25	8,711	-	-	-	2,583	11,294	8,509	-	-	-	3,997	12,506
24	Rate 30	-	-	-	-	63	63	-	-	-	-	89	89
25	Total Contract	19,378	153	-	34,960	91,437	145,928	17,358	363	-	32,359	93,234	143,314
26	LRAM												2,585
27	Average Use												(3,656)
28	Tax Rate Change Impact Adjustment												103
29	Total Revenue	$ 1,182,489	$ 133,882	$ 21,945	$ 61,490	$ 91,507	$ 1,491,313	$ 1,101,496	$ 107,076	$ 14,029	$ 57,744	$ 93,324	$ 1,372,701

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

		2011 Actual						2012 Actual					
Line No.	Particulars ($000s)	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)
	General Service												
1	Rate M1 Firm	736,330	53,542	19,650	847	-	810,370	663,484	41,900	12,342	766	-	718,492
2	Rate M2 Firm	114,577	16,488	2,218	11,338	-	144,621	97,835	13,718	1,410	10,403	-	123,366
3	Rate 01 Firm	265,773	50,868	-	1,240	-	317,881	261,058	38,309	-	1,215	-	300,582
4	Rate 10 Firm	43,977	12,069	-	12,052	70	68,168	40,551	10,649	-	11,628	88	62,916
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-
6	Total General Service	1,160,658	132,967	21,868	25,477	70	1,341,039	1,062,928	104,576	13,752	24,012	88	1,205,356
	Wholesale - Utility												
7	Rate M9 Firm	-	-	-	833	-	833	-	-	-	796	-	796
8	Rate M10 Firm	8	4	-	-	-	12	18	2	-	-	-	20
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utility	8	4	-	833	-	846	18	2	-	796	-	816
	Contract												
11	Rate M4	3,963	119	-	11,363	-	15,446	3,898	330	-	10,107	-	14,335
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	5,890	-	5,890	-	-	-	3,909	-	3,909
14	Rate 20 Storage	-	-	-	-	1,701	1,701	-	-	-	-	1,784	1,784
15	Rate 20 Transportation	3,282	-	-	9,151	7,617	20,050	1,488	-	-	9,076	6,848	17,412
16	Rate 100 Storage	-	-	-	-	186	186	-	-	-	-	174	174
17	Rate 100 Transportation	-	-	-	-	12,823	12,823	-	-	-	-	11,866	11,866
18	Rate T-1 Storage	-	-	-	-	9,555	9,555	-	-	-	-	8,622	8,622
19	Rate T-1 Transportation	-	-	-	-	52,202	52,202	-	-	-	-	55,411	55,411
20	Rate T-3 Storage	-	-	-	-	1,310	1,310	-	-	-	-	1,200	1,200
21	Rate T-3 Transportation	-	-	-	-	3,397	3,397	-	-	-	-	3,243	3,243
22	Rate M5	3,422	34	-	8,556	-	12,012	3,463	33	-	9,267	-	12,763
23	Rate 25	8,711	-	-	-	2,583	11,294	8,509	-	-	-	3,997	12,506
24	Rate 30	-	-	-	-	63	63	-	-	-	-	89	89
25	Total Contract	19,378	153	-	34,961	91,436	145,928	17,358	363	-	32,359	93,234	143,314
26	LRAM												2,585
27	Average Use						(5,076)						(3,656)
28	Tax Rate Change Impact Adjustment												103
29	Total Revenue	$ 1,180,044	$ 133,124	$ 21,868	$ 61,271	$ 91,506	$ 1,482,738	$ 1,080,304	$ 104,941	$ 13,752	$ 57,167	$ 93,322	$ 1,348,519

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

Line		2007 Board-Approved						2011 Actual						2012 Actual					
No.	Particulars ($000s)	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	-	-	-	-	-	-	298,602	53,542	19,650	847	-	372,641	312,963	41,900	12,342	766	-	367,971
2	Rate M2 Firm	253,336	133,485	12,252	11,336	-	410,409	22,477	16,488	2,218	11,338	-	52,521	22,289	13,718	1,410	10,403	-	47,820
3	Rate 01 Firm	74,884	57,873	-	195	-	132,952	106,469	31,958	-	568	-	138,995	113,960	23,497	-	521	-	137,978
4	Rate 10 Firm	8,156	8,706	-	5,024	-	21,886	8,359	5,003	-	4,147	70	17,579	7,703	3,892	-	3,466	88	15,149
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total General Service	336,376	200,064	12,252	16,555	-	565,247	435,907	106,991	21,868	16,900	70	581,736	456,915	83,007	13,752	15,156	88	568,918
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	592	-	592	-	-	-	833	-	833	-	-	-	796	-	796
8	Rate M10 Firm	5	-	-	-	-	5	1	4	-	-	-	5	2	2	-	-	-	4
9	Rate 77 Firm	-	-	-	-	28	28	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utilit	5	-	-	592	28	625	1	4	-	833	-	838	2	2	-	796	-	800
	Contract																		
11	Rate M4	739	-	-	13,030	-	13,769	558	119	-	11,363	-	12,040	684	330	-	10,107	-	11,121
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	6,670	-	6,670	-	-	-	5,890	-	5,890	-	-	-	3,909	-	3,909
14	Rate 20 Storage	-	-	-	-	56	56	-	-	-	-	1,701	1,701	-	-	-	-	-	
15	Rate 20 Transportation	522	-	-	1,940	4,982	7,444	291	-	-	1,548	7,617	9,456	142	-	-	1,362	6,848	8,352
16	Rate 100 Storage	-	-	-	-	1,767	1,767	-	-	-	-	186	186	-	-	-	-	-	
17	Rate 100 Transportatioı	-	-	-	-	16,153	16,153	-	-	-	-	12,823	12,823	-	-	-	-	11,866	11,866
18	Rate T-1 Storage	-	-	-	-	8,206	8,206	-	-	-	-	9,406	9,406	-	-	-	-	8,622	8,622
19	Rate T-1 Transportatioı	-	-	-	-	46,827	46,827	-	-	-	-	52,202	52,202	-	-	-	-	55,398	55,398
20	Rate T-3 Storage	-	-	-	-	1,578	1,578	-	-	-	-	1,310	1,310	-	-	-	-	1,200	1,200
21	Rate T-3 Transportatioı	-	-	-	-	4,010	4,010	-	-	-	-	3,397	3,397	-	-	-	-	3,243	3,243
22	Rate M5	-	-	-	8,038	-	8,038	308	34	-	8,556	-	8,898	416	33	-	9,267	-	9,716
23	Rate 25	908	-	-	-	1,497	2,405	811	-	-	-	2,466	3,277	864	-	-	-	3,997	4,861
24	Rate 30	-	-	-	-	-	-	-	-	-	-	63	63	-	-	-	-	-	
25	Total Contract	2,169	-	-	29,678	85,076	116,923	1,968	153	-	27,357	91,171	120,649	2,106	363	-	24,645	91,174	118,288
26	LRAM																		2,585
27	Average Use												(5,076)						(3,656)
28	Tax Rate Change Impact Adjustment																		103
29	Total Revenue	$ 338,550	$ 200,064	$ 12,252	$ 46,825	$ 85,104	$ 682,795	$ 437,876	$ 107,148	$ 21,868	$ 45,090	$ 91,241	$ 698,147	$ 459,023	$ 83,372	$ 13,752	$ 40,597	$ 91,262	$ 687,038

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

Line No.	Particulars	2007 Board-Approved System Sales (a)	ABC-T (b)	ABC-Unbundled (c)	Bundled T (d)	T-Service (e)	Total (f)	2011 Actual System Sales (g)	ABC-T (h)	ABC-Unbundled (i)	Bundled T (j)	T-Service (k)	Total (l)	2012 Actual System Sales (m)	ABC-T (n)	ABC-Unbundled (o)	Bundled T (p)	T-Service (q)	Total (r)
	General Service																		
1	Rate M1 Firm	-	-	-	-	-	-	861,125	130,667	44,484	870	-	1,037,146	909,139	107,370	33,166	984	-	1,050,659
2	Rate M2 Firm	663,740	297,276	34,458	1,690	-	997,164	3,346	2,339	174	778	-	6,637	3,637	2,140	112	800	-	6,689
3	Rate 01 Firm	172,580	125,484	-	166	-	298,230	252,289	60,991	-	353	-	313,633	269,708	48,952	-	367	-	319,027
4	Rate 10 Firm	1,329	1,344	-	300	-	2,973	1,220	661	-	275	4	2,160	1,221	600	-	268	5	2,094
5	Rate 16 Interruptible	-	-	-		-	-					-	-	-	-	-	-	-	-
6	Total General Service	837,649	424,104	34,458	2,156	-	1,298,367	1,117,980	194,658	44,658	2,276	4	1,359,576	1,183,705	159,062	33,278	2,419	5	1,378,469
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	2	-	2	-	-	-	2	-	2	-	-	-	2	-	2
8	Rate M10 Firm	4	-	-	-	-	4	1	1	-	-	-	2	3	-	-	-	-	3
9	Rate 77 Firm	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utility	4	-	-	2	1	7	1	1	-	2	-	4	3		-	2	-	5
	Contract																		
11	Rate M4	13	-	-	181	-	194	11	2	-	119	-	132	16	5	-	122	-	143
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	8	-	8	-	-	-	5	-	5	-	-	-	4	-	4
14	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Rate 20 Transportation	10	-	-	20	35	65	2	-	-	18	29	49	2	-	-	18	28	48
16	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Rate 100 Transportation	-	-	-	-	19	19	-	-	-	-	14	14	-	-	-	-	15	15
18	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Rate T-1 Transportation	-	-	-	-	68	68	-	-	-	-	56	56	-	-	-	-	59	59
20	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Rate T-3 Transportation	-	-	-	-	1	1	-	-	-	-	1	1	-	-	-	-	1	1
22	Rate M5	-	-	-	133	-	133	4	1	-	119	-	124	9	1	-	113	-	123
23	Rate 25	56	-	-	-	67	123	44	-	-	-	50	94	35	-	-	-	51	86
24	Rate 30	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	
25	Total Contract	79	-	-	342	190	611	61	3	-	261	151	476	62	6	-	257	154	479
26	Total Customers	837,732	424,104	34,458	2,500	191	1,298,985	1,118,042	194,662	44,658	2,539	155	1,360,056	1,183,770	159,068	33,278	2,678	159	1,378,953

* Customer count for storage is included in the transportation customer count.

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	M12 Transportation	120,667	138,273	133,688
2	M12-X Transportation	-	1,477	5,923
3	C1 Long Term Transportation	2,900	7,570	7,042
4	C1 Short Term Transportation	2,500	12,533	10,115
5	Exchanges	1,242	9,695	51,553
6	C1 Rebate Program	(2,178)	-	-
7	M13 - Local Production	864	323	308
8	M16	553	642	558
9	Other S&T Revenue	810	1,092	972
10	Tax Rate Change Impact Adjustment	-	-	29
11	Total S&T Revenue	$ 127,358	$ 171,605	$ 210,188

UNION GAS LIMITED
Other Revenue
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	Delayed payment charges	7,231	6,770	5,889
2	Account opening charges	5,858	6,586	6,156
3	Billing revenue	9,041	6,013	4,652
4	Mid market transactions	2,000	1,298	1,411
5	Other operating revenue	304	2,413	1,782
6	Total other revenue	$ 24,434	$ 23,080	$ 19,890

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

Line No.	Particulars ($000s)	Board-Approved 2007 (a)	Actual 2011 (b)	Actual 2012 (c)
1	Salaries/Wages	159,896	191,837	183,418
2	Benefits	55,621	81,179	83,891
3	Materials	9,132	10,701	8,164
4	Employee Training	12,798	13,514	12,043
5	Contract Services	50,061	63,608	65,002
6	Consulting	6,447	7,713	7,787
7	General	20,645	22,262	22,627
8	Transportation and Maintenance	7,523	9,012	8,634
9	Company Used Gas	4,911	2,401	2,043
10	Utility Costs	3,269	4,069	4,064
11	Communications	7,969	6,394	5,761
12	Demand Side Management Programs	11,874	17,925	24,039
13	Advertising	2,255	2,376	2,311
14	Insurance	7,004	8,101	8,141
15	Donations	404	632	725
16	Financial	2,884	1,682	1,438
17	Lease	3,202	4,092	4,496
18	Cost Recovery from Third Parties	(2,106)	(5,869)	(7,981)
19	Computers	4,226	5,287	5,251
20	Regulatory Hearing & OEB Cost Assessment	6,000	3,306	4,486
21	Outbound Affiliate Services	(5,741)	(11,697)	(13,812)
22	Inbound Affiliate Services	11,933	8,956	9,995
23	Bad Debt	11,600	4,455	4,957
24	Other	100	206	-
25	Total	391,907	452,142	447,482
26	Indirect Capitalization (OH)	(51,528)	(52,220)	(52,351)
27	Direct Captialization (DCC)	(7,350)	(15,149)	(15,016)
28	Total	333,029	384,773	380,115
29	Non Utility Costs (1)	(7,406)	(15,303)	(15,173)
30	Total Net Utility Operating and Maintenance Expens	$ 325,623	$ 369,470	$ 364,942

Notes:
(1) Includes non utility storage, charitable donations and loss on Conservation Demand Management Program.

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
	Determination of Taxable Income			
1	Utility income before interest and income taxes	246,829	297,953	313,399
	Adjustments required to arrive at taxable utility income:			
2	Interest expense	(153,932)	(143,821)	(145,109)
3	Utility permanent differences	1,333	3,941	2,281
4		94,230	158,073	170,571
	Utility timing differences			
5	Capital Cost Allowance	(163,089)	(170,080)	(178,604)
6	Depreciation	173,780	195,477	200,864
7	Depreciation through clearing	1,114	1,674	1,549
8	Other	(38,911)	(43,105)	(47,489)
9	Gas Cost Deferrals and Other (current)	-	(2,581)	(42,414)
10		(27,106)	(18,615)	(66,094)
11	Taxable income	67,124	139,458	104,477
	Calculation of Utility Income Taxes			
12	Income taxes (line 11 * line 18)	24,245	39,397	27,686
13	Deferred tax on Gas Cost Deferrals	-	1,589	11,240
14	Deferred tax drawdown	(15,500)	(15,789)	(14,835)
15	Total taxes	8,745	25,197	24,091
	Tax Rates			
16	Federal tax	22.12%	16.50%	15.00%
17	Provincial tax	14.00%	11.75%	11.50%
18	Total tax rate	36.12%	28.25%	26.50%

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

Line No.	Class	Particulars ($000s)	2007 Board-Approved Depreciable UCC Balance (a)	2007 Board-Approved Rate (%) (b)	2007 Board-Approved CCA (c)	2011 Actual Depreciable UCC Balance (d)	2011 Actual Rate (%) (e)	2011 Actual CCA (f)	2012 Actual Depreciable UCC Balance (g)	2012 Actual Rate (%) (h)	2012 Actual CCA (i)
1	1	Buildings, structures and improvements, services, meters, mains		4%	-	1,365,023	4%	54,601	1,311,517	4%	52,461
2	1	Non-residential building acquired after March 19, 2007		6%	-	55,279	6%	3,317	63,559	6%	3,814
3	2	Mains acquired before 1988		6%	-	166,925	6%	10,016	156,910	6%	9,415
4	3	Buildings acquired before 1988		5%	-	4,741	5%	237	4,504	5%	225
5	6	Other buildings		10%	-	213	10%	21	192	10%	19
6	7	Compression equipment acquired after February 22, 2005		15%	-	141,567	15%	21,235	178,062	15%	26,709
7	8	Compression assets, office furniture, equipment		20%	-	93,524	20%	18,705	70,170	20%	14,034
8	10	Transportation, computer equipment		30%	-	21,193	30%	6,358	21,272	30%	6,381
9	12	Computer software, small tools		100%	-	7,934	100%	7,934	10,921	100%	10,921
10	13	Leasehold improvements (1)		N/A	-	656	N/A	(1) 121	2,488	N/A	(1) 205
11	17	Roads, sidewalk, parking lot or storage areas		8%	-	1,118	8%	89	1,028	8%	82
12	38	Heavy work equipment		30%	-	5,688	30%	1,706	5,438	30%	1,631
13	41	Storage assets		25%	-	9,352	25%	2,338	7,290	25%	1,823
14	45	Computers - Hardware acquired after March 22, 2004		45%	-	815	45%	367	448	45%	202
15	49	Transmission pipeline additions acquired after February 23, 2005		8%	-	196,657	8%	15,733	191,033	8%	15,283
16	50	Computers hardware acquired after March 18, 2007		55%	-	6,889	55%	3,789	13,676	55%	7,522
17	51	Distribution pipelines acquired after March 18, 2007		6%	-	374,598	6%	22,476	464,620	6%	27,877
18	52	Computers hardware acquired after January 27, 2009 and before February 2011			-	1,038	100%	1,038	0	100%	0
19		Total	$ 0		$ 0	$ 2,453,210		$ 170,080	$ 2,503,128		$ 178,604

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)	2007 Board-Approved	2011 Actual	2012 Actual
1	Total provision for depreciation and amortization before adjustments (per page 3)	-	197,151	202,413
2	Adjustments: vehicle depreciation through clearing	-	1,674	1,549
3	Provision for depreciation amortization and depletion	$ -	$ 195,477	$ 200,864

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

		2007 Board-Approved			2011 Actual			2012 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			$	1,321	Amortized	63	$ 1,321	Amortized	63
2	Intangible plant - Other				6,370	Amortized	122	6,370	Amortized	122
3		-		-	7,692		185	7,692		185
	Local Storage Plant									
4	Structures and improvements		3.30%	-	2,813	3.30%	93	3,264	3.30%	108
5	Gas holders - storage		2.68%	-	4,574	2.68%	-	4,574	2.68%	0
6	Gas holders - equipment		3.68%	-	9,817	3.68%	361	9,990	3.68%	368
7		-		-	17,204		454	17,828		475
	Storage:									
8	Land rights		2.23%	-	32,023	2.23%	714	31,984	2.23%	713
9	Structures and improvements		2.34%	-	56,111	2.34%	1,313	58,474	2.34%	1,369
10	Wells and lines		2.66%	-	87,951	2.66%	2,339	88,695	2.66%	2,361
11	Compressor equipment		3.19%	-	218,016	3.19%	6,955	228,588	3.19%	7,299
12	Measuring & regulating equipment		4.30%	-	60,484	4.30%	2,601	62,892	4.30%	2,707
13	Other equipment				1,758		372	2,134		487
14		-		-	456,343		14,295	472,767		14,937
	Transmission:									
15	Land rights		2.00%	-	37,791	2.00%	756	37,874	2.00%	757
16	Structures and improvements		2.66%	-	53,903	2.66%	1,434	53,340	2.66%	1,419
17	Mains		2.37%	-	1,046,190	2.37%	24,795	1,055,538	2.37%	25,016
18	Compressor equipment		3.52%	-	306,731	3.52%	10,797	327,680	3.52%	11,534
19	Measuring & regulating equipment		3.61%	-	162,971	3.61%	5,883	166,832	3.61%	6,023
20		-		-	1,607,587		43,665	1,641,264		44,750
	Distribution - Southern Operations:									
21	Land rights		1.67%	-	5,552	1.67%	93	5,755	1.67%	96
22	Structures and improvements		2.91%	-	103,801	2.91%	3,041	109,063	2.91%	3,196
23	Services - metallic		3.69%	-	109,721	3.69%	4,049	110,308	3.69%	4,070
24	Services - plastic		3.18%	-	748,811	3.18%	23,812	763,268	3.18%	24,272
25	Regulators		3.30%	-	72,011	3.30%	2,376	75,906	3.30%	2,505
26	Regulator and meter installations		3.51%	-	67,740	3.51%	2,378	68,384	3.51%	2,400
27	Mains - metallic		2.54%	-	403,980	2.54%	10,261	411,205	2.54%	10,445
28	Mains - plastic		2.34%	-	508,277	2.34%	11,894	519,963	2.34%	12,167
29	Measuring & regulating equipment		4.64%	-	29,730	4.64%	1,379	30,929	4.64%	1,435
30	Meters		3.70%	-	199,423	3.70%	7,379	214,263	3.70%	7,928
31	Other equipment			-	-		-	-		-
32		$ -		$ -	$ 2,249,046		$ 66,661	$ 2,309,045		$ 68,514

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

Line No.	Particulars ($000s)	2007 Board-Approved Average Plant (1)	Rate (%)	Provision	2011 Actual Average Plant (1)	Rate (%)	Provision	2012 Actual Average Plant (1)	Rate (%)	Provision
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Distribution plant - Northern & Eastern Operations:									
1	Land rights		1.68%	-	9,075	1.68%	152	9,194	1.68%	154
2	Structures & improvements		3.13%	-	62,322	3.13%	1,967	62,478	3.13%	1,950
3	Services - metallic		3.58%	-	93,240	3.58%	3,338	94,382	3.58%	3,379
4	Services - plastic		3.19%	-	359,075	3.19%	11,454	370,135	3.19%	11,807
5	Regulators		3.34%	-	28,012	3.34%	936	29,581	3.34%	988
6	Regulator and meter installations		3.50%	-	29,308	3.50%	1,026	29,767	3.50%	1,042
7	Mains - metallic		2.52%	-	353,866	2.52%	8,917	362,288	2.52%	9,130
8	Mains - plastic		2.35%	-	202,160	2.35%	4,751	206,342	2.35%	4,849
9	Compressor equipment		3.34%	-	-	3.34%	-	-	3.34%	0
10	Measuring & regulating equipment		4.63%	-	106,119	4.63%	4,913	111,386	4.63%	5,157
11	Meters		3.67%	-	52,711	3.67%	1,934	54,131	3.67%	1,987
12	Other distribution equipment			-	-		-	-		-
13		-		-	1,295,887		39,389	1,329,685		40,443
	General:									
14	Structures and improvements		2.13%		41,635	2.13%	942	44,790	2.13%	1,075
15	Office furniture and equipment		6.67%	-	10,470	6.67%	698	10,674	6.67%	704
16	Office equipment - computers		25.00%	-	78,684	25.00%	19,671	73,775	25.00%	18,294
17	Transportation equipment		10.07%	-	46,067	10.07%	4,639	47,732	10.07%	4,824
18	Heavy work equipment		4.55%	-	15,156	4.55%	707	14,638	4.55%	691
19	Tools and other equipment		6.67%	-	30,285	6.67%	2,019	29,843	6.67%	1,967
20	Communications equipment & structures		6.67%	-	15,870	6.67%	1,010	15,234	6.67%	974
21	Other equipment			-	-		-	-		-
22		-		-	238,167		29,686	236,686		28,496
23	Regulatory Assets				80,346		2,817	133,683		4,614
24	Sub-total	-		-	5,952,271		197,151	6,148,649		202,413
24	Total provision for depreciation and amortization			-			$ 197,151			$ 202,413
25	Depreciation through clearing						1,674			1,549
26		$ -		$ -	$ 5,952,271		$ 195,477	$ 6,148,649		$ 200,864

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, 2012

Line No.	Particulars ($000's)	Board Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	Storage	10,024	23,805	11,623
2	Transmission	139,121	48,291	23,309
3	Distribution	89,565	112,326	138,270
4	General	49,943	37,732	31,262
5	Other	59,312	52,387	52,119
6	Total	$ 347,965	$ 274,542	$ 256,583
7	Rate Base Reduction via ADR	(35,000)		
8		$ 312,965		

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
	Gas Utility Plant			
1	Gross plant at cost	5,170,809	5,998,663	6,221,188
2	Less: accumulated depreciation	2,014,712	2,505,353	2,636,558
3	Net utility plant	3,156,097	3,493,310	3,584,630
	Working Capital and Other Components			
4	Cash working capital	32,672	31,678	30,534
5	Gas in storage and line pack gas	188,792	150,999	177,372
6	Balancing gas	129,618	79,764	77,334
7	ABC receivable (gas in storage)	(53,791)	(55,323)	(22,519)
8	Inventory of stores, spare equipment	28,469	28,464	27,080
9	Prepaid and deferred expenses	2,741	5,080	5,119
10	Customer deposits	(43,902)	(50,281)	(44,668)
11	Customer interest	(300)	(736)	(680)
12	Total working capital and other components	284,299	189,645	249,572
13	Total rate base before deduction of accumulated deferred income taxes	3,440,396	3,682,955	3,834,202
14	Accumulated deferred income taxes	169,502	99,698	85,093
15	Total rate base	$ 3,270,894	$ 3,583,258	$ 3,749,109

APPENDIX B

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ended December 31

Line No.	Particulars ($000s)	2012 (a)	Non-Utility Storage (b)	Adjustments (c)		2012 Utility (d)=(a)-(b)+(c
	Operating Revenues:					
1	Gas Sales and distribution	$ 1,349,488	$ -	$ (969)	i	1,348,519
2	Storage & Transportation	268,590	111,225	52,823	ii	210,188
3	Other	28,677	-	(8,787)	iii	19,890
4		1,646,755	111,225	43,067		1,578,597
	Operating Expenses:					
5	Cost of gas	637,755	182	(1,018)	vii	636,555
6	Operating and maintenance expenses	380,114	14,451	(721)	iv	364,942
7	Depreciation	211,794	10,357	(574)	v	200,864
8	Other financing	-	-	243	vi	243
9	Property taxes	62,819	1,412	-		61,407
10		1,292,482	26,402	(2,070)		1,264,011
	Other					
11	Gain / (Loss) on sale of assets	(500)	(509)	-		9
12	Other / HTLP	(986)	(986)	-		-
13	Gain / (Loss) on foreign exchange	(1,243)	(47)	-		(1,196)
14		(2,729)	(1,542)	-		(1,187)
15	Earning Before Interest and Taxes	$ 351,544	$ 83,281	$ 45,137	$	313,399
	Financial Expenses:					
16	Long-term debt					142,999
17	Unfunded short-term debt					2,110
18						145,109
19	Utility income before income taxes					168,290
20	Income taxes					24,091
21	Preferred dividend requirements					3,112
22	Utility earnings					141,087
23	Long term storage premium subsidy (after tax)					-
24	Short term storage premium subsidy (after tax)					8,272
25						8,272
26	Earnings subject to sharing				$	149,359
27	Common equity					1,349,679
28	Return on equity (line 26 / line 27)					11.07%
29	Benchmark return on equity					9.67%
30	50% Earnings sharing % (line 28 - line 29, maximum 1%)					1.00%
31	90% Earnings sharing to ratepayer % (if line 30 = 1% then line 28 - line 29 - line 30)					0.40%
32	50% Earnings sharing $ (line 27 x line 30 x 50%)					6,748
33	90% Earnings sharing to ratepayer $ (line 27 x line 31 x 90%)					4,813
34	Total earnings sharing $ (line 32 + line 33)					11,562
35	Pre-tax earnings sharing (line 34 / (1 minus tax rate))				$	15,730

Notes:

i)	Impact of removing St. Clair Transmission Line from rates	(1,072)
	Tax rate change	103
		(969)
ii)	Impact of removing St. Clair Transmission Line from rates	(101)
	Reversal of 2011 Upstream Transportation FT-RAM Optimization Deferral	19,800
	Reversal of 2012 Upstream Transportation FT-RAM Optimization Provisio	33,771
	Reversal of avoided costs	(676)
	Tax rate change	29
		52,823
iii)	Demand Side Management Incentive	
iv)	Charitable Donations	(689)
	CDM program	(32)
		(721)
v)	Impact of removing St. Clair Transmission Line from rates	(540)
	Customer Service Standards - Low Income	(34)
		(574)
vi)	Interest on Customer Deposits	
vii)	Impact of removing St. Clair Transmission Line from rates	(342)
	Reversal of avoided costs	(676)
		(1,018)

APPENDIX C

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 2
Appendix C
Schedule 1

UNION GAS LIMITED
Continuity of Property, Plant and Equipment
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)	Balance Dec. 31/11	Additions: Capital Additions	Additions: Transfers	Additions: Net Salvage	Additions: Net Additions	Retirements	Balance Dec. 31/12	Adjustments	Adjusted Balance
		(a)	(b)	(c)	(g)	(h)	(d)	(e)	(f)	(g)
	Unregulated Gas Plant in Service:									
	Underground storage plant:									
1	Land	1,643				-		1,643		1,643
2	Land rights	21,659				-		21,659		21,659
3	Structures and improvements	19,629	366	48		414		20,043		20,043
4	Wells	86,252	573	113		686		86,938		86,938
5	Compressor equipment	136,773	11,737	573		12,310	(1,169)	147,914		147,914
6	Measuring & regulating equipment	34,228	(11,100)	(115)		(11,215)	(604)	22,408		22,408
7	Base pressure gas	22,928				-		22,928		22,928
8	Other equipment	-				-		-		-
9		323,112	1,576	619	-	2,195	(1,773)	323,534	-	$ 323,534
	General plant:									
10	Land	19				-	(2)	17		$ 17
11	Structures & improvements	1,260	242	1		243		1,503		1,503
12	Office furniture & equipment	304	93			93	(35)	362		362
13	Office equipment - computers	2,220	4,653			4,653	(619)	6,254		6,254
14	Transportation equipment	2,334	192	(37)		155	(336)	2,153		2,153
15	Heavy work equipment	683	49	38		87	(82)	688		688
16	Tools & work equipment	895	83			83	(54)	924		924
17	Communication equipment	392	48			48	(5)	435		435
18	Communication structures	78				-	(57)	21		21
19	Other general equipment	-				-		-		-
20		8,185	5,360	2	-	5,362	(1,190)	12,357	-	$ 12,357
21	Total gas plant in service	331,297	6,936	621	-	7,557	(2,963)	335,890	-	$ 335,890
22	Gas plant under construction	6,590	430			430		7,020		7,020
23	Total unregulated property plant and equipment	337,887	7,366	621	-	7,987	(2,963)	342,911	-	$ 342,911

UNION GAS LIMITED
Continuity of Accumulated Depreciation
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)	Balance Dec. 31/11	Transfers	Provisions	Retirements	Net Salvage /(Costs)	Balance Dec. 31/12
		(a)	(b)	(c)	(d)	(e)	(f)
	Unregulated Gas Plant in Service:						
	Underground storage plant:						
1	Land rights	6,680		431			7,111
2	Structures & improvements	6,169	(6)	649			6,812
3	Wells and lines	22,012		1,915			23,927
4	Compressor equipment	33,139	151	4,031	(998)		36,323
5	Measuring & regulating equipment	9,280	(157)	513	(604)		9,032
6		77,280	(12)	7,539	(1,602)	-	83,205
	General plant:						
7	Structures & improvements	592	1	45			638
8	Office furniture & equipment	143		30	(35)		138
9	Office equipment - computers	1,097		1,243	(619)		1,721
10	Transportation equipment	605	(8)	209	(336)	16	486
11	Heavy work equipment	-	8	30	(44)		(6)
12	Tools and other equipment	449		83	(54)		478
13	Communication structures	63		3	(57)		9
14	Communication equipment	193		37	(5)		225
15		3,142	1	1,680	(1,150)	16	3,689
	Miscellaneous Plant						
16	Heavy Work Equipment	(25)			(38)	4	(59)
17	Total unregulated gas plant in service	80,397	(11)	9,219	(2,790)	20	86,835

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)	UNREGULATED
1	Total unregulated provision for depreciation and amortization before adjustments (per page 3)	9,219
	Adjustments:	
2	Vehicle depreciation through clearing	(67)
3	Establish Asset Retirement Obligation for Non-Regulated storage wells.	1,204
4	Unregulated provision for depreciation amortization and depletion	**10,356**

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2012

Line No.	Particulars ($000's)	Average Plant (1) (a)	Rate (%) (b)		Total Provision
	Storage:				
1	Land rights	21,659	Allocation		431
2	Structures and improvements	18,226	Allocation		649
3	Wells and lines	84,410	Allocation		1,915
4	Compressor equipment	141,372	Allocation		4,031
5	Measuring & regulating equipment	26,324	Allocation		513
6	Other equipment				
7		291,992			7,539
	General:				
8	Structures & improvements	1,382	Allocation	$	45
9	Office furniture and equipment	333	Allocation		30
10	Office equipment - computers	4,237	Allocation		1,243
11	Transportation equipment	2,243	Allocation		209
12	Heavy work equipment	685	Allocation		30
13	Tools and other equipment	910	Allocation		83
14	Communications structures	414	Allocation		3
15	Communications equipment	50	Allocation		37
16	Other equipment				
17		10,253			1,680
18	Sub-total	302,244			9,219
19	Total unregulated provision for depreciation and amortization before adjustments			$	9,219
20	Vehicle depreciation through clearing				(67)
21	Establish Asset Retirement Obligation for Non-Regulated storage wells.				1,204
22	Unregulated provision for depreciation amortization and depletion	302,244			**10,356**

Notes:

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

APPENDIX D

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 2
Appendix D
Schedule 1

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	Operating revenue	1,948,549	1,677,423	1,541,417
2	Cost of service	1,710,465	1,404,667	1,278,968
3	Utility income	238,084	272,756	262,449
4	Requested return	259,490	251,384	251,741
5	Revenue deficiency / (sufficiency) after tax	21,407	(21,372)	(10,708)
6	Provision for income taxes on deficiency / (sufficiency)	12,104	(8,415)	(3,861)
7	Distribution revenue deficiency / (sufficiency)	$ 33,511	$ (29,787)	$ (14,569)
8	Storage premium adjustment	33,511	11,254	11,254
9	Total revenue deficiency/ (sufficiency)	-	(41,041)	(25,823)

UNION GAS LIMITED
Statement of Utility Income
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
	Operating Revenues:			
1	Gas sales and distribution	1,796,757	1,482,738	1,348,519
2	Transportation	127,358	171,605	173,008
3	Other	24,434	23,080	19,890
4		1,948,549	1,677,423	1,541,417
	Operating Expenses:			
5	Cost of gas	1,134,293	754,190	635,919
6	Operating and maintenance expenses	325,623	369,470	364,942
7	Depreciation	173,780	195,477	200,864
8	Other financing	315	343	243
9	Property and capital taxes	67,709	60,699	61,407
10		1,701,720	1,380,179	1,263,375
	Other Income (Expense)			
11	Gain/(Loss) on sale of assets	-	35	9
12	Gain/(Loss) on foreign exchange	-	674	(1,196)
13			709	(1,187)
14	Utility income before income taxes	246,829	297,953	276,855
15	Income taxes	8,745	25,197	14,407
16	Total utility income	$ 238,084	$ 272,756	$ 262,449

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

Line No.	Particulars ($000s)	2007 Board-Approved Corporate (a)	2007 Board-Approved Non-Utility Storage (b)	2007 Board-Approved Adjustments (c)	2007 Board-Approved Utility (d)=(a)-(b)+(c)	2011 Actual Corporate (e)	2011 Actual Non-Utility Storage (f)	2011 Actual Adjustments (g)	2011 Actual Utility (h)=(e)-(f)+(g)	2012 Actual Corporate (i)	2012 Actual Non-Utility Storage (j)	2012 Actual Adjustments (k)	2012 Actual Utility (l)= (i)-(j)+(k)
	Operating Revenues:												
1	Gas sales and distribution	1,796,757	-	-	1,796,757	1,484,768	-	(2,030)	1,482,738	1,349,488	-	(969) i	1,348,519
2	Storage & Transportation	191,444	60,019	(4,067)	127,358	310,109	116,314	(22,190)	171,605	268,590	111,224	15,642 ii	173,008
3	Other	24,434	-	-	24,434	34,226	-	(11,146)	23,080	28,677	-	(8,787) iii	19,890
4	Earnings Sharing	-	-	-	-	-	-	-	-	-	-	-	-
5		2,012,635	60,019	(4,067)	1,948,549	1,829,103	116,314	(35,366)	1,677,423	1,646,755	111,224	5,886	1,541,417
	Operating Expenses:												
6	Cost of gas	1,135,842	1,549	-	1,134,293	755,265	- 215	(1,290)	754,190	637,755	182	(1,654) iv	635,919
7	Operating and maintenance expenses	333,029	7,002	(404)	325,623	384,773	14,716	(587)	369,470	380,114	14,451	(721) v	364,942
8	Depreciation	178,502	4,722	-	173,780	204,344	8,731	(136)	195,477	211,794	10,357	(574) vi	200,864
9	Other financing	-	-	315	315	-	-	343	343	-	-	243 vii	243
10	Property and capital taxes	68,671	962	-	67,709	62,057	1,358	-	60,699	62,819	1,412	-	61,407
11		1,716,044	14,235	(89)	1,701,720	1,406,439	24,590	(1,670)	1,380,179	1,292,482	26,402	(2,706)	1,263,375
	Other Income (Expense)												
12	Gain/(Loss) on sale of assets	-	-	-	-	6,322	(115)	(6,402)	35	(500)	(509)	-	9
13	Other	-	-	-	-	(1,165)	(1,165)	-	-	(986)	(986)	-	-
14	Gain/(Loss) on foreign exchange	-	-	-	-	701	27	-	674	(1,243)	(47)	-	(1,196)
15						5,858	(1,253)	(6,402)	709	(2,729)	(1,542)	-	(1,187)
16	Earnings Before Interest and Taxes	$ 296,591	$ 45,784	$ (3,978)	$ 246,829	$ 428,522	$ 90,471	$ (40,098)	$ 297,953	$ 351,544	$ 83,280	$ 8,592	$ 276,855

Notes:

i)	Impact of removing St. Clair Transmission Line from rates	(1,072)
	Tax rate change	103
		(969)
ii)	Impact of removing St. Clair Transmission Line from rates	(101)
	Reversal of 2011 Upstream Transportation FT-RAM Optimization Deferral	19,800
	Removal of 10% of 2012 Upstream Transportation FT-RAM Optimization revenue	(3,718)
	Tax rate change	29
	Reversal of avoided costs	(676)
	Reversal of avoided costs - Adjustment to deferral	308
		15,642
iii)	Demand Side Management Incentive	
iv)	Impact of removing St. Clair Transmission Line from rates	(342)
	Fuel costs related to FT-RAM optimization	(636)
	Reversal of avoided costs	(676)
		(1,654)
v)	Charitable Donations	(689)
	CDM program	(32)
		(721)
vi)	Impact of removing St. Clair Transmission Line from rates	(540)
	Customer Service Standards - Low Income	(34)
		(574)
vii)	Impact of removing St. Clair Transmission Line from rates	

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

		2007 Board-Approved				2011 Actual				2012 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	2,016,833	61.66	7.66%	154,389	2,109,129	58.86	6.76%	142,509	2,151,082	57.38%	6.65%	142,999
2	Unfunded short-term debt	(28,980)	(0.89)	1.58%	(457)	81,473	2.27	1.61%	1,312	145,620	3.88%	1.45%	2,110
3	Total debt	1,987,853	60.77	7.74%	153,932	2,190,602	61.13		143,821	2,296,702	61.26%		145,109
4	Preference shares	105,519	3.23	4.74%	4,998	102,683	2.87	2.99%	3,075	102,725	2.74%	3.03%	3,112
5	Common equity	1,177,522	36.00	8.54%	100,560	1,289,973	36.00	8.10%	104,488	1,349,678	36.00%	7.67%	103,520
6	Total rate base	$ 3,270,894	100.00		$ 259,490	$ 3,583,258	100.00		$ 251,384	$ 3,749,105	100.00%		$ 251,741

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

Line No.	Particulars (10^3m^3)	2007 Board Approved System Sales (a)	ABC-T (b)	ABC-Unbundled (c)	Bundled-T (d)	T-Service (e)	Total (f)	2011 Actual System Sales (g)	ABC-T (h)	ABC-Unbundled (i)	Bundled-T (j)	T-Service (k)	Total (l)	2012 Actual System Sales (m)	ABC-T (n)	ABC-Unbundled (o)	Bundled-T (p)	T-Service (q)	Total (r)
	General Service																		
1	Rate M1 Firm	-	-	-	-	-	-	2,329,600	444,445	159,056	15,303	-	2,948,404	2,452,544	353,475	93,729	15,677	-	2,915,425
2	Rate M2 Firm	2,249,002	1,377,551	105,414	230,800	-	3,962,767	489,179	354,059	29,065	269,983	-	1,142,286	515,928	312,812	19,001	265,777	-	1,113,518
3	Rate 01 Firm	502,613	400,625	-	2,073	-	905,311	703,936	215,011	-	7,631	-	926,578	762,494	159,987	-	7,533	-	930,014
4	Rate 10 Firm	135,308	139,784	-	106,277	-	381,369	161,653	88,660	-	95,251	1,635.00	347,199	175,518	80,357	-	95,182	2,460	353,517
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
6	Total General Service	2,886,923	1,917,960	105,414	339,150	-	5,249,447	3,684,368	1,102,175	188,121	388,168	1,635.00	5,364,467	3,906,484	906,631	112,730	384,169	2,460	5,312,474
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	24,506	-	24,506	-	-	-	60,129	-	60,129	-	-	-	57,798	-	57,798
8	Rate M10 Firm	202	-	-	-	-	202	39	153	-	-	-	192	99	79	-	-	-	178
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
10	Total Wholesale - Utility	202	-	-	24,506	-	24,708	39	153	-	60,129	-	60,321	99	79	-	57,798	-	57,976
	Contract																		
11	Rate M4	23,609	-	-	429,418	-	453,027	17,744	4,174	-	420,265	-	442,183	20,328	10,773	-	397,699	-	428,800
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	277,546	-	277,546	-	-	-	257,671	-	257,671	-	-	-	141,853	-	141,853
14	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Rate 20 Transportation	24,982	-	-	146,571	354,035	525,588	13,034	-	-	98,449	533,322	644,805	6,727	-	-	95,123	551,437	653,287
16	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Rate 100 Transportation	-	-	-	-	2,275,112	2,275,112	-	-	-	-	1,892,180	1,892,180	-	-	-	-	1,912,745	1,912,745
18	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Rate T-1 Transportation	-	-	-	-	4,889,989	4,889,989	-	-	-	-	4,607,226	4,607,226	-	-	-	-	5,024,870	5,024,870
20	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Rate T-3 Transportation	-	-	-	-	321,455	321,455	-	-	-	-	264,032	264,032	-	-	-	-	239,361	239,361
22	Rate M5	-	-	-	404,634	-	404,634	16,360	1,437	-	493,002	-	510,799	19,048	1,109	-	448,934	-	469,091
23	Rate 25	41,048	-	-	-	63,597	104,645	40,515	-	-	-	117,269	157,784	44,159	-	-	-	163,136	207,295
24	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Contract	89,639	-	-	1,258,169	7,904,188	9,251,996	87,653	5,611		1,269,387	7,414,029	8,776,680	90,262	11,882	-	1,083,609	7,891,549	9,077,302
26	Total Throughput Volume	2,976,764	1,917,960	105,414	1,621,825	7,904,188	14,526,151	3,772,060	1,107,939	188,121	1,717,684	7,415,664	14,201,468	3,996,845	918,592	112,730	1,525,576	7,894,009	14,447,752

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 2
Appendix D
Schedule 6

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

Line No.	Particulars (10^3m^3)	2007 Board-Approved						2011 Actual						2012 Actual					
		System	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total	System Sales	ABC-T	ABC-Unbundled	Bundled-T	T-Service	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	General Service																		
1	Rate M1 Firm	-	-	-	-	-	-	2,308,386	440,398	157,607	15,164	-	2,921,555	2,166,173	312,202	82,784	13,847	-	2,575,006
2	Rate M2 Firm	2,249,002	1,377,551	105,414	230,800	-	3,962,767	484,725	350,835	28,801	267,525	-	1,131,886	470,418	285,219	17,325	242,333	-	1,015,295
3	Rate 01 Firm	502,613	400,625	-	2,073	-	905,311	688,496	210,295	-	7,463	-	906,254	695,192	145,865	-	6,868	-	847,925
4	Rate 10 Firm	135,308	139,784	-	106,277	-	381,369	158,487	86,923	-	93,386	1,635.00	340,431	162,477	74,386	-	88,110	2,277	327,250
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total General Service	2,886,923	1,917,960	105,414	339,150	-	5,249,447	3,640,094	1,088,451	186,408	383,538	1,635.00	5,300,126	3,494,260	817,672	100,109	351,158	2,277	4,765,476
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	24,506	-	24,506	-	-	-	60,129	-	60,129	-	-	-	57,798	-	57,798
8	Rate M10 Firm	202	-	-	-	-	202	39	153	-	-	-	192	99	79	-	-	-	178
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utility	202	-	-	24,506	-	24,708	39	153	-	60,129	-	60,321	99	79	-	57,798	-	57,976
	Contract																		
11	Rate M4	23,609	-	-	429,418	-	453,027	17,744	4,174	-	420,265	-	442,183	20,328	10,773	-	397,699	-	428,800
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	277,546	-	277,546	-	-	-	257,671	-	257,671	-	-	-	141,853	-	141,853
14	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Rate 20 Transportation	24,982	-	-	146,571	354,035	525,588	13,034	-	-	98,449	533,322	644,805	6,727	-	-	95,123	551,437	653,287
16	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Rate 100 Transportation	-	-	-	-	2,275,112	2,275,112	-	-	-	-	1,892,180	1,892,180	-	-	-	-	1,912,745	1,912,745
18	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Rate T-1 Transportation	-	-	-	-	4,889,989	4,889,989	-	-	-	-	4,607,226	4,607,226	-	-	-	-	5,024,870	5,024,870
20	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Rate T-3 Transportation	-	-	-	-	321,455	321,455	-	-	-	-	264,032	264,032	-	-	-	-	239,361	239,361
22	Rate M5	-	-	-	404,634	-	404,634	16,360	1,437	-	493,002	-	510,799	19,048	1,109	-	448,934	-	469,091
23	Rate 25	41,048	-	-	-	63,597	104,645	40,515	-	-	-	117,269	157,784	44,159	-	-	-	163,136	207,295
24	Rate 30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total Contract	89,639	-	-	1,258,169	7,904,188	9,251,996	87,653	5,611	-	1,269,387	7,414,029	8,776,680	90,262	11,882	-	1,083,609	7,891,549	9,077,302
26	Total Throughput Volume	2,976,764	1,917,960	105,414	1,621,825	7,904,188	14,526,151	3,727,786	1,094,215	186,408	1,713,054	7,415,664	14,137,127	3,584,621	829,633	100,109	1,492,565	7,893,826	13,900,754

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

		2011 Actual						2012 Actual					
Line No.	Particulars ($000s)	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)
	General Service												
1	Rate M1 Firm	737,279	53,723	19,715	853	-	811,570	675,894	42,684	12,573	781	-	731,932
2	Rate M2 Firm	114,776	16,632	2,230	11,448	-	145,086	100,998	14,162	1,456	10,739	-	127,355
3	Rate 01 Firm	266,915	51,216	-	1,252	-	319,383	265,967	39,030	-	1,238	-	306,235
4	Rate 10 Firm	44,133	12,154	-	12,144	70	68,501	41,261	10,835	-	11,831	90	64,017
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-
6	Total General Service	1,163,103	133,725	21,945	25,697	70	1,344,540	1,084,120	106,711	14,029	24,589	90	1,229,539
	Wholesale - Utility												
7	Rate M9 Firm	-	-	-	833	-	833	-	-	-	796	-	796
8	Rate M10 Firm	8	4	-	-	-	12	18	2	-	-	-	20
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	
10	Total Wholesale - Utility	8	4	-	833	-	845	18	2	-	796	-	816
	Contract												
11	Rate M4	3,963	119	-	11,363	-	15,445	3,898	330	-	10,107	-	14,335
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	
13	Rate M7	-	-	-	5,890	-	5,890	-	-	-	3,909	-	3,909
14	Rate 20 Storage	-	-	-	-	1,701	1,701	-	-	-	-	1,784	1,784
15	Rate 20 Transportation	3,282	-	-	9,151	7,617	20,050	1,488	-	-	9,076	6,848	17,412
16	Rate 100 Storage	-	-	-	-	186	186	-	-	-	-	174	174
17	Rate 100 Transportation	-	-	-	-	12,823	12,823	-	-	-	-	11,866	11,866
18	Rate T-1 Storage	-	-	-	-	9,555	9,555	-	-	-	-	8,622	8,622
19	Rate T-1 Transportation	-	-	-	-	52,202	52,202	-	-	-	-	55,411	55,411
20	Rate T-3 Storage	-	-	-	-	1,310	1,310	-	-	-	-	1,200	1,200
21	Rate T-3 Transportation	-	-	-	-	3,397	3,397	-	-	-	-	3,243	3,243
22	Rate M5	3,422	34	-	8,556	-	12,012	3,463	33	-	9,267	-	12,763
23	Rate 25	8,711	-	-	-	2,583	11,294	8,509	-	-	-	3,997	12,506
24	Rate 30	-	-	-	-	63	63	-	-	-	-	89	89
25	Total Contract	19,378	153	-	34,960	91,437	145,928	17,358	363	-	32,359	93,234	143,314
26	LRAM												2,585
27	Average Use												(3,656)
28	Tax Rate Change Impact Adjustment												103
29	Total Revenue	$ 1,182,489	$ 133,882	$ 21,945	$ 61,490	$ 91,507	$ 1,491,313	$ 1,101,496	$ 107,076	$ 14,029	$ 57,744	$ 93,324	$ 1,372,701

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 2
Appendix D
Schedule 8

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

Line No.	Particulars ($000s)	2011 Actual System Sales (a)	2011 Actual ABC-T (b)	2011 Actual ABC Unbundled (c)	2011 Actual Bundled-T (d)	2011 Actual T-Service (e)	2011 Actual Total (f)	2012 Actual System Sales (g)	2012 Actual ABC-T (h)	2012 Actual ABC Unbundled (i)	2012 Actual Bundled-T (j)	2012 Actual T-Service (k)	2012 Actual Total (l)
	General Service												
1	Rate M1 Firm	736,330	53,542	19,650	847	-	810,370	663,484	41,900	12,342	766	-	718,492
2	Rate M2 Firm	114,577	16,488	2,218	11,338	-	144,621	97,835	13,718	1,410	10,403	-	123,366
3	Rate 01 Firm	265,773	50,868	-	1,240	-	317,881	261,058	38,309	-	1,215	-	300,582
4	Rate 10 Firm	43,977	12,069	-	12,052	70	68,168	40,551	10,649	-	11,628	88	62,916
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-	-	-	-
6	Total General Service	1,160,658	132,967	21,868	25,477	70	1,341,039	1,062,928	104,576	13,752	24,012	88	1,205,356
	Wholesale - Utility												
7	Rate M9 Firm	-	-	-	833	-	833	-	-	-	796	-	796
8	Rate M10 Firm	8	4	-	-	-	12	18	2	-	-	-	20
9	Rate 77 Firm	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utility	8	4	-	833	-	846	18	2	-	796	-	816
	Contract												
11	Rate M4	3,963	119	-	11,363	-	15,446	3,898	330	-	10,107	-	14,335
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	5,890	-	5,890	-	-	-	3,909	-	3,909
14	Rate 20 Storage	-	-	-	-	1,701	1,701	-	-	-	-	1,784	1,784
15	Rate 20 Transportation	3,282	-	-	9,151	7,617	20,050	1,488	-	-	9,076	6,848	17,412
16	Rate 100 Storage	-	-	-	-	186	186	-	-	-	-	174	174
17	Rate 100 Transportation	-	-	-	-	12,823	12,823	-	-	-	-	11,866	11,866
18	Rate T-1 Storage	-	-	-	-	9,555	9,555	-	-	-	-	8,622	8,622
19	Rate T-1 Transportation	-	-	-	-	52,202	52,202	-	-	-	-	55,411	55,411
20	Rate T-3 Storage	-	-	-	-	1,310	1,310	-	-	-	-	1,200	1,200
21	Rate T-3 Transportation	-	-	-	-	3,397	3,397	-	-	-	-	3,243	3,243
22	Rate M5	3,422	34	-	8,556	-	12,012	3,463	33	-	9,267	-	12,763
23	Rate 25	8,711	-	-	-	2,583	11,294	8,509	-	-	-	3,997	12,506
24	Rate 30	-	-	-	-	63	63	-	-	-	-	89	89
25	Total Contract	19,378	153	-	34,961	91,436	145,928	17,358	363	-	32,359	93,234	143,314
26	LRAM												2,585
27	Average Use						(5,076)						(3,656)
28	Tax Rate Change Impact Adjustment												103
29	Total Revenue	$ 1,180,044	$ 133,124	$ 21,868	$ 61,271	$ 91,506	$ 1,482,738	$ 1,080,304	$ 104,941	$ 13,752	$ 57,167	$ 93,322	$ 1,348,519

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

Line No.	Particulars ($000s)	2007 Board-Approved System Sales (a)	ABC-T (b)	ABC Unbundled (c)	Bundled-T (d)	T-Service (e)	Total (f)	2011 Actual System Sales (g)	ABC-T (h)	ABC Unbundled (i)	Bundled-T (j)	T-Service (k)	Total (l)	2012 Actual System Sales (m)	ABC-T (n)	ABC Unbundled (o)	Bundled-T (p)	T-Service (q)	Total (r)
	General Service																		
1	Rate M1 Firm	-	-	-	-	-	-	298,602	53,542	19,650	847	-	372,641	312,963	41,900	12,342	766	-	367,971
2	Rate M2 Firm	253,336	133,485	12,252	11,336	-	410,409	22,477	16,488	2,218	11,338	-	52,521	22,289	13,718	1,410	10,403	-	47,820
3	Rate 01 Firm	74,884	57,873	-	195	-	132,952	106,469	31,958	-	568	-	138,995	113,960	23,497	-	521	-	137,978
4	Rate 10 Firm	8,156	8,706	-	5,024	-	21,886	8,359	5,003	-	4,147	70	17,579	7,703	3,892	-	3,466	88	15,149
5	Rate 16 Interruptible	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-
6	Total General Service	336,376	200,064	12,252	16,555	-	565,247	435,907	106,991	21,868	16,900	70	581,736	456,915	83,007	13,752	15,156	88	568,918
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	592	-	592	-	-	-	833	-	833	-	-	-	796	-	796
8	Rate M10 Firm	5	-	-	-	-	5	1	4	-	-	-	5	2	2	-	-	-	4
9	Rate 77 Firm	-	-	-	-	28	28	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utilit	5	-	-	592	28	625	1	4	-	833	-	838	2	2	-	796	-	800
	Contract																		
11	Rate M4	739	-	-	13,030	-	13,769	558	119	-	11,363	-	12,040	684	330	-	10,107	-	11,121
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	6,670	-	6,670	-	-	-	5,890	-	5,890	-	-	-	3,909	-	3,909
14	Rate 20 Storage	-	-	-	-	56	56	-	-	-	-	1,701	1,701	-	-	-	-	-	
15	Rate 20 Transportation	522	-	-	1,940	4,982	7,444	291	-	-	1,548	7,617	9,456	142	-	-	1,362	6,848	8,352
16	Rate 100 Storage	-	-	-	-	1,767	1,767	-	-	-	-	186	186	-	-	-	-	-	
17	Rate 100 Transportation	-	-	-	-	16,153	16,153	-	-	-	-	12,823	12,823	-	-	-	-	11,866	11,866
18	Rate T-1 Storage	-	-	-	-	8,206	8,206	-	-	-	-	9,406	9,406	-	-	-	-	8,622	8,622
19	Rate T-1 Transportation	-	-	-	-	46,827	46,827	-	-	-	-	52,202	52,202	-	-	-	-	55,398	55,398
20	Rate T-3 Storage	-	-	-	-	1,578	1,578	-	-	-	-	1,310	1,310	-	-	-	-	1,200	1,200
21	Rate T-3 Transportation	-	-	-	-	4,010	4,010	-	-	-	-	3,397	3,397	-	-	-	-	3,243	3,243
22	Rate M5	-	-	-	8,038	-	8,038	308	34	-	8,556	-	8,898	416	33	-	9,267	-	9,716
23	Rate 25	908	-	-	-	1,497	2,405	811	-	-	-	2,466	3,277	864	-	-	-	3,997	4,861
24	Rate 30	-	-	-	-	-	-	-	-	-	-	63	63	-	-	-	-	-	
25	Total Contract	2,169	-	-	29,678	85,076	116,923	1,968	153	-	27,357	91,171	120,649	2,106	363	-	24,645	91,174	118,288
26	LRAM																		2,585
27	Average Use												(5,076)						(3,656)
28	Tax Rate Change Impact Adjustment																		103
29	Total Revenue	$ 338,550	$ 200,064	$ 12,252	$ 46,825	$ 85,104	$ 682,795	$ 437,876	$ 107,148	$ 21,868	$ 45,090	$ 91,241	$ 698,147	$ 459,023	$ 83,372	$ 13,752	$ 40,597	$ 91,262	$ 687,038

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

Line No.	Particulars	2007 Board-Approved						2011 Actual						2012 Actual					
		System Sales	ABC-T	ABC-Unbundlec	Bundled T	T-Service	Total	System Sales	ABC-T	ABC-Unbundlec	Bundled T	T-Service	Total	System Sales	ABC-T	ABC-Unbundlec	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	-	-	-	-	-	-	861,125	130,667	44,484	870	-	1,037,146	909,139	107,370	33,166	984	-	1,050,659
2	Rate M2 Firm	663,740	297,276	34,458	1,690	-	997,164	3,346	2,339	174	778	-	6,637	3,637	2,140	112	800	-	6,689
3	Rate 01 Firm	172,580	125,484	-	166	-	298,230	252,289	60,991	-	353	-	313,633	269,708	48,952	-	367	-	319,027
4	Rate 10 Firm	1,329	1,344	-	300	-	2,973	1,220	661	-	275	4	2,160	1,221	600	-	268	5	2,094
5	Rate 16 Interruptible	-	-	-		-	-					-	-	-	-	-	-	-	-
6	Total General Service	837,649	424,104	34,458	2,156	-	1,298,367	1,117,980	194,658	44,658	2,276	4	1,359,576	1,183,705	159,062	33,278	2,419	5	1,378,469
	Wholesale - Utility																		
7	Rate M9 Firm	-	-	-	2	-	2	-	-	-	2	-	2	-	-	-	2	-	2
8	Rate M10 Firm	4	-	-	-	-	4	1	1	-	-	-	2	3	-	-	-	-	3
9	Rate 77 Firm	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-
10	Total Wholesale - Utility	4	-	-	2	1	7	1	1	-	2	-	4	3		-	2	-	5
	Contract																		
11	Rate M4	13	-	-	181	-	194	11	2	-	119	-	132	16	5	-	122	-	143
12	Rate M6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rate M7	-	-	-	8	-	8	-	-	-	5	-	5	-	-	-	4	-	4
14	Rate 20 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Rate 20 Transportation	10	-	-	20	35	65	2	-	-	18	29	49	2	-	-	18	28	48
16	Rate 100 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Rate 100 Transportation	-	-	-	-	19	19	-	-	-	-	14	14	-	-	-	-	15	15
18	Rate T-1 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Rate T-1 Transportation	-	-	-	-	68	68	-	-	-	-	56	56	-	-	-	-	59	59
20	Rate T-3 Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Rate T-3 Transportation	-	-	-	-	1	1	-	-	-	-	1	1	-	-	-	-	1	1
22	Rate M5	-	-	-	133	-	133	4	1	-	119	-	124	9	1	-	113	-	123
23	Rate 25	56	-	-	-	67	123	44	-	-	-	50	94	35	-	-	-	51	86
24	Rate 30	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	
25	Total Contract	79	-	-	342	190	611	61	3	-	261	151	476	62	6	-	257	154	479
26	Total Customers	837,732	424,104	34,458	2,500	191	1,298,985	1,118,042	194,662	44,658	2,539	155	1,360,056	1,183,770	159,068	33,278	2,678	159	1,378,953

* Customer count for storage is included in the transportation customer count.

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	M12 Transportation	120,667	138,273	133,688
2	M12-X Transportation	-	1,477	5,923
3	C1 Long Term Transportation	2,900	7,570	7,042
4	C1 Short Term Transportation	2,500	12,533	10,115
5	Exchanges	1,242	9,695	14,373
6	C1 Rebate Program	(2,178)	-	-
7	M13 - Local Production	864	323	308
8	M16	553	642	558
9	Other S&T Revenue	810	1,092	972
10	Tax Rate Change Impact Adjustment	-	-	29
11	Total S&T Revenue	$ 127,358	$ 171,605	$ 173,008

UNION GAS LIMITED
Other Revenue
Year Ended December 31

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	Delayed payment charges	7,231	6,770	5,889
2	Account opening charges	5,858	6,586	6,156
3	Billing revenue	9,041	6,013	4,652
4	Mid market transactions	2,000	1,298	1,411
5	Other operating revenue	304	2,413	1,782
6	Total other revenue	$ 24,434	$ 23,080	$ 19,890

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	Salaries/Wages	159,896	191,837	183,418
2	Benefits	55,621	81,179	83,891
3	Materials	9,132	10,701	8,164
4	Employee Training	12,798	13,514	12,043
5	Contract Services	50,061	63,608	65,002
6	Consulting	6,447	7,713	7,787
7	General	20,645	22,262	22,627
8	Transportation and Maintenance	7,523	9,012	8,634
9	Company Used Gas	4,911	2,401	2,043
10	Utility Costs	3,269	4,069	4,064
11	Communications	7,969	6,394	5,761
12	Demand Side Management Programs	11,874	17,925	24,039
13	Advertising	2,255	2,376	2,311
14	Insurance	7,004	8,101	8,141
15	Donations	404	632	725
16	Financial	2,884	1,682	1,438
17	Lease	3,202	4,092	4,496
18	Cost Recovery from Third Parties	(2,106)	(5,869)	(7,981)
19	Computers	4,226	5,287	5,251
20	Regulatory Hearing & OEB Cost Assessment	6,000	3,306	4,486
21	Outbound Affiliate Services	(5,741)	(11,697)	(13,812)
22	Inbound Affiliate Services	11,933	8,956	9,995
23	Bad Debt	11,600	4,455	4,957
24	Other	100	206	-
25	Total	391,907	452,142	447,482
26	Indirect Capitalization (OH)	(51,528)	(52,220)	(52,351)
27	Direct Captialization (DCC)	(7,350)	(15,149)	(15,016)
28	Total	333,029	384,773	380,115
29	Non Utility Costs (1)	(7,406)	(15,303)	(15,173)
30	Total Net Utility Operating and Maintenance Expens	$ 325,623	$ 369,470	$ 364,942

Notes:
(1) Includes non utility storage, charitable donations and loss on Conservation Demand Management Program.

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
	Determination of Taxable Income			
1	Utility income before interest and income taxes	246,829	297,953	276,855
	Adjustments required to arrive at taxable utility income:			
2	Interest expense	(153,932)	(143,821)	(145,109)
3	Utility permanent differences	1,333	3,941	2,281
4		94,230	158,073	134,027
	Utility timing differences			
5	Capital Cost Allowance	(163,089)	(170,080)	(178,604)
6	Depreciation	173,780	195,477	200,864
7	Depreciation through clearing	1,114	1,674	1,549
8	Other	(38,911)	(43,105)	(47,489)
9	Gas Cost Deferrals and Other (current)	-	(2,581)	9,731
10		(27,106)	(18,615)	(13,949)
11	Taxable income	67,124	139,458	120,078
	Calculation of Utility Income Taxes			
12	Income taxes (line 11 * line 18)	24,245	39,397	31,821
13	Deferred tax on Gas Cost Deferrals	-	1,589	(2,579)
14	Deferred tax drawdown	(15,500)	(15,789)	(14,835)
15	Total taxes	8,745	25,197	14,407
	Tax Rates			
16	Federal tax	22.12%	16.50%	15.00%
17	Provincial tax	14.00%	11.75%	11.50%
18	Total tax rate	36.12%	28.25%	26.50%

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 2
Appendix D
Schedule 15

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

Line No.	Class	Particulars ($000s)	2007 Board-Approved Depreciable UCC Balance (a)	2007 Board-Approved Rate (%) (b)	2007 Board-Approved CCA (c)	2011 Actual Depreciable UCC Balance (d)	2011 Actual Rate (%) (e)	2011 Actual CCA (f)	2012 Actual Depreciable UCC Balance (g)	2012 Actual Rate (%) (h)	2012 Actual CCA (i)
1	1	Buildings, structures and improvements, services, meters, mains		4%	-	1,365,023	4%	54,601	1,311,517	4%	52,461
2	1	Non-residential building acquired after March 19, 2007		6%	-	55,279	6%	3,317	63,559	6%	3,814
3	2	Mains acquired before 1988		6%	-	166,925	6%	10,016	156,910	6%	9,415
4	3	Buildings acquired before 1988		5%	-	4,741	5%	237	4,504	5%	225
5	6	Other buildings		10%	-	213	10%	21	192	10%	19
6	7	Compression equipment acquired after February 22, 2005		15%	-	141,567	15%	21,235	178,062	15%	26,709
7	8	Compression assets, office furniture, equipment		20%	-	93,524	20%	18,705	70,170	20%	14,034
8	10	Transportation, computer equipment		30%	-	21,193	30%	6,358	21,272	30%	6,381
9	12	Computer software, small tools		100%	-	7,934	100%	7,934	10,921	100%	10,921
10	13	Leasehold improvements (1)		N/A	-	656	N/A	(1) 121	2,488	N/A	(1) 205
11	17	Roads, sidewalk, parking lot or storage areas		8%	-	1,118	8%	89	1,028	8%	82
12	38	Heavy work equipment		30%	-	5,688	30%	1,706	5,438	30%	1,631
13	41	Storage assets		25%	-	9,352	25%	2,338	7,290	25%	1,823
14	45	Computers - Hardware acquired after March 22, 2004		45%	-	815	45%	367	448	45%	202
15	49	Transmission pipeline additions acquired after February 23, 2005		8%	-	196,657	8%	15,733	191,033	8%	15,283
16	50	Computers hardware acquired after March 18, 2007		55%	-	6,889	55%	3,789	13,676	55%	7,522
17	51	Distribution pipelines acquired after March 18, 2007		6%	-	374,598	6%	22,476	464,620	6%	27,877
18	52	Computers hardware acquired after January 27, 2009 and before February 2011			-	1,038	100%	1,038	0	100%	0
19		Total	$ 0		$ 0	$ 2,453,210		$ 170,080	$ 2,503,128		$ 178,604

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)	2007 Board-Approved	2011 Actual	2012 Actual
1	Total provision for depreciation and amortization before adjustments (per page 3)	-	197,151	202,413
2	Adjustments: vehicle depreciation through clearing	-	1,674	1,549
3	Provision for depreciation amortization and depletion	$ -	$ 195,477	$ 200,864

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

Line No.	Particulars ($000s)	2007 Board-Approved Average Plant (1) (a)	2007 Board-Approved Rate (%) (b)	2007 Board-Approved Provision (c)	2011 Actual Average Plant (1) (d)	2011 Actual Rate (%) (e)	2011 Actual Provision (f)	2012 Actual Average Plant (1) (g)	2012 Actual Rate (%) (h)	2012 Actual Provision (i)
	Intangible plant:									
1	Franchises and consents			$	1,321	Amortized	63	$ 1,321	Amortized	63
2	Intangible plant - Other				6,370	Amortized	122	6,370	Amortized	122
3		-		-	7,692		185	7,692		185
	Local Storage Plant									
4	Structures and improvements		3.30%	-	2,813	3.30%	93	3,264	3.30%	108
5	Gas holders - storage		2.68%	-	4,574	2.68%	-	4,574	2.68%	0
6	Gas holders - equipment		3.68%	-	9,817	3.68%	361	9,990	3.68%	368
7		-		-	17,204		454	17,828		475
	Storage:									
8	Land rights		2.23%	-	32,023	2.23%	714	31,984	2.23%	713
9	Structures and improvements		2.34%	-	56,111	2.34%	1,313	58,474	2.34%	1,369
10	Wells and lines		2.66%	-	87,951	2.66%	2,339	88,695	2.66%	2,361
11	Compressor equipment		3.19%	-	218,016	3.19%	6,955	228,588	3.19%	7,299
12	Measuring & regulating equipment		4.30%	-	60,484	4.30%	2,601	62,892	4.30%	2,707
13	Other equipment				1,758		372	2,134		487
14		-		-	456,343		14,295	472,767		14,937
	Transmission:									
15	Land rights		2.00%	-	37,791	2.00%	756	37,874	2.00%	757
16	Structures and improvements		2.66%	-	53,903	2.66%	1,434	53,340	2.66%	1,419
17	Mains		2.37%	-	1,046,190	2.37%	24,795	1,055,538	2.37%	25,016
18	Compressor equipment		3.52%	-	306,731	3.52%	10,797	327,680	3.52%	11,534
19	Measuring & regulating equipment		3.61%	-	162,971	3.61%	5,883	166,832	3.61%	6,023
20		-		-	1,607,587		43,665	1,641,264		44,750
	Distribution - Southern Operations:									
21	Land rights		1.67%	-	5,552	1.67%	93	5,755	1.67%	96
22	Structures and improvements		2.91%	-	103,801	2.91%	3,041	109,063	2.91%	3,196
23	Services - metallic		3.69%	-	109,721	3.69%	4,049	110,308	3.69%	4,070
24	Services - plastic		3.18%	-	748,811	3.18%	23,812	763,268	3.18%	24,272
25	Regulators		3.30%	-	72,011	3.30%	2,376	75,906	3.30%	2,505
26	Regulator and meter installations		3.51%	-	67,740	3.51%	2,378	68,384	3.51%	2,400
27	Mains - metallic		2.54%	-	403,980	2.54%	10,261	411,205	2.54%	10,445
28	Mains - plastic		2.34%	-	508,277	2.34%	11,894	519,963	2.34%	12,167
29	Measuring & regulating equipment		4.64%	-	29,730	4.64%	1,379	30,929	4.64%	1,435
30	Meters		3.70%	-	199,423	3.70%	7,379	214,263	3.70%	7,928
31	Other equipment			-	-		-	-		-
32		$ -		$ -	$ 2,249,046		$ 66,661	$ 2,309,045		$ 68,514

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

Line No.	Particulars ($000s)	2007 Board-Approved Average Plant (1) (a)	2007 Board-Approved Rate (%) (b)	2007 Board-Approved Provision (c)	2011 Actual Average Plant (1) (d)	2011 Actual Rate (%) (e)	2011 Actual Provision (f)	2012 Actual Average Plant (1) (g)	2012 Actual Rate (%) (h)	2012 Actual Provision (i)
	Distribution plant - Northern & Eastern Operations:									
1	Land rights		1.68%	-	9,075	1.68%	152	9,194	1.68%	154
2	Structures & improvements		3.13%	-	62,322	3.13%	1,967	62,478	3.13%	1,950
3	Services - metallic		3.58%	-	93,240	3.58%	3,338	94,382	3.58%	3,379
4	Services - plastic		3.19%	-	359,075	3.19%	11,454	370,135	3.19%	11,807
5	Regulators		3.34%	-	28,012	3.34%	936	29,581	3.34%	988
6	Regulator and meter installations		3.50%	-	29,308	3.50%	1,026	29,767	3.50%	1,042
7	Mains - metallic		2.52%	-	353,866	2.52%	8,917	362,288	2.52%	9,130
8	Mains - plastic		2.35%	-	202,160	2.35%	4,751	206,342	2.35%	4,849
9	Compressor equipment		3.34%	-	-	3.34%	-	-	3.34%	0
10	Measuring & regulating equipment		4.63%	-	106,119	4.63%	4,913	111,386	4.63%	5,157
11	Meters		3.67%	-	52,711	3.67%	1,934	54,131	3.67%	1,987
12	Other distribution equipment			-	-		-	-		-
13		-		-	1,295,887		39,389	1,329,685		40,443
	General:									
14	Structures and improvements		2.13%		41,635	2.13%	942	44,790	2.13%	1,075
15	Office furniture and equipment		6.67%	-	10,470	6.67%	698	10,674	6.67%	704
16	Office equipment - computers		25.00%	-	78,684	25.00%	19,671	73,775	25.00%	18,260
17	Transportation equipment		10.07%	-	46,067	10.07%	4,639	47,732	10.07%	4,824
18	Heavy work equipment		4.55%	-	15,156	4.55%	707	14,638	4.55%	691
19	Tools and other equipment		6.67%	-	30,285	6.67%	2,019	29,843	6.67%	1,967
20	Communications equipment & structures		6.67%	-	15,870	6.67%	1,010	15,234	6.67%	974
21	Other equipment			-	-		-	-		-
22		-		-	238,167		29,686	236,686		28,496
23	Regulatory Assets				80,346		2,817	133,683		4,614
24	Sub-total	-		-	5,952,271		197,151	6,148,649		202,413
24	Total provision for depreciation and amortization			-			$ 197,151			$ 202,413
25	Depreciation through clearing						1,674			1,549
26		$ -		$ -	$ 5,952,271		$ 195,477	$ 6,148,649		$ 200,864

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, 2012

Line No.	Particulars ($000's)	Board Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
1	Storage	10,024	23,805	11,623
2	Transmission	139,121	48,291	23,309
3	Distribution	89,565	112,326	138,270
4	General	49,943	37,732	31,262
5	Other	59,312	52,387	52,119
6	Total	$ 347,965	$ 274,542	$ 256,583
7	Rate Base Reduction via ADR	(35,000)		
8		$ 312,965		

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

Line No.	Particulars ($000s)	Board-Approved 2007	Actual 2011	Actual 2012
		(a)	(b)	(c)
	Gas Utility Plant			
1	Gross plant at cost	5,170,809	5,998,663	6,221,188
2	Less: accumulated depreciation	2,014,712	2,505,353	2,636,558
3	Net utility plant	3,156,097	3,493,310	3,584,630
	Working Capital and Other Components			
4	Cash working capital	32,672	31,678	30,530
5	Gas in storage and line pack gas	188,792	150,999	177,372
6	Balancing gas	129,618	79,764	77,334
7	ABC receivable (gas in storage)	(53,791)	(55,323)	(22,519)
8	Inventory of stores, spare equipment	28,469	28,464	27,080
9	Prepaid and deferred expenses	2,741	5,080	5,119
10	Customer deposits	(43,902)	(50,281)	(44,668)
11	Customer interest	(300)	(736)	(680)
12	Total working capital and other components	284,299	189,645	249,568
13	Total rate base before deduction of accumulated deferred income taxes	3,440,396	3,682,955	3,834,198
14	Accumulated deferred income taxes	169,502	99,698	85,093
15	Total rate base	$ 3,270,894	$ 3,583,258	$ 3,749,105

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ended December 31

Line No.	Particulars ($000s)	2012 (a)	Non-Utility Storage (b)	Adjustments (c)		2012 Utility (d)=(a)-(b)+(c)
	Operating Revenues:					
1	Gas Sales and distribution	$ 1,349,488	$ -	$ (969)	i	1,348,519
2	Storage & Transportation	268,590	111,224	15,642	ii	173,008
3	Other	28,677	-	(8,787)	iii	19,890
4		1,646,755	111,224	5,886		1,541,417
	Operating Expenses:					
5	Cost of gas	637,755	182	(1,654)	iv	635,919
6	Operating and maintenance expenses	380,114	14,451	(721)	v	364,942
7	Depreciation	211,794	10,357	(574)	vi	200,864
8	Other financing	-	-	243	vii	243
9	Property taxes	62,819	1,412	-		61,407
10		1,292,482	26,402	(2,706)		1,263,375
	Other					
11	Gain / (Loss) on sale of assets	(500)	(509)	-		9
12	Other / HTLP	(986)	(986)	-		-
13	Gain / (Loss) on foreign exchange	(1,243)	(47)	-		(1,196)
14		(2,729)	(1,542)	-		(1,187)
15	Earning Before Interest and Taxes	$ 351,544	$ 83,280	$ 8,592		$ 276,855
	Financial Expenses:					
16	Long-term debt					142,999
17	Unfunded short-term debt					2,110
18						145,109
19	Utility income before income taxes					131,746
20	Income taxes					14,407
21	Preferred dividend requirements					3,112
22	Utility earnings					114,227
23	Long term storage premium subsidy (after tax)					-
24	Short term storage premium subsidy (after tax)					8,272
25						8,272
26	Earnings subject to sharing					$ 122,499
27	Common equity					1,349,678
28	Return on equity (line 26 / line 27)					9.08%
29	Benchmark return on equity					9.67%
30	50% Earnings sharing % (line 28 - line 29, maximum 1%)					0.00%
31	90% Earnings sharing to ratepayer % (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 to ratepayer $ (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)	Impact of removing St. Clair Transmission Line from rates	(1,072)
	Tax rate change	103
		(969)
ii)	Impact of removing St. Clair Transmission Line from rates	(101)
	Reversal of 2011 Upstream Transportation FT-RAM Optimization Deferral	19,800
	Removal of 10% of 2012 Upstream Transportation FT-RAM Optimization revenue	(3,718)
	Tax rate change	29
	Reversal of avoided costs	(676)
	Reversal of avoided costs - Adjustment to deferral	308
		15,642
iii)	Demand Side Management Incentive	
iv)	Impact of removing St. Clair Transmission Line from rates	(342)
	Fuel costs related to FT-RAM optimization	(636)
	Reversal of avoided costs	(676)
		(1,654)
v)	Charitable Donations	(689)
	CDM program	(32)
		(721)
vi)	Impact of removing St. Clair Transmission Line from rates	(540)
	Customer Service Standards - Low Income	(34)
		(574)
vii)	Interest on Customer Deposits	

TAB 3

ALLOCATION AND DISPOSITION OF 2012 DEFERRAL ACCOUNT BALANCES, 2012 FEDERAL AND PROVINCIAL TAX CHANGES AND 2012 EARNINGS SHARING AMOUNTS

The purpose of this evidence is to address the allocation and disposition of 2012 deferral account balances identified at Tab 1, Appendix A, Schedule 1, the 2012 Federal and Provincial Tax Changes identified at Tab 1, Appendix A, Schedule 1 and 2012 earnings sharing amounts identified at Tab 2, Appendix B, Schedule 1.

The allocation of 2012 deferral account balances to rate classes appears at Tab 3, Appendix A, Schedule 1, page 1. The allocation of 2012 earnings sharing amounts to rate classes appears at Tab 3, Appendix A, Schedule 1, page 2. 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 impact of the proposed disposition for general service customers in Union South and Union North.

With the exception of the Gas Distribution Access Rule ("GDAR") Costs Deferral Account (179-112) and the Pension Charge on Transition to US GAAP Account (179-127), the allocation of 2012 deferral account balances and 2012 earnings sharing to rate classes is consistent with the allocation methodologies approved by the Board in EB-2012-0087 (Union's 2011 Deferral Account Disposition proceeding).

UNABSORBED DEMAND COST VARIANCE

Union proposes that the portion of the balance in the Unabsorbed Demand Cost (“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 direct purchase customers in proportion to 2007 excess peak over annual average. This allocation is consistent with the allocation of UDC in approved 2007 rates (EB-2005-0520, Rate Order Working Papers, Schedule 25, page 3).

The UDC associated with Union South is applicable to sales service customers only. Accordingly, Union proposes that the portion of the balance in the Unabsorbed Demand Cost (“UDC”) Variance Account (179-108) related to Union South be allocated to sales service customers only.

UPSTREAM TRANSPORTATION FT-RAM OPTIMIZATION

There is no balance in the Upstream Transportation FT-RAM Optimization Deferral Account (179-130) at December 31, 2012.

2012 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

With the closing of the Long-Term Peak Storage Services Account (179-72) effective January 1, 2012 (per the Board's Decision in EB-2012-0025), the remaining storage-related deferral account is the Short Term Storage and Other Balancing Services Deferral Account (179-70).

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

Union proposes to allocate the Short-Term Storage and Other Balancing Services Deferral Account balance related to in-franchise customers in Union South among rate classes in proportion to EB-2005-0520 design (peak) day demand. Union proposes to allocate the balance to in-franchise customers in Union North (by virtue of their use of storage in Union South) among rate classes in proportion to the allocation of 2007 storage demand costs as approved in EB-2005-0520.

OTHER DEFERRAL ACCOUNTS

Union proposes to allocate the balance in the Lost Revenue Adjustment Mechanism Deferral Account (179-75) to rate classes in proportion to the margin reduction attributable to demand side management activities appearing at Tab 1, Appendix A, Schedule 4, page 1 of 3.

There is no balance in the Unbundled Services Unauthorized Storage Overrun Deferral Account (179-103) at December 31, 2012.

Union proposes to allocate the balance in the Demand Side Management ("DSM") Variance Account (179-111) to rate classes in proportion to the actual DSM spending by rate class in 2012. This allocation methodology is consistent with the methodology approved by the Board in past deferral dispositions.

Union proposes to allocate the balance in the Gas Distribution Access Rule ("GDAR") Costs Deferral Account (179-112) in proportion to the Board-approved average number of customers in Rate 01 and Rate M1 in approved 2007 rates.

There is no balance in the Late Payment Penalty Litigation Deferral Account (179-113). This account was closed effective January 1, 2013 per the Board's Decision in EB-2011-0210.

The overall balance in the Shared Savings Mechanism ("SSM") Deferral Account (179-115) is zero. Based on audited 2011 DSM results there are small variances between rate classes as indicated in Tab 1, Appendix A, Schedule 7. The SSM Deferral Account has been replaced by the Demand Side Management Incentive Deferral Account ("DSMIDA") effective January 1, 2012. The allocation of the balance in the DSMIDA is described below.

There is no balance in the Carbon Dioxide Offset Credits Deferral Account (179-117) at December 31, 2012.

Union proposes to allocate the balance in the Average Use Per Customer Account (179-118) to General Service rate classes in proportion to the margin variances by rate class resulting from the difference between the actual rate of decline in use-per-customer and the forecast rate of decline included in approved rates by rate class.

Union proposes to allocate the balance in the IFRS Conversion Costs Account (179-120) to rate classes in proportion to 2007 Board-approved EB-2005-0520 Administrative & General O&M Expense (per Exhibit G3, Tab 2, Schedule 2, updated for the EB-2005-0520 Board Decision).

There is no balance in the Conservation Demand Management ("CDM") Deferral Account (179-123) at December 31, 2012.

Union proposes to allocate the balances in the Harmonized Sales Tax Deferral Account (179-124) by component using 2007 Board-Approved allocators as follows:

i) Capital savings using rate base (EB-2005-0520, Exhibit G3, Tab 2, Schedule 2, Rate Base, Updated for EB-2005-0520 Board Decision);
ii) Operations & Maintenance savings using O&M expenses excluding cost of gas (EB-2005-0520, Exhibit G3, Tab 2, Schedule 2, Rate Base, Updated for EB-2005-0520 Board Decision);
iii) Compressor fuel costs using the allocation of Compressor Fuel less Customer Supplied Fuel (EB-2005-0520, Decision Cost Study, Operating Expenses, C. Underground Storage &

D. Transmission, Compressor Fuel, pages 13-16).

Union proposes to allocate the balance in the Demand Side Management Incentive Deferral Account (179-126) to rate classes in proportion to the actual DSM spending by rate class in 2012. This allocation methodology is consistent with the methodology approved by the Board in the EB-2011-0327 (2012-2014 DSM Plan) Settlement Agreement.

Union proposes to allocate the balance in the Pension Charge on Transition to US GAAP Account (179-127) to rate classes in proportion to the 2007 Board-approved allocation of Employee Benefits expense in Administrative & General O&M Expense.

2012 FEDERAL AND PROVINCIAL TAX CHANGES

The balance in the 2012 Federal and Provincial Tax Changes Account represents the difference between the tax savings included in 2012 rates based on forecast 2012 tax rates, and the tax savings based on actual 2012 tax rates. Union proposes to allocate the amount related to the 2012 Federal and Provincial Tax Changes Account to rate classes in proportion to the 2007 Board-approved allocation of rate base (EB-2005-0520, Exhibit G3, Tab 2, Schedule 2, Rate Base, Updated for EB-2005-0520 Board Decision). This approach is consistent with how tax changes are allocated in approved rates.

2012 Earnings Sharing

Union is proposing to allocate the 2012 earnings sharing of $15.730 million to all rate classes based on the allocation of the 2007 Board-approved return on equity. The allocation of 2007 Board-approved return on equity underpins 2012 approved rates. The allocation of 2012 earnings sharing appears at Tab 3, Appendix A, Schedule 1, page 2. Union's proposal to use the allocation of return on equity approved for 2007 to allocate earnings sharing related to 2012 is consistent with how Union allocated the 2011 earnings sharing.

Disposition of 2012 Deferral Account Balances, 2012 Federal and Provincial Tax Changes and 2012 Earnings Sharing Amounts

For General Service M1, M2, Rate 01 and Rate 10 customers Union proposes to dispose of net 2012 deferral account balances, 2012 Federal and Provincial tax changes and 2012 earnings sharing amounts prospectively, over the October 1, 2013 to March 31, 2014 time period. The prospective refund / recovery approach over six months proposed for M1, M2, Rate 01 and Rate 10 customers is consistent with how Union disposed of 2011 deferral account and earnings sharing balances in EB-2012-0087.

For in-franchise contract and ex-franchise rate classes, Union is proposing to dispose of net 2012 delivery-related deferral account balances, 2012 Federal and Provincial tax changes and 2012 earnings sharing amounts as a one-time adjustment with October 2013 bills customers receive in

November 2013. This approach is consistent with the methodology used for the disposition of 2011 deferral account and earnings sharing balances in EB-2012-0087.

GENERAL SERVICE BILL IMPACTS

General Service customer impacts are presented at Tab 3, Appendix A, Schedule 3. For a sales service residential customer in Union South with annual consumption of 2,200 m^3, the charge for the period October 1, 2013 to March 31, 2014 is $3.39. This $3.39 charge consists of a delivery-related charge of $1.81 (line 13, column (c)) and a commodity-related charge of $1.58 (line 14, column (c)). For a bundled direct purchase residential customer the charge is $1.81.

For a sales service residential customer in Union North with annual consumption of 2,200 m^3, the credit for the period October 1, 2013 to March 31, 2014 is $12.44. This $12.44 credit consists of a delivery-related credit of $5.89 (line 1, column (c)) and a gas transportation-related credit of $6.55 (line 3, column (c)). For a bundled direct purchase residential customer the credit is $12.44.

TREATMENT OF FT-RAM RELATED TRANSPORTATION EXCHANGE REVENUE AS A GAS COST REDUCTION

As described in Tab 1, in EB-2012-0087 (Union's 2011 Deferral Account Disposition proceeding) the Board determined that 2011 transportation exchange revenue related to FT-RAM optimization should be recorded in the Upstream Transportation FT-RAM Optimization deferral account and treated as a gas cost reduction. In 2012, Union proposes to include FT-RAM revenues in utility earnings, rather than as a gas cost reduction. Union's proposal is described in Exhibit B of this evidence.

Notwithstanding Union's proposal to include FT-RAM revenues in utility earnings, Union has provided the rate impacts associated with the treatment of FT-RAM revenue as a gas cost reduction in Tab 3, Appendix B. For 2012, the treatment of FT-RAM revenue as a gas cost reduction would result in a credit balance of $32.977 million in the Upstream Transportation FT-RAM Optimization deferral account and no earnings sharing with ratepayers.

FT-RAM net revenues are allocated between Union North and Union South based on the upstream transportation contracts used to serve each delivery area. FT-RAM net revenues generated using upstream transportation long-haul contracts and STS contracts designed to serve Union North (with delivery points of SSMDA, WDA, NDA, NCDA and EDA) have been allocated to Union North. FT-RAM net revenues generated using upstream transportation long-haul contract designed to serve Union South (the CDA delivery point) have been allocated to Union South. Specifically, with respect to capacity assignments, the revenue from each capacity assignment was attributed to either Union North or Union South based on the delivery point. With respect to FT-RAM optimization, the total revenue earned from all optimization was allocated based on the quantity of transportation capacity optimized, either Union North or Union South.

The portion of the balance in the Upstream Transportation FT-RAM Optimization deferral account related to Union North has been allocated to rate classes in proportion to the allocation of 2007 Board-approved TCPL FT transportation demand costs. The portion of the balance in the Upstream Transportation FT-RAM Optimization deferral account related to Union South is applicable to sales service customers only. Accordingly, Union has allocated the Union South portion of the balance to sales service customers based on sales service volumes.

The allocation of the balance in the Upstream Transportation FT-RAM Optimization deferral account between Union North and Union South and amongst rate classes is consistent with the methodology approved by the Board in EB-2012-0087.

The allocation of 2012 deferral account balances to rate classes appears at Tab 3, Appendix B, Schedule 1, page 1. The allocation of the balance in the Upstream Transportation FT-RAM Optimization deferral account appears at Tab 3, Appendix B, Schedule 1, page 2. Tab 3, Appendix B, 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 B, Schedule 3 provides the impact of the disposition for general service customers in Union South and Union North.

General Service bill impacts are presented at Tab 3, Appendix B, Schedule 3. For a sales service residential customer in Union South with annual consumption of 2,200 m^3, the credit for the period October 1, 2013 to March 31, 2014 is $4.17. This $4.17 credit consists of a delivery-related charge of $6.55 (line 13, column (c)) and a commodity-related credit of $10.72 (line 14, column (c)). For a bundled direct purchase residential customer the charge is $6.55.

For a sales service residential customer in Union North with annual consumption of 2,200 m^3, the credit for the period October 1, 2013 to March 31, 2014 is $28.85. This $28.85 credit consists of a delivery-related charge of $0.66 (line 1, column (c)) and a gas transportation-related credit of $29.51 (line 3, column (c)). For a bundled direct purchase residential customer the credit is $28.85.

APPENDIX A

UNION GAS LIMITED
Allocation of 2012 Deferral Account Balances, 2012 Federal and Provincial Tax Changes,
and 2012 Earnings Sharing Amounts to Rate Classes

			Union North						Union South													
Line No.	Particulars	Acct No.	Rate 01 ($000's)	Rate 10 ($000's)	Rate 20 ($000's)	Rate 77 ($000's)	Rate 100 ($000's)	Rate 25 ($000's)	M1 ($000's)	M2 ($000's)	M4 ($000's)	M5A ($000's)	M7 ($000's)	M9 ($000's)	M10 ($000's)	T1 ($000's)	T3 ($000's)	M12 ($000's)	M13 ($000's)	C1 ($000's)	M16 ($000's)	Total (1) ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
	Gas Supply Related Deferrals:																					
1	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(2,702)	(865)	(104)	-	-	-	1,873	389	10	9	-	-	0	-	-	-	-	-	-	(1,388)
2	Upstream Transportation FT-RAM Optimization	179-130	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Gas Supply Related Deferrals		(2,702)	(865)	(104)	-	-	-	1,873	389	10	9	-	-	0	-	-	-	-	-	-	(1,388)
	Storage Related Deferrals:																					
4	Short-Term Storage and Other Balancing Services	179-70	245	78	9	-	13	-	669	219	75	5	53	5	0	442	64	-	-	-	-	1,879
	Delivery Related Deferrals:																					
5	Lost Revenue Adjustment Mechanism	179-75	355	272	27	-	39	-	611	636	104	417	10	-	-	159	-	-	-	-	-	2,629
6	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Demand Side Management Variance Account (2)	179-111	(634)	356	373	-	24	-	(295)	(71)	1,136	(534)	(432)	-	-	445	-	-	-	-	-	368
8	Gas Distribution Access Rule (GDAR) Costs	179-112	45	-	-	-	-	-	149	-	-	-	-	-	-	-	-	-	-	-	-	194
9	Late Payment Penalty Litigation	179-113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Shared Savings Mechanism	179-115	(1)	(0)	0	-	0	-	(3)	(0)	0	1	0	-	-	2	-	-	-	-	-	(0)
11	Carbon Dioxide Offset Credits	179-117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Average Use Per Customer	179-118	(1,575)	(2,244)	-	-	-	-	111	44	-	-	-	-	-	-	-	-	-	-	-	(3,665)
13	IFRS Conversion Costs	179-120	95	10	6	0	9	2	283	27	12	5	5	0	0	29	3	38	0	12	0	538
14	Conservation Demand Management	179-123	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Harmonized Sales Tax	179-124	(182)	(28)	(17)	(0)	(14)	(7)	(503)	(48)	(16)	(7)	(9)	(0)	(0)	(66)	(7)	(220)	(0)	(41)	0	(1,167)
16	Demand Side Management Incentive	179-126	441	303	296	-	506	-	3,509	1,058	616	478	92	-	-	1,300	-	-	-	-	-	8,598
17	Pension Charge on Transition to US GAAP	179-127	1,460	146	93	0	136	34	4,134	404	167	90	77	4	0	417	38	595	0	15	1	7,811
18	Total Delivery-Related Deferrals		4	(1,184)	779	0	701	29	7,995	2,050	2,019	449	(257)	4	0	2,286	33	414	(0)	(15)	1	15,306
19	Total 2012 Storage and Delivery Disposition (Line 4 + Line 18)		249	(1,106)	788	0	714	29	8,664	2,269	2,095	454	(204)	9	1	2,728	97	414	(0)	(15)	1	17,185
20	Total 2012 Deferral Account Disposition (Line 3 + Line 19)		(2,453)	(1,971)	684	0	714	29	10,537	2,658	2,105	463	(204)	9	1	2,728	97	414	(0)	(15)	1	15,797
	Other Items:																					
21	Federal & Provincial Tax Changes		22	4	2	0	3	1	51	8	2	1	1	0	0	6	1	25	0	4	0	132
22	Total 2012 Deferrals plus Other Items (Line 20 + Line 21)		(2,431)	(1,967)	686	0	716	30	10,588	2,666	2,107	465	(203)	9	1	2,735	98	438	(0)	(10)	1	15,929
23	2012 Earnings Sharing (3)		(2,701)	(499)	(258)	(0)	(342)	(116)	(6,313)	(960)	(256)	(157)	(159)	(13)	(1)	(778)	(94)	(3,065)	(2)	(11)	(3)	(15,730)
24	Grand Total (Line 22 + Line 23)		(5,132)	(2,466)	427	-	374	(86)	4,275	1,706	1,851	308	(361)	(4)	(0)	1,956	4	(2,627)	(3)	(22)	(2)	199

Notes:
(1) EB-2013-0109, Exhibit A, Tab 1, Appendix A, Schedule 1.
(2) EB-2013-0109, Exhibit A, Tab 1, Appendix A, Schedule 5, Column (c).
(3) EB-2013-0109, Exhibit A, Tab 3, Appendix A, Schedule 1, page 2.

UNION GAS LIMITED
Allocation of 2012 Earnings Sharing Amounts to Rate Classes

Line No.	Particulars	Rate Class	C2007 Return on Equity Allocation (1) ($000's)	2012 Earnings Sharing ($000's)	
			(a)	(b)	
	Union North				
1	Small Volume General Firm Service	01	44,549	(2,701)	
2	Large Volume General Firm Service	10	8,234	(499)	
3	Medium Volume Firm Service	20	4,263	(258)	
4	Large Volume High Load Factor Firm Service	100	5,641	(342)	
5	Large Volume Interruptible Service	25	1,913	(116)	
6	Wholesale Transportation Service	77	8	(0)	
7	Total Northern & Eastern Operations Area		64,608	(3,917)	
	Union South				
8	Small Volume General Service Rate	M1	104,130	(6,313)	
9	Large Volume General Service Rate	M2	15,828	(960)	
10	Firm Industrial and Commercial Contract Rate	M4	4,220	(256)	
11	Interruptible Industrial & Commercial Contract Rate	M5A	2,587	(157)	
12	Special Large Volume Industrial & Commercial Contract Rate	M7	2,617	(159)	
13	Large Wholesale Service Rate	M9	219	(13)	
14	Small Wholesale Service Rate	M10	10	(1)	
15	S & T Rates for Contract Carriage Customers	T1	12,835	(778)	
16	S & T Rates for Contract Carriage Customers	T3	1,546	(94)	
	Storage and Transportation				
17	Cross Franchise Transportation Rates	C1	186	(11)	
18	Storage & Transportation Rates	M12	50,557	(3,065)	
19	Transportation of Locally Produced Gas	M13	39	(2)	
20	Storage & Transportation Services - Transportation Charges	M16	55	(3)	
21	Total Southern Operations Area		194,830	(11,813)	
22	Total		259,438	(15,730)	(2)

Notes:
(1) Allocated costs per 2007 Decision in EB-2005-0520.
(2) EB-2013-0109, Exhibit A, Tab 2, Appendix B, Schedule 1, column (d), line 35.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing Mechanism ($000's)	Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
1	Small Volume General Service	01	249	22	(2,701)	(2,430)	714,975	(0.3399)
2	Large Volume General Service	10	(1,106)	4	(499)	(1,601)	242,068	(0.6614)
3	Small Volume General Service	M1	8,664	51	(6,313)	2,401	2,232,879	0.1076
4	Large Volume General Service	M2	2,269	8	(960)	1,317	797,745	0.1650

Notes:
(1) Forecast volume for the period October 1, 2013 to March 31, 2014.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing Mechanism ($000's)	Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
1	Small Volume General Service	01	(2,702)	-	-	(2,702)	714,975	(0.3779)
2	Large Volume General Service	10	(865)	-	-	(865)	241,642	(0.3578)

Notes:
(1) Forecast volume for the period October 1, 2013 to March 31, 2014.

UNION GAS LIMITED
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing Mechanism ($000's)	Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
1	Small Volume General Service	M1	1,873	-	-	1,873	1,985,247	0.0944
2	Large Volume General Service	M2	389	-	-	389	412,655	0.0944
3	Firm Com/Ind Contract	M4	10	-	-	10	10,777	0.0944
4	Interruptible Com/Ind Contract	M5	9	-	-	9	10,062	0.0944
5	Small Wholesale	M10	0	-	-	0	37	0.0944

Notes:
(1) Forecast sales service volumes for the period October 1, 2013 to March 31, 2014.

UNION GAS LIMITED
Contract Unit Rates for One-Time Adjustment - Delivery
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing ($000's)	Balance for Disposition ($000's)	2012 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
	Union North							
1	Medium Volume Firm Service (1)	20	111	2	(40)	73	102,497	0.0710
2	Medium Volume Firm Service (2)	20T	657	-	(218)	439	552,219	0.0794
3	Large Volume High Load Factor (2)	100T	712	3	(342)	372	1,912,232	0.0195
4	Wholesale Service	77	0	0	(0)	(0)	-	
5	Large Volume Interruptible	25	29	1	(116)	(86)	207,636	(0.0416)
	Union South							
6	Firm Com/Ind Contract	M4	2,095	2	(256)	1,841	428,641	0.4295
7	Interruptible Com/Ind Contract	M5	454	1	(157)	298	470,246	0.0635
8	Special Large Volume Contract	M7	(204)	1	(159)	(361)	141,165	(0.2559)
9	Large Wholesale	M9	9	0	(13)	(4)	57,878	(0.0068)
10	Small Wholesale	M10	1	0	(1)	(0)	197	(0.0330)
11	Contract Carriage Service	T1	2,728	6	(778)	1,956	5,023,637	0.0389
12	Contract Carriage- Wholesale	T3	97	1	(94)	4	239,361	0.0016

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
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	Billing Units	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing ($000's)	Balance for Disposition ($000's)	2012 Actual Volume/ Demand	Unit Volumetric/ Demand Rate
				(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
	Gas Supply Transportation (cents/m^3)								
1	Medium Volume Firm Service	20	10^3m^3/d	(104)	-	-	(104)	5,295	(1.9698)
2	Large Volume Interruptible	25	10^3m^3	-	-	-	-	44,659	-
	Storage ($/GJ)								
3	Bundled-T Storage Service	20T/100T	GJ/d	22	-	-	22	155,904	0.143

UNION GAS LIMITED
Storage and Transportation Service Amounts for Disposition
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars ($000's) (1)	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing ($000's)	Balance for Disposition ($000's)
			(a)	(b)	(c)	(d) = (a+b+c)
1	Storage and Transportation	M12	414	25	(3,065)	(2,627)
2	Local Production	M13	(0)	0	(2)	(3)
3	Short-Term Cross Franchise	C1	(15)	4	(11)	(22)
4	Storage Transportation Service	M16	1	0	(3)	(2)

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

UNION GAS LIMITED
General Service 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	(0.3399)	1,733	(5.89)
2		Commodity	-	1,733	-
3		Transportation	(0.3779)	1,733	(6.55)
4			(0.7178)		(12.44)
5	Sales Service				(12.44)
6	Direct Purchase Bundled T				(12.44)
7	Rate 10	Delivery	(0.6614)	66,961	(442.88)
8		Commodity	-	66,961	-
9		Transportation	(0.3578)	66,961	(239.58)
10			(1.0192)		(682.46)
11	Sales Service				(682.46)
12	Direct Purchase Bundled T				(682.46)
13	Rate M1	Delivery	0.1076	1,679	1.81
14		Commodity	0.0944	1,679	1.58
15			0.2020		3.39
16	Sales Service				3.39
17	Direct Purchase				1.81
18	Rate M2	Delivery	0.1650	55,772	92.02
19		Commodity	0.0944	55,772	52.65
20			0.2594		144.67
21	Sales Service				144.67
22	Direct Purchase				92.02

Notes:
(1) EB-2013-0109 Exhibit A, Tab 3, Appendix A, Schedule 2, Pages 1-3.
(2) Average consumption, per customer, for the period October 1, 2013 to March 31, 2014.

APPENDIX B

UNION GAS LIMITED
Allocation of 2012 Deferral Account Balances, 2012 Federal and Provincial Tax Changes,
and 2012 Earnings Sharing Amounts to Rate Classes

			Union North						Union South														
Line No.	Particulars	Acct No.	Rate 01 ($000's)	Rate 10 ($000's)	Rate 20 ($000's)	Rate 77 ($000's)	Rate 100 ($000's)	Rate 25 ($000's)	M1 ($000's)	M2 ($000's)	M4 ($000's)	M5A ($000's)	M7 ($000's)	M9 ($000's)	M10 ($000's)	T1 ($000's)	T3 ($000's)	M12 ($000's)	M13 ($000's)	C1 ($000's)	M16 ($000's)	Total (1) ($000's)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
	Gas Supply Related Deferrals:																					
1	Unabsorbed Demand Cost (UDC) Variance Account	179-108	(2,702)	(865)	(104)	-	-	-	1,873	389	10	9	-	-	0	-	-	-	-	-	-	(1,388)
2	Upstream Transportation FT-RAM Optimization (2)	179-130	(9,477)	(3,854)	(1,621)	-	-	(287)	(14,559)	(3,026)	(79)	(74)	-	-	(0)	-	-	-	-	-	-	(32,977)
3	Total Gas Supply Related Deferrals		(12,179)	(4,719)	(1,725)	-	-	(287)	(12,685)	(2,637)	(69)	(64)	-	-	(0)	-	-	-	-	-	-	(34,365)
	Storage Related Deferrals:																					
4	Short-Term Storage and Other Balancing Services	179-70	245	78	9	-	13	-	669	219	75	5	53	5	0	442	64	-	-	-	-	1,879
	Delivery Related Deferrals:																					
5	Lost Revenue Adjustment Mechanism	179-75	355	272	27	-	39	-	611	636	104	417	10	-	-	159	-	-	-	-	-	2,629
6	Unbundled Services Unauthorized Storage Overrun	179-103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Demand Side Management Variance Account (3)	179-111	(634)	356	373	-	24	-	(295)	(71)	1,136	(534)	(432)	-	-	445	-	-	-	-	-	368
8	Gas Distribution Access Rule (GDAR) Costs	179-112	45	-	-	-	-	-	149	-	-	-	-	-	-	-	-	-	-	-	-	194
9	Late Payment Penalty Litigation	179-113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Shared Savings Mechanism	179-115	(1)	(0)	0	-	0	-	(3)	(0)	0	1	0	-	-	2	-	-	-	-	-	(0)
11	Carbon Dioxide Offset Credits	179-117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Average Use Per Customer	179-118	(1,575)	(2,244)	-	-	-	-	111	44	-	-	-	-	-	-	-	-	-	-	-	(3,665)
13	IFRS Conversion Costs	179-120	95	10	6	0	9	2	283	27	12	5	5	0	0	29	3	38	0	12	0	538
14	Conservation Demand Management	179-123	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Harmonized Sales Tax	179-124	(182)	(28)	(17)	(0)	(14)	(7)	(503)	(48)	(16)	(7)	(9)	(0)	(0)	(66)	(7)	(220)	(0)	(41)	0	(1,167)
16	Demand Side Management Incentive	179-126	441	303	296	-	506	-	3,509	1,058	616	478	92	-	-	1,300	-	-	-	-	-	8,598
17	Pension Charge on Transition to US GAAP	179-127	1,460	146	93	0	136	34	4,134	404	167	90	77	4	0	417	38	595	0	15	1	7,811
18	Total Delivery-Related Deferrals		4	(1,184)	779	0	701	29	7,995	2,050	2,019	449	(257)	4	0	2,286	33	414	(0)	(15)	1	15,306
19	Total 2012 Storage and Delivery Disposition (Line 4 + Line 18)		249	(1,106)	788	0	714	29	8,664	2,269	2,095	454	(204)	9	1	2,728	97	414	(0)	(15)	1	17,185
20	Total 2012 Deferral Account Disposition (Line 3 + Line 19)		(11,930)	(5,825)	(937)	0	714	(259)	(4,022)	(368)	2,026	390	(204)	9	0	2,728	97	414	(0)	(15)	1	(17,180)
	Other Items:																					
21	Federal & Provincial Tax Changes		22	4	2	0	3	1	51	8	2	1	1	0	0	6	1	25	0	4	0	132
22	Total 2012 Deferrals plus Other Items (Line 20 + Line 21)		(11,908)	(5,821)	(935)	0	716	(258)	(3,970)	(360)	2,028	391	(203)	9	0	2,735	98	438	(0)	(10)	1	(17,048)
23	2012 Earnings Sharing		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Grand Total (Line 22 + Line 23)		(11,908)	(5,821)	(935)	-	716	(258)	(3,970)	(360)	2,028	391	(203)	9	0	2,735	98	438	(0)	(10)	1	(17,048)

Notes:
(1) EB-2013-0109, Exhibit A, Tab 1, Appendix B, Schedule 1.
(2) EB-2013-0109, Exhibit A, Tab 3, Appendix B, Schedule 1, page 2.
(3) EB-2013-0109, Exhibit A, Tab 1, Appendix A, Schedule 5, Column (c).

UNION GAS LIMITED
Allocation of Ratepayer Portion of 2012 Gas Supply Optimization Margin

Line No.	Particulars	Union North FT Demand Allocation Units TRANSALLO (1) ($000's)	Union North Margin (2) ($000's)	Forecast Sales Service Volumes (3) (10^3m^3)	Union South Margin (4) ($000's)	Total Margin ($000's)
		(a)	(b)	(c)	(d)	(e) = (b + d)
	Union North					
1	Rate 01	27,667	9,477			9,477
2	Rate 10	11,252	3,854			3,854
3	Rate 20	4,731	1,621			1,621
4	Rate 25	839	287			287
5	Rate 100	-	-			-
6	Total Union North	44,489	15,239			15,239
	Union South					
7	Rate M1			1,985,247	14,559	14,559
8	Rate M2			412,655	3,026	3,026
9	Rate M4			10,777	79	79
10	Rate M5A			10,062	74	74
11	Rate M7			-	-	-
12	Rate M9			-	-	-
13	Rate M10			37	0	0
14	Rate T1			-	-	-
15	Rate T3			-	-	-
16	Total Union South			2,418,780	17,738	17,738
17	Total Ratepayer Portion of 2012 Gas Supply Optimization Margin (line 6 + line 16)					32,977

Notes:
(1) EB-2005-0520, Exhibit G3, Tab 5, Schedule 25, Page 1, updated for EB-2005-0520 Board Decision.
(2) Allocated using column (a).
(3) Forecast Sales Service volumes for the period October 1, 2013 to March 31, 2014.
(4) Allocated using column (c).

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Delivery
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing Mechanism ($000's)	Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
1	Small Volume General Service	01	249	22	-	271	714,975	0.0379
2	Large Volume General Service	10	(1,106)	4	-	(1,102)	242,068	(0.4552)
3	Small Volume General Service	M1	8,664	51	-	8,715	2,232,879	0.3903
4	Large Volume General Service	M2	2,269	8	-	2,276	797,745	0.2853

Notes:
(1) Forecast volume for the period October 1, 2013 to March 31, 2014.

UNION GAS LIMITED
General Service Unit Rates for Prospective Recovery/(Refund) - Gas Supply Transportation
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing Mechanism ($000's)	Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
1	Small Volume General Service	01	(12,179)	-	-	(12,179)	714,975	(1.7034)
2	Large Volume General Service	10	(4,719)	-	-	(4,719)	241,642	(1.9529)

Notes:
(1) Forecast volume for the period October 1, 2013 to March 31, 2014.

UNION GAS LIMITED
Unit Rates for Prospective Recovery/(Refund) - Gas Supply Commodity
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing Mechanism ($000's)	Balance for Disposition ($000's)	Forecast Volume (10^3m^3) (1)	Unit Rate for Prospective Recovery/(Refund) (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
1	Small Volume General Service	M1	(12,685)	-	-	(12,685)	1,985,247	(0.6389)
2	Large Volume General Service	M2	(2,637)	-	-	(2,637)	412,655	(0.6389)
3	Firm Com/Ind Contract	M4	(69)	-	-	(69)	10,777	(0.6389)
4	Interruptible Com/Ind Contract	M5	(64)	-	-	(64)	10,062	(0.6389)
5	Small Wholesale	M10	(0)	-	-	(0)	37	(0.6389)

Notes:
(1) Forecast sales service volumes for the period October 1, 2013 to March 31, 2014.

UNION GAS LIMITED
Contract Unit Rates for One-Time Adjustment - Delivery
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing ($000's)	Balance for Disposition ($000's)	2012 Actual Volume (10^3m^3)	Unit Rate (cents/m^3)
			(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
	Union North							
1	Medium Volume Firm Service (1)	20	111	2	-	113	102,497	0.1105
2	Medium Volume Firm Service (2)	20T	657	-	-	657	552,219	0.1189
3	Large Volume High Load Factor (2)	100T	712	3	-	714	1,912,232	0.0374
4	Wholesale Service	77	0	0	-	0	-	
5	Large Volume Interruptible	25	29	1	-	30	207,636	0.0143
	Union South							
6	Firm Com/Ind Contract	M4	2,095	2	-	2,097	428,641	0.4892
7	Interruptible Com/Ind Contract	M5	454	1	-	455	470,246	0.0968
8	Special Large Volume Contract	M7	(204)	1	-	(203)	141,165	(0.1435)
9	Large Wholesale	M9	9	0	-	9	57,878	0.0161
10	Small Wholesale	M10	1	0	-	1	197	0.2877
11	Contract Carriage Service	T1	2,728	6	-	2,735	5,023,637	0.0544
12	Contract Carriage- Wholesale	T3	97	1	-	98	239,361	0.0408

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
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars	Rate Class	Billing Units	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing ($000's)	Balance for Disposition ($000's)	2012 Actual Volume/ Demand	Unit Volumetric/ Demand Rate
				(a)	(b)	(c)	(d) = (a+b+c)	(e)	(f) = (d/e)*100
	Gas Supply Transportation (cents/m^3)								
1	Medium Volume Firm Service	20	$10^3m^3/d$	(1,725)	-	-	(1,725)	5,295	(32.5779)
2	Large Volume Interruptible	25	10^3m^3	(287)	-	-	(287)	44,659	(0.6434)
	Storage ($/GJ)								
3	Bundled-T Storage Service	20T/100T	GJ/d	22	-	-	22	155,904	0.143

UNION GAS LIMITED
Storage and Transportation Service Amounts for Disposition
2012 Deferral Account Disposition, Federal and Provincial Tax Changes and 2012 Earnings Sharing Mechanism

Line No.	Particulars ($000's) (1)	Rate Class	2012 Deferral Balances ($000's)	2012 Federal & Provincial Tax Changes ($000's)	2012 Earnings Sharing ($000's)	Balance for Disposition ($000's)
			(a)	(b)	(c)	(d) = (a+b+c)
1	Storage and Transportation	M12	414	25	-	438
2	Local Production	M13	(0)	0	-	(0)
3	Short-Term Cross Franchise	C1	(15)	4	-	(10)
4	Storage Transportation Service	M16	1	0	-	1

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

UNION GAS LIMITED
General Service 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	0.0379	1,733	0.66
2		Commodity	-	1,733	-
3		Transportation	(1.7034)	1,733	(29.51)
4			(1.6655)		(28.85)
5	Sales Service				(28.85)
6	Direct Purchase Bundled T				(28.85)
7	Rate 10	Delivery	(0.4552)	66,961	(304.80)
8		Commodity	-	66,961	-
9		Transportation	(1.9529)	66,961	(1,307.67)
10			(2.4081)		(1,612.48)
11	Sales Service				(1,612.48)
12	Direct Purchase Bundled T				(1,612.48)
13	Rate M1	Delivery	0.3903	1,679	6.55
14		Commodity	(0.6389)	1,679	(10.72)
15			(0.2486)		(4.17)
16	Sales Service				(4.17)
17	Direct Purchase				6.55
18	Rate M2	Delivery	0.2853	55,772	159.12
19		Commodity	(0.6389)	55,772	(356.33)
20			(0.3536)		(197.21)
21	Sales Service				(197.21)
22	Direct Purchase				159.12

Notes:
(1) EB-2013-0109 Exhibit A, Tab 3, Appendix B, Schedule 2, Pages 1-3.
(2) Average consumption, per customer, for the period October 1, 2013 to March 31, 2014.

TAB 4

INCREMENTAL TRANSPORTATION CONTRACTING ANALYSIS

Introduction

Pursuant to Union's EB-2005-0520 Settlement Agreement (pg 13, Subsection 3.1, paragraph 2; and, Appendix B – Incremental Transportation Contracting Analysis), 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 six following contracts:

1. Vector Pipeline (1 year extension)
2. Panhandle Eastern Pipeline (1 year)
3. Vector Pipeline (1 year)
4. Panhandle Eastern Pipeline (5 year)
5. TransCanada PipeLines, Empress to Union CDA (3 year)
6. Panhandle Eastern/Trunkline (5 year)

1. VECTOR PIPELINE (1 YEAR EXTENSION) TRANSPORTATION CONTRACT

Capacity History

As stated in EB-2011-0210, Union Gas holds 84,405 GJ/day of capacity on Vector Pipeline LP and Vector Pipeline Limited Partnership (Vector) as part of the Alliance/Vector transportation path to transport gas from the Western Canadian Sedimentary Basin ("WCSB") to Union's system at Dawn. This contract on Vector includes extension rights that could be exercised before November 30, 2012 for capacity due to terminate on December 1, 2015.

Renewed Capacity

Union Gas has exercised its right to extend the contracts for a one year period ending November 30, 2016 at the existing $0.25 US/dth rate. This capacity will continue to serve sales service customers in Union's Southern Operations Area and continue to be allocated to customers migrating from sales service to direct purchase using the vertical slice methodology.

Rationale for Transportation Capacity

Union's 2012 - 2016 Gas Supply Plan supports the extension of Vector capacity in order for Union to meet forecasted demand within the Southern sales service customer base. The landed cost of gas arriving at Dawn is forecast to be competitive with supply flowing on alternative upstream pipelines.

The benefits of this capacity are:

1. The landed cost of gas flowing to Union along this route is competitive with supply flowing on alternative upstream pipelines;
2. The extended term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;

3. Access to the Chicago market hub that receives competing gas supplies from the WCSB, the U.S. Midwest, Gulf and the expanding Rockies basin which supports Union's objective of diversity of supply basins;
4. Maintains and supports the acquisition of secure supply from a liquid market hub with many gas suppliers accessing multiple gas supply basins;
5. Low unabsorbed demand charge ("UDC") exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
6. Provides a fixed-rate toll which provides toll certainty on a portion of Union's upstream transportation.
7. Provides Union with both receipt and delivery flexibility within the path.
8. Lands gas at Dawn to support diversity of deliveries and system integrity.
9. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation.

Contract Parameters

- Transportation providers: Vector Pipeline Limited Partnership, Vector Pipeline L.P.
- Service: Firm Transportation
- Term: December 1, 2000 through November 30, 2016
- Volume: 80,000 Mmbtu/day (84,405 GJ/day)
- Rate: $0.25 US/ Mmbtu at 100% Load Factor (exclusive of fuel)
- Receipt Point: Alliance Pipelines L.P. Interconnect (Joliet)

- Delivery Point: Union (Dawn)

Incremental Contracting Analysis Form

Schedule 1 shows a comparison of landed costs for the Vector contract relative to the alternatives reviewed by Union in the format agreed upon in the EB-2005-0520 Settlement Agreement.

2. PANHANDLE EASTERN PIPELINE (1 YEAR) TRANSPORTATION CONTRACT

Capacity History

Union holds 25,000 Mmbtu/day of firm transportation on Panhandle Eastern Pipeline (PEPL) from the Panhandle Field Zone to Union's pipeline system at Ojibway through to October 31, 2017.

New Capacity

Union entered into 10,000 Mmbtu/day (10,551 GJ/d) of incremental firm transportation on PEPL from the PEPL Field Zone to Union's pipeline system at Ojibway for a one year term initiating on November 1, 2012 through to October 31, 2013 at a 100% Load Factor rate of $0.269US/dth.

This new capacity was purchased from the secondary market through an RFP process and will serve sales service customers in Union's Southern Operations Area. This transportation capacity is allocated to customers migrating from system sales service to direct purchase using the vertical slice methodology.

Rationale for Transportation Capacity

Union's 2012-2016 Gas Supply Plan supports the new Panhandle capacity in order for Union to meet forecasted demand within the Southern sales service customer base.

The benefits of this capacity are:

1. The landed cost of gas flowing to Union along this route is competitive with supply flowing on alternative upstream pipelines;
2. The one year term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
3. Maintains and supports the acquisition of secure supply from the Panhandle Field Zone gas supply basin, maintaining Union's supply diversity;
4. Low UDC exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
5. Fixed-rate toll which provides toll certainty on a portion of Union's supply;
6. Provides Union with both receipt and delivery flexibility within the path.
7. Lands gas at Ojibway to support diversity of deliveries and support system integrity.

Contract Parameters

- Transportation provider: Panhandle Eastern Pipe Line Company, LP
- Service: FT (Firm Transportation Service)
- Term: November 1, 2012 through October 31, 2013
- Volume: 10,000 Mmbtu/day
- Rate: $0.269 US/Mmbtu at 100% Load Factor (exclusive of fuel)
- Receipt Point: Sneed-Parallel Energy (12724)
- Delivery Point: Union Ojibway-Wayne County (UNION)

Incremental Contracting Analysis Form

Schedule 2 shows a comparison of landed costs for the Panhandle contract relative to the alternatives reviewed by Union in the format agreed upon in the EB-2005-0520 Settlement Agreement.

3. VECTOR PIPELINE (1 YEAR) TRANSPORTATION CONTRACT

Capacity History

As stated in EB-2011-0210, Union Gas holds 84,405 GJ/day of capacity on Vector Pipeline LP and Vector Pipeline Limited Partnership (Vector) as part of the Alliance/Vector transportation path to transport gas from the WCSB to Union's system at Dawn. Union also holds 85,460 GJ/day of capacity on Vector to move gas from Chicago to Union's system at Dawn. Prior to the 1 year extension identified on page one of this evidence, both of these contracts have an expiry date of November 30, 2015 and a 100% Load Factor rate of $0.25 US/Mmbtu.

New Capacity

A contract for capacity of 10,000 Mmbtu/day (10,551 GJ/d) of incremental firm transportation was entered into for a one year term initiating on November 1, 2012 through to October 31, 2013 at a 100% Load Factor rate of $0.18 US/Mmbtu.

This new capacity will serve sales service customers in Union's Southern Operations Area. This transportation path is allocated to customers migrating from sales service to direct purchase using the vertical slice methodology.

Rationale for Transportation Capacity

Union's 2012-2016 Gas Supply Plan supports the new Vector capacity in order for Union to meet forecasted demand within the Southern sales service customer base.

The benefits of this capacity are:

1. The landed cost of gas flowing to Union along this route is competitive with supply flowing on alternative upstream pipelines;
2. The one year term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;

3. Access to the Chicago market hub that receives competing gas supplies from the WCSB, the U.S. Midwest, Gulf and the expanding Rockies basin which supports Union's objective of diversity of supply basins;
4. Maintains and supports the acquisition of secure supply from a liquid market hub with many gas suppliers accessing multiple gas supply basins;
5. Low UDC exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
6. Provides a fixed-rate toll which provides toll certainty on a portion of Union's supply.
7. Provides Union with both receipt and delivery flexibility within the path.
8. Lands gas at Dawn to support diversity of deliveries and system integrity.
9. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation.

Contract Parameters

- Transportation provider: Vector Pipeline Limited Partnership
- Service: FT-1 (Firm Transportation Service)
- Term: November 1, 2012 through October 31, 2013
- Volume: 10,000 Mmbtu/day
- Rate: $0.18 US/Mmbtu at 100% Load Factor (exclusive of fuel)
- Receipt Point: Alliance Pipelines L.P. Interconnect (Joliet)
- Delivery Point: Union (Dawn)

Incremental Contracting Analysis Form

Schedule 2 shows a comparison of landed costs for this Vector contract relative to the alternatives reviewed by Union in the format agreed upon in the EB-2005-0520 Settlement Agreement.

4. PANHANDLE EASTERN PIPELINE (5 YEAR) TRANSPORTATION CONTRACT

Capacity History

Union holds 25,000 Mmbtu/d of firm transportation on PEPL from the Panhandle Field Zone to Union's pipeline system at Ojibway through to October 31, 2017. These volumes are then delivered to Parkway by a firm Ojibway-to-Parkway service.

New Capacity

Union acquired 2,000 Mmbtu/d (2,110 GJ/d) of incremental firm transportation on PEPL from Panhandle Field Zone to Ojibway for a 5 year term initiating on November 1, 2012 through to October 31, 2017 at a 100% Load Factor rate of $0.32 US/Mmbtu.

This new capacity will serve sales service customers in Union's Southern Operations Area. This transportation capacity is allocated to customers migrating from system sales service to direct purchase using the vertical slice methodology. These volumes are then delivered to Parkway by a firm Ojibway-to-Parkway service.

Rationale for Transportation Capacity

Subsequent to Union's 2012-2016 Gas Supply Plan, incremental long-term load was introduced which supports the need for this upstream additional capacity to continue to meet forecasted demand within the Southern sales service customer base.

The benefits of renewing this capacity are:

1. The landed cost of gas flowing to Union along this route is competitive with supply flowing on alternative upstream pipelines.
2. The 5 year term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins.
3. Maintains and supports the acquisition of secure supply from the Panhandle Field Zone gas supply basin, maintaining Union's supply diversity;
4. Provides a supply connection with the Rockies Express (REX) pipeline which provides access the Rockies supply basin.
5. Low UDC exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
6. Fixed-rate toll for the 5-year term providing toll certainty on a portion of Union's supply;
7. Provides Union receipt and delivery flexibility within the US Midwest and Great Lakes area due to the secondary Receipt and Delivery rights as provided by the service.

8. Lands gas at Union CDA (Parkway is a point in the CDA) to support diversity of deliveries and support system integrity.
9. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation.

Contract Parameters

- Transportation provider: Panhandle Eastern Pipe Line Company, LP
- Service: EFT (Enhanced Firm Transportation Service)
- Term: November 1, 2012 through October 31, 2017
- Volume: 2,000 Mmbtu/day
- Rate: $0.32 US/Mmbtu at 100% Load Factor
- Primary Receipt Point: PEPL Field Zone (Cheyenne Plains - CHYPL)
- Secondary Receipt Points: Putnam County-Rockies Express Pipeline, Lebanon Lateral
- Primary Delivery Point: Union Gas-Ojibway
- Secondary Delivery Points: Lebanon Lateral, Consumers Energy, Michigan Consolidated Gas

Incremental Contracting Analysis Form

Schedule 3 shows a comparison of landed costs for the PEPL contract relative to the alternatives reviewed by Union in the format agreed upon in the EB-2005-0520 Settlement Agreement.

5. TRANSCANADA PIPELINES LIMITED , EMPRESS TO UNION CDA (3 YEAR) TRANSPORTATION CONTRACT

Capacity History

Union currently holds 67,327 GJ/d of firm transportation on TCPL from Empress to Union's CDA through to October 31, 2013.

Capacity

This firm transportation (FT) capacity of 8,145 GJ/d Empress-Union CDA was obtained through a permanent assignment from a 3rd party. An equal and offsetting quantity of Empress-CDA transportation contract was turned back to TCPL by Union Gas effective November 1, 2012. There is no net increase or decrease in quantity to Union's portfolio of Empress to Union CDA long-haul based on these two transactions. The three-year term initiated on November 1, 2012 and terminates October 31, 2015 at the current 100% load factor tariff rate of $2.2429/GJ (TCPL 2012 Mainline Interim Tolls). This capacity will continue to serve sales service customers in Union's CDA. This transportation path is allocated to customers migrating from sales service to direct purchase using the vertical slice methodology.

Rationale for Transportation Capacity

Union's 2012-2016 Gas Supply Plan supports this TCPL capacity in order for Union to meet forecasted demand within the Southern sales service customer base.

The benefits of this capacity are:

1. The three-year term supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins;
2. Flexibility to divert deliveries into multiple delivery areas;
3. Lands gas at Union CDA (Parkway is a point in the CDA) to support diversity of deliveries and system integrity.
4. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation.

Contract Parameters

- Transportation provider: TransCanada Pipelines Limited
- Service: (FT) Firm Gas Transportation Service
- Term: November 1, 2012 through December 31, 2015
- Volume: 8,145 GJ/day
- Rate: $2.2429 Cdn/GJ at 100% Load Factor (exclusive of fuel)
- Primary Receipt Point: Empress
- Delivery Point: Union CDA

Incremental Contracting Analysis Form

The path, supplier and cost of the new capacity are identical to that of the previous capacity held and as such, the landed cost of both paths is also identical and therefore no landed cost analysis is provided.

6. PANHANDLE/TRUNKLINE (5 YEAR) TRANSPORTATION CONTRACT

Capacity History

Between November 1, 2004 and October 31, 2007 Union Gas held 22,000 Mmbtu/day (23,211 GJ/d) of firm transportation on Trunkline from the Gulf of Mexico to Bourbon, Illinois; and a corresponding short-haul contract on Panhandle from Bourbon to Union's pipeline system at Ojibway. These volumes were then delivered to Parkway by a firm Ojibway-to-Parkway service. The contracts were subsequently renewed through to October 31, 2012 for a quantity of 20,000 dth/d (21,101 GJ/d) at the same tolls as the previous contracts. This capacity served sales service customers in Union's Southern Operations Area and was allocated to customers migrating from system sales service to direct purchase using the vertical slice methodology.

Capacity Renewal

Prior to the expiry of these contracts, Union negotiated contract extensions with Trunkline/Panhandle for a 5-year term (November 1, 2012 to October 31, 2017) for the same quantity and at the same aggregate tolls as the previous contracts. This capacity continues to serve sales service customers in Union's Southern Operations Area and be allocated to customers migrating from system sales service to direct purchase using the vertical slice methodology.

Rationale for Renewing Transportation Capacity

Union's 2012-2016 Gas Supply Plan supports the replacement of the expiring Trunkline/Panhandle capacity in order for Union to continue to meet forecasted demand within the Southern sales service customer base. The benefits of this capacity are:

1. The landed cost of gas flowing to Union along this route is competitive with supply flowing on alternative upstream pipelines;
2. The 5-year renewal supports Union's objective of structuring a portfolio with a diversity of contract terms and supply basins.
3. Maintains and supports the acquisition of secure supply from the Gulf of Mexico, maintaining Union's supply diversity;
4. Low UDC cost exposure relative to alternative upstream pipeline routes due to the low demand charge on this route;
5. Achieves a fixed-rate toll for the 5-year term providing toll certainty on a portion of Union's supply;
6. Provides Union receipt and delivery flexibility due to the secondary Receipt and Delivery rights negotiated within the contract.

7. Lands gas at Union CDA (Parkway is a point in the CDA) to support diversity of deliveries and support system integrity.
8. The right to renew this capacity is a component of the agreement which ensures secure access to this transportation.

Contract Parameters

Transportation provider: Trunkline Gas Company & Panhandle Eastern Pipe Line;

- Term: November 1, 20012 through October 31, 2017
- Volume: 20,000 Mmbtu/day
- Rate: $0.217 US/Mmbtu at 100% Load Factor (exclusive of fuel)

Trunkline Gas Company

- Service: FT (Firm Transportation Service)
- Primary Receipt Points: ST165 – Stone Energy (80274), EW873 – Marathon Oil (92572), SMI268A – Apache (82670)
- Secondary Receipt Points: East Louisiana (ELA), West Louisiana (WLA), Zone 1A Receipt Points, Douglas County Receipt – Rockies Express Pipeline (82745)
- Primary Delivery Point: Panhandle Bourbon (80023)
- Secondary Delivery Point: Texas Eastern Lick Creek (93074)

- Secondary Delivery Point plus 5.00 cents: Champaign Transport – Peoples (80601)

Panhandle Eastern Pipe Line;

- Service: EFT (Enhanced Firm Transportation Service)
- Primary Receipt Point: Panhandle Bourbon (PBRBN)
- Secondary Receipt Points: Scotland Interconnect – Midwestern Gas Trans (09248), ANR Defiance (ANRDF), NIPSCO Defiance – Crossroads (CRSRD), Union Ojibway – Wayne County (UNION), Putnam County – Rockies Express Pipeline (09254)
- Primary Delivery Point: Union Ojibway – Wayne County (UNION)
- Secondary Delivery Points: Lebanon Lateral (02821), Michigan Consolidated Gas – Detroit (MCON), Consumers Energy (MGS)

Incremental Contracting Analysis Form

Schedule 4 shows a comparison of landed costs for the TGC/PEPL transportation path contracts relative to the alternatives reviewed by Union in the format agreed upon in the EB-2005-0520 Settlement Agreement.

SCHEDULES

UNION GAS LIMITED
Dec 1, 2012 - Oct 31, 2016 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/Gj	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
	Trunkline/Panhandle	Zone 1a	-0.145	4.2431	0.1900	0.0248	0.1587	0.3735	$4.62	**$ 4.89**	Ojibway
*	**Vector**	Chicago	0.080	4.4674	0.2500	0.0018	0.0487	0.3005	$4.77	**$ 5.05**	Dawn
	Dawn	Dawn	0.437	4.8247	0.0000	0.0000	0.0000	0.0000	$4.82	**$ 5.11**	Dawn
	Panhandle Longhaul	Panhandle Field Zone	-0.246	4.1414	0.4251	0.0441	0.2174	0.6866	$4.83	**$ 5.11**	Ojibway
	TCPL Niagara	Niagara	0.441	4.8291	0.1337	0.0000	0.0000	0.1337	$4.96	**$ 5.25**	Kirkwall
	Alliance/Vector	CREC	-0.669	3.7189	1.7275	-0.2875	0.2142	1.6543	$5.37	**$ 5.69**	Dawn
	TCPL SWDA (1)	Empress	-0.455	3.9328	1.8752	0.1284	0.0665	2.0700	$6.00	**$ 6.35**	Dawn

(1) for reference only

Assumptions used in Devleoping Long-term Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Dec 2012 - Nov 2013 $US/mmBtu	Dec 2013 - Nov 2014 $US/mmBtu	Dec 2014 - Nov 2015 $US/mmBtu	Dec 2015 - Nov 2016 $US/mmBtu	Average Annual Gas Supply Cost $US/mmBtu	Fuel Ratio Forecasts Col (G) above
	Henry Hub (NYMEX) $US/mmBtu		$4.26	$4.16	$4.30	$4.41	$4.28	
	Trunkline/Panhandle	Zone 1a	$4.23	$4.12	$4.26	$4.37	$4.24	3.74%
*	**Vector**	Chicago	$4.41	$4.34	$4.51	$4.61	$4.47	1.09%
	Dawn	Dawn	$4.77	$4.70	$4.87	$4.96	$4.82	N/A
	Panhandle Longhaul	Panhandle Field Zone	$4.13	$4.01	$4.16	$4.26	$4.14	5.25%
	TCPL Niagara	Niagara	$4.78	$4.70	$4.87	$4.97	$4.83	0.00%
	Alliance/Vector	CREC	$3.71	$3.59	$3.75	$3.82	$3.72	5.69%
	TCPL SWDA	Empress	$3.91	$3.80	$3.97	$4.06	$3.93	1.68%

Sources for Assumptions:

Gas Supply Prices (Col D): ICF International Q4 2012 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 = $0.997 CDN Bank of Canada Closing Rate - Nov 1, 2012

Energy Conversions (Col K) 1 dth = 1 mmBtu = 1.055056

Union's Analysis Completed: Nov-12

* indicates path referenced in evidence for this analysis

UNION GAS LIMITED
2012-2013 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/Gj	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
	Dawn	Dawn	0.245	3.9160	0.0000	0.0000	0.0000	0.0000	$3.92	**$ 4.12**	Dawn
*	**PEPL (2012-2013)**	Panhandle Field Zone	-0.175	3.4960	0.2249	0.0441	0.1940	0.4630	$3.96	**$ 4.16**	Ojibway
*	**Vector (2012-2013)**	Chicago	0.084	3.7542	0.1800	0.0018	0.0417	0.2235	$3.98	**$ 4.18**	Dawn
	Trunkline/Panhandle	Trunkline Field Zone 1A	-0.040	3.6308	0.1900	0.0248	0.1391	0.3538	$3.98	**$ 4.19**	Ojibway
	Vector	Chicago	0.084	3.7542	0.2500	0.0018	0.0417	0.2935	$4.05	**$ 4.26**	Dawn
	TCPL Niagara	Niagara	0.266	3.9369	0.1329	0.0000	0.0139	0.1469	$4.08	**$ 4.30**	Kirkwall
	Panhandle Longhaul	Panhandle Field Zone	-0.175	3.4960	0.4251	0.0441	0.1940	0.6632	$4.16	**$ 4.38**	Ojibway
	Alliance/Vector	CREC	-0.400	3.2704	1.7275	-0.2875	0.1874	1.6275	$4.90	**$ 5.15**	Dawn
	TCPL SWDA (1)	Empress	-0.520	3.1503	1.9430	0.1330	0.0539	2.1299	$5.28	**$ 5.55**	Dawn

(1) For reference only

Sources for Assumptions:

Gas Supply Prices (Col D):	ICE Settlement Data; July 31, 2012		
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 =	$1.003 CDN	From Bank of Canada Closing Rate July 31, 2012
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Aug-12		

* indicates path referenced in evidence for this analysis

UNION GAS LIMITED
2012 -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/Gj	Point of Delivery
	(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
	Trunkline/Panhandle	Trunkline Field Zone 1A	-0.090	4.7416	0.1900	0.0248	0.1816	0.3964	$5.14	**$ 5.41**	Dawn
*	**PEPL (2012-2017)**	Panhandle Field Zone	-0.269	4.5624	0.3200	0.0441	0.2532	0.6173	$5.18	**$ 5.45**	Ojibway
	Vector	Chicago	0.091	4.9218	0.2500	0.0018	0.0551	0.3069	$5.23	**$ 5.50**	Dawn
	Dawn	Dawn	0.454	5.2855	0.0000	0.0000	0.0000	0.0000	$5.29	**$ 5.56**	Dawn
	Panhandle Longhaul	Panhandle Field Zone	-0.269	4.5624	0.4251	0.0441	0.2532	0.7224	$5.28	**$ 5.56**	Ojibway
	TCPL Niagara	Niagara	0.466	5.2969	0.1329	0.0000	0.0000	0.1329	$5.43	**$ 5.71**	Kirkwall
	Alliance/Vector	CREC	-0.670	4.1608	1.7275	-0.2875	0.2384	1.6785	$5.84	**$ 6.14**	Dawn
	TCPL SWDA (1)	Empress	-0.459	4.3718	1.9430	0.1330	0.0748	2.1508	$6.52	**$ 6.86**	Dawn

(1) for reference only

Assumptions used in Devleoping Long-term Transportation Contracting Analysis:

	Annual Gas Supply & Fuel Ratio Forecasts	Point of Supply Col (B) above	Nov 2012 - Oct 2013 $US/mmBtu	Nov 2013 - Oct 2014 $US/mmBtu	Nov 2014 - Oct 2015 $US/mmBtu	Nov 2015 - Oct 2015 $US/mmBtu	Nov 2016 - Oct 2017 $US/mmBtu	Average Annual Gas Supply Cost $US/mmBtu Col (D) above	Fuel Ratio Forecasts Col (G) above
	Henry Hub (NYMEX)		$4.01	$4.30	$4.43	$4.91	$6.25	$4.78	
*	**PEPL**	Panhandle Field Zone	$3.82	$4.12	$4.25	$4.67	$5.95	$4.56	5.55%
	Vector	Chicago	$4.12	$4.45	$4.59	$5.05	$6.39	$4.92	1.12%
	Dawn	Dawn	$4.46	$4.82	$4.97	$5.41	$6.76	$5.29	
	TCPL Niagara	Niagara	$4.47	$4.83	$4.98	$5.43	$6.78	$5.30	0.00%
	Alliance/Vector	CREC	$3.41	$3.70	$3.84	$4.27	$5.58	$4.16	5.73%
	TCPL Empress to SSMDA	Empress	$3.60	$3.91	$4.05	$4.49	$5.82	$4.37	1.71%

Sources for Assumptions:

Gas Supply Prices (Col D):	ICF International Q3 2012 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 =	$1.003 CDN	From Bank of Canada Closing Rate July 31, 2012
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056	
Union's Analysis Completed:	Aug-12		

* indicates path referenced in evidence for this analysis

UNION GAS LIMITED
2012-2017 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/Gj	Point of Delivery
(A)	(B)	(C)	(D) = Nymex + C	(E)	(F)	(G)	(I) = E + F + G	(J) = D + I	(K)	(L)
Vector	Chicago	0.052	5.8863	0.2500	0.0019	0.0712	0.3231	$6.21	**$ 6.81**	Dawn
Panhandle Longhaul	Panhandle Field Zone	-0.349	5.4854	0.4251	0.0442	0.3203	0.7896	$6.28	**$ 6.88**	Ojibway
Trunkline/Panhandle	Trunkline Field Zone	0.049	5.8841	0.1926	0.0274	0.2507	0.4707	$6.35	**$ 6.97**	Ojibway
Dawn	Dawn	0.675	6.5101	0.0000	0.0000	0.0000	0.0000	$6.51	**$ 7.14**	Dawn
Alliance/Vector	CREC	-0.973	4.8615	1.6991	-0.2875	0.2825	1.6941	$6.56	**$ 7.19**	Dawn
TCPL Niagara	Niagara	0.757	6.5922	0.1386	0.0000	0.0000	0.1386	$6.73	**$ 7.38**	Kirkwall
TCPL SWDA (1)	Empress	-0.859	4.9754	1.9430	0.1330	0.1209	2.1970	$7.17	**$ 7.87**	Dawn

(1) For reference only

Assumptions used in Developing Long-term Transportation Contracting Analysis:

Annual Gas Supply & Fuel Ratio Forecasts	**Point of Supply Col (B) above**	**2012 $US/mmBtu**	**2013 $US/mmBtu**	**2014 $US/mmBtu**	**2015 $US/mmBtu**	**2016 $US/mmBtu**	**Average Annual Gas Supply Cost $US/mmBtu**	**Fuel Ratio Forecasts Col (G) above**
Henry Hub (NYMEX) $US/mmBtu		$5.11	$5.65	$6.07	$5.94	$6.40	$5.83	
Vector	Chicago	$5.18	$5.69	$6.12	$6.00	$6.44	$5.89	1.21%
Panhandle Longhaul	Panhandle Field Zone	$4.80	$5.33	$5.74	$5.58	$5.98	$5.49	5.84%
Trunkline/Panhandle	Trunkline Field Zone	$5.14	$5.69	$6.12	$6.00	$6.46	$5.88	4.26%
Dawn	Dawn	$5.77	$6.26	$6.77	$6.65	$7.10	$6.51	0.00%
Alliance/Vector	CREC	$4.13	$4.64	$5.11	$5.02	$5.41	$4.86	5.81%
TCPL Niagara	Niagara	$5.85	$6.35	$6.85	$6.72	$7.19	$6.59	0.35%
TCPL SWDA	Empress	$4.23	$4.75	$5.23	$5.14	$5.53	$4.98	2.43%

Sources for Assumptions:

Gas Supply Prices (Cols C & D):	ICF International; April 2011	
Transportation Tolls (Cols E & F):	Tolls in effect on Alternative Routes at the time of Union's Analysis	
Fuel Ratios (Col G):	Average ratio over the previous 12 months or Pipeline Forecast	
Foreign Exchange (Col K)	$1 US =	$0.962 CDN
Energy Conversions (Col K)	1 dth = 1 mmBtu =	1.055056
Union's Analysis Completed:	May-11	

*Previously filed in EB-2011-0210 at J.D-14-7-2 Attachment 1

EXHIBIT B

TAB 1

UNION'S PROPOSED TREATMENT OF FT-RAM[1] RELATED TRANSPORTATION EXCHANGE REVENUE FOR 2012

INTRODUCTION

This evidence supports Union Gas Limited's ("Union's") proposal to treat 2012 net FT-RAM related transportation exchange revenue ("FT-RAM revenue") as utility revenue subject to earnings sharing pursuant to the EB-2007-0606 and EB-2009-0101 Settlement Agreements for Union's 2008-2012 Incentive Regulation Mechanism ("IRM") . Union's proposed treatment is consistent with the treatment of upstream transportation exchange revenue for 2008, 2009 and 2010 and the IRM Settlement Agreement. The proposed treatment is supported by Union's response to the Board's EB-2011-0210 (2013 Rebasing Proceeding) directive to review the Gas Supply planning process. The evidence is organized as follows:

1. Exhibit B, Tab 1 – Union's Proposed Treatment of FT-RAM Related Transportation Exchange Revenue for 2012 - This evidence provides an overview of Union's proposed treatment of FT-RAM revenue and reviews the treatment of transportation exchange revenue prior to IRM, during IRM (2008, 2009 and 2010), and the treatment of transportation exchange revenue as a result of recent Board decisions;

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[1] FT-RAM refers to TransCanada's Firm Transportation Risk Alleviation Mechanism. For purposes of this evidence, references to FT-RAM include both FT-RAM and STS-RAM.

2. Exhibit B, Tab 2 – Transportation Exchange Services – This evidence provides a detailed description of transportation exchange services offered by Union and how these services utilize temporarily surplus upstream transportation capacity and, accordingly, should be treated as revenue;

3. Exhibit B, Tab 3 – Union's Gas Supply Planning Process – This evidence details Union's gas supply planning process, the Gas Supply Plan that is developed to meet system sales service and bundled direct purchase requirements, and how, through the application of well established gas supply planning principles, Union's Gas Supply Plan does not have any planned excess upstream transportation capacity supporting transportation exchange services;

4. Exhibit B, Tab 4 – Rate Impacts of Union's Proposed Treatment of Transportation Exchange Revenue in 2012 – This evidence compares the rate impacts of Union's proposed treatment of FT-RAM revenue to the alternative gas cost deferral treatment approved by the Board in its EB-2012-0087 Decision.

5. Exhibit B, Tab 5 – Union's Response to the Board's EB-2011-0210 Directive to Review the Gas Supply Planning Process – This evidence provides background to the Board's directive to conduct an independent review of the Gas Supply Plan and Union's response;

6. Exhibit C, Tab 1 - The Secondary Natural Gas Market in Ontario prepared by Stephen Acker – This evidence reviews the importance of transportation exchange services to the secondary market and the resulting benefits to Ontario consumers of natural gas;
7. Exhibit C, Tab 2 – Union's Gas Supply Planning Review prepared by Sussex Economic Advisors ("Sussex") – This exhibit provides Sussex's report in response to the Board's Gas Supply Directive from EB-2011-0210 related to Union's gas supply planning principles and processes and peak (Design) day methodology; and
8. Exhibit C, Tab 3 – Review of Union's Gas Supply-Related Cost Allocation/Rate Design and Deferral Accounting prepared by Concentric Energy Advisors ("Concentric") – This exhibit provides Concentric's report in response to the Board's Gas Supply Directive from EB-2011-0210 related to the appropriateness of Union's Cost Allocation/Rate Design and Deferral Accounting.

A glossary of terms used in this evidence is set out at Appendix A.

As indicated above, Union is proposing to treat net FT-RAM revenue, also known as margin, as utility revenue subject to earnings sharing. Union's proposed treatment is consistent with the treatment of transportation exchange revenue for 2008, 2009 and 2010 and the IRM Settlement Agreement. Pursuant to the Board's EB-2012-0087 Decision (2011 Deferral and Earnings Sharing Disposition Proceeding), net 2011 FT-RAM revenue was recorded in the Upstream Transportation FT-RAM Optimization Deferral

Account (179-130) and is being disposed of to sales service and Union North bundled direct purchase customers between April 1, 2013 and September 30, 2013.

For 2012, Union has included net revenue from transportation exchanges, including FT-RAM-related transportation exchanges, in utility earnings subject to earnings sharing. Including net FT-RAM revenue in utility earnings, although consistent with the treatment in 2008, 2009 and 2010, is not consistent with the Board's EB-2012-0087 Decision which required Union to defer this FT-RAM revenue less applicable unaccounted for gas and fuel costs as an offset to cost of gas. The 2012 deferral account balances and 2012 earnings sharing calculation applying Union's proposed treatment of FT-RAM revenue is provided at Exhibit A, Tab 1, Appendix A, Schedule 1 and Exhibit A, Tab 2, Appendix B, Schedule 1, respectively. The 2012 deferral account balances and 2012 earnings sharing calculation pursuant to the EB-2012-0087 treatment of FT-RAM revenue is provided at Exhibit A, Tab 1, Appendix B, Schedule 1 and Exhibit A, Tab 2, Appendix D, Schedule 19, respectively. The only difference between the two scenarios is the inclusion of FT-RAM revenue in 179-130. Table 1 summarizes the impact of Union's proposal and the EB-2012-0087 calculation in total.

Table 1
Comparison of Union's Proposed Treatment of net FT-RAM Revenue to the Treatment Established by the Board in EB-2012-0087
($000s)

Line No.	Particulars	Proposed Treatment	Treatment per EB-2012-0087
1	Total Deferral Account Balance	15,929	(17,048)
2	Earnings Sharing	(15,730)	-
3	Total	199	(17,048)

Union is proposing to treat 2012 net FT-RAM revenue as utility revenue subject to earnings sharing because:

1. A key premise of the Board's EB-2012-0087 Decision with respect to the treatment of net FT-RAM revenue is that Union's Gas Supply Plan was driven, in part, by optimization opportunities. As shown in the report at Exhibit C, Tab 2, Union's Gas Supply Plan is right-sized and does not consider opportunities for optimization. Accordingly, the Board should reinstate the treatment of FT-RAM revenue as part of utility earnings and consistent with its past treatment of these revenues.
2. Notwithstanding the Board's EB-2012-0087 Decision, treating net FT-RAM revenue as a gas cost offset (Y Factor) is inconsistent with (1) the historical treatment of upstream transportation exchange revenue; (2) the terms of Union's gas supply deferral accounts (attached as Appendix B) which were disposed of in 2012 by final orders of the Board in QRAM proceedings and which orders cannot be changed retroactively, and (3) represents a significant departure from the EB-

2007-0606 and EB-2009-0101 Settlement Agreements for Union's IRM for 2008-2012 approved by the Board. (Exhibit B, Tab 1);

3. The Board's EB-2012-0055 Decision (Enbridge Gas Distribution 2011 Deferral Account Disposition Proceeding) finding that temporarily surplus upstream assets may be used to support transportation exchange is consistent with how Union generates transportation exchange revenue. (Exhibit B, Tab 1 and Tab 2);
4. Base exchanges and FT-RAM exchanges are transportation services sold to customers pursuant to a Board Approved rate schedule. They are fundamentally the same in that they use upstream transportation assets that are temporarily surplus, only differing as a result of the value provided by TCPL's FT-RAM service. (Exhibit B, Tab 2);
5. The upstream transportation assets underpinning Union's Gas Supply Plan are contracted based on a set of gas supply principles that are consistent with those used in other jurisdictions in Canada and the United States. Union's Gas Supply Plan does not have excess upstream capacity that can be used to facilitate transportation exchange services.(Exhibit B, Tab 3 and Exhibit C, Tab 2); and
6. Union's proposed treatment of net FT-RAM revenue will ensure that a robust and active secondary market for transportation services will continue to exist and provide ongoing benefits to Ontario (Exhibit C, Tab 1).

REGULATORY TREATMENT OF TRANSPORTATION EXCHANGE REVENUE AND RECENT RELATED BOARD DECISIONS

The remainder of this evidence addresses the historical treatment of upstream transportation exchange revenues prior to IRM, the context in which IRM was implemented and the comprehensive nature of Union's IRM from 2008-2012. It also reviews the benefits that accrued to ratepayers over the IRM term, how transportation exchange revenue contributed to Union's ability to manage through the IRM term and that Union's proposed treatment of 2012 transportation exchange revenues is both consistent with the treatment of 2008-2010 transportation exchange revenues and appropriate in the context of a comprehensive IRM. In addition, the evidence addresses the Board's EB-2012-0087 and EB-2012-0055 Decisions related to the treatment of upstream transportation exchange revenues and the implications on Union's proposed treatment of FT-RAM revenue.

This portion of the evidence is organized in the following sections:

1/ Treatment of Upstream Transportation Exchange Revenues Prior to 2008 – Reviews the treatment of upstream transportation prior to 2008 and the elimination of the S&T deferral accounts;

2/ Principles Underpinning Natural Gas Incentive Regulation – Reviews the background and issues considered by the Board when IRM was established for Ontario's natural gas utilities;

3/ Union's 2008-2012 IRM – Summarizes the components of the IRM in place for 2008-2012 including the components of the Price Cap formula, the rationale for the elimination of the Transportation & Exchange Revenue Deferral Account and the earnings sharing mechanism. Also highlights the other regulatory proceedings from 2008-2012 that impacted the IRM;

4/ Ratepayer Benefits from Union's 2008-2012 IRM – Discusses the change in base rates over the 2008-2012 period and the amounts shared with ratepayers through earnings sharing on an annual basis;

5/ The Board's Review of Natural Gas IRM (EB-2011-0052) – Reviews the conclusions of the Board's review of Natural Gas IRM as outlined by Pacific Economics Group Research;

6/ Implications of the Board's Decisions Related to Temporarily Surplus Upstream Transportation Capacity on Union's Proposed Treatment of FT-RAM revenue – Reviews the Board's Decisions in EB-2012-0087 (Union 2011 Non-Commodity Deferral Account and Earnings Sharing Disposition Proceeding) and EB-2012-0055 (Enbridge Gas Distribution 2011 Deferral Account and Earnings Sharing Disposition Proceeding) and the criteria determining why transportation exchange revenue should be treated as revenue.

1/ TREATMENT OF UPSTREAM TRANSPORTATION EXCHANGE REVENUES PRIOR TO 2008

Union has a long history generating revenue from storage and transportation (S&T) activity, including the upstream transportation exchange revenue that is the subject of this evidence. S&T revenue was shared between ratepayers and Union in various ways going back to the early 1990s.

Origination of S&T Deferral Accounts and Sharing

The first S&T deferral account (179-34) was created in 1993, in the E.B.R.O. 476-03 Settlement Agreement. Forecast margin for S&T transactional services was directly credited to ratepayers through delivery rates (not gas supply commodity or transportation rates) and any positive variance to forecast was recorded in the deferral account to be shared 75/25 between ratepayers and Union. The sharing of deferred transactions service margin recognized "Union's role in developing opportunities and facilitating arrangements under the proposed account" (E.B.R.O. 476-03 ADR Settlement Agreement, page 4). The Board reaffirmed 75/25 sharing of deferred margin in its 1996 Decision in E.B.R.O. 486.

In the E.B.R.O. 499 Settlement Agreement parties agreed to share forecast S&T transactional margin 90/10 between ratepayers and Union, with variances in excess of forecast shared 75/25[2]. It was in this proceeding that the Transportation and Exchange Services Deferral Account (179-69), Other S&T Services Deferral Account (179-73), and Other Direct Purchase Services Deferral Account (179-74) were established.

The Transportation and Exchange Services Deferral Account (179-69) was a revenue deferral account that tracked the ratepayer share of the difference between actual net revenues for transportation and exchange services, and the net revenues forecast for these services and included in delivery rates. Transportation and exchange service revenue in excess of forecast was shared 75/25 in favour of ratepayers. The balance in the deferral account was disposed of on an annual basis with Union's other non-commodity deferral accounts. The ratepayer portion was allocated to in-franchise customers in Union North and Union South, and firm ex-franchise customers.

In RP-2003-0063/EB-2003-0087 (2004 Cost of Service Proceeding) Union's evidence addressed increased upstream transportation and exchange revenue as being attributable to TCPL's implementation of its FT Make-Up and Authorized Overrun Service ("AOS") service enhancements in 2002. These service enhancements, while not identical to the FT-RAM program, were precursors to FT-RAM. Union used the FT Make-Up Credit program and the AOS Credit program to generate transportation exchange revenue. It did

[2] Parties agreed that Union would build 90% of the 1999 forecast S&T transaction margin into delivery rates and to the extent that there was any variance in excess of what was built into rates, that amount would be shared 75/25 in favour of ratepayers.

so in the same way that Union used FT-RAM in 2012; that is, by taking advantage of temporarily surplus transportation capacity to respond to a market need. These services were available from TCPL in 2002 only. The revenues associated with Union's use of the FT Make-Up and AOS flowed through the Transportation and Exchange Services Deferral Account.

In the RP-2003-0063/EB-2003-0087 Decision the Board continued to approve 90/10 sharing of forecast S&T transactional service margin for inclusion in delivery rates with 75/25 sharing of deferred S&T margin. The Board also extended the 75/25 sharing to variances where actual S&T transactional service margin was below forecast, thereby providing symmetrical treatment of positive and negative variances from forecast. The Board noted that "symmetrical variance account treatment of these revenues is appropriate to hold ratepayers and Union harmless" (Decision with Reasons, page 67).

Elimination of S&T Deferral Accounts

Following the Board's issuance of its Natural Gas Forum ("NGF") Report (discussed in more detail below) Union proposed the elimination of S&T Transactional Deferral Accounts in its application for 2007 rates, EB-2005-0520. The issue was moved from EB-2005-0520 to EB-2005-0511, the Natural Gas Electricity Interface Review ("NGEIR") which was an outcome of the NGF. Ultimately the Board determined in

NGEIR that elimination of the S&T deferral accounts that were not related to storage forbearance should be addressed in Union's IRM application.

Union thus proposed eliminating Transportation & Exchange Services Account (179-69), Other S&T Services Account (179-73) and Other Direct Purchase Services Account (179-74) as part of its IRM in EB-2007-0606. As part of the overall Settlement Agreement in EB-2007-0606, parties agreed to eliminate these deferral accounts. Section 3 discusses the increased margin Union built into rates in exchange for the elimination of the deferral accounts.

2/ PRINCIPLES UNDERPINNING NATURAL GAS INCENTIVE REGULATION

In April 2012, Union filed its application and evidence supporting the annual disposition of its 2011 non-commodity deferral account and earnings sharing balances, EB-2012-0087. In that proceeding, the Board determined that it would address the issue of Union's treatment of upstream transportation exchange revenue in 2011 as a distinct, preliminary issue. Specifically, the Board determined that, as a preliminary matter, it would address whether or not Union had treated upstream transportation exchange revenues appropriately in the context of Union's 2008-2012 IRM.

On November 19, 2012, the Board issued its decision on the preliminary issue, finding that Union's 2011 FT-RAM revenue should be classified and treated as a gas cost reduction (Y Factor). In its EB-2012-0087 Decision the Board stated:

> *"Union has argued that a finding to this effect will undo the IRM Framework. The Board does not agree. This determination is in no way a departure from the IRM Framework. The Board is simply re-classifying revenues based on evidence that has been filed with the Board, as part of Union's rebasing proceeding (EB-2011-0210) and incorporated by reference in this proceeding. This re-classification of revenues results in a treatment that is consistent with the IRM Framework and the regulatory principles inherent in it. As stated earlier, the Board considers the rate adjustment processes embedded in the IRM Framework to have the purpose of facilitating the type of review that has occurred here in this case." (page 27)*

Respectfully, Union disagrees with the Board's findings. The Board's EB-2012-0087 Decision marks a fundamental departure from the principles on which natural gas IRMs are based and as articulated in the NGF. Contrary to the Board's EB-2012-0087 Decision, rates arising from the IRM mechanism were just and reasonable. FT-RAM revenues were accounted for properly and ratepayers received the benefits of those revenues as part of earnings sharing.

The Decision also fundamentally undermines the regulatory certainty necessary to underpin successful IRM frameworks on a going forward basis.

The NGF was initiated by the Board in 2004 to address changing dynamics in the supply and demand of natural gas in Ontario. The objective of the NGF was to improve the regulation of Ontario's gas markets. The Board undertook an analysis and review of rate regulation, storage and transportation, and regulated gas supply.

In March 2005, the Board released the NGF Report entitled, "Natural Gas Regulation in Ontario: A Renewed Policy Framework, Report on the Ontario Energy Board Natural Gas Forum" ("the NGF Report"). In the NGF Report, the Board determined that improvements could be made to the regulatory framework that would be in the public interest. The Board expressed concern that annual cost of service proceedings were inefficient, costly and time consuming. The challenge noted by the Board of moving away from annual cost of service proceedings was that the new model would need to be structured to provide utilities with appropriate incentives and the time necessary to generate productivity improvements, while, at the same time, ensuring that ratepayers would benefit from any productivity improvements. In addition, the NGF Report noted an appropriate level of transparency had to be maintained with the absence of annual cost of service proceedings.

To ensure that the Board fulfilled its statutory objectives related to consumer protection, infrastructure development and the financial viability of the industry, the Board established that the new rate regulation framework needed to:

1. Establish incentives for sustainable efficiency improvements that benefit customers and shareholders;
2. Ensure appropriate quality of service for customers; and
3. Create an environment that is conducive to investment, to the benefit of customers and shareholders (NGF Report, page 18).

Incentive Regulation, the Board concluded, would be an effective ratemaking framework for natural gas utilities in Ontario. In the Board's view, a comprehensive, properly designed plan would ensure downward pressure on rates. A comprehensive approach would also offer more balanced incentive properties than a targeted approach, with an overall expectation that the overall regulatory burden would be reduced (NGF Report, page 22).

An IRM would provide the utilities the opportunity to generate productivity improvements during the IRM term, with an up-front sharing of these efficiencies through a productivity factor offsetting inflationary increases. Rebasing at the end of the incentive term would ensure sustainable efficiencies were built into new base rates on which the next IRM would be layered. The Board did not intend for earnings sharing mechanisms to form part of the IRM framework. In addition, the Board stated its view that an appropriate balance of risk and reward in the IRM framework would result in reduced reliance on deferral accounts.

Union developed its IRM proposal based on the principles outlined in the NGF Report. The objectives Union outlined in its evidence of fairness, alignment, earnings opportunities, efficiency, comprehensive, rate predictability and stability, flexibility and accountability, sustainability and simplicity were consistent both with the submissions made by Union throughout the NGF process and with the NGF Report findings themselves.

Union's 2008-2012 IRM was a comprehensive regulatory framework established in consultation with stakeholders through a Board-convened Settlement Conference. Union managed its business throughout the term of the plan with a combination of revenue generating and cost reduction initiatives. It is Union's position that productivity efficiencies in the IRM can be achieved either by increasing revenues or decreasing costs. Said another way, input costs could be reduced for the same output (revenue), or output could be increased at a rate greater than the growth in costs – both are traditional definitions of productivity. This is, in fact, what happened over the 2008-2012 period, where absent inflationary rate increases, Union managed cost increases through a combination of cost initiatives and revenue generating activities such as an increased focus on upstream transportation exchange services. Customers shared in the benefits of these productivity efficiencies both through annual productivity base rate reductions and the annual earnings sharing process.

The growth of transportation exchange revenue, including FT-RAM revenue, was a critical contributor to Union's ability to become more productive during the IRM term. That productivity gain helped Union manage many of the unexpected circumstances that occurred during the five year IRM term. Below is a table indicating some of the primary, un-forecast changes that materialized after the establishment of the IR framework:

Table 2
Changes during the 2008-2012 IRM Term

At time of IRM Settlement (2007)	**Actual Conditions (2008-2012)**
Strong economic growth	Recession beginning in 2008, with weak recovery since 2009
2007 GDP: 2.33%	Average GDP: 1.75%, with 2011 at 0.72%
Fixed productivity factor: 1.82%	Fixed productivity factor: 1.82%
Pension expense: $29.4 million	Pension expense: average of $37.2 million, with 2012 at $49.8 million
Interest Expense: $153.9 million on total debt of $2.0 billion at a cost rate of 7.74%	Interest Expense 2012: $145.1 million on total debt of $2.3 billion at a cost rate of 6.32%
Benchmark ROE: 8.54%	Benchmark ROE for 2012: 7.67%, resulting in greater earnings sharing for ratepayers
Government of Canada Long Bond Yield: 4.32%	Government of Canada Long Bond Yield: 2.43%
Transportation Exchange revenues: - 18 counterparties - 37 transactions - $6.9 million net revenue	Transportation Exchange revenues (2012): - 33 counterparties - 1,688 transactions - $51.6 million net revenue
Gas Supply: primarily from WCSB	Gas Supply: emergence of shale gas, the largest single change in North American gas supply history
TCPL Empress to Eastern Zone Toll: $1.03/GJ	TCPL Empress to Eastern Zone Toll: increased to $2.24/GJ as a result of significant changes in North American natural gas markets and shifting supplies/flows that were not contemplated at the beginning of the IRM term
Commodity Price - Average NYMEX Close in 2007: $6.86 US/MMBtu	Commodity Price - Average NYMEX Close in 2012: $2.79 US/MMBtu

Despite a number of significant changes and unfavourable impacts, the IRM Framework and Union's industry-leading approach to investing in the resources needed to maximize the benefit of transportation exchange-related market opportunities protected customers and provided significant benefits to ratepayers. The IRM worked the way the Board expected it to work, but has now been changed as a result of the EB-2012-0087 Decision. Union believes that all of the components of the IRM should remain together.

3/ Union's 2008-2012 IRM

Union filed its application and evidence for its 2008-2012 IRM (EB-2007-0606) in May, 2007. Union proposed to use the rates determined in the 2007 Cost of Service proceeding as a base for the IRM, to which a Price Cap Index would be applied in each of the years 2008-2012.

In the Settlement Agreement dated January 3, 2007, Union and stakeholders agreed to a Price Cap Index formula defined as:

PCI = I – X + Z + Y + AU

Where: I is the inflation factor;

X is the productivity factor;

Z represents certain non-routine adjustments;

Y represents certain predetermined pass-through items; and

AU is the average use factor.

The parties agreed that, “the X factor and, indeed, the IR plan described in this Agreement, including any adjustments to base rates, are reasonable and fall within a reasonable range available on the evidence (page 6 of the Settlement Agreement).”

As part of the EB-2007-0606 Settlement Agreement, in addition to the annual pricing formula, parties also agreed to:

1. Eliminate four deferral accounts, including the Transportation and Exchange Services Deferral Account (179-69) (Section 5.1);
2. Establish an “Off-Ramp” review of the IRM in the event of a 300 basis point variance in weather normalized utility earnings above or below the amount calculated annually by the application of the Board’s Return on Equity (“ROE”) formula (Section 9.1);
3. Implement an Earnings Sharing Mechanism (“ESM”) based on actual utility earnings, with 50/50 sharing of earnings above 200 basis points over the amount calculated annually by the application of the Board’s ROE formula (Section 10.1);
4. Adjust the 2008 base revenue requirement by $4.3 million to reflect the elimination of deferral accounts above (Section 14.1); and

5. Maintain the existing Board approved gas supply deferral accounts without modification.

Exhibit B, Tab 2 describes what exchanges are and how Union generates revenue from exchanges. The way in which Union sold exchanges did not change after the deferral account was eliminated. Under the terms of Union's IRM, however, Union was incented with the elimination of the deferral account to focus on generating incremental transportation exchange revenue. This is exactly what Union did and as indicated by Union on numerous occasions throughout the IR term was a significant contributor to earnings sharing which ultimately benefited ratepayers.

As Union outlined in its EB-2007-0606 IRM evidence, IRM should provide earnings opportunities. One of the objectives of IRM is a ratemaking framework that provides the utility not only with the opportunity to earn a fair return, but also the opportunity to earn a superior return for superior performance.

In its Decision dated January 17, 2008, the Board approved the EB-2007-0606 Settlement Agreement. The Board determined that the Settlement Agreement was put forward by the major stakeholders and constituents with an interest in Union's rates and met the criteria set out in the NGF Report. In addition, the Board stated that the EB-2007-0606 Settlement Agreement represented "an important step forward in establishing long term rates stability in a manner that will promote maximum efficiencies for the benefit of both ratepayers and shareholders (pages 2-3 of the EB-2007-0606 Decision dated January 17, 2008)."

During the IRM period, Union filed an application in the fall of each year to set rates effective the following January 1. Union also filed annually to dispose of non-commodity deferral account balances and earnings sharing amounts. The timing of these filings was after Union's financial results had been made publicly available, typically at the end of March or in early April. On a quarterly basis, Union filed QRAM applications to set new commodity rates and to dispose of the gas supply deferral account balances. In each application to the Board, Union provided information in pre-filed evidence, and, where applicable, through interrogatory responses, technical conferences and oral hearings.

As mentioned above, Union's gas supply deferral account balances (or Y-factors) were addressed through the QRAM process. The balances in these commodity deferral accounts were calculated on a quarterly basis according to Board approved accounting orders. No gas supply deferral account was set in advance by the Board to capture net FT-RAM revenues. Please see Appendix B for the gas supply deferral account accounting orders.

EB-2008-0220: 2009 Rates Proceeding

Union filed an application in September 2008 to set rates effective January 1, 2009. The topics covered in Union's evidence included the 2009 Inflation and Productivity Factors, Y and Z factor adjustments, Average Use adjustments and annual adjustments to general service monthly charges as defined in the EB-2007-0606 Settlement Agreement. Intervenors raised DOS-MN as an issue during the course of the proceeding. DOS-MN was a temporary service enhancement provided by TCPL in the winter of 2008/2009 and the winter of 2009/2010. With DOS-MN, firm transportation shippers, like Union, made a commitment to deliver gas to TCPL at Empress and receive gas from TCPL at Dawn each day of the winter, paying substantially less than the demand charge for transportation service from Empress to Dawn. This was incremental to the firm transportation quantities for which shippers had contracted. DOS-MN was put in place to allow TCPL to manage its short haul capacity shortfall from Dawn to points east of Parkway. Union made use of the service enhancement each of the two winters it was made available, and earned approximately $1.7 million of transportation exchange revenue as a result.

In EB-2008-0220 intervenors questioned why Union treated the transportation exchange revenue as S&T revenue included in utility earnings, and not as a Y-factor, or gas transportation cost offset.

Union pointed to the increased S&T margin that was built into base rates, and how increased S&T revenue could lead to earnings sharing. Specifically, Union stated ratepayers were provided with, "a fixed level of benefits from S&T transactional activity", which provided "Union with a strong incentive to exceed that level of fixed benefit". It was Union that was at risk for achieving the forecast results, and Union would only be rewarded if the net benefits exceeded the threshold incorporated in rates. (EB-2008-0220, Union Reply Argument, page 7, para 31-32).

The Board considered Union's explanation to be, "a fair approach that is consistent with the general architecture of the IRM plan and the Settlement Agreement" (EB-2008-0220 Decision with Reasons, January 29, 2009, pages 8-9).

EB-2009-0101: 2008 Earnings Sharing and IRM Review

In April 2009, Union filed its application concerning the calculation of the 2008 earnings sharing amount, and a review of the IRM in EB-2009-0101. Union's application to dispose of 2008 non-commodity deferral account balances was filed separately in March 2009.

The EB-2009-0101 application addressed two major issues. The first was the calculation of 2008 earnings for the purposes of earning sharing itself, and the second was the need to review of the IRM because Union's 2008 earnings exceeded the Return on Equity ("ROE") generated by the Board-approved formula by more than 300 basis points. This review was required by Section 9.1 of the EB-2007-0606 Settlement Agreement. Union filed evidence that showed its calculation of utility earnings and the earnings sharing amount. The amount Union proposed to share with ratepayers was $15.2 million. In accordance with Section 10.1 of the EB-2007-0606 Settlement Agreement, this amount represented 50/50 sharing of the utility earnings in excess of 200 basis points above the amount calculated by the application of the Board's ROE formula. In addition, Union provided evidence that supported the continuation of the IRM.

Union's EB-2009-0101 evidence described the primary drivers of its financial results relative to 2007 Board Approved levels. The drivers included increased gas distribution revenues (both contract and general service), increased short-term transportation and exchange revenue and increased long-term transportation revenue, offset by increased tax expense. On page 7, Union noted that increased short-term transportation and exchange revenues resulted from increased customer activity and service values due to colder than normal weather and new market opportunities. In addition, Union described how Union's approach to marketing of transactional services changed as a direct result of the implementation of Union's IRM and the elimination of the Transportation and Exchange Services deferral account. In response to an interrogatory asked specifically with respect to this evidence, Union referred explicitly to its use of FT-RAM to generate S&T revenue.

Union's calculation of the earnings sharing amount was based on actual utility earnings. To calculate actual utility earnings Union started with Union's total corporate revenues and operating expenses as reported in the annual financial statements. From there, Union 1) removed revenues and costs associated with Union's unregulated storage operations per the Board's NGEIR Decision and 2) made adjustments that would normally be made under cost of service to arrive at utility earnings before interest and income taxes. To arrive at utility earnings for the purposes of earnings sharing, deemed interest, income taxes and preferred dividends were calculated and deducted from utility earnings before interest and income taxes.

Union's calculation of 2008 weather normalized utility earnings for the purposes of the IRM review threshold calculation included all of the adjustments made to arrive at utility earnings for sharing purposes, as well as an adjustment to reduce revenues by $6.9 million as a result of colder than normal weather. Union stated that IR was working as it was intended and that ratepayers would not be harmed by continuing with the existing parameters.

In the EB-2009-0101 Settlement Conference, parties agreed to amend Section 10.1 of the EB-2007-0606 Settlement Agreement in two ways:

1. A change to the earnings sharing calculation. Earnings between 200 and 300 basis points above the amount calculated annually by the application of the Board's ROE formula would continue to be shared 50/50 between ratepayers and Union, while earnings in excess of 300 basis points would be shared 90/10 between ratepayers and Union.
2. A clarification of the revenues and expenses to be included as part of the earnings sharing calculation. Specifically, all revenues and expenses (operating or capital) that would be included in a cost of service application would be included in the earnings sharing calculation. The parties agreed to specific examples of what would and would not be allowed as adjustments to the earnings sharing calculation. Union's one-time adjustment for an unbilled revenue accrual was excluded from the calculation, while the use of actual unaccounted for gas volume was included in the calculation.

The Off-Ramp review provision in Section 9.1 of the IRM Settlement Agreement was simultaneously deleted.

The parties outlined the benefits of the amendments within the EB-2009-0101 Settlement Agreement on pages 5 to 7:

1. Clarifies potential ambiguities in the calculation of earnings sharing and in calculated actual utility earnings
2. Provides additional benefits to ratepayers in circumstances where Union's actual utility income exceeds the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan by 300 basis points
3. Provides greater certainty and incentive for Union to explore and make investments in productivity improvements during the 2008-2012 term
4. Continues to provide for annual reviews during which intervenors will be able to carefully review the reasons and calculation of sharing for all earnings in excess of 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan
5. Avoids complex, lengthy and highly controversial and contested disputes over the potential for termination of the IR plan and the need for a new full cost of service proceeding
6. Avoids complex, lengthy and highly controversial and contested disputes over 2007 base rates and the potential for further adjustments to those base rates during the IR plan

The effect of the EB-2009-0101 Settlement Agreement was an increase in the amount shared with ratepayers. The earnings sharing amount increased from $15.2 million to $34.2 million. Intervenors supported the amendments to the IRM Settlement Agreement as the amendments were seen to be fair, and even favourable to ratepayers (EB-2009-0101 Transcript, June 8, 2009).

In approving the EB-2009-0101 Settlement Agreement, the Board stated the changes would, "not only reduce the regulatory cost but will allow greater certainty for all parties going forward" (EB-2009-0101 Oral Decision rendered June 8, 2009, page 88 of Transcript, lines 25-27).

4/ Ratepayer Benefits from Union's 2008-2012 IRM

Ratepayers benefited directly from Union's IRM, though a combination of flat delivery rates and earnings sharing during the five-year term. Rates increased by only 0.6% net of pass-through items over the five year term, relative to 2007 Board-approved rates. This meant that Union had to manage inflationary and economic pressures over the IRM term with a combination of cost related productivity initiatives and capitalizing on revenue-generating activities, such as transportation exchange revenue opportunities.

Productivity Factor

As indicated above, under the Price Cap formula, ratepayers benefited from an up-front productivity commitment called the X-factor. The X-factor reduced what would otherwise have been inflationary adjustments to rates as an incentive to the utility to implement efficiency measures. The X-factor, in effect, offsets the utility's ability to pass through inflationary increases, requiring it to manage cost increases through a combination of cost reducing measures and revenue generating activity.

To assist Union and Enbridge in the development of X-factors for the natural gas IRM, the Board hired Pacific Economics Group ("PEG") as an advisor on IRM matters. PEG performed input price and productivity research to support the development of an X-factor for each of Union and Enbridge. In its November 20, 2007 Report entitled, "Rate Adjustment Indexes for Ontario's Natural Gas Utilities", PEG recommended a price cap X-factor for Union in a range of 1.57% to 1.73%, net of an average use adjustment.

As part of the EB-2007-0606 Settlement Agreement, parties agreed to a fixed X-factor of 1.82% for the term of the IRM. This was a stringent productivity factor, above what even PEG recommended. In Union's IRM formula, rates were increased/decreased by the net result of inflation less productivity, or I – X, in each year plus or minus Y, Z and AU factors. In the first year of plan, 2008, the inflation factor was 2.04%. In the absence of the productivity factor, Union's base revenue would have increased by $17.6 million. Applying the productivity factor meant that base revenue increased by 0.22% instead (2.04% - 1.82%), or $1.9 million. The inflation factors in 2009 through 2012 were 1.54%, 2.73%, 0.72% and 1.72%, respectively.

Table 3 shows the total annual adjustments, and how the fixed productivity factor offset inflation[3]:

Table 3
Annual Price Cap Adjustment during the 2008-2012 IRM Term
($000s)

Line No.	Particulars	2008	2009	2010	2011	2012	Total
1	Inflation	17,647	13,446	23,826	6,215	14,660	75,795
2	Productivity	(15,744)	(15,891)	(15,884)	(15,711)	(15,513)	(78,743)
3	Net Adjustment	1,903	(2,445)	7,942	(9,495)	(852)	(2,947)

The productivity was guaranteed to ratepayers, regardless of either the level of inflation, or how well Union performed during IRM term.

Incremental S&T Margin in Base Rates

As part of the EB-2007-0606 Settlement Agreement, Union and stakeholders agreed to increase S&T margin in rates by $4.3 million, to a total of $6.9 million. In order to generate this amount of margin, Union would have to generate revenues of $10 to $12 million. The adjustment was made as part of the negotiated settlement to reflect the elimination of S&T revenue deferral accounts. As this adjustment was made to base rates, ratepayers enjoyed the effects throughout the term of the IRM.

[3] Although the net I-X adjustment was $(2.9) million over the five year IRM term, there was also a net storage premium adjustment of $15.5 million and net Z factor adjustments of $(6.9) million, which represents an overall increase of 0.6% over the 2007 Board Approved revenue

Earnings Sharing Mechanism

In addition to the base rate decreases (absent inflationary increases), ratepayers shared in Union's success under the IRM through the ESM. For the period of 2008-2011, the earnings sharing amount shared with customers was $47.5 million. Based on Union's proposal in this proceeding, ratepayers will receive an earnings sharing amount of $15.7 million.

As part of the EB-2007-0606 Settlement Agreement, Union and stakeholders agreed to share earnings in excess of 200 basis points 50/50 between Union and ratepayers. As indicated above the earnings sharing mechanism was amended in EB-2009-0101 such that earnings in excess of 300 basis points would be shared 90/10 in favour of ratepayers. In the years 2008-2010 the earnings sharing amount included the effects of net exchange revenue. That is, net exchange revenues contributed to Union's ability to meet, and exceed, the productivity factor that was set under very different conditions, and all ratepayers benefited from Union generating this revenue, as it was included in the utility income subject to sharing.

The earnings sharing amounts are shown in the table below:

Table 4
Earnings Sharing During the 2008-2012 IRM Term
($000s)

2008	2009	2010	*2011 (Proposed)*	2011	2012 (Proposed)	Total
(34,170)	(7,397)	(3,433)	*(16,652)*	(2,542)	(15,730)	(63,272)

The X-factor increased S&T margin in base rates and the earnings sharing components of the IRM ensured that ratepayers benefited from IRM during the term of the plan. In return, Union was to be provided the opportunity to generate productivity improvements, including revenue generating opportunities, during the IRM term. Union's incentive lay in achieving results beyond those which were already included in rates.

The total ratepayer benefit during the IRM term is shown in Table 5. The earnings sharing total in line 2 assumes Union's proposal in this proceeding. The incremental S&T margin is the five year impact of the base rate decrease in the first year of the plan (e.g. $4.3 million multiplied by five years).

Table 5
Ratepayer Benefits during the 2008-2012 IRM Term
($ millions)

Line No.	Particulars	
1	Productivity Factor	(79)
2	Earnings Sharing	(63)
3	Incremental S&T Margin	(22)
4	Total	(164)

Service Quality Requirements

Prior to the approval of IRM for Ontario's natural gas utilities, the Board implemented Service Quality Requirements ("SQRs") and associated reporting requirements. The purpose of the SQRs was to ensure the utilities maintained service quality throughout their IRM terms. The Board set out targets for various Service Quality Indicators ("SQIs"), including gas emergency response, call handling and appointment times. Table 6 shows Union's results versus target for each of the SQIs, throughout the IRM term.

Table 6
Union SQI Performance, 2008-2012

SQI	**Target**	**2008**	**2009**	**2010**	**2011**	**2012**
Appointments met within 4 hours	85%	89.4%	96.0%	97.1%	98.2%	98.8%
Missed Appointments Rescheduled within 2 hours of the end of Original Appointment Time	100.0% Missed Total Appointments	100.0% 3 20,869	99.9% 5 8,064	99.9% 6 5,756	99.8% 6 3,294	99.9% 2 2,228
Gas Emergency Response	90% within 1 hour	97.5%	97.7%	98.0%	98.3%	98.1%
Reconnections after disconnect for non-payment	85% within 2 business days	92.5%	93.2%	91.5%	93.5%	91.7%
Calls Answered within 30 seconds	Annual average 75%	78.2%	77.2%	82.5%	79.9%	81.4%
	Lowest month not to be less than 40%	69.7%	68.9%	72.3%	66.8%	76.7%
Call Abandon Rate	Not to exceed 10%	3.6%	4.3%	3.2%	4.3%	3.5%
Meter Reading (Consecutive Estimates > 4 months)	Not to exceed 0.5%	0.1%	0.2%	0.1%	0.1%	0.1%
Written Response to Customer Complaints	80% within 10 days	100%	100%	100%	100%	100%

Union's performance was at a consistently high level for all five years of the IRM term. In most cases Union significantly exceeded the target as it developed a world-class customer care process. The exception was on Rescheduled Missed Appointments. Union was unable to meet the targeted performance during the IRM period on this metric given that the target was 100%. During the IRM period, Union failed to reschedule 22 of 40,211 missed appointments within two hours of the appointment time.

5/ THE BOARD'S REVIEW OF NATURAL GAS IRM (EB-2011-0052)

In 2011, in anticipation of rebasing proceedings being filed for 2013, the Board asked Pacific Economics Group Research ("PEG-R") to assess how Union's and Enbridge's IRMs operated in practice. Due to the timing of the request, PEG-R reviewed the utilities' performance and results in the 2008-2010 timeframe. Specifically, PEG-R focused on the following issues:

1. Did the incentive regulation plans encourage cost control and generate productivity and efficiency improvements?
2. Did both customers and shareholders share in the benefits of any efficiency gains that were achieved?
3. Did the Companies provide appropriate service quality to their customers?
4. Was the incentive regulation framework conducive to capital investment?

These issues were driven by the criteria related to the Board meeting its statutory obligations with the new rate regulation framework, and outlined in the NGF Report.

In its April 2012 report entitled, "Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans" PEG-R presented its findings. PEG-R concluded:

1. Union's IRM encouraged cost control and generated productivity and efficiency improvements
2. Union's IRM allowed both customers and shareholders to share in the benefits of any efficiency gains that were achieved
3. Union provided appropriate service quality to its customers
4. Union's IRM was conducive to capital investment

Overall, PEG-R's analysis of prices, earnings and total factor productivity showed that IR generated win-win outcomes for customers and shareholders (page 7). PEG-R observed that Union appeared to have responded to the incentives of its IR plan somewhat more strongly than Enbridge (page v). In PEG-R's view, the structure of Union's IRM had the potential to create stronger incentives, and more upside earnings potential, than Enbridge's IRM. At the same time, the Union plan offered shareholders less protection against risk than the Enbridge plan (page 24).

6/ IMPLICATIONS OF THE BOARD'S DECISIONS RELATED TO TEMPORARILY SURPLUS UPSTREAM TRANSPORTATION CAPACITY ON UNION'S PROPOSED TREATMENT OF FT-RAM REVENUE

In both the EB-2012-0087 and EB-2012-0055 Decisions, the Board provided guidance related to the treatment of revenues associated with transportation exchange services. Specifically, in both the EB-2012-0087 and EB-2012-0055 Decisions, the Board indicated that the key distinction when determining if proceeds were to be treated as revenue versus a reduction to gas costs was whether the underlying transportation asset was "temporarily surplus" to system sales and bundled direct purchase customers' needs. In the Board's EB-2012-0087 Decision and Order on Preliminary Issue, the Board states:

> *"In the Board's view…the portion of utility gas supply assets that is available to support transactional service activities is only the portion of those assets that is temporarily surplus to the gas supply plan as a result of factors beyond Union's control.*" (page 28)

Similarly, in Enbridge's EB-2012-0055 Decision and Order, page 6, the Board states:

> *"The essential characteristic of transactional services is that they are arrangements made to generate revenue from unplanned, temporary surplus transportation capacity that Enbridge may have, from time to time, as part of its gas supply arrangements. The portion of utility gas supply assets that is available to support transactional services activities is only the portion of those assets that are temporarily surplus because of factors beyond Enbridge's control (e.g. weather, market demand)."*

Pursuant to these decisions, the Board treated transactional or exchange service activity resulting from a temporarily surplus resource as revenue. Underlying this evaluation was the acceptance that the utility's Gas Supply Plan was sized appropriately, and did not include any resources for the sole purpose of planned optimization activity. As discussed in Exhibit B, Tab 3 and Exhibit C, Tab 2, Union's Gas Supply Plan is developed using a set of generally accepted principles, contains an appropriate mix of assets and is appropriately sized.

In light of the Board's references to temporarily surplus assets, Union reviewed the transportation exchange service transactions, including those utilizing the FT-RAM program, to determine if they meet the criteria of being underpinned by temporarily surplus upstream transportation assets. Union also believes that, in addition to whether or not the upstream transportation capacity is temporarily surplus, the determination of how transportation exchange revenue should be treated must take into account how the temporary surplus capacity was used. If the temporary surplus capacity was used to provide a service to an S&T Customer, and the purchase and delivery of gas supplies for system supply and direct purchase customers continued, then it is appropriate to treat any proceeds as utility revenue subject to earnings sharing. However, if the asset was used to reduce existing costs, such as LBA fees, then Union proposes that it be recorded as a gas cost reduction. Union treated the reduction of LBA costs as gas cost reductions throughout the 2008-2012 IRM term.

Union also considered the nature of the temporarily surplus assets and identified two types:

1. System Supply Balancing – Union does not require the gas supply and therefore the planned transportation capacity is surplus. In this case, Union does not purchase the supply and assigns the capacity to a third party. The net revenue from these assignments is accounted for in the Unabsorbed Demand Cost Deferral Account (179-108) for future disposition. In this case, Union does not use the surplus transportation capacity due to system supply balancing to sell transportation exchange services.
2. Portion of Transportation Path Distance Is Not Required – Market demands are lower than design day requirements, and a portion of the transportation path is surplus. For example, gas supply purchased at Empress needs only to move to Dawn in the summer rather than the full distance to Union EDA. The portion of the path between Dawn and Union EDA is temporarily surplus. Union monetizes the temporarily surplus capacity through the sale of transportation exchange services which include base exchanges, FT-RAM related exchanges and transportation assignments.

As discussed in Exhibit B, Tab 3 and Exhibit C, Tab 2, all upstream transportation assets in the Gas Supply Plan serve the purpose of meeting design day market demands and annual customer requirements. Any surplus that is available to support transportation exchange service activity (whether daily, monthly or seasonal) is only available on a temporary basis. The temporary surplus arises as a result of factors outside of Union's control, such as weather and consumption levels. It is not available on a planned basis, that is, it has not been built into the Gas Supply Plan.

Table 1 in Section 3 of Exhibit B, Tab 2 applies the evaluation criteria described above to categorize the total net transportation exchange revenue for 2012 of $51.6 million of which $37.3 million is net FT-RAM revenue. Union uses the criteria to determine if each transaction type generates revenue or reduces costs.

The Table shows how each of Union's exchange service transaction types has been evaluated against the three criteria. If the transaction was underpinned by upstream transportation capacity that was temporarily surplus, if the activity was not planned in the Gas Supply Plan, and if the activity was the sale of a service to an S&T Customer, then the proceeds from that transaction are proposed to be treated as revenue. A more detailed discussion of the Table and the underlying transactions is provided in Exhibit B, Tab 2.

APPENDIX A

UNION GAS LIMITED
TRANSPORTATION EXCHANGE REVENUE GLOSSARY

Aggregate Excess Storage Method ("Aggregate Excess") – A methodology used to allocate storage space to Union's bundled customers in order to fulfill seasonal load balancing needs. The aggregate excess calculation determines the amount of storage space required based on the difference between gas consumption in the 151 day winter period (November through March) and the average daily gas consumption during the entire year. Total winter consumption is forecast using normal weather conditions. The formula can be expressed as: Aggregate Excess = Total winter consumption – [(151/365)*(Total annual consumption)] .

Alberta Energy Company price point ("AECO") – The price of gas at the Alberta Energy Company storage facility located to the west of Empress.

Alberta Border Reference Price – The Alberta border forward price established in Union's QRAM process.

Alliance – A transmission line originating in northeastern B.C., to Joliet, Illinois (near Chicago)

Alternate Receipt Point – A receipt point is the location where one party is contracted to receive natural gas from another party. If the contracted receipt point is changed, this becomes an alternate receipt point.

Annual Requirement – The natural gas required by an end-use customer for consumption over the course of one year.

Assignment – A temporary arrangement where a party relinquishes a transportation contract to a third party for a price. Usually these arrangements are for no less than one month.

Authorized Overrun Service ("AOS") Credit Program – A program offered by TCPL in 2002 which provided shippers with credits equal to 4% of their total firm transportation demand charges. These credits were then applied towards interruptible transportation charges for the same month.

Bcf – Billion cubic feet

Basis – The differential between the value of a given commodity in different locations or different time periods. For example, if the price of natural gas is $5/GJ at Dawn and $4/GJ at AECO, the basis would be $1/GJ.

Basis Point ("bp") – A unit equal to 1/100th of 1% and is used in denoting the change in a financial instrument. The basis point is commonly used for calculating changes in yield of a fixed-income security, interest rates and equity indexes.

Biddable Service – A service for which the price is determined by the market value interested participants are willing to pay. Service is awarded to market participants based on highest price.

Bundled Direct Purchase ("DP") Customers – Customers who acquire their own gas supply and the utility provides transportation options.

Bundled Service – a service in which the demand for natural gas at a customer delivery point is met by Union using whatever resources/functions or combination of resources/functions (e.g. transportation, storage, daily nominations) are required. Union offers bundled (e.g. M1, M2), semi-bundled (e.g. T-1,T-2, T-3) and unbundled (e.g. U2, U5, U7) services to its in-franchise customers.

Daily Contract Quantity ("DCQ") – The maximum amount of natural gas per day that a direct purchaser may deliver to Union's system under the provisions of a direct purchase contract.

Dawn Compressor Station ("Dawn") – The location of Union's main compressor station. Dawn is referred to as a "hub" as it represents the point where Union's supply, storage and transmission systems meet. A number of other pipeline systems (e.g. TCPL, Vector) are interconnected to Union's system at Dawn. Dawn is located southeast of Sarnia, Ontario.

Dawn Delivered Service – A service where gas supplies are purchased at Dawn. These supplies may have been transported to Dawn by a third party, or withdrawn from storage at Dawn by a third party.

Dawn Overrun Service – Must Nominate ("DOS-MN") – A service introduced in 2008 by TCPL to meet its Dawn Area short haul receipt commitments during the winter seasons of 2008/2009 and 2009/2010 using long haul services. The service is "firm", long-haul transportation to the Dawn Area. It was allocated to FT shippers and the service had to be utilized each and every day of the term of the contract.

Default Supplier/Supplier of Last Resort – A responsibility borne by a utility to ensure sufficient supply is available to serve all customers, including customers who have elected to purchase their supply through alternative sources, but whose alternative sources failed to serve as contracted.

Demand –The level of need for natural gas at a specific location. Examples of where this can be found are: the point of end use (a residential, commercial or industrial customer), at the supply point to a community, a takeoff point from a transmission, or at an interconnect with another pipeline system.

Demand Forecast – A prediction of the total natural gas expected to be consumed in a future period. This could apply to a customer class, rate class or market.

Design Day Requirements – The expected demands by customers at Union's design weather condition. Union plans to have facilities in place to meet these requirements.

Direct purchase ("DP") – A service whereby a customer or their agent arranges for gas supply and/or upstream transmission services directly, and arranges for Union's distribution service to deliver gas to end-user locations.

Diversion – A transaction used in combination with a transportation service where gas is delivered to a delivery point and/or delivery area not specified in the shipper's contract.

Earnings Sharing Mechanism ("ESM") – A component of Union's 2008-2012 Incentive Regulation Mechanism. Union annually calculated its allowed return on equity using the OEB formula. Where Union's utility earnings were above 200 bps but below 300 bps of the allowed return on equity, Union shared the amount 50/50 with ratepayers. Union shared any amounts greater than 300 bps 90/10, to the account of the ratepayer.

EGD – Enbridge Gas Distribution

Empress – The Interconnect between NOVA and TCPL immediately west of the Alberta/Saskatchewan border.

End-Use Customer/Consumer – Individuals or businesses that consume natural gas delivered to them.

Ex-Franchise – Customers located outside Union's franchised service areas.

FT (Firm Transportation) – A firm service, pipeline companies offer for the transportation of gas on their system.

FT Make-up Credit Program – A program offered by TCPL in 2002 which allowed credits to be generated on unutilized firm transportation demand charges. These credits were then credited towards interruptible transportation charges for the same month. This service was a pre-cursor to TCPL's FT RAM program.

Fuel Gas – Gas used as fuel to operate the compressors that move the gas through the pipeline. Usually expressed as a percentage of volumes transported.

GJ (gigajoule) – See Joule. 1 GJ = 10^9 J (refer to conversion table at the end of the glossary).

Gas Distributor – An entity that physically delivers gas to a consumer.

Gas Supply Commodity Rate (North) –Reflects the commodity cost of gas and the associated upstream transportation fuel to transport gas to the delivery area in the North in which the gas is consumed.

Gas Supply Transportation Rate (North) –Reflects the costs of upstream transportation, the associated Dawn-Trafalgar transportation and TCPL STS services that are used to provide daily firm service to each delivery area in the North.

Gas Supply Commodity Charge (South) – Reflects the commodity cost of gas and the associated upstream transportation fuel to transport gas to the South.

Gas Vendor – An entity who (a) sells or offers to sell gas to a consumer, or (b) acts as the agent or broker for a seller of gas to a consumer, or (c) acts or offers to act as the agent or broker of a consumer in the purchase of gas.

Great Lakes Gas Transmission ("GLGT") – A wholly owned transmission pipeline affliaite of TPCL connecting to TCPL at Emerson 2 (in Manitoba near the Canadian/US border), and continuing through Minnesota, Wisconsin and Michigan to reconnect to TCPL at St. Clair (near Port Huron).

Greater Toronto Area ("GTA") Project – A leave to construct project initiated by Enbridge for OEB Approval under docket EB-2012-0451. The stated purpose of the project is to support future growth in the GTA from 2015-2025, eliminate distribution system constraints, diversify gas supply entry points, reduce operational risks, and provide improved reliability, risk mitigation and cost savings from upstream gas supply.

Heating Degree Day ("HDD") – Heating degree-day is the unit of measurement for weather normalization. One heating degree-day (HDD) is a measure of the heating demand for natural gas caused by a one-degree temperature difference relative to Union's temperature benchmark of 18°C. The number of HDDs, on one day, is determined by subtracting the mean daily temperature for the day from the benchmark temperature. For example, if the mean daily temperature is 11°C, then there are 7 HDDs (i.e. 18-11) on that day. If the mean daily temperature is above 18°C, there are no HDDs.

Hub – An interchange where multiple pipelines interconnect and form a market center.

Interruptible Transportation Service ("IT") – Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the service provider.

In-Franchise – Customers inside Union's franchise areas.

Joule (J) – The metric unit of energy.

Limited Balancing Agreement ("LBA") –Used to record variances between nominated and measured receipts and deliveries at interconnect locations. Fees may apply for daily and cumulative balances and will depend on the magnitude of the variance.

Local Distribution Company ("LDC") – A company that owns and operates a distribution system that delivers electricity or gas to a given geographic service area in accordance with an order of the regulator.

Liquidity – A term used to describe the ability or ease natural gas can be bought, sold, or traded at a specific location. A point that is more liquid has many buyers and sellers where gas sales can be easily transacted at competitive prices.

Load Balancing – The efforts of a utility to meet its bundled customer requirements in the most economic manner on a daily or seasonal basis. It involves balancing the gas supply to meet total demands by using storage and other peak supply sources (e.g. spot gas) curtailment of interruptible demands, and diversions from one delivery point to another.

Load Factor – The ratio of average load to peak load during a specific period of time, expressed as a percent. It indicates the average utilization of a pipeline system relative to total system capacity.

Long Haul –A term applied to TCPL transportation capacity that has its primary receipt point originating from Alberta (eg. Empress) or Saskatchewan and primary delivery point in Ontario or Québec.

Main – Pipe used to carry natural gas from one point to another. As contrasted with service gas pipes, mains usually carry natural gas in large volume for general or collective use.

Marcellus Shale Basin – An emerging and abundant natural gas supply source located in New York, Pennsylvania, Ohio, West Virginia and other states in the region.

Michigan Consolidated Gas Company ("MichCon") - a utility, storage, and pipeline company which operates as a gas distributor in Michigan. MichCon also provides transmission and storage services.

Mid-Continent – Refers to supply basin located in the mid-United States, such as Texas, Oklahoma, and Kansas.

Minimum Floor Price – The lowest amount that is allowed to be paid for a service. Usually minimum floor price is in reference to biddable services, indicating that bids cannot be lower than the minimum.

Natural Gas Forum ("NGF") – A process initiated by the Ontario Energy Board to review the policy underlying the key structural components of the natural gas regulatory system within the province of Ontario.

Natural Gas Forum Report ("NGF Report") – the output of the Natural Gas Forum, a report released March 30, 2005.

Normal Weather – Normal weather is used to calculate normalized average consumption, which is a key element in determining the demand forecast for natural gas. Normal weather is the term used to describe the most likely weather, or more accurately, heating degree-days that can be expected in the long run. Normal weather can be determined by various methods. The current method being used by Union to define normal weather is a 50/50 blended approach of the 20-year declining trend and the 30-year average methodology.

Obligated Direct Purchase Deliveries – Direct purchase customers have an obligation to deliver on a daily basis a certain amount to Union (i.e. their obligated DCQ). Union counts on these deliveries arriving at a specified location in determining the facilities required to meet the design day demand.

Ontario Landed Reference Price – The Alberta Border Reference Price plus 100% load factor TCPL tolls (to the Eastern Delivery Area) plus compressor fuel established in Union's QRAM process. It is the price that Union charges its sales service customers for the costs of gas supplies and benchmark for recording debits or credits to its gas supply-related deferral accounts.

Panhandle ("PEPL") – The Panhandle Eastern Pipeline system that runs from the U.S. mid-continent (Kansas, Texas, Oklahoma) to Michigan and Southwestern Ontario.

Parkway Compressor Station ("Parkway") - Located at the east end of Union's Dawn Parkway system. At this location, Union connects with Enbridge and TCPL. Facilities at this site include custody transfer measurement to Enbridge and TCPL. Compression is also located there to facilitate the movement of volumes between Union and TCPL.

Parkway–Maple Bottleneck – A portion of TransCanada PipeLine's transportation pipeline between its interconnect with Union at Parkway and Maple (located near Toronto at Mississauga) that is currently constrained and limiting the movement of gas supply into, around, and through Ontario.

Peak Day – The 24-hour period of greatest total gas sendout.

Peak Day Requirement – Also referenced as Design Day requirements.

Peaking Supply – Supplies which are required to meet spikes in demand. Usually spikes are short term and measured in days.

Price Cap Index ("PCI") – The annual adjustment factor in Union's 2008-2012 Incentive Regulation Mechanism. PCI = I – X + Z + Y + AU, where I is the inflation factor, X is the productivity factor, Z represents certain non-routine adjustments, Y represents certain predetermined pass-throughs and AU is the average use factor.

Quarterly Rate Adjustment Mechanism ("QRAM") – Quarterly Rate Adjustment Mechanism, a streamlined process for obtaining approvals of changes to Union's commodity rates.

Risk Alleviation Mechanism ("RAM") Credits –The RAM credit is a dollar amount and is designed to allow a shipper to transport an interruptible quantity equal to the quantity of unutilized firm transportation (FT) if used over the same path, for no additional charge beyond the minimum commodity charge, assuming the interruptible is bid at the interruptible floor price. For example, a shipper's eligible FT contract that has a daily demand toll of $1.00/GJ would generate a RAM credit of approximately $1.10/GJ towards that shipper's monthly IT invoice. Credits must be applied within the same month they are generated, and cannot be carried over to subsequent months.

Risk Alleviation Mechanism ("RAM") Program – A program developed by TCPL whereby eligible firm capacities generate credits when unutilized. The program has two components: 1) FT-RAM refer to credits generated on firm long-haul transportation capacity, or firm short-haul capacity that is linked to a firm long-haul contract, and 2) STS-RAM refers to credits generated on unutilized capacity on the Storage Transportation Service ("STS"). This program will be discontinued effective June 30, 2013.

Receipt & Delivery Point – The starting and ending locations for the transportation of gas. For example, if gas is transported from Empress to Dawn, the receipt point is Empress and the delivery point is Dawn.

Renewal Rights – The legal guarantee available to a party to continue to receive the same service as under an existing contractual arrangement.

Storage and Transportation ("S&T") Group – The function at Union responsible for the utilization, marketing and sales of storage and transportation services to ex-franchise customers.

Sales Service – Otherwise referred to as system gas supply. Refers to the sale of the commodity to in-franchise customers by Union.

Secondary Market – A secondary market exists when buyers purchase services from holders of existing capacity rather than purchasing directly from the primary service provider.

SENDOUT © – An optimization software provided by Ventyx which is used by Union for supply/demand modeling as part of its annual gas supply planning process.

Short Term Firm Transportation ("STFT") – A non-renewable transportation service offered by TCPL that provides guaranteed service for terms of greater than 7 days, and less than 1 year

Short Haul – Generally a term applied to transportation paths that do not originate from the supply source, but rather closer to end-use markets. For purposes of this Application, this specifically refers to TCPL transportation service where both the receipt and delivery points are within Ontario or Québec.

South Portfolio – The mix of upstream transportation capacities that are used to serve customers in the Southern Operations area.

Spot gas – Gas supplies that are not underpinned by upstream transportation capacities and which are purchased for delivery at a specific location (e.g. Dawn) usually for a short duration.

Storage Transportation Service (“STS”) – A service offered by TCPL that allows for the movement of gas from a specified delivery area in the North to Parkway (summer “injections”) and from Parkway to a specified delivery area (winter “withdrawals”) in the North.

STS Pooling – As part of the Storage Transportation Service (“STS”), eligible withdrawal capacity that is not used in one delivery area may be used to provide withdrawal to another eligible delivery area.

System Capacity –The measure of the capability of the pipeline system. It is expressed under a set of pressure conditions and shows the system’s ability to meet a set of demands specific locations.

System Sales Customers – End-use customers who purchase their natural gas supply and transportation from the utility.

System Supply – Natural gas acquired for the purpose of meeting needs of system sales customers.

TCPL – TransCanada Pipelines Limited

Temporary Surplus – A reference to any upstream transportation capacity that is available on a short-term basis (e.g. day, month, season), over and above what is required to serve utility customers. This capacity becomes available due to factors such as weather and market consumption variances.

Throughput – The total annual amount of natural gas transported through Union’s transmission system.

Toll – A charge levied by a pipeline company.

Transportation Exchange – The movement of gas between two locations, where at least one location is not located on the Union transmission System. Using a transportation exchange service, Union “exchanges” gas at one location for gas held by a counterparty at another location.

Transportation Service (“T-Service”) – Service offered by a pipeline company or distributor to transport gas owned by others for a toll.

Transportation Service DP Customers – Customers who acquire their supply and upstream transportation from an energy marketer rather than the utility. These customers are large contract and commercial and industrial customers.

Trunkline – A pipeline system that runs from the Gulf of Mexico to the border of Indiana and Michigan.

Unabsorbed Demand Charge ("UDC") – Occurs when gas is transported on an upstream transmission pipeline with demand charges included in its toll, at less than 100% load factor.

UDC Mitigation – Occurs when the utility takes action to minimize UDC charges.

Unaccounted for Gas ("UFG") – The difference between the total gas available from all sources, and the total gas accounted for as delivery, net interchange, and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times and at different points on the system.

Unbundled DP Customers – Customers who acquire their supply, upstream transportation and storage from an energy marketer rather than the utility. These customers can be small residential, commercial, and industrial customers.

Unbundled Service – A service for which the demand for natural gas at a customer delivery point is met by the level of separate services and functions (e.g. transportation, storage space, storage injection/withdrawal, daily nominations) contracted to be available.

Union North – Refers to the Northern and Eastern Operations Area, or the sections of Union's system that spans north of Toronto to the Manitoba border and east of Toronto to Cornwall.

Union South – Refers to the Southern Operations Area, or the southern section of Union's system that spans west of Mississauga and south of Georgian Bay.

Upstream transportation – Pipeline capacity required to transport natural gas supplies from locations close to production sources to market areas.

Vector Pipeline – A transmission line originating at Joliet, Illinois (near Chicago) to the interconnect with Union at Dawn.

WACOG – Weighted average cost of gas.

Western Canadian Sedimentary Basin ("WCSB") – The mature natural gas supply source located primarily in Alberta.

APPENDIX B

UNION GAS LIMITED

Accounting Entries for
TCPL Tolls and Fuel – Northern and Eastern Operations Area
Deferral Account No. 179-100

This account is applicable to the Northern and Eastern Operations of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-100 Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-100, the difference in the costs between the actual per unit TCPL tolls and associated fuel and the forecast per unit TCPL tolls and associated fuel costs included in the rates as approved by the Board.

Debit	-	Account No. 623 Cost of Gas
Credit	-	Account No.179-100 Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

To record, as a credit (debit) in Deferral Account No. 179-100, the benefit from the temporary assignment of unutilized capacity under Union's TCPL transportation contracts to the Northern and Eastern Operations Area. The benefit will be equal to the recovery of pipeline demand charges and other charges resulting from the temporary assignment of unutilized capacity that have been included in gas sales rates.

Debit	-	Account No. 179-100 Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-100 charges that result from the Limited Balancing Agreement with TCPL.

Debit	-	Account No. 500 Sales Revenue
Credit	-	Account No. 179-100 Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

To record, as a credit (debit) in Deferral Account No. 179-100 revenue from T-Service customers for load balancing service resulting from the Limited Balancing Agreement with TCPL.

Debit	-	Account No. 179-100 Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-100 interest expense on the balance in Deferral Account No. 179-100. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
North Purchase Gas Variance Account
Deferral Account No. 179-105

This account is applicable to the Northern and Eastern Operations area of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-105 Other Deferred Charges – North Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-105, the difference between the unit cost of gas purchased each month for the Northern and Eastern Operations area and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-105 Other Deferred Charges - North Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-105, interest expense on the balance in Deferral Account No. 179-105. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
South Purchase Gas Variance Account
Deferral Account No. 179-106

This account is applicable to the Southern Operations area of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-106 Other Deferred Charges – South Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-106, the difference between the unit cost of gas purchased each month for the Southern Operations and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-106 Other Deferred Charges - South Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-106, interest expense on the balance in Deferral Account No. 179-106. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Spot Gas Variance Account
Deferral Account No. 179-107

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-107 Other Deferred Charges –Spot Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-107, 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.

Debit	-	Account No. 623 Cost of Gas
Credit	-	Account No. 179-107 Other Deferred Charges –Spot Gas Variance Account

To record, as a credit (debit) in Deferral Account No. 179-107, the approved gas supply charges recovered through the delivery component of rates.

Debit	-	Account No. 179-107 Other Deferred Charges – Spot Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-107, interest expense on the balance in Deferral Account No. 179-107. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Unabsorbed Demand Cost (UDC) Variance Account
Deferral Account No. 179-108

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-108, the difference between the actual unabsorbed demand costs incurred by Union and the amount of unabsorbed demand charges included in rates as approved by the Board.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-108, interest expense on the balance in Deferral Account No. 179-108. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for Inventory Revaluation Account Deferral Account No. 179-109

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-109 Other Deferred Charges – Inventory Revaluation
Credit	-	Account No. 152 Gas Stored Underground - Available for Sales
Credit	-	Account No. 153 Transmission Line Pack Gas

To record, as a debit (credit) in Deferral Account No. 179-109, the decrease (increase) in the value of gas inventory available for sale to sales service customers due to changes in Union's weighted average cost of gas approved by the Board for rate making purposes.

Debit	-	Account No. 179-109 Other Deferred Charges – Inventory Revaluation Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-109, interest expense on the balance in Deferral Account No. 179-109. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

TAB 2

TRANSPORTATION EXCHANGE SERVICES

INTRODUCTION

This evidence describes transportation exchange services sold to meet market demands of S&T customers, how these transportation exchange services are provided, and how the introduction of TCPL's Firm Transportation - Risk Alleviation Mechanism ("FT-RAM") program did not change the fundamental transportation exchange services that Union provides. The evidence demonstrates that the transportation exchange services provided by Union meet the criteria established by the Board in recent Decisions.

Specifically, this evidence reviews exchange services in the following sections:

1/ What are Transportation Exchanges?
2/ Financial Results for 2012 Transportation Exchange Services
3/ Revenue Treatment of 2012 Transportation Exchange Services
4/ Who Purchases Transportation Exchange Services?
5/ Who Benefits from Transportation Exchange Service Revenue?
6/ What Resources are Available for Transportation Exchange Services?
7/ Determining the Resource for Transportation Exchange Services
8/ Transportation Exchange Service Risks
9/ Transportation Exchange Service Examples – Base Transportation Exchange

1/ WHAT ARE TRANSPORTATION EXCHANGES?

Transportation exchange services are the movement of gas between two locations, where at least one location is not located on the Union transmission system. Using a transportation exchange service, Union "exchanges" gas held by it at one location for gas held by a counterparty at another location. Transportation exchanges are comparable to transportation services, where Union moves gas between two locations on its own transmission system. These descriptions were first provided in EBRO 499:

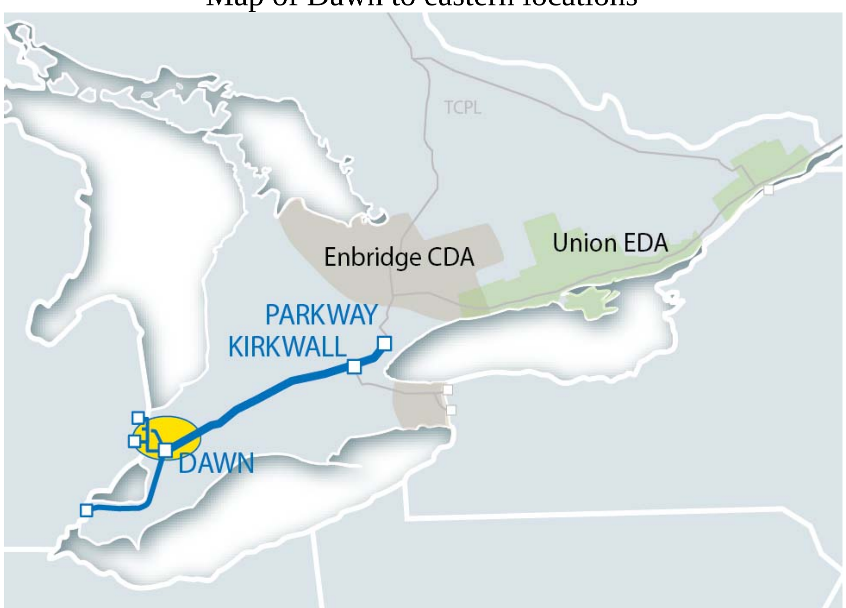
> *Transportation and Exchanges*
> *Both of these services allow customers to move gas from one location to another. Transportation service transports gas between any 2 points on Union's system on a short term firm, limited firm or interruptible basis. Under an exchange agreement, gas is typically received by Union at a point on the Union system in exchange for gas delivered to the other party at a point outside the Union system.*
> *EBRO 499, Exhibit C1, tab 3, Page 8*

An example of a transportation service is a service from Dawn to Parkway, where both Dawn and Parkway are locations on Union's transmission system.

An example of a transportation exchange is service from Dawn to Enbridge CDA,[1] where only Dawn is a location on the Union transmission system and Enbridge CDA is a location on the TCPL transmission system. In this example, Union combines transportation from Dawn to Parkway (on its transmission system) with transportation contracted on TCPL to deliver gas to Enbridge CDA to provide this service.

The location of Dawn, Parkway and Enbridge CDA is shown on Figure 1.

Figure 1
Map of Dawn to eastern locations



Union has provided transportation exchange services since the early 1990s, treating transportation exchange services as revenue until 2011. Between 1993 and 2007

[1] Enbridge CDA is a delivery area defined in TCPL's tariff. It extends from Barrie to Niagara Falls, and includes the Greater Toronto Area (GTA).

variances in transportation exchange service revenues were recorded in a deferral account and shared with ratepayers. From 2008 to 2010, transportation exchange revenue was recorded as utility revenue, subject to earnings sharing as defined by the IRM. In 2011, the Board determined $18.9 million of Union's net FT-RAM related transportation exchange revenue ("FT-RAM revenue") should be treated as a gas cost reduction.

Responsibility for Transportation Exchange Services

Union's S&T group has responsibility for the sale of transportation exchange services. This function is separate and distinct from the Gas Supply department, which is responsible for establishing the Gas Supply Plan. This separation is necessary to ensure that the Gas Supply Plan is developed independently and maintains an exclusive focus on meeting in-franchise (system sales and bundled direct purchase) customer requirements in accordance with the Gas Supply planning principles. As a result, the Gas Supply Plan is not influenced by potential sales and marketing opportunities of transportation exchange services.

The Gas Supply Plan is one component of the overall management of Union's transmission and storage operations. Union ensures all customer requirements, including in-franchise and ex-franchise customers, are met each day. As part of the overall system management, the Gas Control and Volume Planning function forecast daily demands across the entire Union franchise. This determines the required flows on upstream transportation contracts and on Union's transmission system in order to meet all customer requirements. Consequently, this function determines the transportation that is required and the transportation that is temporarily surplus on a daily basis. In conjunction with the Gas Control and Volume Planning function, the Capacity Management and Utilization group forecasts the transportation that is required and that is temporarily surplus for a longer time period, including the next month and season. The Capacity Management and Utilization group also assesses the costs and potential risks associated with using temporarily surplus capacities to support the sale of transportation exchange services by S&T Sales.

S&T Sales is responsible for assessing market opportunities and selling transportation exchange services to S&T Customers. This group also purchases any additional resources for the purpose of increasing the value of S&T exchange services; the cost of which is netted against transportation exchange revenue.

In this evidence, Union refers to the Capacity Management and Utilization group and the S&T Sales group collectively as the “S&T Group” or “S&T”. Along with the Gas Control and Volume Planning function, they manage the use of storage and transmission assets to meet all utility and non-utility demands.

2/ FINANCIAL RESULTS FOR 2012 TRANSPORTATION EXCHANGE SERVICES

In 2012, Union realized net transportation exchange service revenues of $51.6 million, of which $37.3 million is net FT-RAM revenue. This revenue is in excess of the net revenue (also known as margin) included in delivery rates, and contributes towards Union's utility earnings that are proposed to be shared with ratepayers through the earnings sharing mechanism. The alternative treatment of the FT-RAM related activity is provided in Exhibit B, Tab 4. The S&T group was able to achieve the level of transportation exchange revenues due to a number of reasons:

1. Weather: The warmer than normal winter and warmer than normal summer of 2012 provided opportunities to provide transportation exchange services throughout each season. During the winter months, this resulted in additional temporarily surplus transportation available for transportation exchange services. During the summer months, this resulted in additional market demands for transportation exchange services.
2. Continued de-contracting on TCPL: De-contracting on TCPL resulted in increased TCPL tolls and increased participation of parties in the secondary market. This trend supported a corresponding increase in transportation exchange service value and revenue.
3. Sales Experience: As S&T continues to gain experience with the changing market dynamics, transportation exchange services and FT-RAM, the overall transportation exchange service revenue results improve.

4. Market Experience: Participants in the secondary market have also gained experience with how to use the FT-RAM program and related transportation exchange services to meet market opportunities. With this experience, S&T Customers have generated an increased number of requests for Union's transportation exchange services.

3/ REVENUE TREATMENT OF 2012 TRANSPORTATION EXCHANGE SERVICES

For 2012, Union proposes that the net FT-RAM revenue be treated as utility earnings, subject to earnings sharing. This treatment is supported by the following:

- Transportation exchange service revenue criteria established by the Board in recent regulatory decisions (discussed in further detail in Exhibit B, Tab 1); and,
- Risk accepted by S&T to provide transportation exchange services while also meeting obligations to system sales and bundled direct purchase customers.

Table 1 applies the evaluation criteria used by the Board and outlined in Exhibit B, Tab 1 to distribute transportation exchange service benefits to the 2012 transportation exchange service activity. The Table also shows the result of the additional criteria identified by Union, that is, whether the surplus capacity was used to sell a service. Union uses the following three criteria to determine if each transaction type generates revenue or reduces costs:

1. Temporary Surplus – the activity is served by some quantity of the upstream transportation capacity, or a portion of its path distance, that is not required on a temporary basis to meet market area demands. The temporary surplus capacity varies depending on weather and market demands. This concept is fully described in Section 7.2
2. Unplanned – the activity is not included in the Gas Supply Plan
3. Sold as Service – the activity is a service provided to an S&T Customer

Table 1

Evaluation of 2012 Transportation Exchange service and FT-RAM related activity

		2012 Results	Criteria			Conclusion*
			Temporary Surplus	Unplanned	Sold as Service	
	Utility Use of FT-RAM					
①	System Supply Balancing (LBA)	$0.6 M	✓	✓	X	Cost Reduction
②	System Supply Balancing (UDC Assignments)	$6.7M	✓	**both planned and unplanned**	**N/A**	Cost Reduction
					Total Utility Benefit	$7.3M
	Transportation Exchange Services					
③	Transportation Exchanges - Base	$14.3M	✓	✓	✓	Revenue
					Total Transportation Exchanges - Base	$14.3M
	Transportation Exchange Services and Use of FT-RAM					
④	Transportation Exchanges - FT-RAM related (Summer**)	$3.7M	✓	✓	✓	Revenue
⑤	Transportation Exchanges - FT-RAM related (Winter)	$1.8M	✓	✓	✓	Revenue
⑥	Transportation Exchanges - Transportation Assignments (Summer**)	$25.9M	✓	✓	✓	Revenue
⑦	Transportation Exchanges - Transportation Assignments (Winter)	$5.9M	X	✓	✓	Revenue
					Total Transportation Exchanges - FT-RAM related	$37.3M
					Total All Transportation Exchanges	$51.6M

* If transaction was underpinned by temporary surplus asset and sold as a service, it is classified as revenue. If Union assumed incremental risk, regardless if the asset is temporary surplus, it is classified as revenue. All other cases, it is classified as cost reduction.

** Summer defined in this analysis as Summer months April - October plus shoulder months, March & November

The Table illustrates how each of Union's transportation exchange service transaction types has been evaluated against these three criteria. For example, if the transaction was underpinned by a resource that was temporarily surplus, if the activity was not planned in the Gas Supply Plan, and if the activity was the sale of a service to an S&T Customer, then the proceeds from that transaction are proposed to be treated as revenue. These results are discussed for each transaction type below. A further description of Base Exchange services, FT-RAM related transportation exchange services and transportation exchanges (transportation assignments) is provided in the remainder of this evidence.

Utility Use of RAM

- System Supply Balancing (LBA) (Line 1) - These transactions occur when Union uses FT-RAM credits to reduce Limited Balancing Agreement ("LBA") fees, as described in Section 11. The FT-RAM benefits are due to temporary surplus capacity, but are not used to sell a transportation exchange service, and therefore do not generate revenue. The entire benefit of the LBA cost reduction is streamed to ratepayers.
- System Supply Balancing (UDC Assignments) (Line 2) - These transactions occur when it is determined there is more system supply than is required to meet seasonal demands. In this case, there is both temporary surplus of system supply and the associated upstream transportation. Therefore, gas supply purchases are reduced, and transportation capacity is released to mitigate UDC (UDC Assignments). Proceeds from the assignment of capacity are credited to ratepayers through the UDC deferral account. UDC occurs on both a planned and unplanned basis.

Base Transportation Exchange Services

Base Transportation Exchanges (Line 3) - Base transportation exchange services are the same transactions that occurred historically and are described in Section 9. The resources underlying these transactions are temporarily surplus to the Gas Supply Plan, and result from temporary weather and consumption variances. Since these transactions are served by resources required by in-franchise customers on a design day, most of these transactions are completed on an interruptible basis. The Gas Supply Plan does not allocate any resources to base transportation exchange services on a planned basis. All transportation exchange services are sold to S&T Customers. Union proposes to treat these transportation exchange service proceeds as revenue.

FT-RAM Related Transportation Exchange Services

- Transportation exchanges (FT-RAM related - Summer and Winter) (Lines 4&5) - Both of these items meet the criteria outlined by the Board and should be treated as revenue. As described in Section 12.1, these transactions are completed when the market area does not require the full use of transportation capacity on that day (non-design day), and only a portion of the contracted path distance is required to meet annual requirements. The portion of the contract distance that is not required is temporarily surplus. For example, if not all of the Empress to Union EDA path is required, and the gas is transported to storage at Dawn, then Dawn to

Union EDA is temporarily surplus. The value of this temporary surplus is monetized through FT-RAM credits. These surplus credits are not required by system supply and bundled direct purchase customers and can be used to provide transportation exchange services to S&T Customers. The ability to generate FT-RAM credits to support these transactions is dictated by market requirements and weather. For example, during the coldest winter days, this capacity is not surplus and the gas supply flows on a firm basis to the market area, meaning that no FT-RAM credits are generated.

- Transportation Exchanges (Transportation Assignments Summer/Shoulder) (Line 6) - This item, described in Section 12.2, meets the criteria outlined by the Board. In this case, the service sold to the S&T Customer is a combination of a temporary release of Union's TCPL transportation capacity and the sale of a transportation exchange service. The temporary surplus capacity results from the unlikely event that a design day will occur between March and the following November, and that a portion of the transportation path is not required. In the summer, this portion of the path is the distance between Dawn and the market area. The Gas Supply Plan does not plan for the assignment of this capacity. To do so would compromise the accepted gas supply planning principles, expose customers to operational and price risk, and may not result in a more cost effective option. Union proposes to treat the proceeds from summer assignment/transportation exchange service as revenue.

- <u>Transportation Exchanges – (Transportation Assignments - Core Winter) (Line 7)</u> - Union proposes that this item does not meet the criteria of temporary surplus as outlined by the Board. In this scenario, as with the temporary assignments in the summer, the service sold is a combination of Transportation Assignment and transportation exchange service. While on most days during this period there may be transportation that is temporarily surplus to the utility needs, at the time of sale, Union cannot be certain that a design day will not occur. On days where there is a design day, then there is no temporary surplus asset. As a result, S&T incurs risk to provide the transportation exchange service. The risks assumed by S&T and the mitigation of those risks are discussed in Section 8. Union believes, as part of the 2008-2012 IRM mechanism, that the assumption of incremental risk results in proceeds from that transaction flowing to revenue. As with the above listed transportation exchange service transactions, the Gas Supply Plan does not plan for or allocate resources to support the sale of transportation assignments. As a result of the risk, Union proposes to treat the proceeds from winter assignment/transportation exchange service as revenue.

All FT-RAM related transportation exchange services in 2012 were sold on a daily, monthly or seasonal basis. There were no annual transactions.

4/ WHO PURCHASES TRANSPORTATION EXCHANGE SERVICES?

Buyers of transportation exchange services include market participants who have not purchased transportation services from the primary service provider (e.g. TCPL) that meet all of their needs. When buyers purchase services from holders of existing capacity rather than purchasing directly from the primary service provider, it is referred to as the secondary market. These buyers may be seeking transportation services in the secondary market because:

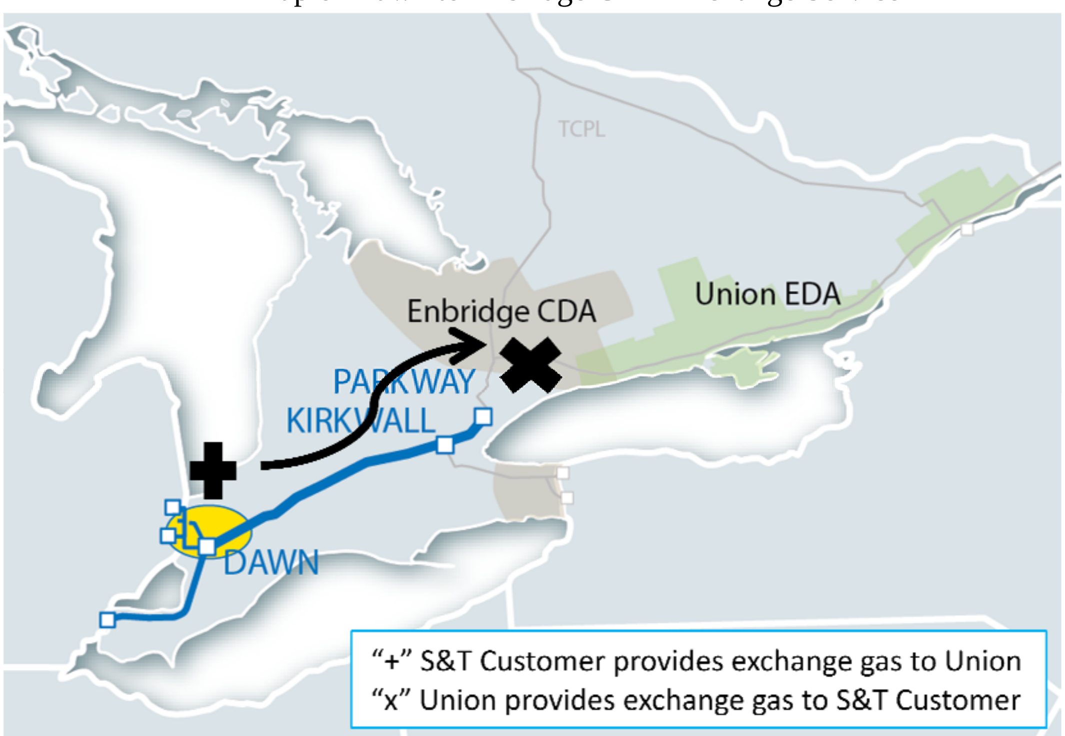
- the requested service is not available from the primary service provider; or
- they may be seeking a reduced term or price that was not available from the primary service provider

Secondary market participants include Ontario power producers, industrial customers and marketers serving end-use residential and commercial consumers. Union supports secondary market transactions through the sale of transportation exchange services, including the releasing of upstream transportation capacity on a temporary basis. Buyers in the secondary transportation market approach Union with a request for a transportation exchange service, Union confirms its capability to provide the service, and determines the market value and assumed risks prior to committing to the sale of the transportation exchange service. The process of determining capability, market value and risk is discussed later in this evidence.

For example, if a secondary market participant is seeking a transportation service from Dawn to Enbridge CDA for one month, this may not be available from TCPL (the primary service provider), and the market participant may search for capacity in the secondary market, including from Union or Enbridge.

A map that illustrates a Dawn to Enbridge CDA transportation exchange service is included as Figure 2.

Figure 2
Map of Dawn to Enbridge CDA Exchange Service



Union has played an increasing role in providing transportation exchange services to the secondary market. The number of secondary market participants who have purchased transportation exchange services from Union has increased in 2012 versus 2006 as shown in the Table below. In 2012, Union provided transportation exchange services to 33 different secondary market participants, or S&T Customers. S&T Customers include large industrial and power customers, as well as agents and marketers who serve end-use residential, commercial and industrial customers in Ontario.

Table 2
Number of Transportation Exchange Service Counterparties and Transactions

	2006	2007	2008	2009	2010	2011	2012
Number of Counterparties	15	18	22	22	37	34	33
Number of Billed Transactions	27	37	131	338	614	1,026	1,688

The secondary market has been a key part of the natural gas market in Ontario and ensures that market participants have multiple options to secure the most economic supply. The Table also shows how the number of billed transactions has increased significantly in 2012 versus 2006. Increased activity by Union and other LDC's since 2008 including the use of FT-RAM played a key role in the growth of the secondary market, as evidenced by the increases in the number of counterparties transacting with Union, as well as the number of billed transactions.

A description of the secondary market for transportation exchanges and the economic benefits they deliver can be found in Exhibit C, Tab 1. Even when the FT-RAM program ceases on July 1, 2013, the secondary market will continue to exist. The size and depth of activity of this market is likely to shrink but will ultimately depend upon the financial opportunity available for all market participants.

5/ WHO BENEFITS FROM TRANSPORTATION EXCHANGE SERVICE REVENUE?

Revenue generated from the sale of transportation exchange services provides benefits to all natural gas market participants and consumers in Ontario. The benefits and the beneficiaries include:

1. Reduction in rates: Throughout Union's history of transportation exchange services, a level of forecasted exchange margin has been shared with all of Union's in-franchise customers by reducing the revenue requirement included in rates. During IRM (2008-2012), Union's revenue requirement was reduced by $6.9 million, to build an incremental forecast of transportation and exchange service margin into delivery rates. This is discussed in further detail in Exhibit B, Tab 1.
2. Sharing: Prior to 2008, ratepayers realized the benefits of transportation exchange service revenue greater than forecast through the disposition of a transportation and exchange deferral account. If exchange service margin

exceeded forecast, the difference was recorded in a deferral account and shared on a 75/25 basis with ratepayers. Effective in 2008, as part of the EB-2007-0606 IRM Settlement Agreement, the deferral account was eliminated and, as an offset, a higher level of transportation and exchange service margin was included in delivery rates. Further, any actual transportation and exchange service margins in excess of $6.9 million contributed to the amount of utility earnings that was shared with ratepayers, according to the IRM provisions. Between 2008 and 2010, transportation exchange activity contributed to $14.9 million in benefit to ratepayers. In 2011, the Board directed Union to treat net FT-RAM revenue as a gas cost offset, benefitting only system sales and bundled direct purchase customers. For 2012, Union proposes that $15.7 million in earnings be shared with ratepayers, largely driven by transportation exchange activity.

3. Price transparency: The increased gas purchases/sales transactions at Dawn and at other exchange service locations such as Parkway, Enbridge CDA and Waddington[2] increase price transparency and overall market liquidity, increasing the opportunity for natural gas consumers (including industrial customers and power producers) to pay a market responsive and competitive price for gas commodity and services.
4. Efficient use of pipeline assets: The sale of transportation exchange services and the resulting increase in pipeline utilization promotes the efficient use of pipeline

[2] Waddington is a location on the TCPL system near Kingston, Ontario. Gas at this location can be exported to/imported from the US northeast.

assets, thereby reducing the need for pipeline expansions that may otherwise only be supported by intermittent or non-firm loads.

5. Access to a liquid supply hub: Union's sale of transportation exchange services provides greater access to the Dawn market hub. Access to this hub, the second largest in Canada, provides supply certainty at market competitive prices to the benefit of gas consumers.

All Ontario gas consumers benefit from the sale of transportation exchange services, as more fully described in Exhibit C, Tab 1. The margins from transportation exchange services are shared with ratepayers through the earnings sharing mechanism, and the availability of transportation exchange services, including exchange services supported by FT-RAM, contributes to the secondary market in Ontario and a reduction in natural gas delivery rates and commodity costs for all Ontario consumers.

6/ WHAT RESOURCES ARE AVAILABLE FOR TRANSPORTATION EXCHANGE SERVICES?

When an S&T Customer approaches Union to provide a transportation exchange service, Union considers all of the resources that may be available to meet this market demand. During 2012, the three types of resources used to provide transportation exchange services included: transportation on Union's system, use of temporarily surplus upstream transportation capacity from the Gas Supply Plan, and purchased resources. These resources are often combined together in order to provide transportation exchange services.

1. Union transportation. Union often uses its own transmission system, primarily Dawn to Parkway transportation, to provide transportation exchange services. Many exchange services include Dawn as a receipt point because it is a Market Hub. The receipt point is the location where an S&T Customer provides gas to Union. For example, in a Dawn to Enbridge CDA exchange service, this transaction requires the use of Dawn to Parkway transportation, as well as service on TCPL from Parkway to Enbridge CDA. An illustration of this can be found in Section 9.
2. Upstream transportation. Upstream transportation includes all of the transportation contracts that are within Union's Gas Supply Plan. These are transportation services that are contracted by Union to meet the firm demands of system sales and bundled direct purchase customers.

Examples in this evidence focus on TCPL capacity, but transportation on all of the pipelines included in the Gas Supply Plan may be used to provide a transportation exchange service.

The use of upstream transportation to provide a transportation exchange service does not affect the purchases of gas supply to meet Union's system supply and bundled direct purchase customer consumption requirements; Union continues to purchase its supply in accordance with the Gas Supply Plan. A temporary surplus of upstream transportation capacity is related to the demands in the market area, and not to the supply to be delivered pursuant to the Gas Supply Plan. When a transportation exchange service is sold, it may affect the path on which that gas flows, but in all cases, the gas supply is purchased at the planned location (e.g. Empress) and arrives at the required locations to meet the needs of the system sales and bundled direct purchase customers.

The map included in the Appendix to this evidence illustrates Union's system and pipelines included in its upstream transportation portfolio.

3. Purchased Resources. S&T may purchase additional firm or interruptible transportation services to pair with upstream transportation or Union transportation in order to provide transportation exchange services or to enhance their value. These purchases are not considered within the Gas Supply Plan and are not charged to, nor intended to serve, system sales and bundled direct purchase customers.

For example, to provide a firm transportation exchange service from Dawn to Union SSMDA[3] for the period of November 2011 to March 2012, S&T

[3] Union SSMDA is the delivery area that includes Sault Ste. Marie, Ontario, and can be seen on the map in the Appendix.

purchased a firm exchange service contract from the secondary market for transportation between these same two points. To meet the customer requirement of an annual transportation exchange service, this winter exchange was combined with existing upstream transportation to Union SSMDA that is temporarily surplus in the summer months. There was no impact to the Gas Supply Plan as the transportation exchange service was completely offset by the purchase of a firm exchange contract in the winter, and used temporarily surplus capacity in the summer. All incremental costs to service the deal, including the purchased winter exchange service, were charged against transportation exchange service revenue.

7/ DETERMINING THE RESOURCE FOR TRANSPORTATION EXCHANGE SERVICES

The determination of which of the three resources to use when providing a transportation exchange service is driven by three factors:

1. The locations of the S&T Customer request;
2. The availability of the resources; and
3. The market value and costs for the exchange service.

7.1 The Locations of the S&T Customer Request

The first determinant of which resources to use to provide a transportation exchange service is the location (receipt and delivery points) of the requested transportation exchange service. The receipt and delivery point dictate which pipelines can be used to provide the transportation exchange service. For example, a transportation exchange service from Dawn to Enbridge CDA means Union receives gas from the S&T Customer at Dawn and exchanges it to the customer in the Enbridge CDA. This transaction requires use of Union's Dawn to Parkway transmission system as well as use of TCPL transportation to Enbridge CDA. The transportation used on TCPL may be sourced as a purchased asset, or may be some temporarily available capacity on TCPL from the Gas Supply Plan.

7.2 The Availability of the Resources

Once the exchange location narrows which transportation assets can be used to serve the transportation exchange, Union then determines which of these assets are available to use. Before considering the purchase of a new asset, Union first evaluates if there is any available capacity on existing assets, such as those on its own system and in the Gas Supply Plan.

Temporarily Surplus

The Gas Supply Plan determines the appropriate quantity, path and term of gas supplies and upstream transportation services needed to meet customer requirements. Specifically, these are the annual, seasonal, and design day requirements of its system sales and bundled direct purchase customers. On non-design days, a portion of any upstream transportation path may be temporarily surplus and available to facilitate transportation exchange service transactions. Upstream transportation is temporarily surplus when the path, or a portion of the path distance, is not required to meet the market area demands. The quantity of temporarily surplus capacity varies daily, based on factors such as market demands and weather. Examples of temporary surplus resources include:

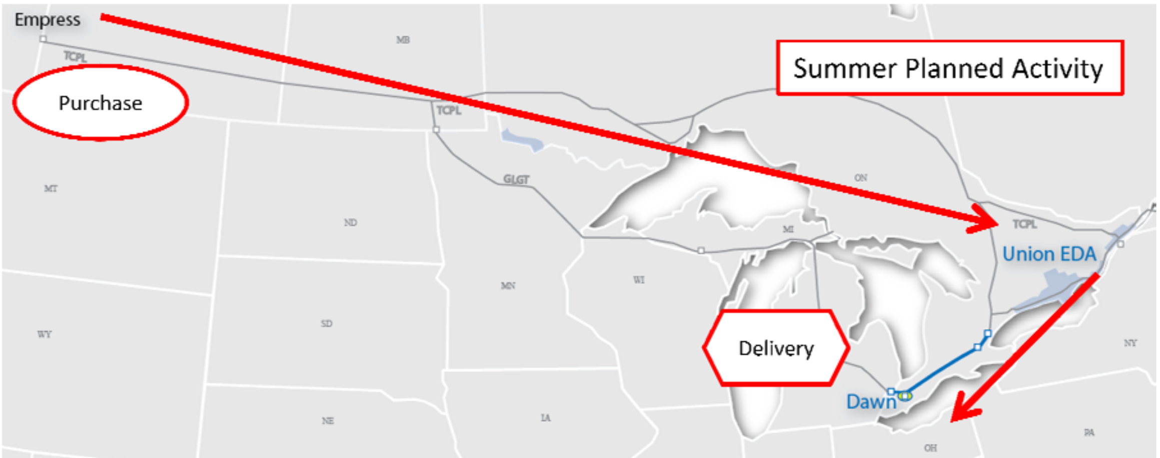
- In the summer months, system sales and bundled direct purchase customer requirements are lower than average in the market area on a given day, resulting in gas supply injected into storage at Dawn. Therefore, some of the transportation capacity into the market area would be temporarily surplus.
- In the winter months, system sales and bundled direct purchase customer requirements may be lower than design day in the market area on a given day, resulting in a reduction in the need for withdrawals from Dawn. The transportation capacity between Dawn and the market area may be temporarily surplus.

Example of Temporarily Surplus Capacity - Summer

Figure 3 illustrates summer activity to serve the Union EDA market, pursuant to the Gas Supply Plan.

Figure 3

Gas Supply Plan for Union EDA Summer Activity



On a planned basis in the summer months, Union needs some gas supply to serve markets and some gas supply to replenish storage inventory. Excess supply not needed by the market on any given day flows from the market area to Parkway using TCPL's storage transportation service ("STS"), then to Dawn for injection to storage. For gas destined for storage, only a portion of the contracted distance from Empress is needed. The remaining distance between storage and the market area (the contracted delivery point) is temporarily surplus capacity, and is available to provide transportation exchange services. For example, only some of the gas supply purchased at Empress for the Union EDA in the summer is needed to serve the market; the remainder only needs to travel as far as storage at Dawn. Therefore, there is some capacity on the path between Dawn and the Union EDA that is *surplus* on a temporary basis. The temporarily surplus capacity is illustrated in Figure 4.

Figure 4
Union EDA Temporarily Surplus Capacity – Summer

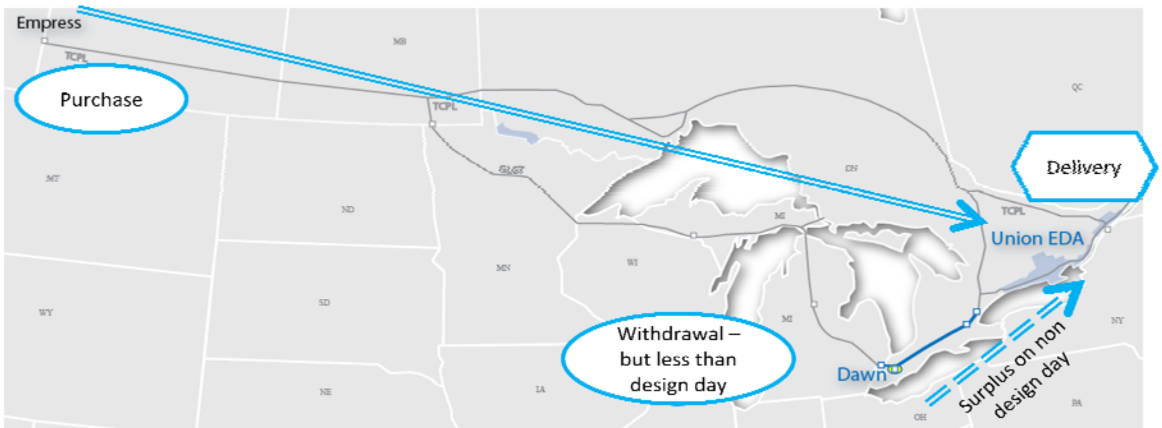
Example of Temporarily Surplus Capacity - Winter

Union also provides exchange services using upstream transportation during the winter months. During these months, Union plans to meet market Union EDA demands by transporting gas supplies using long haul transportation from Empress as well as using short haul transportation services (including TCPL's STS) to move gas from Dawn storage. Figure 5 illustrates the Gas Supply Plan winter activity.

Figure 5
Gas Supply Plan Winter Activity

On non-design days during the winter months, there may be transportation capacity that is temporarily available to provide transportation exchange services. Since the demands of system sales and direct purchase customers may be less than the design day, some gas will remain in storage instead of being withdrawn to serve the Union EDA market. Therefore, some of the transportation path between Dawn and the Union EDA is *surplus* on a temporary basis. The temporarily surplus capacity is illustrated in Figure 6.

Figure 6
Union EDA Temporarily Surplus Capacity – Winter



During the winter season, Union cannot always be certain if the upstream transport beyond the next day will be temporarily surplus because there is the risk that a design day will occur. Therefore, most transportation exchange services sold are shorter term (one month or less) or interruptible. From time to time (and during IRM), S&T sells transportation exchange services for one month or the entire winter season, taking the risk that a design day will not occur during that time and that there will be upstream transportation that is surplus to the market requirements. If sustained cold weather or a design day does occur, S&T takes action to serve both the in-franchise firm customer and firm transportation exchange services, and any costs to do so are charged against transportation exchange service revenue. The risks and potential costs related to transportation exchange services are described in greater detail in Section 8.

In addition to whether the upstream transportation resource is temporarily surplus, Union also considers the level of transportation exchange service reliability being requested, that is, firm or interruptible service. Union's capability to provide a firm or interruptible transportation exchange service is impacted by the certainty of the availability of the temporary surplus capacity, and is therefore dependent on the season of the service (summer or winter) and the forecasted weather.

If Union determines it does not have the sufficient capacity available using existing assets to serve the transportation exchange, then purchased resources are considered, as described in Section 6.

7.3 The Market Value and Costs for the Transportation Exchange Service

After determining which capacity may be used to provide the transportation exchange service, Union considers the costs of providing the service, as well as potential costs relating to transaction risk. Union evaluates the market value relative to the total costs of the proposed transportation exchange service, and proceeds if there is positive net revenue.

The market value for the transportation exchange service is typically the difference in gas value between the receipt and the delivery location (referred to as the "basis").[4] The

[4] For example, if the value of gas at Dawn is $4/GJ and the value of gas at Enbridge CDA is $5/GJ, the value of the exchange is $1/GJ.

difference in gas value between two locations is impacted by supply and demand at each location, the transportation costs of primary transportation providers, and the transportation alternatives available.

The costs of providing a transportation exchange service include the applicable variable pipeline costs and fuel owing to the pipeline (e.g. TCPL), variable costs of compressor fuel and unaccounted for gas ("UFG") incurred on Union's own transmission system, and opportunity cost of C1 Dawn to Parkway transportation. For example, to provide a winter Dawn to Enbridge CDA transportation exchange service, Union requires Dawn to Parkway transmission and Parkway to Enbridge CDA transportation. In this case, Union considers the following costs:

- Dawn to Parkway fuel and UFG on Union's system
- the opportunity cost of using Dawn to Parkway capacity to provide a transportation exchange service rather than selling C1 Dawn to Parkway transportation directly
- TCPL variable and fuel charges to transport the gas to Enbridge CDA

In some cases, Union may have more than one method of providing the transportation exchange service. Only options with costs less than the market value will be pursued.

When Union incurs incremental cost to provide a transportation exchange service, either from purchasing a service or from using upstream transportation capacity in a different manner than was included in the Gas Supply Plan, these costs are attributed to transportation exchange service revenue.

There may also be potential costs relating to transaction risk, as described below.

8/ TRANSPORTATION EXCHANGE SERVICE RISKS

S&T assumes a number of risks when it sells a transportation exchange service. These risks include temporarily surplus capacity becoming no longer available, interruptible transportation service on other pipelines being curtailed, or counterparties failing in the delivery of their service to S&T. Overall, transaction risks are lower in the summer months, driven by lower customer demands and less expensive mitigation measures. Directionally, transactions with a higher risk have the potential for higher revenues, while lower risk transactions result in lower revenues. In some situations, S&T chooses to mitigate a risk before it occurs. Table 3 outlines the potential risks, mitigations and impacts related to transportation exchange services.

Table 3
Description of Risks Assumed by S&T

	S&T's Risk	Description	S&T Mitigation Actions	Potential Mitigation Impact
1	Temporary Surplus No Long Available	Weather could be colder than forecast and/or market consumption could be higher than forecast – reducing the temporary surplus transportation	S&T purchases gas supplies for delivery to transportation exchange service location	Cost of purchased gas may exceed transportation exchange service revenue
			S&T sells transportation exchange services as interruptible service	Interruptible transportation exchange services have less value than firm transportation exchange services
			S&T sells transportation exchange services for a shorter term (end date is closer to current date)	Lack of demand and value for short term transportation exchange services
			S&T sells transportation exchange services close to flow date (start date is closer to current date)	Lack of demand and value for short term transportation exchange services
2	Upstream Transportation Reliability	Upstream transportation to provide exchange services is an interruptible service that may be curtailed	S&T reviews flow information from pipeline to determine potential bottlenecks and any changes in operations in order to use alternative transportation routes.	Alternative routes may not be available or costs may exceed exchange service revenue
			S&T purchases additional pipeline resources to improve reliability	Purchased resource may not be available or costs may exceed transportation exchange service revenue
3	Pipeline Disruption or any other risk	Pipeline has a force majeure event or gas is not delivered to serve transportation exchange services as per contract arrangements	S&T purchases gas supplies for delivery to transportation exchange service location	Cost of purchased gas may exceed transportation exchange service revenue

S&T only provides a transportation exchange service and implements the appropriate risk mitigation measures if:

1. There is a market request for the transportation exchange service;
2. There is temporarily surplus upstream transportation available or purchased resources to provide transportation exchange services;
3. The expected revenues exceed the costs to provide the service; and
4. The overall risk is acceptable.

In recent history, S&T experienced a number of the risks identified above:

- Scheduling reductions – During the winter of 2012/2013, interruptible and diversion transportation services which underpin transportation exchange service activity was curtailed on 79 days. This affected 24 paths on the TCPL system that S&T uses to serve exchanges.
- Gas not delivered – In three of the last five years, there were incidents where firm transportation exchange service gas was not delivered to S&T according to contractual arrangements. In each of these events, S&T took immediate action to arrange delivery of the exchange gas, or to utilize other surplus transportation to continue to meet the market demands.

The risks associated with scheduling reductions were demonstrated on February 20, 2011. On this day, there was an incident on the TCPL pipeline (at Beardmore) that limited TCPL's ability to provide interruptible transportation services. On the day prior to this event, S&T was flowing 70,356 GJ of interruptible transportation from Empress to various locations across the TCPL system. The use of interruptible transportation created

FT-RAM credits and reduced the costs of providing transportation exchange services. On the day of the incident, S&T received notice of the potential curtailments of interruptible service prior to the commencement of the gas day. S&T immediately changed its nomination for services and began flowing supply on its firm transportation contracts rather than using interruptible transportation. Had S&T not responded immediately to the notice, or if the notice was received later in the gas day, S&T would have missed the opportunity to change its nominations, the interruptible transportation would have been curtailed, and S&T would have had stranded gas supply at Empress. With respect to market demands, if S&T was unable to transport gas to the market areas, either S&T would have incurred substantial imbalance penalties from TCPL, or alternatively, S&T would have purchased premium priced gas at locations beyond the incident and transported it to the market areas.

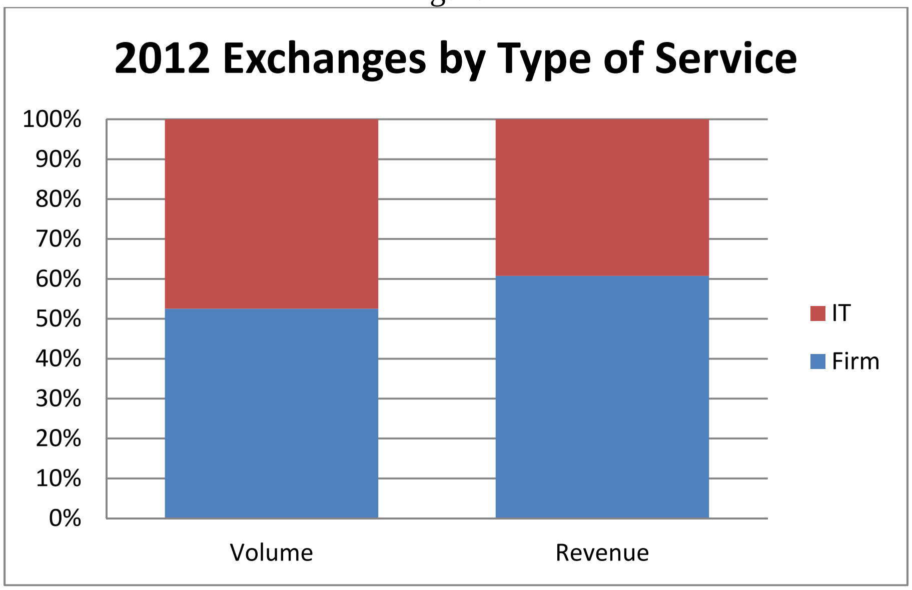
S&T incurred $77,000 of balancing penalties on this day that were attributed to transportation exchange service revenue. However, if the timing of the incident were different and S&T had not been able to use firm transportation to meet demands, the penalties on this day were estimated to be $1.5 million. This single-day cost represents more than 50% of the value that S&T earned for all transportation exchange transactions during the month of February.

The impact of these risks required S&T to manage daily consumption and market requirements at any cost necessary to meet firm demands. On all occasions, all firm requirements were met.

S&T cannot eliminate all risks when providing transportation exchange services, however it does take steps to proactively mitigate them. During 2012, S&T entered into both firm and interruptible transportation exchange services, sold contracts with both short and longer terms (one day, one season) and sold contracts immediately before flow day (the day prior) and a few months before the flow date. S&T purchased additional resources outside of the Gas Supply Plan (such as the Union SSMDA to Dawn exchange service discussed in Section 6) to expand the range of services offered, to improve reliability and to reduce risk.

The diversity of the transportation exchange service portfolio, including a blend of contract terms and service quality, maximizes net revenues, while managing, but not eliminating risk. The chart in Figure 7 shows the split of firm versus interruptible for both volume and revenue in 2012.

Figure 7



Firm transportation exchange services are a much higher quality service than interruptible transportation exchange service, but firm transportation exchange services have a greater likelihood that one or several risks may occur during the term of the service. If a risk materializes, S&T may incur additional costs in order to meet the obligations of both the firm transportation exchange service and the firm in-franchise requirements. For example, during IRM, if S&T sold a firm transportation exchange service from Dawn to Enbridge CDA, and the weather forecast was incorrect and the transportation resource underpinning the service was required to serve Union's firm in-franchise customers, S&T transportation exchange revenue would be reduced by whatever further costs are required to serve the firm Dawn to Enbridge CDA transportation exchange service. The costs may include purchasing a service from another secondary market participant or purchasing gas at Enbridge CDA. For example, in January 2013, if S&T had to purchase a backstop service to serve the firm exchange commitment at Enbridge CDA, the costs were as high as \$22.87/GJ. This would equate to a cost of nearly \$230,000 per day to serve an exchange of 10,000 GJ/day.

The acceptable risk profile of transportation exchange services in 2012 was determined and accepted by Union based on the assumption that revenues and costs would be treated in a manner consistent with past practices within the IRM. In 2012, all transportation exchange service risks, whether or not the risk materialized, were a factor in the determination of Union's transportation exchange revenue.

9/ TRANSPORTATION EXCHANGE SERVICE EXAMPLES – BASE TRANSPORTATION EXCHANGE

The following two examples illustrate transportation exchange services that apply to all transportation exchange service activity, independent of the FT-RAM program. In all of the cases in this evidence (Case 1 – 6), an S&T Customer has requested a transportation exchange service and Union has followed the steps described in Section 6 through Section 8 to determine if the service can be provided for a price acceptable to Union and the S&T Customer. This price considers the underlying costs of using Union's transmission system, the incremental costs of using TCPL's transportation services, and the potential exchange service risks discussed above.

Case 1

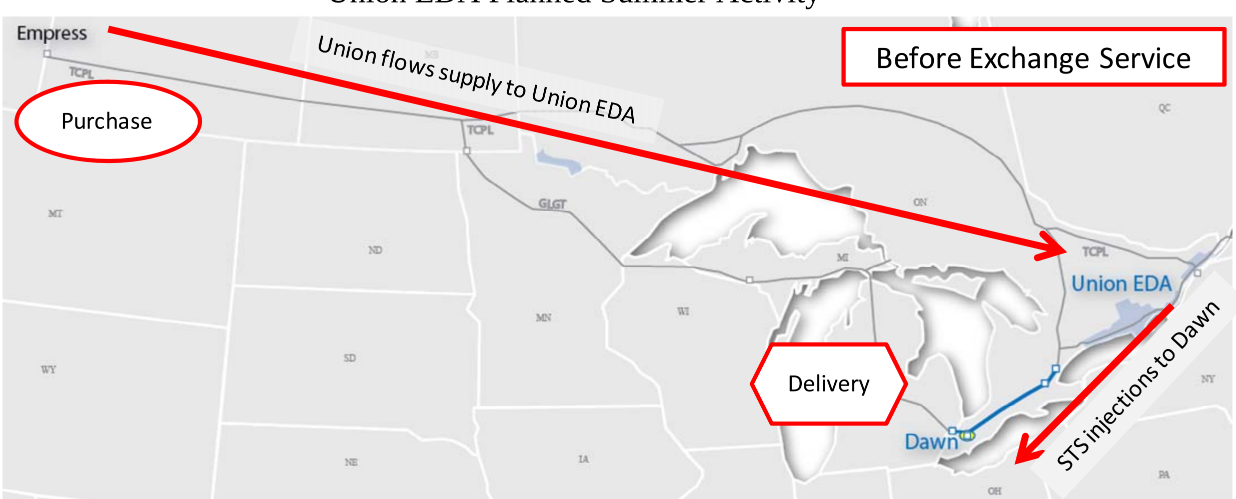
Dawn to Enbridge CDA Transportation Exchange Service (1 day) – Summer

Exchange service parameters:

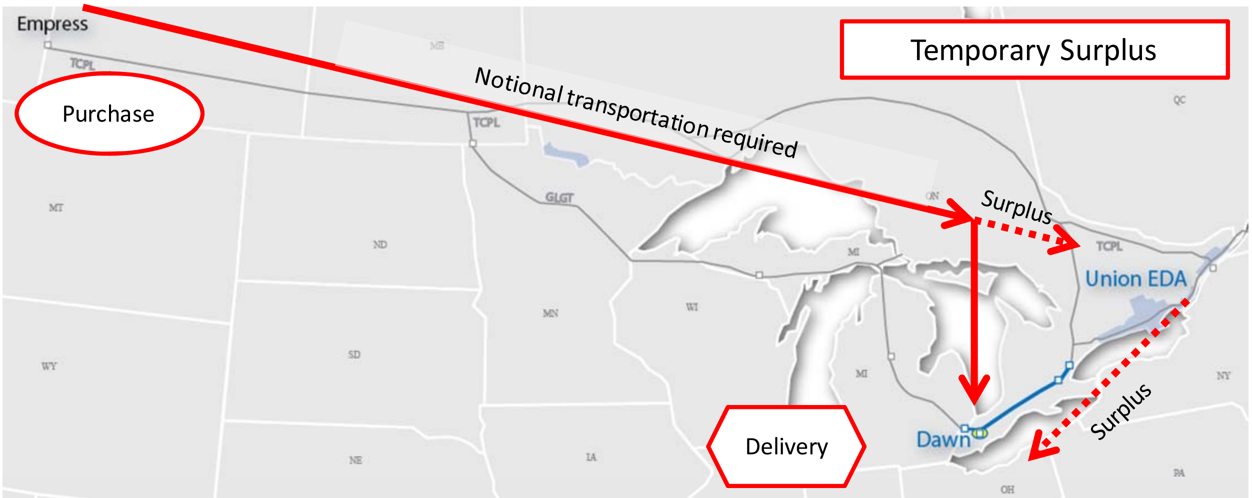
Service Requested:	Interruptible Exchange
Location of gas to Union:	Dawn
Location of gas to S&T Customer:	Enbridge CDA
Season of Exchange Service:	Summer
Term of Exchange Service:	1 day (next day)

The following three figures illustrate how the transportation exchange service is provided.

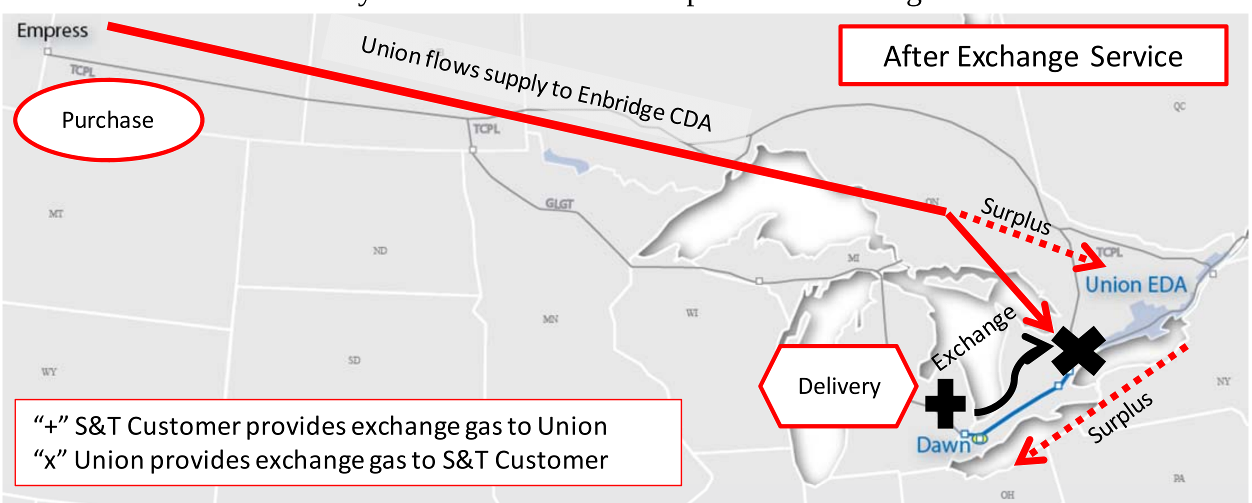
Case 1, Figure 1
Union EDA Planned Summer Activity



Case 1, Figure 2
Illustration of Temporary Surplus Transportation Capacity in Union EDA



Case 1, Figure 3
Union EDA Activity with the Sale of a Transportation Exchange Service



<u>Before the Transportation Exchange Service: Gas Supply Plan Activity</u>

Case 1, Figure 1 illustrates that on a planned basis, Union purchases gas supply at Empress and transports that gas supply to the Union EDA. Consumption in the Union EDA is lower than the total gas supply available and the difference is transported from

Union EDA to Dawn for injection into storage using the TCPL Storage Transportation Service ("STS").

Temporary Surplus Capacity

Case 1, Figure 2 illustrates the portion of the Empress to Union EDA path distance that is temporarily surplus into the market area since gas supply available exceeds demand in Union EDA. The supplies that are not needed in the market area are injected into storage at Dawn. This temporarily surplus capacity allows S&T to provide the Dawn to Enbridge CDA transportation exchange service.

After the Transportation Exchange Service: Operational Results

Case 1, Figure 3 illustrates that S&T has arranged to deliver (divert) the gas to the S&T Customer at Enbridge CDA. The S&T Customer provides the same quantity of gas to Union at Dawn. In both Figure 1 and Figure 3, Union purchases the gas supply at Empress and takes delivery of the same quantity of gas at Dawn.

Financial Impacts

In this example, Union continues to pay TCPL the transportation demand costs from Empress to Union EDA, and the STS demand costs for Union EDA – there is no change to these costs. Any incremental cost to deliver gas from the Union EDA to Enbridge CDA is charged against transportation exchange service revenue.

Case 2

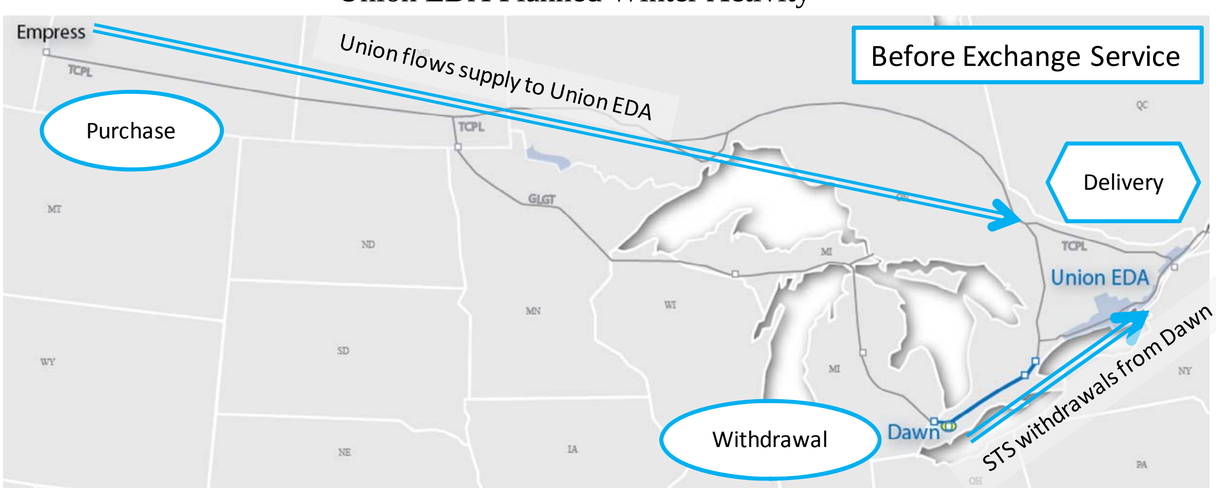
Dawn to Enbridge CDA Transportation Exchange Service (1 month) - Winter

Exchange service parameters:

Service Requested:	Firm Exchange
Location of gas to Union:	Dawn
Location of gas to S&T Customer:	Enbridge CDA
Season of Exchange Service:	Winter
Term of Exchange Service:	1 month (next month)

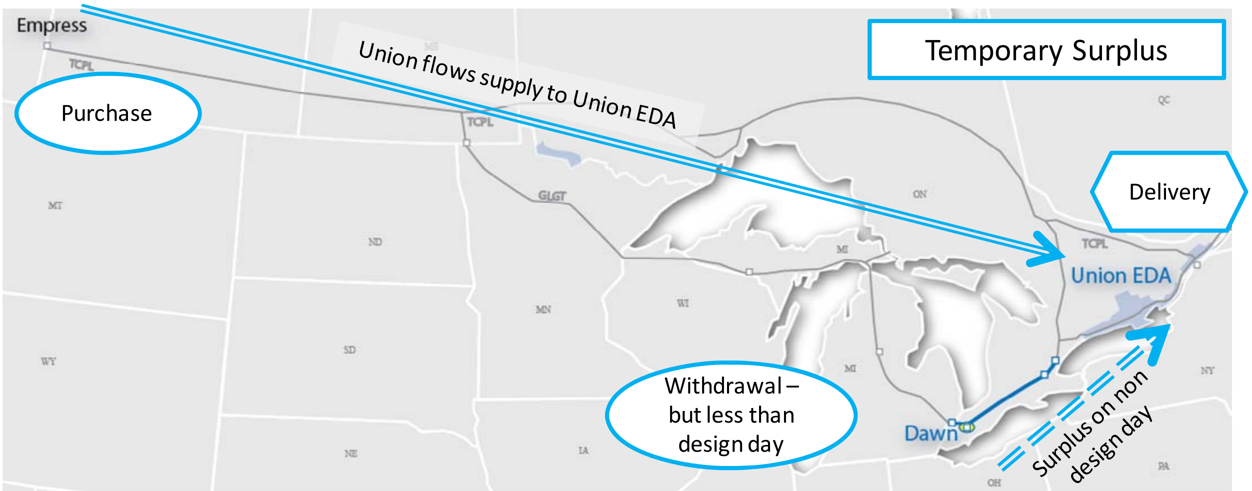
The following three figures illustrate how the transportation exchange service is provided.

Case 2, Figure 1
Union EDA Planned Winter Activity



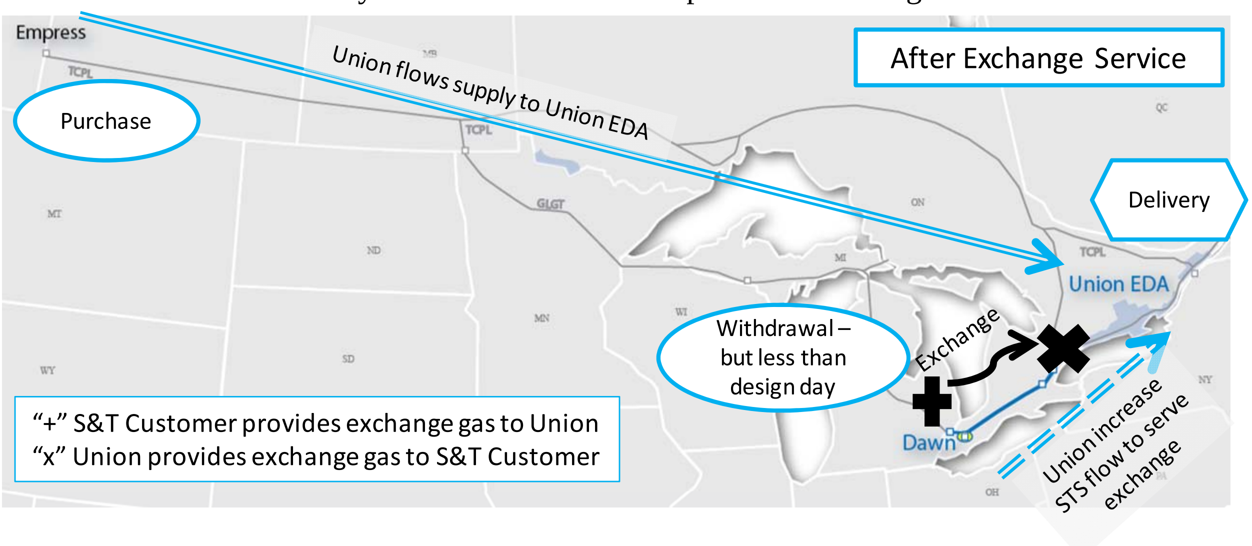
Case 2, Figure 2

Illustration of Temporary Surplus Transportation Capacity in Union EDA



Case 2, Figure 3

Union EDA Activity with the Sale of a Transportation Exchange Service



<u>Before the Transportation Exchange Service: Gas Supply Plan Activity</u>

Case 2, Figure 1 illustrates that on a planned basis, Union purchases gas supply at Empress and transports that gas supply to the Union EDA. In addition, on a typical winter day, gas flows from Dawn storage to Parkway on Union's transmission system, and then to the Union EDA (using STS service on TCPL).

Temporary Surplus Capacity

Case 2, Figure 2 illustrates the portion of the Dawn to Union EDA path that is temporarily surplus into the market area since supply available exceeds demand in Union EDA. This temporarily surplus capacity allows S&T to provide the Dawn to Enbridge CDA transportation exchange service.

After the Transportation Exchange Service: Operational Results

Case 2, Figure 3 illustrates that S&T has arranged to deliver (divert) the gas to the S&T Customer at Enbridge CDA using STS. The S&T Customer provides the same quantity of gas to Union at Dawn. In both Figure 1 and Figure 3, Union purchases the gas supply as planned at Empress and takes delivery of the same quantity of gas at Union EDA.

If on any day of the transportation exchange service the transportation on these paths is no longer temporarily surplus and is required to meet firm system gas supply requirements, Union's S&T group must make alternative arrangements (e.g. purchase a delivered service) to meet the transportation exchange service requirements in the Enbridge CDA.

Financial Impacts

In this example, Union continues to pay to TCPL the transportation demand costs from Empress to Union EDA, and the STS demand costs for Union EDA – there are no changes to these costs. Any incremental cost to deliver gas to Enbridge CDA is charged against exchange service revenue. The price for the transportation exchange service in Case 2 is higher than in Case 1 due to the incremental risk and incremental value for the service.

10/ CHANGES TO TCPL FT SERVICE

From time to time, TCPL offers enhancements to its transportation services that may be temporary or permanent in nature. In 2002, TCPL introduced two temporary service enhancements, available in 2002 only, to its firm transportation services: FT Make-up Credits and Authorized Overrun Service ("AOS") Credits.

In the FT Make-up Credit program, TCPL customers were allocated credits equal to any unutilized firm transportation that could be used to offset interruptible transportation costs incurred within the same month. In the AOS Credit program, TCPL customers were provided with credits equal to 4% of their total firm transportation demand charges that could be used to offset interruptible transportation costs within the same month.

TCPL proposed these services on a temporary basis to give additional flexibility to its existing firm transportation customers.[5]

S&T used both the FT Make-up Credit program and the AOS Credit program to provide transportation exchange services. The corresponding revenues were treated as Transportation and Exchange service revenue[6] and shared with customers consistent with the deferral account treatment at the time.

Shortly after the conclusion of these temporary services, TCPL initiated another temporary service enhancement – FT-RAM. This program was introduced in November 2004, for a one year term, and was then later extended by one year terms in each of 2005 and 2006. In 2006 and 2007, the program was enhanced to include additional transportation services. Also in 2007, the program was extended for a temporary two year term. At this time, TCPL extended the FT-RAM program to include credits earned on unutilized STS capacity. In this evidence, Union includes this feature in discussion of FT-RAM. Unlike the earlier FT Make-up Credit and AOS Credit programs, and after five years of program extensions, FT-RAM was made permanent in March 2009. However, two years later in September, 2011, TCPL proposed in its RH-003-2011 NEB application to terminate the FT-RAM program effective January 1, 2012, again pointing

[5] National Energy Board, Reasons for Decision, RH-1-2001, November 2001, pages 15-17
[6] RP-2003-0063/EB-2003-0087, Exhibit C1, Tab 3, page 6

to the temporary nature of this service. In its March 2013 Decision for that proceeding, the NEB ordered that the program end effective July 1, 2013.

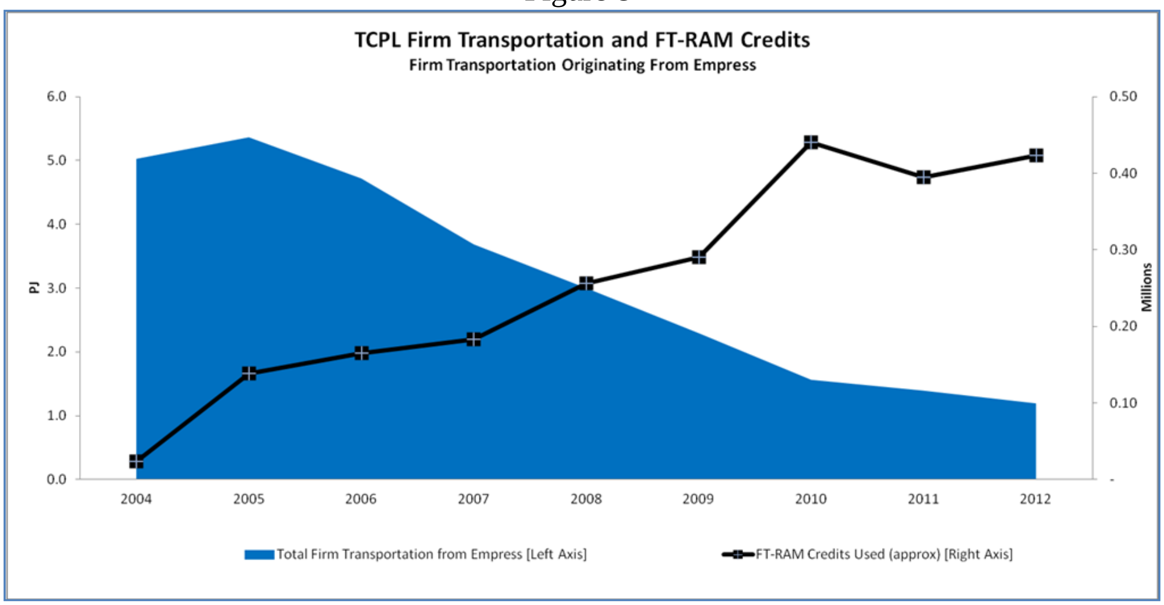
FT-RAM Program Characteristics

The FT-RAM program provided transportation customers "credits" for any un-used firm transportation capacity on each day. These credits can be used within the same month to offset the costs of interruptible transportation. The credits have no value until they are used and they expire on the last day of the month.

FT-RAM had many similarities to the FT Make-up Credits and AOS Credits program, as all three services offered credits that could be used to offset the costs of interruptible transportation on TCPL's pipeline. Like FT Make-up Credits, the FT-RAM program allowed customers to accumulate credits according to the value of firm transportation that is unutilized on TCPL's system.

Since the commencement of the FT-RAM program in 2004, there have been many changes to TCPL's transportation system – most notably the quantity of firm long haul transportation contracts has decreased. This decrease was driven primarily by the fact that the market value (basis) of the long haul transportation was lower than the corresponding toll. This has resulted in increased demand for transportation exchange services, which are available in the secondary market for a shorter term, potentially at a lower cost than other transportation alternatives. FT-RAM provided a method for Union and other Ontario utilities to respond to requests to provide additional transportation exchange services, as the costs to provide transportation exchange services were reduced by the availability of FT-RAM credits. The chart in Figure 8 illustrates the decrease in firm long haul transportation contracts and the increased use of FT-RAM credits over the TCPL Mainline system.

Figure 8



Source: TCPL website

11/ UTILITY USE OF FT-RAM

In the Gas Supply Plan, Union plans to use its firm TCPL transportation at high load factors. If the Empress to Union EDA firm transportation is used as planned, there would be no FT-RAM credits created to reduce the cost of providing transportation exchange services or to offset Gas Supply costs through LBA cost reductions. The FT-RAM program is not included in the Gas Supply Plan as it would not meet Union's principles of providing reliable, secure supplies on a planned basis at low risk. A further description of why the FT-RAM program is not included in the Gas Supply Plan is included in Exhibit B, Tab 3. Despite its exclusion from the Gas Supply Plan, Union's system sales and bundled direct purchase customers still realize benefits directly from FT-RAM in two different ways.

First, Union uses the FT-RAM program and any credits that became available to reduce the costs to ratepayers associated with System Supply Balancing, and specifically to manage its contract with TCPL for Limited Balancing Agreement ("LBA") activity. Union has a LBA at its market area interconnects with TCPL (e.g. Union EDA, Union SSMDA, etc) and any variance between daily gas consumption and daily gas supply is tracked in the LBA[7]. When LBA imbalances occur, LBA fees accrue, depending on the duration and magnitude of the imbalance. Union uses TCPL interruptible transportation to reduce the LBA imbalance and minimize LBA fees. The cost of this interruptible transportation is reduced by the application of FT-RAM credits. Union does not use any FT-RAM credits for transportation exchange services until the costs associated with balancing the LBA for system sales and bundled direct purchase customers are covered. The remaining costs of managing the LBA, if any, are paid by the ratepayers.

[7] The variances at the TCPL interconnect at Union CDA is managed through an Operating Balancing Agreement ("OBA"), not an LBA. There are no fees associated with an OBA.

Second, if Union reduces its gas supply purchases to manage its annual consumption balance, it may conclude that some of its surplus TCPL capacity may be released in the market. Union temporarily assigns the unutilized capacity to a secondary market participant to reduce the unabsorbed demand charges ("UDC") passed through to customers ("UDC Assignment"). The secondary market participant places a higher value on the assigned capacity because it has possible FT-RAM credits associated with it. All proceeds from these UDC Assignments are recorded in the UDC deferral account and flow to ratepayers.

In 2012, all system sales and bundled direct purchase customers realized a benefit of $7.3million attributable to the FT-RAM program due to a reduction in LBA management fees of $0.6 million and UDC relief of $6.7 million.

Table 4
Ratepayer FT-RAM Benefit

	Benefit due to FT-RAM Credits
Interruptible Transportation for LBA management	$0.6M
TCPL - UDC Assignments	$6.7M
Total	$7.3M

12/ TRANSPORTATION EXCHANGE SERVICES AND USE OF FT-RAM

The introduction and utilization of the FT-RAM program did not change the type of transportation exchange services provided by Union to the secondary market. S&T

Customers continue to have a value that they are willing to pay for transportation exchange service, which may not be greater than the cost to provide the service. The FT-RAM program also did not change the amount of temporarily surplus capacity available on upstream transportation capacity, as temporarily surplus capacity is a function of weather and market consumption variations. However, the FT-RAM program did allow Union to monetize the value of some of the temporarily surplus capacities that, without the program, would not otherwise have been realized. In addition, by using the credits from the FT-RAM program, Union is able to more economically provide transportation exchange services that utilize interruptible transportation on TCPL, and therefore meet a greater quantity of the secondary market demands for transportation exchange services.

While Union benefits from increased net transportation exchange service revenue, during 2012, ratepayers also benefited from the additional revenue available for earnings sharing. Without the incentive embedded in the 2008-2012 IRM Framework and the resulting active optimization of upstream transportation, Union and customers would have realized a limited benefit from the FT-RAM program. This limited benefit would relate to the value of the FT-RAM credits realized when surplus capacity is assigned (UDC) and some limited LBA cost reductions. However, Union’s transportation exchange service activity allowed greater credits to be generated that were first applied to reduce utility LBA fees, allowing the full $7.3 million benefit to ratepayers. Any remaining credits available were used to support transportation exchange service activity.

In creating revenue opportunities, S&T used the FT-RAM program primarily in two ways: transportation exchange services funded by FT-RAM and transportation exchange services provided by Transportation Assignments.

12.1 Transportation Exchanges (FT-RAM related)

i) Introduction

The transportation exchange services that are made possible by the availability of the FT-RAM program are similar to the transportation exchange services Union has provided since the early 1990s (Case 1 and Case 2 in Section 9). In each case, Union reviews the availability and costs of resources when determining its ability to sell a transportation exchange service. The FT-RAM program allows S&T to monetize temporarily surplus capacity that otherwise would not have been realized. It also allows S&T to provide exchange services more economically when FT-RAM credits can be applied.

FT-RAM credits can be generated in two ways. First, STS-RAM credits are generated when either injections into storage from the Union NDA or Union WDA or withdrawals from storage to the Union EDA are less than contracted levels. These fluctuations will be driven by market demands, weather, and balancing requirements beyond Union's control.

Second, FT-RAM credits can be generated when firm long-haul transportation capacity, or firm short-haul capacity that is linked to a firm long-haul contract, is left un-used. The full length of the path must be left empty to generate credits. However, since credits can be used to fund interruptible activity on any path distance, the FT-RAM program allows S&T to effectively segment upstream transportation capacity distance in order to monetize temporarily surplus capacity. The portion of upstream transportation capacity that is temporarily surplus will vary, depending on market demands and weather. In all cases, gas supply is still required by Union and purchased as planned.

ii) Generation of FT-RAM credits

Figure 9 again illustrates the planned activity to Union EDA in the summer.

Figure 9
Union EDA Planned Summer Activity

Union purchases gas supply at Empress and transports that supply to the Union EDA using TCPL firm long-haul transportation service. Any supply landing in the Union EDA that exceeds market need is transported to Parkway using TCPL STS capacity and then Union's transmission system from Parkway to Dawn for storage injection.

Figure 10 illustrates transportation from Empress to Union EDA and Union EDA to Dawn paths that is temporarily surplus.

Figure 10
Temporary Surplus Transportation Capacity in Union EDA

The temporary surplus capacity arises along the length of the path – that is, the entire distance of transportation from Empress to the Union EDA is not required. Instead, the actual path required is Empress to Dawn for the long haul transportation capacity. Therefore, the remaining path length is temporarily surplus.

To realize the benefits of the temporarily surplus transportation capacity, Union must leave the entire Empress to Union EDA path un-used to generate FT-RAM credits.[8] Union then uses an interruptible transportation service on TCPL to transport system sales and bundled direct purchase gas from Empress to Dawn, funded by the FT-RAM credits

[8] The FT-RAM program does not allow only a portion of the contracted path distance to be left un-used. It only provides credits to volume that is left un-used along the entire path distance.

generated. Any remaining credits represent the temporarily surplus transportation path distance to Union EDA, as illustrated in Table 5. The remaining credits are not needed by customers served by the Gas Supply Plan and therefore are available to provide transportation exchange services.

Table 5
Creation and Use of FT-RAM Credits

	$/GJ
FT-RAM credits generated on full Empress to Union EDA path	$2.32
FT-RAM credits used to offset incremental costs of interruptible transport of supply from Empress to Dawn	($1.96)
Surplus FT-RAM credits, representing temporarily surplus portion of Empress to Union EDA path distance	$0.36

If S&T uses more interruptible service on TCPL for transportation exchanges than surplus FT-RAM credits, the incremental cost is offset against exchange service revenue. If the interruptible service that is used to transport the system and bundled direct purchase supply is interrupted, S&T ensures all delivery obligations are met and related costs are offset against transportation exchange service revenue.

This example illustrates how the FT-RAM program allows S&T to segment the upstream transportation path in order to realize the benefit of temporarily surplus capacity. In this case, the use of FT-RAM allows the Empress to Union EDA firm transportation capacity to be segmented to Empress to Dawn, leaving the remainder of the path distance temporarily surplus. The value of the temporarily surplus transportation path distance is realized as the surplus FT-RAM credits of $0.36/GJ are used to sell a transportation exchange service, as described below.

iii) Use of FT-RAM Credits for Transportation Exchange Services

Case 3

Dawn to Enbridge CDA Transportation Exchange Service (1 day) - Summer

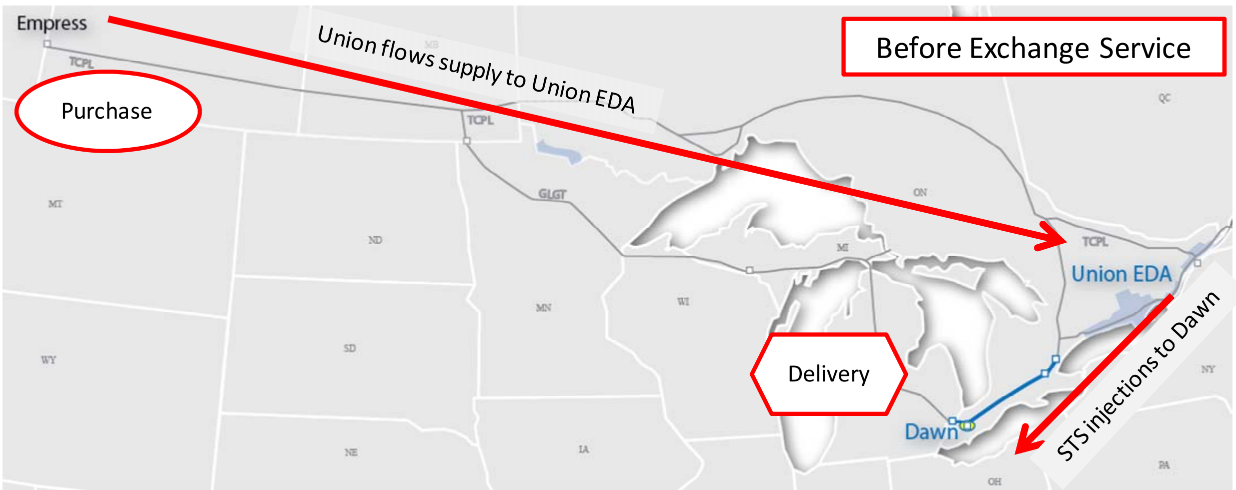
Exchange service parameters:

Service Requested:	Interruptible Exchange
Location of gas to Union:	Dawn
Location of gas to S&T Customer:	Enbridge CDA
Season of Exchange Service:	Summer
Term of Exchange Service:	1 day (next day)

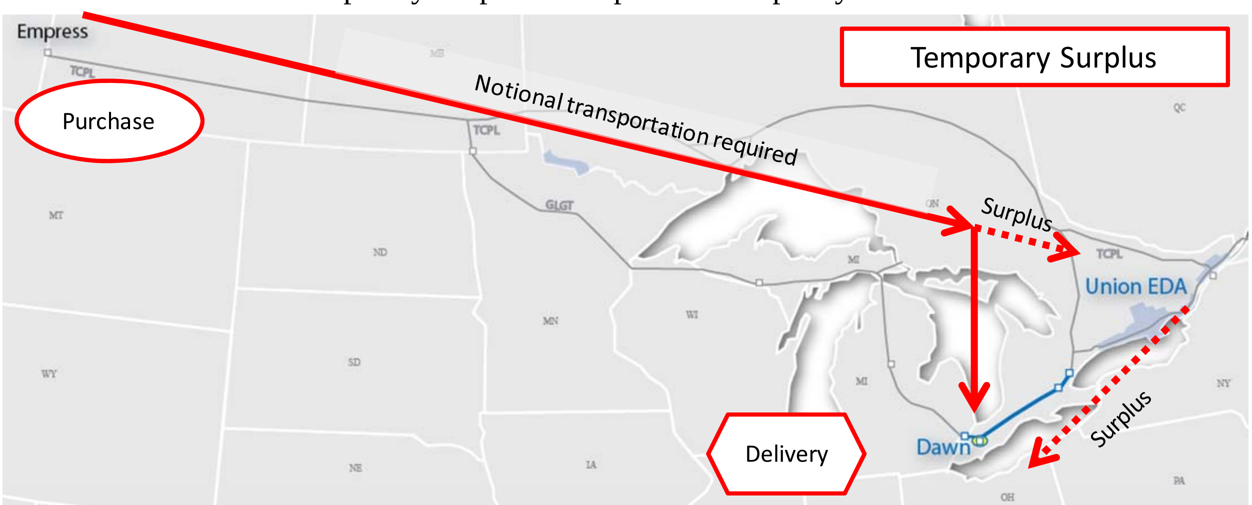
This case is similar to Case 1 in that the same service is being sold. In Case 1, the service was provided when S&T diverted supply to the Enbridge CDA. In this case, S&T combines resources with FT-RAM credits to provide the service.

The following three figures illustrate how the transportation exchange service is provided.

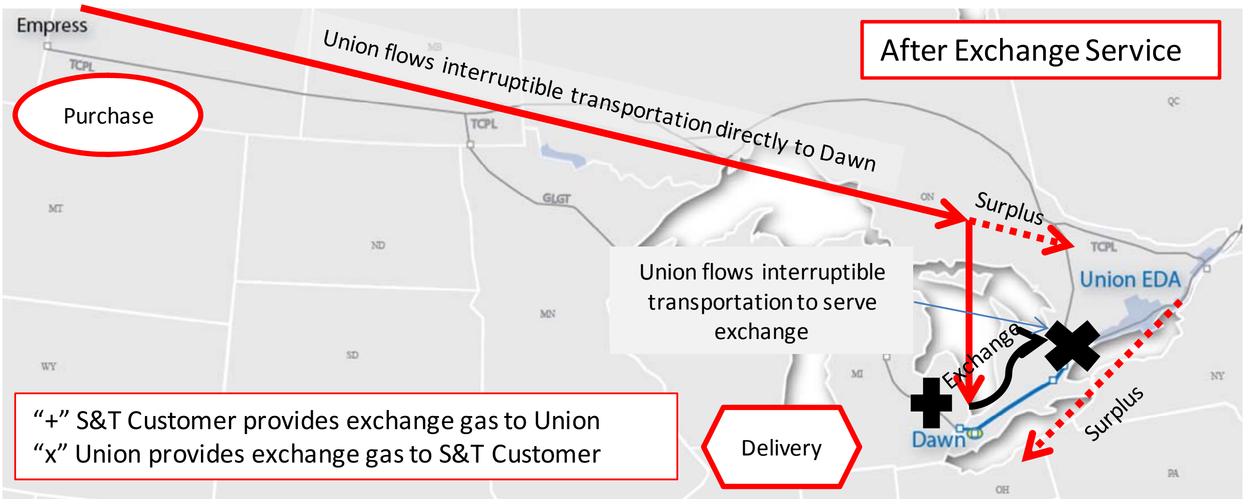
Case 3, Figure 1
Union EDA Planned Summer Activity



Case 3, Figure 2
Illustration of Temporary Surplus Transportation Capacity in Union EDA



Case 3, Figure 3
Union EDA Activity with the Sale of a Transportation Exchange Service and using Interruptible Transportation to Create FT-RAM Credits



Before the Transportation Exchange Service: Gas Supply Plan Activity

Case 3, Figure 1 illustrates that on a planned basis, Union purchases gas supply at Empress and transports that gas supply to the Union EDA. Consumption in the Union EDA is lower than the total gas supply available and the difference is transported from Union EDA to Dawn for injection into storage using the TCPL Storage Transportation Service (“STS”).

Temporary Surplus Capacity

Case 3, Figure 2 illustrates the portion of the Empress to Union EDA path distance that is temporarily surplus into the market area since supply available exceeds demand in Union EDA. The supplies that are not needed in the market area are injected into storage at Dawn. The temporarily surplus capacity between Dawn and Union EDA is represented by the FT-RAM credits that remain after Union's gas supply has been transported from Empress to Dawn using interruptible transportation, as described above.

After the Transportation Exchange Service: Operational Results

Case 3, Figure 3 illustrates that S&T has arranged to deliver the gas to the S&T Customer at Enbridge CDA. S&T uses the Dawn to Parkway transmission system to transport the gas from Dawn to Parkway and uses interruptible transportation on TCPL to transport the gas from Parkway to Enbridge CDA to provide the exchange service. In both Figure 1 and Figure 3, Union purchases the gas supply at Empress and takes delivery of the same quantity of gas at Dawn.

Financial Impacts

In this example, Union continues to pay to TCPL the transportation demand costs from Empress to Union EDA, and the STS demand costs for Union EDA – there is no change to these costs. S&T applies the FT-RAM credits generated from the un-used Empress to Union EDA capacity to offset the incremental costs of the interruptible TCPL service from Empress to Dawn, and the remaining FT-RAM credits to offset the incremental costs of the interruptible TCPL service from Parkway to Enbridge CDA. The revenues from the sale of the transportation exchange service provide compensation for any remaining costs of the interruptible TCPL service which were not covered by FT-RAM credits, the costs and market value related to the use of Dawn to Parkway transportation, and the costs to mitigate any risks, if realized.

12.2 Transportation Exchanges (Transportation Assignments)

Section 12.1 outlines the use of FT-RAM credits and the sale of transportation exchange services. Alternatively, S&T also uses temporary assignments of TCPL transportation contracts to support transportation exchange services which utilize FT-RAM credits. For example, if an S&T Customer requests a Dawn to Enbridge CDA transportation exchange service for one month, S&T can sell a transportation exchange service that utilizes temporarily surplus upstream transportation or FT-RAM credits (Cases 1, 2 or 3), or S&T can assign some of the same Empress to EDA transportation to an S&T Customer to allow the S&T Customer to create FT-RAM credits directly. The FT-RAM credits could be used to offset the transportation costs on any path of value, including from Dawn to Enbridge CDA.

In all cases, gas is purchased at Empress according to the Gas Supply Plan and is exchanged with the S&T Customer for gas in Union's service area. Examples of such a transaction follow in Cases 4 through 6.

<u>Case 4</u>

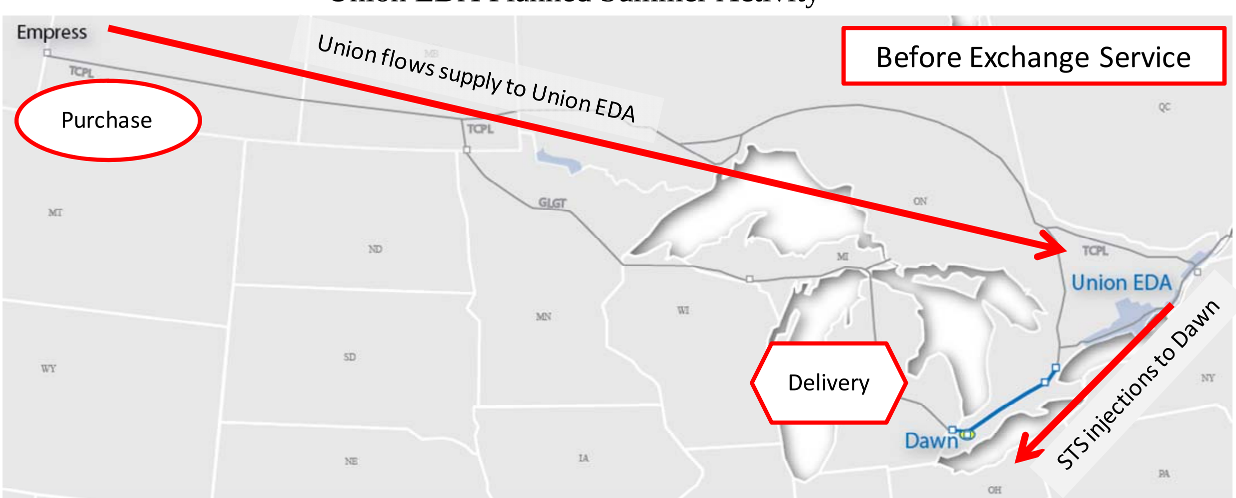
Transportation Assignment (1 month) – Summer

Exchange service parameters:

Service Requested:	Firm Exchange
Location of gas to Union:	Dawn
Location of gas to S&T Customer:	Empress
Season of Exchange Service:	Summer
Term of Exchange Service:	1 month

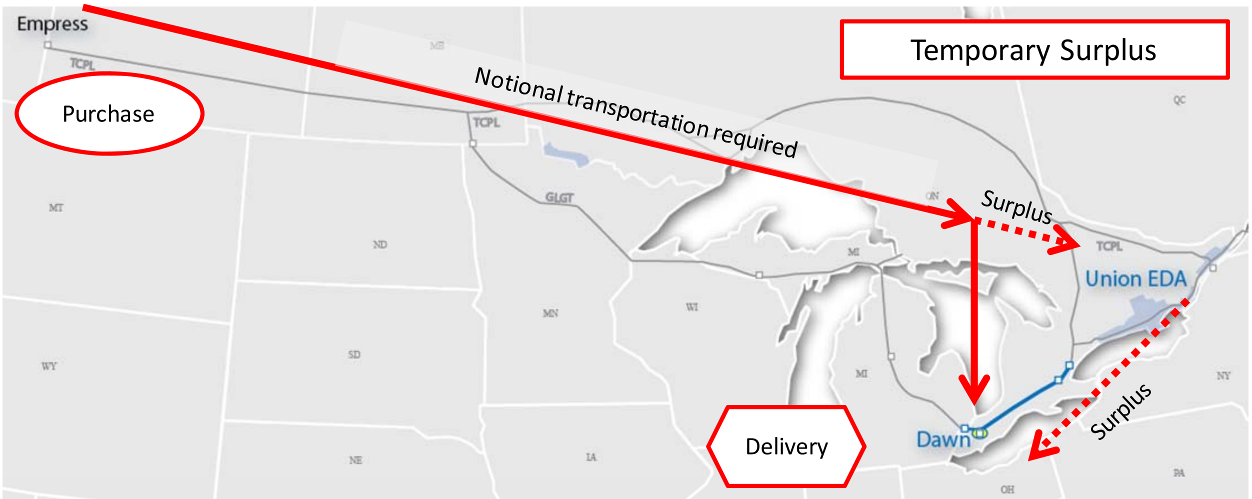
The following three figures illustrate how the transportation exchange service is provided.

Case 4, Figure 1
Union EDA Planned Summer Activity



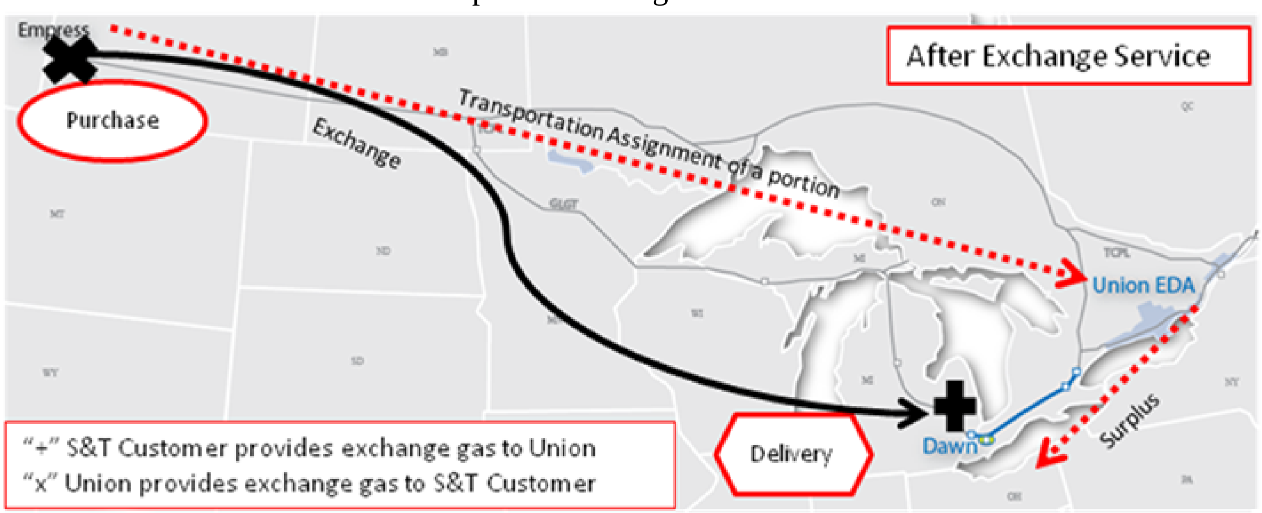
Case 4, Figure 2

Illustration of Temporary Surplus Transportation Capacity in Union EDA



Case 4, Figure 3

Union EDA Activity with the Sale of a Transportation Exchange Service using Transportation Assignment



<u>Before the Transportation Exchange Service: Gas Supply Plan Activity</u>

Case 4, Figure 1 illustrates that on a planned basis, Union purchases gas supply at Empress and transports that gas supply to the Union EDA. Consumption in the Union

EDA is lower than the total gas supply available and the difference is transported from Union EDA to Dawn for injection into storage using the TCPL Storage Transportation Service (“STS”).

Temporary Surplus Capacity

Case 4, Figure 2 illustrates the portion of the Empress to Union EDA path distance that is temporarily surplus into the market area since gas since supply available exceeds demand in Union EDA. The supplies that are not needed in the market area are injected into storage at Dawn. To realize the benefits of the surplus capacity, Union’s S&T group can create FT-RAM credits as outlined in Case 3, or alternatively, it can assign some of the contracted quantity on the Empress to Union EDA path[9] to an S&T Customer to allow them to create FT-RAM credits directly. Once the S&T Customer is assigned the transportation capacity, they can leave it unused each day to create FT-RAM credits which can be used to offset the costs of purchasing interruptible TCPL transportation on any path of value to them.

After the Transportation Exchange Service: Operational Results

Case 4, Figure 3 illustrates that S&T continues to exchange gas, where gas is provided to the S&T Customer at Empress and the S&T Customer provides gas to Union at Dawn. The S&T Customer may use the FT-RAM credits to transport the gas at Empress to

[9] Assignments must be for the entire contracted path (e.g. Empress to Union EDA); a portion of a contracted path cannot be assigned.

Union at Dawn, and use any remaining credits to provide services to the secondary market. In both Figure 1 and Figure 3, Union purchases the gas supply at Empress and takes delivery of the same quantity of gas at Dawn.

Financial Impacts

In this example, Union pays the STS demand costs for Union EDA to TCPL and pays the equivalent of the TCPL transportation demand costs from Empress to Union EDA to the S&T Customer. There are no changes to these costs. Union's payment of the Empress to Union EDA transportation demand costs to the S&T Customer is an exact offset to the demand charges the S&T Customer is invoiced from TCPL as a result of the assignment. The S&T Customer then pays Union for the combined value of the Empress to Union EDA transportation capacity and the Empress to Dawn exchange service. This combined value reflects the expected proceeds the S&T Customer will earn in the secondary market using the FT-RAM credits generated from the assigned Empress to Union EDA capacity. The revenues from the sale of the transportation exchange service provide compensation for the costs and market value related to the use of Dawn to Parkway transportation, and the costs to mitigate any risks, if realized.

Case 5

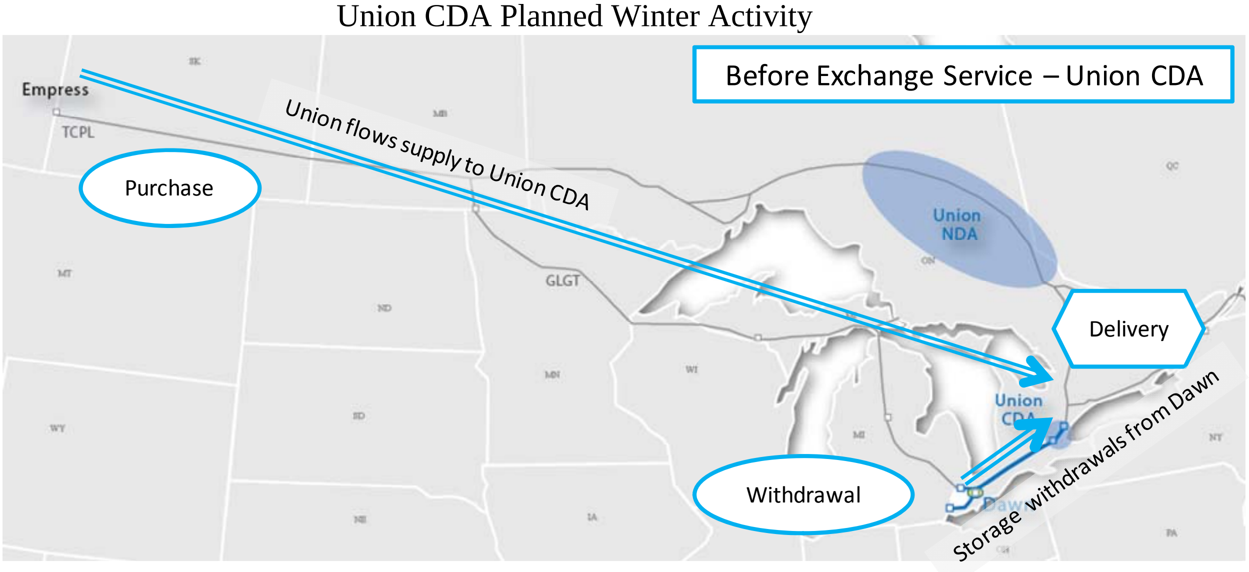
Transportation Assignment (1 month) – Winter

Exchange service parameters:

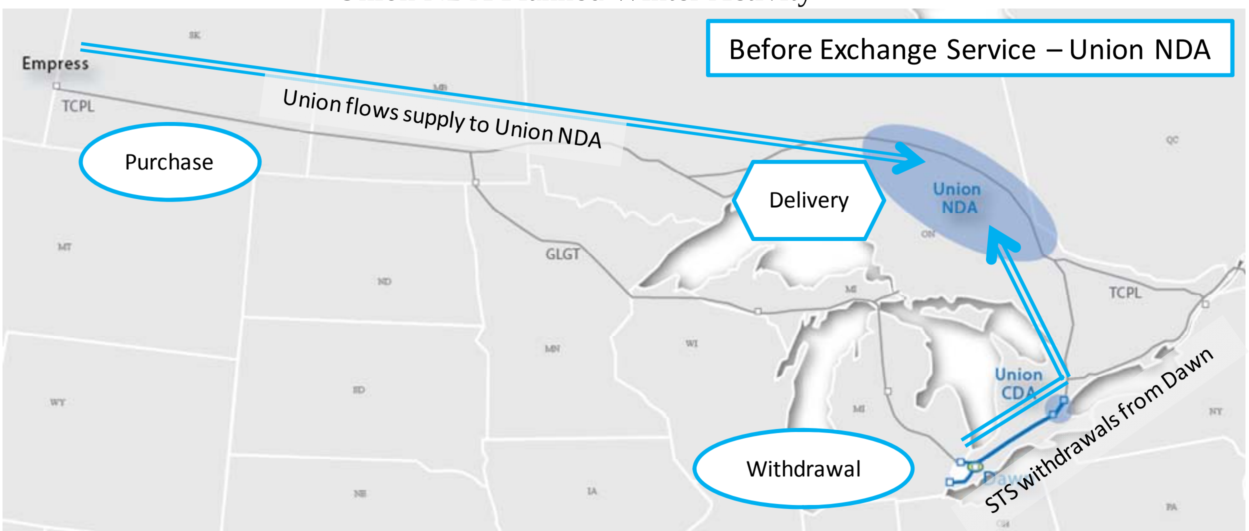
Service Requested:	Firm Exchange
Location of gas to Union:	Union NDA
Location of gas to S&T Customer:	Empress
Season of Exchange Service:	Winter
Term of Exchange Service:	1 month

The following six figures illustrate how the transportation exchange service is provided. In this case, the exchange is serviced using temporarily surplus transportation capacity from two of Union's delivery areas: Union CDA and Union NDA.

Case 5, Figure 1
Union CDA Planned Winter Activity



Case 5, Figure 2
Union NDA Planned Winter Activity

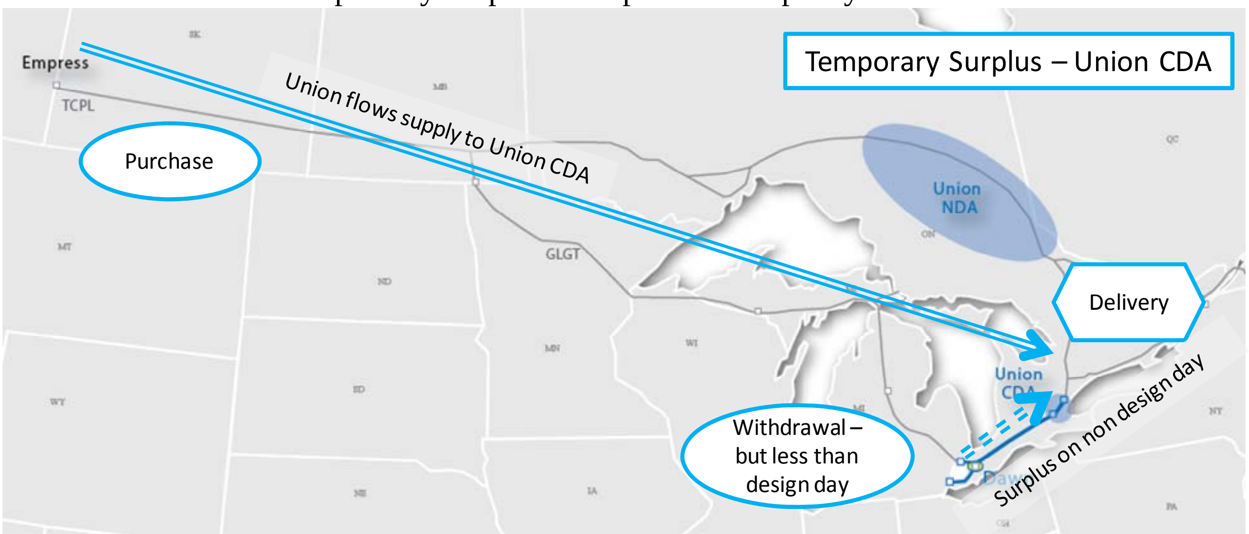


<u>Before the Transportation Exchange Service: Gas Supply Plan Activity</u>

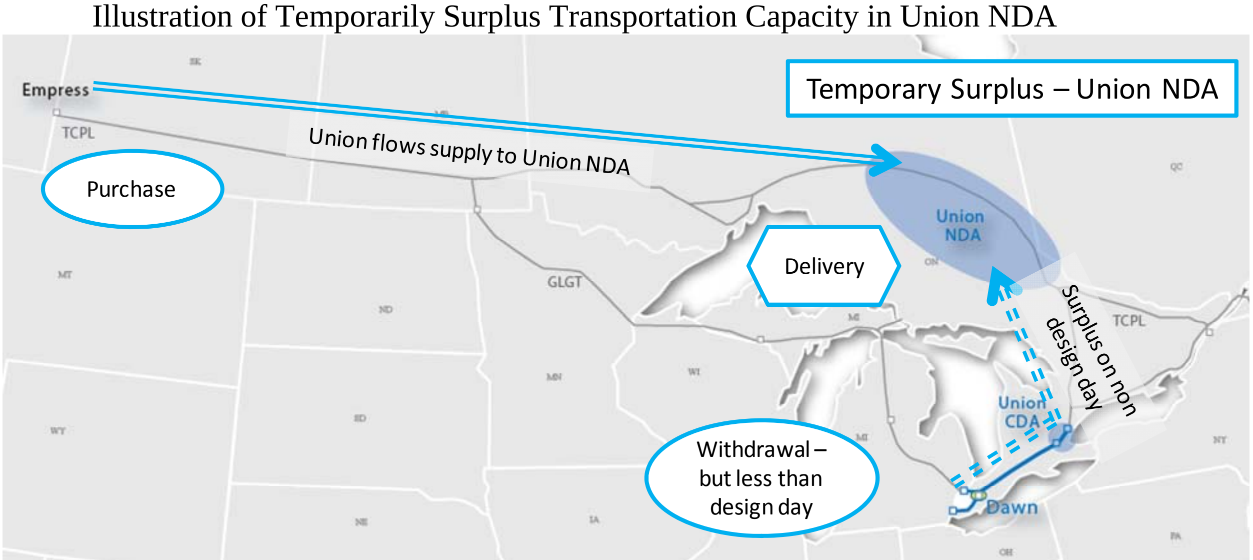
Case 5, Figures 1 and 2 illustrates how the Union CDA and Union NDA markets are planned to be served. On a planned basis for a normal winter day, Union CDA (Case 5, Figure 1) is served through withdrawals from storage transported on the Dawn to Parkway system. It is also served by Empress supply delivered on a TCPL firm transportation contract from Empress to Union CDA. On a planned basis for a normal winter day, the Union NDA (Case 5, Figure 2) is served by Empress supplies delivered on the Empress to Union NDA firm transportation contract. It is also served through withdrawals from storage, using the STS contract with TCPL.

Figures 3 and 4 illustrate the temporary surplus capacity in both Union CDA and Union NDA.

Case 5, Figure 3
Illustration of Temporarily Surplus Transportation Capacity in Union CDA



Case 5, Figure 4
Illustration of Temporarily Surplus Transportation Capacity in Union NDA

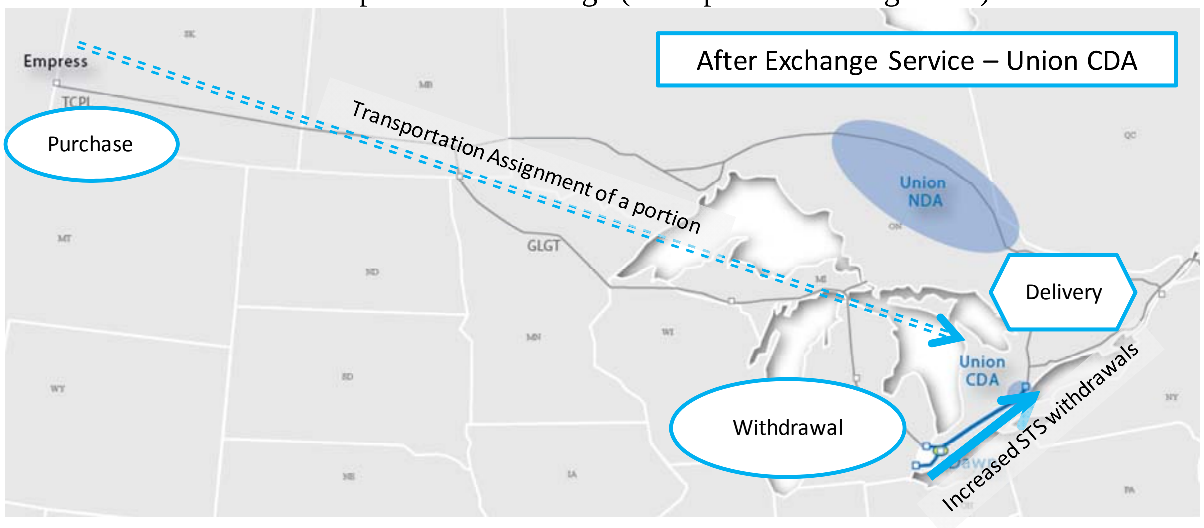


Temporary Surplus Capacity

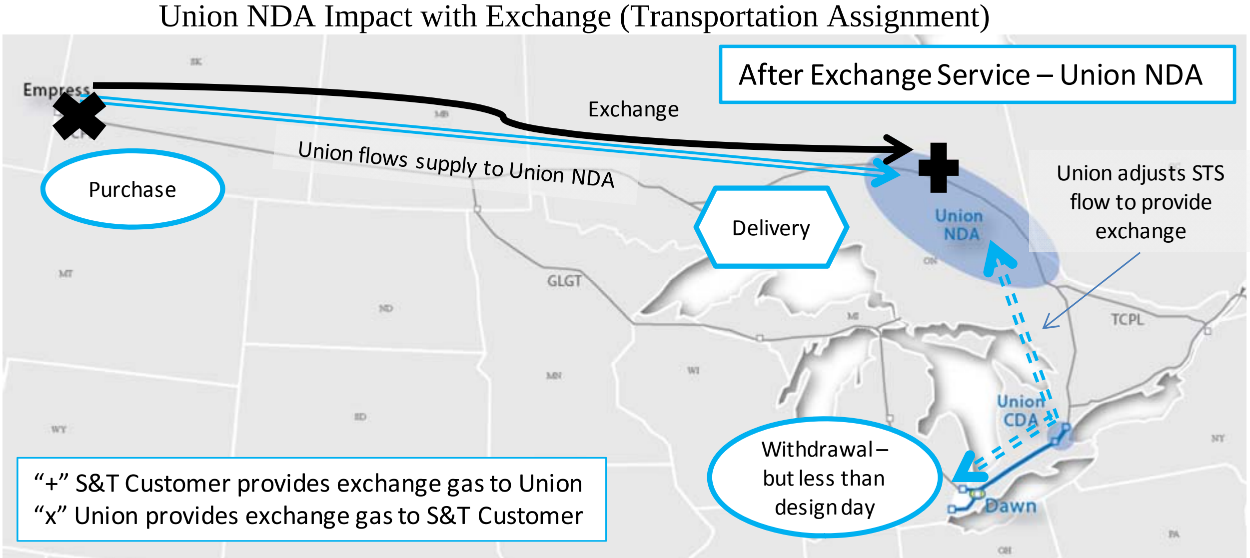
On non-design days there may be temporary surplus transportation available in both delivery areas, as illustrated in Case 5, Figures 3 and 4. For Union CDA, there is temporary surplus capacity from storage to Union CDA. For Union NDA, there is also temporary surplus capacity from storage to Union NDA, through TCPL's STS service. To realize the benefits of the temporary surplus capacity, S&T provides a service to the S&T Customer in two parts. First, S&T assigns some of the contracted quantity on the Empress to Union CDA path to the S&T Customer. Second, S&T provides a transportation exchange service, where gas is provided to the S&T Customer at Empress and the S&T Customer provides gas to Union at the Union NDA on a firm basis. The gas received at the Union NDA will be used to meet the market demands in the Union NDA, or, alternatively, transported to Dawn using the surplus Union NDA STS transportation.

The last two figures, Figure 5 and 6, illustrate how both the Union CDA and Union NDA flows were impacted as a result of the transportation exchange transaction.

Case 5, Figure 5
Union CDA Impact with Exchange (Transportation Assignment)



Case 5, Figure 6
Union NDA Impact with Exchange (Transportation Assignment)



<u>After the Transportation Exchange Service: Operational Results</u>

Case 5, Figures 5 and 6 illustrate how the temporary surplus capacity in both the Union CDA and Union NDA are affected by this transaction. To meet demands in the Union

CDA (Case 5, Figure 5), Union increases withdrawals from storage to Parkway. To meet demands in the Union NDA (Case 5, Figure 6), depending on weather and market demands, STS withdrawals are adjusted to accommodate the increased supply in the Union NDA. On some days, the STS flows may reverse and gas may be transported to Dawn for injection into storage, depending on market requirements.

Financial Impacts

In this example, Union continues to pay the TCPL transportation demand charge for Empress to Union NDA and STS demand charges. Union also continues to pay the TCPL transportation demand charge for Empress to Union CDA, now to the S&T Customer. There is no change to any of these costs. Union's payment of the Empress to Union CDA transportation demand costs to the S&T Customer is an exact offset to the demand charges the S&T Customer is invoiced from TCPL as a result of the assignment. The S&T Customer then pays Union for the combined value of the Empress to Union CDA transportation capacity and the Empress to Union NDA exchange service. This combined value reflects the expected proceeds the S&T Customer will earn in the secondary market using the FT-RAM credits generated from the assigned Empress to Union CDA capacity. Any incremental costs S&T incurs to balance the Union NDA and Union CDA markets are offset against the transportation exchange revenue. The proceeds from the sale of the transportation assignment/transportation exchange transaction with the S&T Customer are also recorded as transportation exchange revenue.

In completing this transaction, S&T assumes risk with respect to the temporarily surplus asset and the transportation exchange transaction. As discussed in Section 8, S&T manages this risk and associated costs. With respect to the example above, there are two main risks. The first is in regard to the temporarily surplus transportation capacity on the Dawn to Parkway system and to the Union CDA. If market demands at Parkway are higher than forecast, then S&T is responsible for ensuring all firm obligations at Parkway are met. Second, Union relies on the S&T Customer fulfilling their obligation as part of the firm exchange transaction. If Union delivers the supply at Empress to the S&T Customer and the S&T Customer does not deliver to the Union NDA, then markets in the Union NDA may not be met. If either, or both, of these scenarios occur on a cold winter day, costs to mitigate these risks are significant. S&T would need to purchase a delivered service in the Union NDA for each day the risk materialized. For the coldest day in January, 2012, the cost to mitigate such a scenario was approximately $4.81/GJ. This greatly exceeds the average daily transportation exchange proceeds of $0.63/GJ for transportation assignments transacted in that same month.

Both methods described above for FT-RAM optimization utilize the same temporarily surplus upstream transportation capacity. As part of its risk management strategy, Union transacts both types of exchanges. In 2012, both types of transactions contributed to increased exchange service net revenue, which contributed to earnings sharing for ratepayers and shareholders. Table 1 earlier in the evidence outlines the net FT-RAM revenue from Union providing exchange services funded by FT-RAM credits and from providing transportation exchange services through Transportation Assignments.

Case 6

Introduction

In Union's 2013 Rebasing Application (EB-2011-0210), an example of an annual exchange transportation assignment relating to 20,000 GJ/d of Empress to Union EDA capacity was discussed. This annual assignment was comprised of a summer component and a winter component. The summer component was an Empress to Dawn exchange for the entire summer season and is identical to the monthly transaction described in Case 4. The winter component was an Empress to Union NDA exchange and is described in Case 6 below.

The annual transaction described in EB-2011-0210 was not transacted in either 2012 or 2013. This type of annual transportation assignment was completed in both the 2009/2010 and 2010/2011 gas years. Since that time, these transactions have not been completed because S&T assessed the overall risks relating to annual transportation assignment services as not acceptable. For example, S&T did not have reasonable assurance that the temporary surplus transaction quantity would be available for the entire term, or that the FT-RAM program would continue for the transaction duration. In addition, another factor for consideration was the changing impact of the capacity constraints on the TCPL system affecting the reliability of interruptible transportation services. However, S&T did use Empress to Union EDA transportation capacity that was temporarily surplus during 2012 to sell transportation exchange services with shorter terms and reduced risks. Examples of these types of transactions have been described in Cases 1 through 4.

The following Case 6 illustrates the winter component of the annual exchange transportation assignment discussed in EB-2011-0210. The summer component of this would be identical to the monthly example illustrated in Case 4. During the entire contract term, Union continued to purchase supplies as planned at Empress, and continued to serve all market requirements. In providing this annual exchange transportation assignment, S&T took the risk that temporarily surplus capacity was available for the entire transaction term. In the event of a design day there would be no temporary surplus capacity in the Union EDA area and S&T would have made the appropriate arrangements to serve market requirements. S&T transportation exchange revenue would have been decreased by the costs to serve the market need.

Case 6

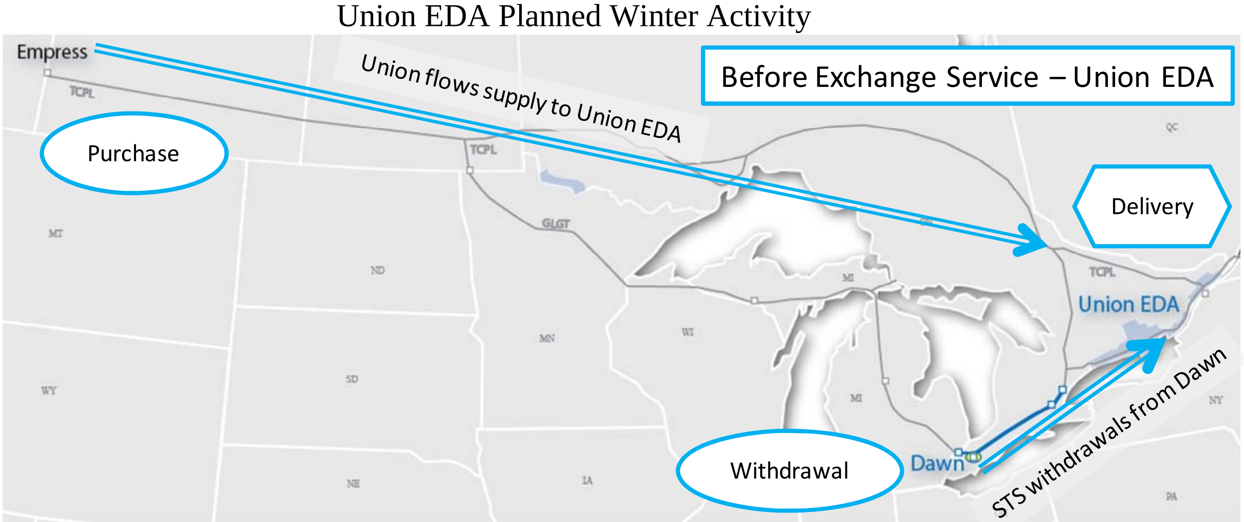
Transportation Assignment – Winter Season

Exchange service parameters:

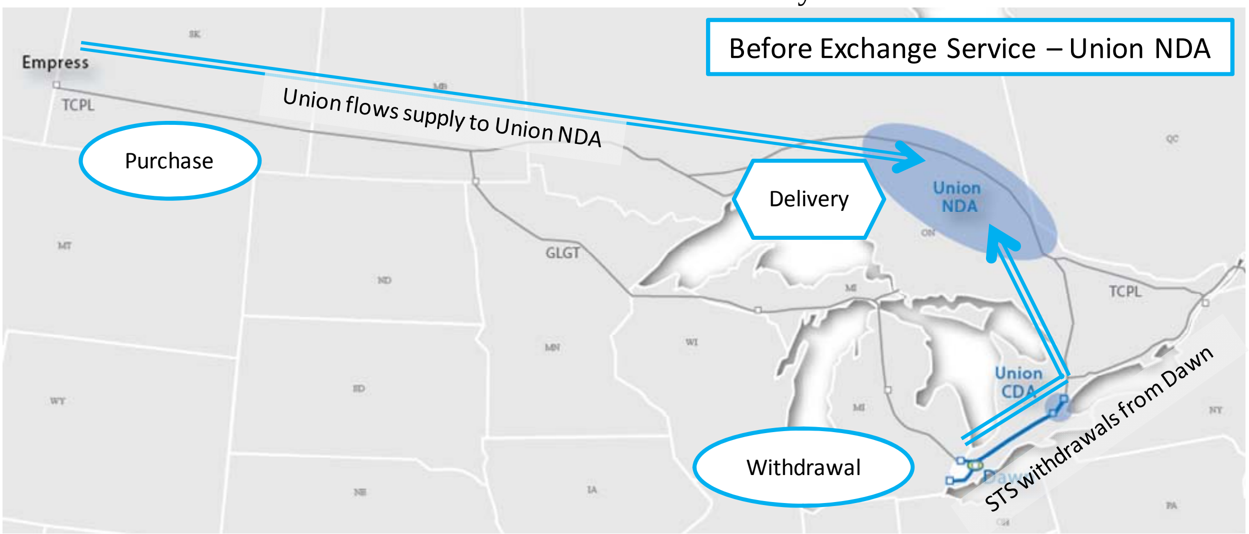
Service Requested:	Firm Exchange
Location of gas to Union:	Union NDA
Location of gas to S&T Customer:	Empress
Season of Exchange Service:	Winter
Term of Exchange Service:	Winter season

The following six figures illustrate how the transportation exchange service is provided. In this case, the exchange is serviced using temporarily surplus transportation capacity from two of Union's delivery areas: Union EDA and Union NDA.

Case 6, Figure 1
Union EDA Planned Winter Activity



Case 6, Figure 2
Union NDA Planned Winter Activity

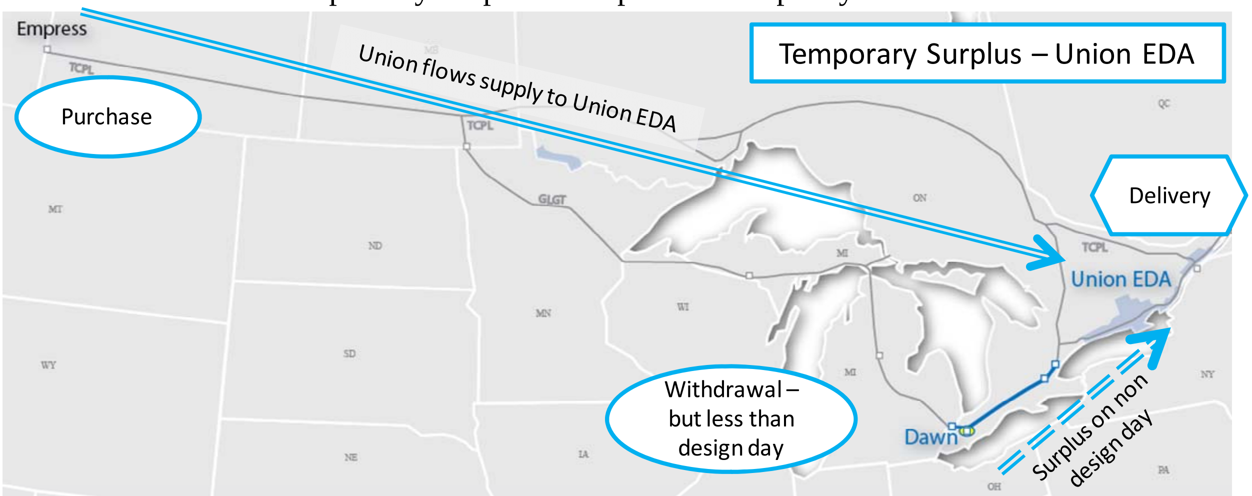


Before the Transportation Exchange Service: Gas Supply Plan Activity

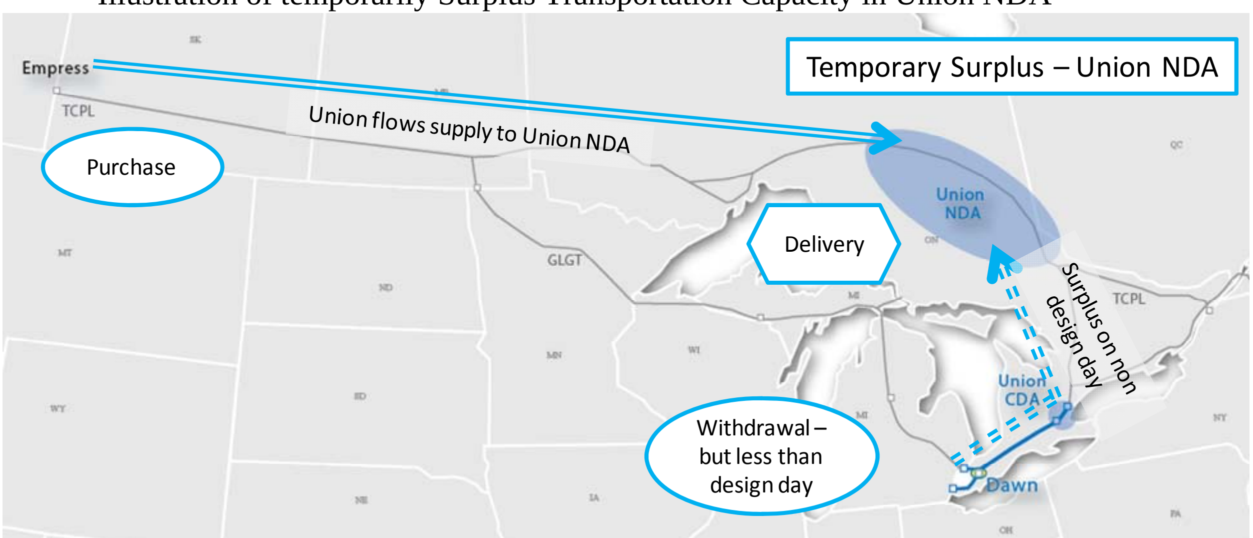
Case 6, Figures 1 and 2 illustrates how the Union EDA and Union NDA markets are planned to be served. On a planned basis for a normal winter day, Union EDA (Case 6, Figure 1) is served through withdrawals from storage transported on the Dawn to Parkway system. It is also served by Empress supply delivered on a TCPL firm transportation contract from Empress to Union EDA. On a planned basis for a normal winter day, the Union NDA (Case 6, Figure 2) is served by Empress supplies delivered on the Empress to Union NDA firm transportation contract. It is also served through withdrawals from storage, using the STS contract with TCPL.

The following Figures 3 & 4 illustrate the temporary surplus capacity in both the Union EDA and Union NDA.

Case 6, Figure 3
Illustration of temporarily Surplus Transportation Capacity in Union EDA



Case 6, Figure 4
Illustration of temporarily Surplus Transportation Capacity in Union NDA

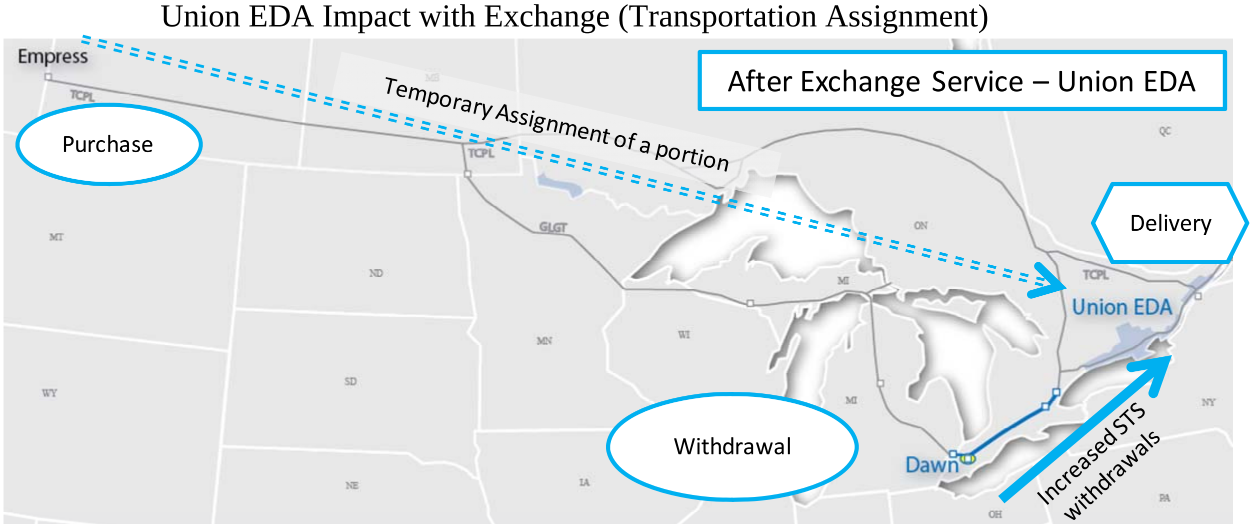


Temporary Surplus Capacity

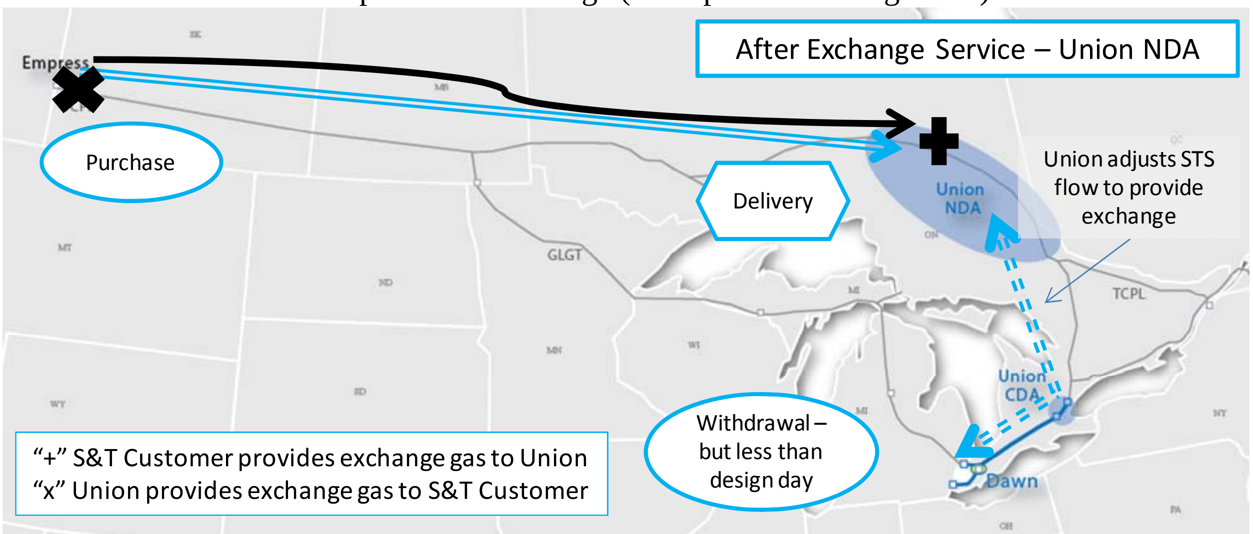
On non-peak days there may be temporary surplus transportation available in both delivery areas, as illustrated in Case 6, Figures 3 and 4. For Union EDA, there is temporary surplus capacity from storage to Union EDA. For Union NDA, there is also temporary surplus capacity from storage to Union NDA, through TCPL's STS service. To realize the benefits of the temporary surplus capacity in Union EDA, S&T provides a service to the S&T Customer in two parts. First, S&T assigns some of the contracted quantity on the Empress to Union EDA path to the S&T Customer. Second, S&T provides a transportation exchange service, where gas is provided to the S&T Customer at Empress and the S&T Customer provides gas to Union at the Union NDA on a firm basis. The gas received at the Union NDA will be used to meet the market demands in the Union NDA, or, alternatively, transported to Dawn using the surplus Union NDA STS transportation.

The last two figures, Figure 5 and 6, illustrate how both the Union EDA and Union NDA flows were impacted as a result of the transportation exchange transaction.

Case 6, Figure 5
Union EDA Impact with Exchange (Transportation Assignment)



Case 6, Figure 6
Union NDA Impact with Exchange (Transportation Assignment)



<u>After the Transportation Exchange Service: Operational Results</u>

Case 6, Figures 5 and 6 illustrate how the temporary surplus capacity in both the Union EDA and Union NDA are affected by this transaction. To meet demands in the Union EDA (Case 6, Figure 5), Union increases withdrawals from storage. To meet demands in the Union NDA (Case 6, Figure 6), depending on weather and market demands, STS withdrawals are adjusted to accommodate the increased supply in the Union NDA. On some days, the STS flows may reverse and gas may be transported to Dawn for injection into storage, depending on market area requirements.

<u>Financial Impacts</u>

In this example, Union continues to pay the TCPL transportation demand charge for Empress to Union NDA and STS demand charges for Union NDA and Union EDA.

Union also continues to pay the TCPL transportation demand charge for Empress to Union EDA, now to the S&T Customer. There is no change to any of these costs. Union's payment of the Empress to Union EDA transportation demand costs to the S&T Customer is an exact offset to the demand charges the S&T Customer is invoiced from TCPL as a result of the assignment. The S&T Customer then pays Union for the combined value of the Empress to Union EDA transportation capacity and the Empress to Union NDA exchange service. The combined value reflects the expected proceeds the S&T Customer will earn in the secondary market using the FT-RAM credits generated from the assigned Empress to Union EDA capacity.

Any incremental costs required to balance the Union NDA and Union EDA markets are offset against the exchange revenue. The proceeds from the sale of the transportation assignment/exchange transaction with the S&T customer are also recorded as exchange revenue.

For 2012, annual assignments of upstream capacity, including Empress to Union EDA, were not completed due to the uncertainty of available temporary surplus capacity, the perceived increased risks of the continuation of the RAM program, and the changing impact of the capacity constraints on the TCPL system affecting the reliability of interruptible transportation service. The description of operational results and financial impacts are for illustrative purposes only and did not occur in 2012.

This is an example of how during the 2008-2012 IRM term, Union found new ways to achieve productivity gains through revenue generation. In this case, the exchange transportation assignment was completed for two years, in 2009/2010 and 2010/2011. Since then, Union determined the incremental risk was too high for these types of transactions and they were not repeated in 2011/2012 or 2012/2013, and will not be repeated in the future.

13/ OPTIMIZATION UPDATE: 2013

In 2013, two significant developments occurred with respect to Union's optimization activity. First, in Union's 2013 rebasing hearing, EB-2011-0210, the Board directed that "optimization activities…are to be considered part of gas supply, not part of transactional services" and that "90% of all optimization net revenues shall accrue to ratepayers and 10% shall accrue to Union as an incentive to continue to undertake these activities on behalf of ratepayers" (Decision and Order, page 39). This development has impacted how exchange transactions are sold because the change in incentive mechanism impacts the risk/reward balance. While S&T continues to provide transportation exchange services, the activities are focused on lower risk transactions which have reduced the value of services for Union and for S&T Customers. This development has restricted the quantity of transportation exchanges transactions completed, the duration of the exchanges, and the timing of their sale. All of these factors have reduced the opportunity for secondary market players in terms of their ability to extract value and provide service to their customers, including end-use energy consumers in Ontario. Reducing the activity in the secondary market reduces opportunities for end-use consumers to reduce their overall energy consumption costs.

Second, on March 27, 2013, the National Energy Board ("NEB") approved the termination of the FT-RAM program. In its decision, the NEB ordered that the FT-RAM program be terminated on June 30, 2013[10]. The impacts of the termination of FT-RAM will be the loss of FT-RAM credits to reduce the costs of managing LBA imbalances, the decline in values for UDC assignments, and a reduction to the quantity of exchange services provided, due to the loss of FT-RAM credits to offset the costs.

14/ CONCLUSIONS

The fundamental nature of transportation exchange services sold to S&T Customers has not changed since the early 1990s. However, the market for transportation exchange services has increased substantially since 2006, driven by changes in natural gas markets that were unforeseen at the outset of the IRM term. These changes include changing gas supply flows across North America and rapid de-contracting on the TCPL system. The resultant increase in TCPL tolls has driven significant growth of the secondary market for transportation and exchange services, and represented market opportunities for Union's S&T Group. Within the context of the 2008-2012 IRM, S&T evaluates these

[10] NEB, Reasons for Decision, RH-003-2011, March 27, 2013

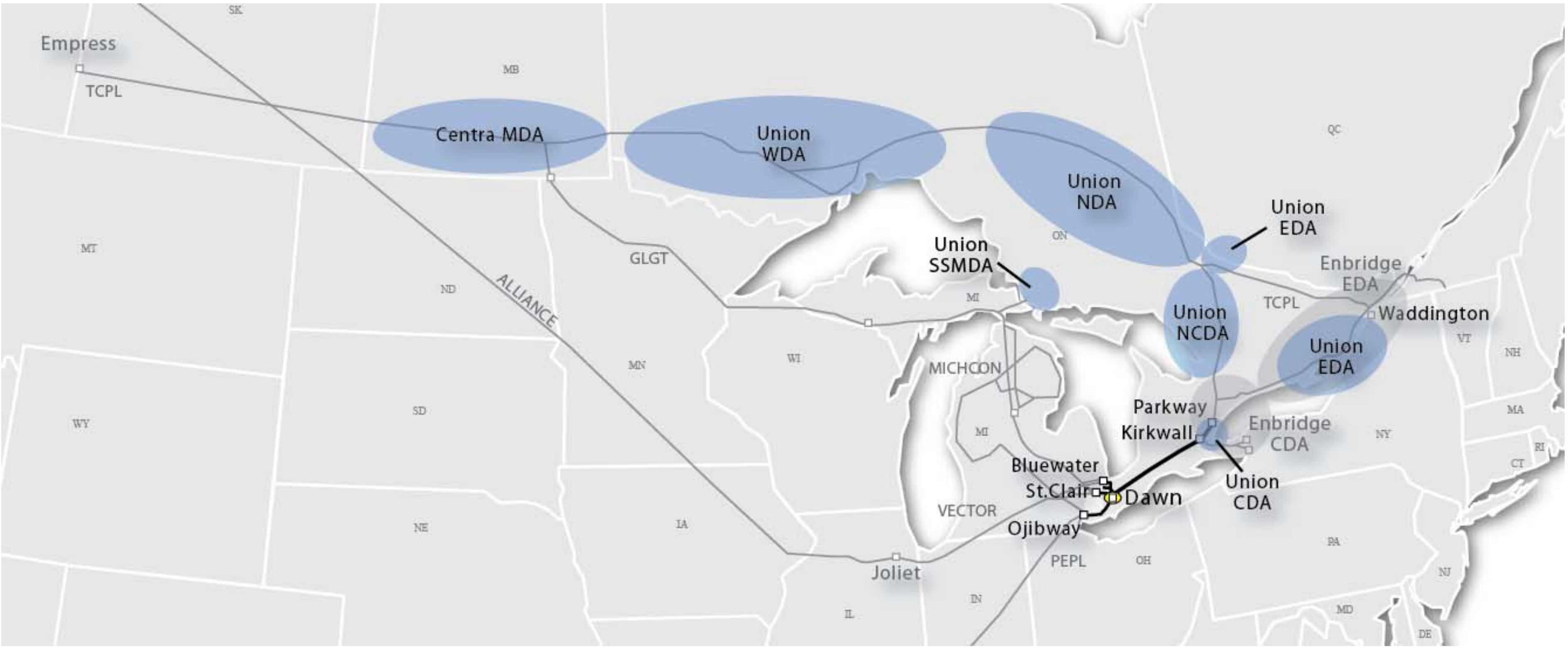
opportunities, the associated risks, and the ability to capture market value. S&T uses temporarily surplus upstream transportation capacities, the Dawn-Parkway transmission system, and purchased resources in order to meet the increasing demand for transportation exchange services. When S&T uses upstream transportation assets to meet demand for transportation exchange services, it uses capacities that are available on a temporary basis due to factors such as variations in weather and market demand. There are no assets in the Gas Supply Plan in excess of what is required to serve system sales and bundled direct purchase needs.

The introduction of the FT-RAM program does not change the types of transportation exchange services Union provides to the secondary market. It does, however, allow S&T to monetize temporary surplus assets in the Gas Supply Plan that otherwise would not be fully utilized. The FT-RAM program provides the secondary marketplace with economic transportation alternatives in response to decreasing firm contracting levels on TCPL, and increasing tolls. The increasing TCPL tolls result in increased value of FT-RAM credits. As a result, Union sold more transportation exchange services and generated more transportation exchange revenue than was anticipated at the outset of the IRM.

The dramatic increase in transportation exchange transactions completed by S&T since 2006 has resulted in significant benefits for Union’s ratepayers and all Ontario end-use energy consumers. Union’s ratepayers have benefitted directly from sharing transportation exchange revenue through a base delivery rate reduction and through earnings sharing. In addition, the growth of a vibrant and active secondary market provides competitive gas supply options to all end-users in Ontario, including residential customers, industrial users and power producers. Union's proposal to include FT-RAM revenue in utility earnings subject to earnings sharing supports the continued sharing of these benefits with ratepayers, while respecting the risk/reward balance inherent in the 2008-2012 IRM.

Filed: 2013-05-08
EB-2013-0109
Exhibit B
Tab 2
<u>Appendix</u>

Map of Union's System and Pipelines in Union's Upstream Transportation Portfolio



TAB 3

UNION'S GAS SUPPLY PLANNING PROCESS

INTRODUCTION

This evidence describes the role of the Gas Supply function, the planning process, and the principles underlying the Gas Supply Plan. The evidence discusses how Union establishes a Gas Supply Plan that is appropriately sized to meet firm system sales and bundled direct purchase customer demands with a diverse, flexible and cost effective portfolio of firm services and assets on an annual, seasonal and design day basis.

As directed by the Board in its EB-2011-0210 Decision, Union has undertaken an expert independent review of its Gas Supply Plan, its gas supply planning process, and gas supply planning methodology. This review, performed by Sussex Economic Advisers verified that Union's gas supply planning process, methodology, and plan reflects appropriate planning principles that are objectively applied and result in a Gas Supply Plan that is "right sized". The report, its findings and recommendations is included as Exhibit C, Tab 2. Union's response to the Sussex report recommendations is provided in Exhibit B, Tab 5.

The evidence is organized in the following sections:

1/ Union Gas and its In-franchise Customers

2/ The Role of the Utility and Gas Supply Function

3/ Gas Supply Guiding Principles

4/ Gas Supply Plan Preparation

1/ UNION GAS AND ITS IN-FRANCHISE CUSTOMERS

Natural gas in Ontario is a significant and critical energy source relied on for providing heat and hot water to homes and institutions, fuelling manufacturing plants and for generating electricity. In 2011 alone, almost 950 PJ of natural gas was consumed in Ontario in residential, commercial, industrial and power generation markets. Approximately 70% of homes in Ontario use natural gas for heating and producing hot water. These applications operate on demand, meaning that consumers expect the energy to be readily available to be used when needed.

Home owners in Ontario depend on a reliable supply of natural gas. The natural gas infrastructure supporting Ontario needs to be robust reflecting the critical role it plays in Ontario, and flexible to allow Ontario to position itself to secure long-term access to economic supply in light of the changing North American supply dynamics. Union Gas serves approximately 1.4 million customers in northern, eastern and southern Ontario through an integrated network of over 67,000 kilometres of natural gas distribution pipelines. Total consumption in Union's franchise areas during 2012 was approximately 528 PJ.

Union operates storage and transmission assets that include 166 PJ of underground natural gas storage at the Dawn Hub and the Dawn-Parkway transmission system. Union's Dawn-Parkway System is an integral part of the natural gas delivery system for Ontario, Québec and U.S. Northeast residents, businesses and industry. The Dawn-Parkway System connects these consuming markets to most of North America's major supply basins, the largest area of underground natural gas storage in North America and the liquid Dawn Hub.

Union's Dawn Hub has been recognized as a key market hub for the Province of Ontario and the entire Great Lakes region. The growth of Dawn as an energy hub and the availability of competitively and transparently priced natural gas supplies and services that come with an effective and efficient trading hub have benefitted all Ontarians. Dawn is one of the most physically traded, liquid hubs in North America. The liquidity of Dawn is the result of the combination of access to underground storage, interconnections with upstream pipelines, take away capacity to growth markets, a large number of buyers and sellers of natural gas, and price transparency.

Of the 1.4 million customers that Union serves, approximately 1.2 million are system sales customers that rely on Union Gas to provide their gas supply. These customers, in terms of numbers, are primarily residential and small commercial customers. The remaining customers rely on Direct Purchase ("DP") arrangements with marketers and alternate suppliers to meet their gas supply needs. From a volume perspective, system sales customers consumed 136 PJ in 2012, while DP customers consumed 392 PJ.

For gas supply planning purposes, Union is divided into two separate operating areas: Union South and Union North. Union South includes customers located west of Mississauga and south of Georgian Bay (Windsor/Chatham, London/Sarnia, Waterloo/Brantford and Hamilton/Halton Districts). To serve Union South, Union contracts for capacity on multiple upstream pipelines to access several supply basins or market hubs. These upstream pipelines provide access to supplies in Western Canada, Gulf of Mexico, Chicago, the U.S. mid-continent and the Appalachian shale basins. Union may also serve Union South by purchasing supply at Dawn.

Union North is located throughout Northern and Eastern Ontario, from the Manitoba border in the west, to Cornwall in the east. Union North is further divided into six delivery areas for gas supply planning purposes. Five of the delivery areas align with delivery areas on the TCPL Mainline. Union's Manitoba Delivery Area is connected to the TCPL Mainline at the Spruce interconnect in the Centra MDA by two additional pipelines (Centra Transmission Holdings and Centra Pipeline Minnesota). From West (Manitoba border) to East (Cornwall) these delivery areas are:

1 Manitoba Delivery Area (" MDA")

2 Union Western Delivery Area ("Union WDA")

3 Union North Delivery Area ("Union NDA")

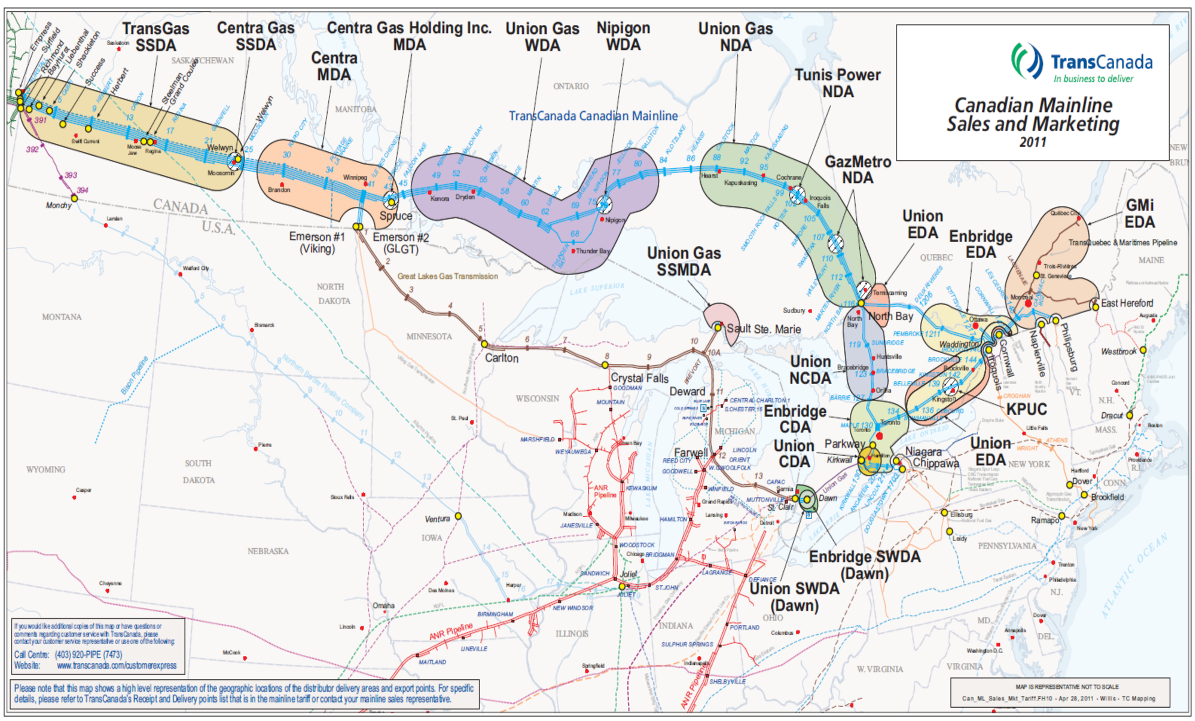
4 Union Sault Ste. Marie Delivery Area (" Union SSMDA")

5 Union North Central Delivery Area ("Union NCDA")

6 Union East Delivery Area ("Union EDA")

A map of these delivery areas is provided in the figure below.

Figure 1



haul firm transportation, TCPL short haul firm transportation and TCPL firm Storage Transportation Service (“STS”) to meet the needs of Union North.

Union’s customers continue to have the option to either purchase their supply from the utility or arrange supply through a DP arrangement. Union’s in-franchise customers fall into four distinct categories.

1. System Sales: Union acquires supply and transportation capacity for these customers in Union North and Union South. System sales demand requirements are included in the Gas Supply Plan. For example, Union may contract with Vector Pipeline for transportation between Chicago and Dawn. Union will purchase natural gas for system sales customers in Chicago and deliver it on Vector to Dawn.
2. Bundled DP: These customers acquire their own supply with Union providing transportation options. In Union North, Union contracts and manages upstream transportation to provide capacity to bundled DP customers. Currently Union North bundled DP customers deliver their supply to Union at Empress and Union uses TCPL services to bring the supply to market. In Union South, customers are given a vertical slice (a proportionate amount of the transportation that Union holds in the Union South portfolio) when they first choose the DP option. They can manage this capacity subject to Union’s DP transportation policies. These customers are included in the Gas Supply Plan.

3. Unbundled DP: These customers acquire their own supply and transportation and storage from an energy marketer and are not considered within the Gas Supply Plan. This service is available to small residential, commercial and industrial customers.
4. Transportation service (or T-Service) DP: These customers acquire their own supply and transportation and are not considered within the Gas Supply Plan. This service is available to large contract commercial and industrial customers.

Details regarding these customer groups are shown in Table 1 below.

Table 1
In-franchise Customer Count and Volume by Service Type
(2012 Actual)

Service Type	In Gas Plan	Number of Customers	Volume (PJ)	Percent of Total Volume
System sales	Yes	1,183,770	136.2	26%
Bundled DP	Yes	161,746	88.3	17%
Unbundled DP	No	33,278	3.8	1%
T-service DP	No	159	299.8	57%
Total		1,378,953	528.1	100.0%

2/ THE ROLE OF THE UTILITY AND THE GAS SUPPLY FUNCTION

Union performs the role of system operator and supplier of last resort. As system operator, Union manages many operational factors. This includes:

1. seasonal balancing requirements,
2. weather variances outside of checkpoint balancing,
3. changes in supply and balancing requirements as customers move between sales service and DP,
4. differences between daily receipts from TCPL and the demands of end users for transportation service customers in the Union North, and
5. unaccounted for gas and compressor fuel variances.

As supplier of last resort, Union is the default supplier to its in-franchise customers (NGF Report, page 62). A supplier of last resort must ensure it has the assets or can acquire the assets to serve customers that others choose not to serve or fail to serve (e.g., for reason of financial failure), or any customer who chooses to be a system sales customer and have Union provide gas supply services.

The Gas Supply department is made up of three areas of responsibility: Gas Supply Planning, Transportation Acquisition, and Gas Supply Acquisition. The primary responsibilities of the Gas Supply department are as follows:

- Develop, execute and manage a Gas Supply Plan that is reliable, secure and cost effective which meets the supply needs of its system sales and bundled DP customers. Developing the plan requires coordination across other internal departments to ensure understanding and alignment of information and operational requirements. The Gas Supply Plan defines the volumetric requirements as well as the budgeted costs that are included in the corporate forecast and regulatory filings. (Gas Supply Planning)
- Acquire transportation services in accordance with the Gas Supply Plan and maintain relationships with pipeline providers. This includes analyzing and managing transportation service contract renewals that have staggered renewal terms throughout the year. (Transportation Acquisition)
- Develop and execute the monthly procurement plan to acquire gas supply for Union's system sales. Gas supply purchases are transacted multiple times throughout the month for next month, next season, or next gas year through requests for proposals to prospective suppliers. (Gas Supply Acquisition)
- Establish and manage the business relationships associated with conducting the gas supply procurement plans. This includes managing the contract requirements for prospective suppliers under NAESB contracts. (Gas Supply Acquisition)
- Manage relationships and contracting requirements for gas supply from local producers in Union's franchise area. (Gas Supply Acquisition)
- Manage and ensure compliance with all government and regulatory reporting requirements for gas supply purchases and price data. (Gas Supply Acquisition)

- Manage the seasonal and annual balances and inventory position of the system sales customers, by either acquiring additional supplies (when weather is colder than normal) or reducing existing supplies (when weather is warmer than normal). (Gas Supply Acquisition)
- Prepare and file the cost of gas requirements in the QRAM process to set transportation and commodity rates for system and bundled DP customers (Gas Supply Acquisition)
- Manage invoicing and reporting of gas supply and transportation costs and provide support and business expertise to assist in recording gas supply and transportation costs through gas supply deferral accounts. (Transportation Acquisition/Gas Supply Acquisition)
- Manage monthly vertical slice requirements on the applicable pipelines. (Transportation Acquisition)
- Develop and monitor gas supply policies and procedures. (All areas)
- Manage operational constraints such as upstream pipeline disruptions as required. (All areas)
- Monitor and develop strategies for the gas supply portfolio anticipating and responding to changes in the gas supply market for Ontario. (All areas)
- Prepare evidence and testify at OEB hearings for gas supply related issues. (All areas)

The Gas Supply department and its functions are managed separately from the Storage and Transportation ("S&T") department. This separation is to ensure that the assets and activities of the Gas Supply department are not influenced by the commercial interests of S&T. It also ensures that the Gas Supply department is focused on developing and managing a Gas Supply Plan based on the guiding principles discussed below.

The Gas Supply Plan defines the gas supply requirements and the necessary upstream transportation capacity and assets to meet customers' annual, seasonal and design day gas delivery requirements as described in detail in Section 5. Union's Gas Supply portfolio is guided by a set of principles that focus on enhancing security and reliability by diversification of the upstream supply basin and the contract terms.

3/ GAS SUPPLY GUIDING PRINCIPLES

Union's Gas Supply function is guided by a set of principles that are designed to ensure customers receive secure, diverse gas supply at a prudently incurred cost and minimal risk. The principles are as follows:

1. Ensure secure and reliable gas supply to Union's service territory;
2. Minimize risk by diversifying contract terms, supply basins and upstream pipelines;
3. Encourage new sources of supply as well as new infrastructure to Union's service territory;

4. Meet planned peak day and seasonal gas delivery requirements;
5. Deliver gas to various receipt points on Union's system to maintain system integrity.

These principles have been presented to and accepted by the Board. Most recently these principles were presented to the Board in Union's 2013 Rebasing proceeding (EB-2011-0210).

Cost is an important consideration in the Gas Supply Plan; however, Union must balance the benefits of all the attributes of the guiding principles. A description of each guiding principle and how this balance is achieved, is provided below.

3.1 Ensure secure and reliable gas supply to Union's service territory

Union has an obligation to ensure its firm system sales and bundled DP customers (i.e. residential and commercial customers) have access to secure and reliable gas supply sources. This includes firm upstream transportation contracts to deliver this supply to Union's franchise areas. Union also provides a load balancing function for all system sales and bundled DP customers to manage the seasonal differences between supply and demand. Union's obligation is to provide gas supply and transportation capacity for system sales customers and transportation capacity for bundled DP customers. To meet this obligation Union uses a combination of firm upstream transportation contracts, Dawn sourced supply and storage capacity. Union ensures adequate firm capacity is available on a sustained basis to meet firm design day and annual demands through transportation capacity contractual rights. This includes a combination of long-term transportation contracts with third parties, transportation contracts with guaranteed renewal rights, as well as dedicated Union storage, transmission and distribution assets.

3.2 Minimize risk by diversifying contract terms, supply basins and upstream pipelines

Union's current upstream transportation portfolio and related supply are diversified with respect to supply basin access, gas supply producers and marketers, contract term and transportation service provider. Union's approach to diversifying the portfolio of firm assets is analogous to a prudent investment portfolio where diversity of funds, risk and term are critical to a successful portfolio.

In Union South, Union utilizes capacity on many upstream pipelines to access several supply basins or market hubs. These pipelines provide access to supplies in Western Canada, Gulf of Mexico, Chicago, the U.S. mid-continent and Marcellus through Niagara. The Gas Supply Plan also includes Dawn purchases as part of the Union South supply portfolio. Union purchases gas from suppliers under a North American Energy Standards Board ("NAESB") contract[1]. Union has NAESB contracts with approximately 80 suppliers. The portfolio of suppliers and upstream transportation contracts provides

[1] The North American Energy Standards Board (NAESB) serves as an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.

diversity and reduces the exposure to price volatility for Union South customers. It also provides Union the flexibility to manage to its seasonal inventory targets.

All of the customers in Union North are served directly from TCPL interconnects and the vast majority are served almost exclusively from the WCSB. In 2011 Union took the first step toward achieving supply diversity in Union North by contracting for firm transportation from Michigan to Union's Sault St. Marie Delivery Area ("SSMDA"). This new path provides diversity to Union North, and is the only area in Union North not totally reliant on WCSB gas.

Union also manages risk to customers by diversifying the length of the contract terms to provide flexibility in managing the upstream transportation portfolio. In Union South, contract terms range from one to ten years. Union holds renewal rights on the majority of these contracts at expiry date. In Union North, approximately 95% of Union's long haul TCPL firm contracts and storage transportation services ("STS") contracts have completed their primary term and renew on a 1 year rolling basis.

For gas supply purchases, the system supply portfolio consists of annual, seasonal, monthly, and in some cases, daily purchases. In addition, Dawn delivered service in the Union South supply portfolio can be re-sized annually to manage changes in demand.

3.3 Encourage new sources of supply as well as new infrastructure to Union's service territory

Union continues to seek new sources of cost-effective supplies to serve its customer base either through accessing new supply sources with existing infrastructure or participating in longer-term projects to encourage the development of new infrastructure to and through Ontario. The development of new supply sources and the related infrastructure often require long-term commitments. In the Board's EB-2010-0300 / EB-2010-0333 Decision (Page 7), the Board recognized the role that regulated utilities play in supporting new infrastructure development:

> *"The Board recognized that the enrolment of regulated utilities for such long term arrangements would be a necessary and desirable element in new infrastructure development…"*

Union supports the development required to bring new supply sources to or through Ontario. For example, Union entered into an open season and signed a ten year agreement with TCPL for capacity on the Niagara to Kirkwall path effective November 1, 2012. This path provided Ontario customers with access to supplies from the Marcellus shale basin.

In addition, Union supports the infrastructure required to allow supply sources other than WCSB to flow to eastern and northern Ontario. In order for all Ontario natural gas customers to access new emerging supply, new infrastructure at Parkway and between Parkway and Maple on the TCPL Mainline is required. Union responded to TCPL's new capacity open season in 2012 for new long-term transportation contracts originating at Parkway on the TCPL system for service in 2015. Holding this short haul transportation capacity that originates at Parkway will allow Union North customers access to Dawn and the multiple supply basins that are attached to the Dawn hub. Union has applied to the OEB under EB-2013-0074 for pre-approval of these contracts.

3.4 Meet planned peak day and seasonal gas delivery requirements

Inherent in the obligation to meet system sales and bundled DP customers' gas supply needs is the requirement to construct a gas supply portfolio that will meet the:

1. Design day requirements – to provide service to system sales and bundled DP customers on the day of highest anticipated peak or design day demand in each delivery area.
2. Seasonal/annual requirements – to be able to meet the annual requirements of the markets while balancing the summer / winter load changes.

A further description of how Union meets these requirements is found in Section 5.

3.5 Deliver gas to various receipt points on Union's system to maintain system integrity

The Union South transportation portfolio has delivery points at Dawn, Parkway, Kirkwall, and Ojibway. It is Union's practice to receive gas at multiple points. This practice provides two benefits.

First, it maintains system integrity as Union is not reliant on one receipt point for all of its gas supplies. A system interruption or upset at one receipt point would not cause a complete supply failure to Union's system.

Second, delivery to multiple receipt points allows Union to minimize its pipeline facilities in the area. For example, the delivery of gas at Ojibway enables the Dawn-Ojibway transmission system to be smaller than would otherwise be necessary to meet design day requirements. In this case, if Union delivers gas to Ojibway, Union does not have to ship the equivalent volume from Dawn to Ojibway.

4/ GAS SUPPLY PLAN PREPARATION

Union's Gas Supply Plan is a five-year rolling plan that is prepared annually, with the primary focus being the first 2 years. The plan identifies the efficient combination of upstream transportation, supply purchases, and storage assets required to serve system sales and bundled DP customers' annual, seasonal and design day gas delivery requirements while adhering to the planning principles described earlier. Once the design day demands are calculated, the planning process continues with a monthly forecast by market of total consumption by each delivery area in Union North and Union South. Union's Gas Supply Plan is then used to generate a forecast of natural gas supplies, transportation and storage services required by Union's in-franchise system sales and bundled DP customers. The upstream transportation contracts in the Plan, along with storage assets, are managed by Union to provide an integrated service to all system sales and bundled DP customers. The costs for both the supply and the transportation services identified in the Plan are recovered through commodity, transportation and storage charges.

Union's integrated supply planning is a complex process that incorporates demand related items such as customer growth, normalized weather, design day requirements, customer consumption patterns and economic outlooks. Demands are analyzed relative to Union's existing system design and gas supply portfolio (supply and transportation). The firm needs of these customers are analyzed to ensure the appropriate level of firm transportation and storage assets are held to meet design day, seasonal and annual demand. The plan is appropriately sized and there are no assets in the Plan in excess of those necessary to meet firm customer requirements.

To complete the Plan, Union uses gas supply planning software known as SENDOUT. SENDOUT, supplied by VENTYX, is a widely recognized gas supply planning tool and is used by a number of LDC's in North America. Union has used this software for 26 years and it has been presented in a number of rate applications since 1987.

Union uses SENDOUT to ensure that the assets incorporated in the Gas Supply Plan meet annual, seasonal, and design day demands. SENDOUT determines the amount of capacity, supply and associated costs required to meet customer demands. Union's five-year Gas Supply Plan includes the following key inputs and assumptions:

- The design day demand forecast for each Union North delivery area;
- Union's in-franchise monthly demand forecast based upon customer location, supply arrangement, storage requirement and service type (excludes Transportation Service and Unbundled service);
- A monthly commodity price forecast using the same pricing methodology as the Quarterly Rate Adjustment Mechanism ("QRAM") process;
- Upstream transportation tolls in effect at the time the forecast was prepared;
- All upstream transportation contracts held by Union plus existing obligated Ontario deliveries for the bundled DP market;
- System sales and bundled DP storage requirements that are cycled completely each year in the Plan with storage full on November 1 and empty by March 31 assuming normal weather**;**

- Sufficient inventory at February 28 to meet the design day requirements for system sales and bundled DP customers;
- No migration between system sales and bundled DP customers for the term of the Plan. Any migration is therefore a risk that needs to be managed by Union.
- 9.5 PJs of system integrity space. This storage space is used in a number of ways to maintain the operational integrity of Union's integrated storage, transmission and distribution systems. The Gas Supply Plan has 6.0 PJs of this space filled with system integrity supply while the remaining 3.5 PJs is left empty as contingency space**.**

The outcome of the annual planning process is a five year plan that provides a monthly volumetric forecast of supplies (by transportation path) and demands and a monthly forecast of Union's costs to serve its system sales and bundled DP customers.

Embedded Efficiencies in the Plan

As indicated earlier, the Gas Supply Plan is structured to balance gas supply planning principles with cost effectiveness. One way that cost effectiveness is achieved is to maximize the benefits of firm transportation contracts by flowing them as close to capacity, or 100% annual load factor, as possible. When transportation capacity is filled at 100% load factor, it represents the lowest unitized cost of the path and there are no Unabsorbed Demand Charges ("UDC"). In Union South, the Gas Supply Plan achieves close to 100% load factor and little, if any, UDC occurs.

In Union North, firm transportation capacity contracted is determined by design day firm demand for system sales and bundled DP customers. The assets to meet design day are greater than what is required to meet average daily demand, and therefore results in unutilized pipe and UDC on an annual basis.

If weather is colder than normal and annual consumption is greater, Union would fill the unutilized capacity to meet the additional demand and reduce UDC.

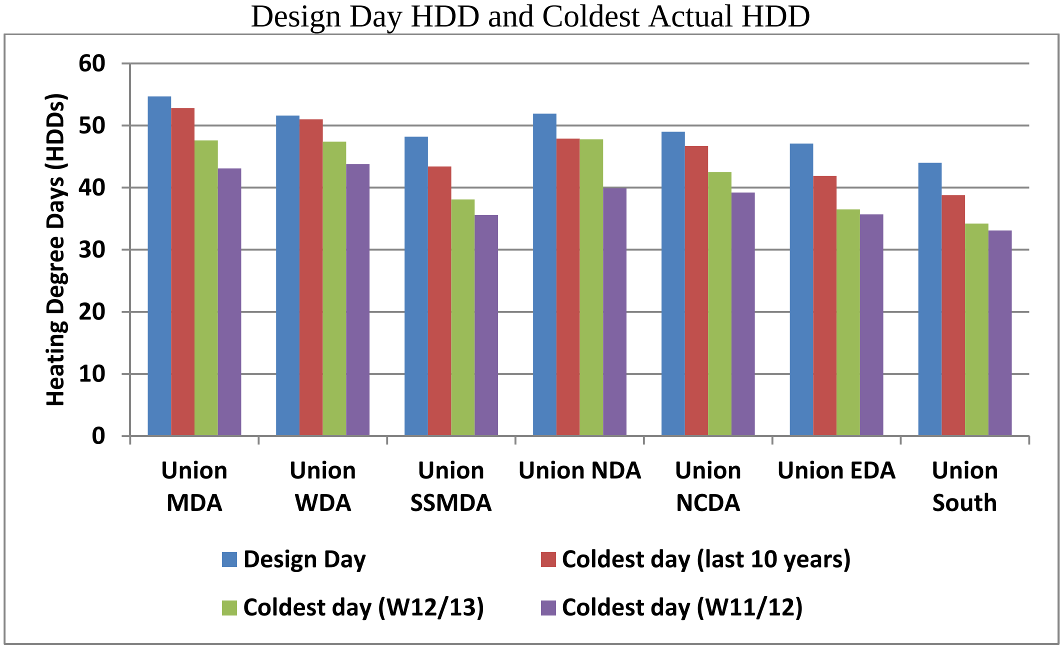
Another example of efficiency built into the Plan is the use of upstream diversions within the integrated portfolio. For example, on design day in Union North, TCPL Empress to Union CDA capacity is diverted upstream to serve Union North markets in certain delivery areas. This TCPL Empress to Union CDA capacity is held as an asset to serve Union South annual needs, and is used on design day to meet market requirements in Union North. Absent this efficiency, more firm transportation capacity would be needed to meet design day in Union North at a greater cost to Union North customers.

5/ DESIGN DAY / SEASONAL LOAD BALANCING REQUIREMENTS

The purpose of the Gas Supply Plan is to determine the appropriate level of assets required to meet firm customer demands for annual, seasonal and design day requirements. Design day is defined as the coldest anticipated day in the year. In the gas industry, temperature is translated to heating degree days (HDD); the colder the temperature, the higher the HDD. A heating degree day is a temperature 1 degree C below 18 degrees C. Therefore an 18 degree HDD would translate to a temperature of 0 degree C on average for the day.

Figure 2 illustrates Union's design day HDD for each delivery area in Union North and for Union South. The chart also indicates Union's coldest day in the winter 2011/2012 and 2012/13 and the coldest day experienced in each delivery area in the last ten years. As depicted on the chart, the coldest HDD in the winter 2012/13 was considerably higher than the winter 2011/12. The coldest day experienced in each delivery area in the last ten years has been very close to the design day HDD planned for each delivery area further supporting Union's planning assumptions for design day HDD.

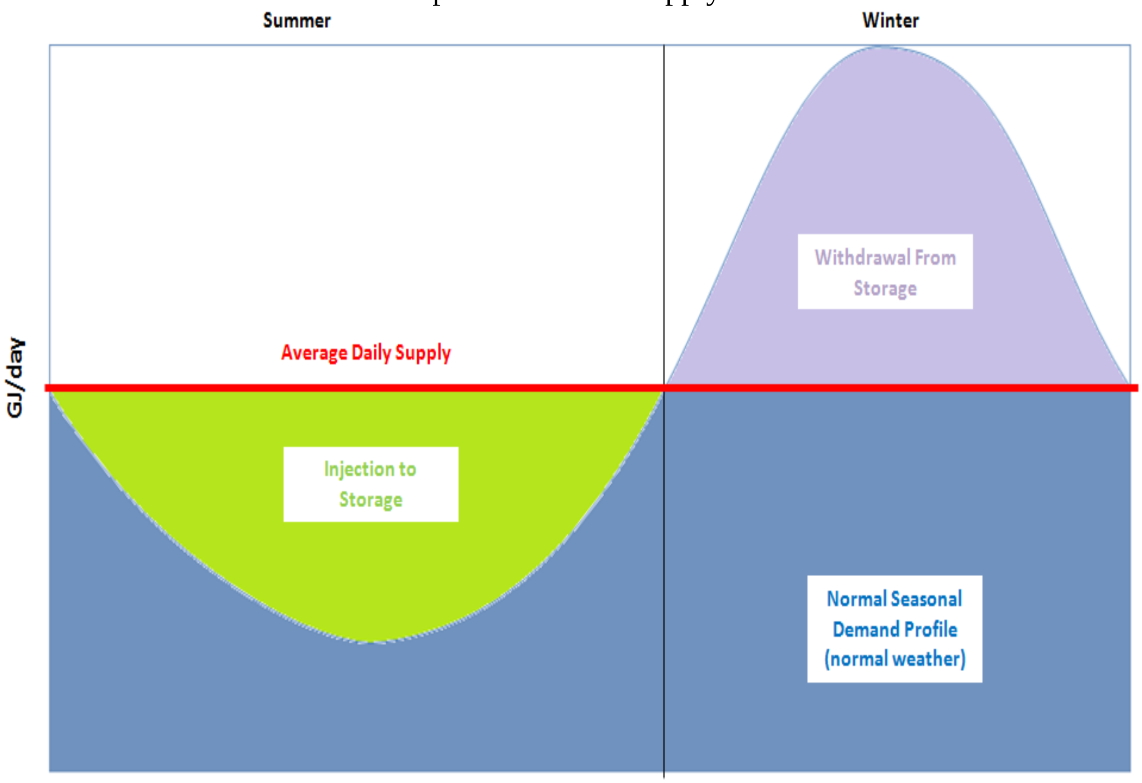
Figure 2
Design Day HDD and Coldest Actual HDD



The design day requirements are met by holding storage and transportation capacity. Design days do not occur every year, however, the assets must be available should that design day occur given Union's role as the supplier of last resort for system sales and bundled DP customers.

Annual supply typically flows on an average daily basis (i.e. annual demand divided by 365 (also referred to as Daily Contract Quantity or DCQ). In the winter, the DCQ (plus storage withdrawals) will flow to the market. In the summer, with reduced demand, supply in excess of the daily demand will go to storage. Figure 3 provides an illustrative example of how storage injections and withdrawals are utilized to manage the seasonal variances in supply and demand.

Figure 3
Illustrative Representation of Supply and Demand



In order to meet these design day requirements for Union South and Union North, Union uses a combination of upstream transportation capacity, storage, transmission, and distribution assets. This is more cost effective than contracting for full, all year firm upstream transportation capacity. Since Union's storage and transmission assets reside within its Union South franchise area, the role of the gas supply portfolio is different on a design day in Union South than in Union North. Union has consistently reflected the Union South and Union North design day methodology described below.

Union South Design Day

The Union South transmission and distribution system is designed to meet the firm requirements of all Union South in-franchise customers including system sales, bundled, unbundled and transportation service customers on a design day. In all cases, it is assumed the customers' supply shows up at the point contracted and Union transports that supply to the end use location. In this case, the Dawn-Parkway system, other transmission systems within the franchise, utility storage assets and distribution assets are all designed to meet the demands associated with a 44 HDD. Design days do not occur every year, however, the assets must be available should the design day occur. A study of the appropriateness of the 44 HDD methodology was completed and filed in EBLO 267[2]. Union has consistently used this methodology for Union South.

The Union South portfolio is structured to:

a) Utilize upstream transportation at a 100% load factor 365 days of the year;

b) Fill the Union South in-franchise storage by November 1;

c) Provide sufficient inventory at February 28 to meet the design day requirement.

Average winter demands are met through a combination of gas flowing on upstream transportation and storage withdrawals as shown in the example at Figure 3. In Union South, design day demands in excess of average annual demands are met through additional withdrawals from storage.

[2] EBLO 267, Dawn to Enniskillen TFEP 1999 Construction, Appendix A, page 19-24

The storage space allocated to Union South customers is based on the Aggregate Excess Storage Method ("Aggregate Excess"). Since 2000, Union has used Aggregate Excess to allocate storage space to its bundled customers in order to fulfill seasonal load balancing needs. This method was reaffirmed by the Board in EB-2007-0724/EB-2007-0725. The aggregate excess calculation determines the amount of storage space required based on the difference between gas consumption in the 151 day winter period (November through March) and the average daily gas consumption during the entire year. Total winter consumption is forecast using normal weather conditions. The formula can be expressed as:

Aggregate Excess = Total winter consumption – [(151/365)*(Total annual consumption)]

Assuming gas is supplied each day equal to 1/365 of annual demand, this will result in a balanced supply and demand outlook. This is a fundamental premise for calculating daily contracted quantity (DCQ) for Union's DP customers and for meeting Union's system sales annual demand requirements. Using Aggregate Excess also allows Union's transportation portfolio to be structured to flow at or close to 100% load factor under normal weather.

As storage is directly connected to Union's transmission and distribution systems in Union South, incremental upstream transportation assets are not required to move these storage supplies to meet design day demand requirements. However, Union needs a robust in-franchise storage, transmission and distribution system to move supply to all parts of the franchise on a peak winter design day of 44 HDD or minus 26 degrees Celsius.

Union North

Union North design day demand requirements are based on the volumetric demands of natural gas that are consumed by firm system sales and bundled DP customers in each of Union's six Northern delivery areas. In this case, transportation service and unbundled customers provide their own transportation and storage services to balance annual load and to meet peak or design day requirements. The design day weather condition is based on the coldest observed temperature that has been experienced in each of the six delivery areas. Union North design day and planning principles were presented in EBRO 489[3]. This design day methodology has been consistently reflected in Union's Gas Supply Plan.

Union North delivery areas are physically separated from Union's Dawn storage and transmission pipeline assets. Therefore, Union requires upstream transportation services to connect each of the 6 northern delivery areas to a supply source (almost exclusively at Empress) and downstream transportation services to connect these 6 delivery areas to storage at Dawn. From Dawn, additional transportation services are required to move gas back to the delivery areas. The amount of storage space available to Union North customers is defined by Aggregate Excess described earlier.

[3] EBRO 489, Exhibit D2, Tab 1, Section 3

The Union North gas supply portfolio ensures there is sufficient, but not excess, firm transportation services available to meet the design day demand requirements in each delivery area. The full suite of assets is only used in each delivery area when a design or peak day occurs. Union uses a portfolio of firm services and assets including TCPL long haul firm transportation, Michcon/GLGT/TCPL transportation capacity, TCPL short haul firm transportation, TCPL STS firm and other TCPL services to meet its design day demand requirement. Union uses TCPL long haul firm transportation and Michcon/GLGT/TCPL capacity to source supply at Empress and Michigan respectively.

Table 2 illustrates what services and assets are relied on in the Gas Supply Plan to meet design day demand. The portfolio of assets in the Gas Supply Plan is appropriately sized and fully utilized on design day. Union does not hold any firm capacity in excess of the design day requirement.

Table 2
Union North Design Day Demand/Supply Balance for 2013 (TJ/d)

		Union North Delivery Area						
Line No.	Item	MDA	WDA	SSMDA	NDA	NCDA	EDA	Total
1	Design Day Heating Degree Day (HDD)	54.7	51.6	48.2	51.9	49.0	47.1	
2	Design Day Demand Forecast (TJ/d)	5	75	34	158	37	154	463
3	Design Day Supplies (TJ/d):							
4	TCPL							
5	Long Haul (from Empress)	4	37	8	49	9	59	166
6	Short Haul (from Dawn)						35	35
7	STS withdrawals (from Dawn)		31	26	52	28	60	197
8	Upstream diversions (1)	1	7		57			65
9	Total	5	75	34	158	37	154	463

(1) Diversions from Union's TCPL Empress to Union CDA contract (Union South Transportation Portfolio)

Gas supply flows on the TCPL long haul firm transportation to meet Union North customers’ seasonal and annual average weather normalized demand requirements. As in Union South, the target is to fill Union North in-franchise storage at November 1 and provide sufficient inventory at February 28 to meet the design day withdrawal requirement. Average winter demands are met through a combination of gas flowing on upstream transportation and storage withdrawals.

The upstream transportation capacity is first sized to meet the winter design day demand requirement. Gas supply flowing on that capacity is also needed to meet average annual demand requirements, and therefore, a portion of Union’s contract capacity is planned to be unutilized during the year. This results in unutilized capacity or UDC. Table 3 shows the total contracted capacity sourcing supply at Empress and Michigan relative to the annual demand and the resulting UDC in the 2013 Gas Supply Plan.

Table 3
Union North Transportation Capacity
2013 Gas Supply Plan (PJ)
(per EB-2011-0210)

	As Filed	Board Approved
Total contracted capacity (166 TJ/day times 365)	60.6	60.6
Total Annual System Sales and DP Demand	50.2	51.3
UDC	10.4	9.3

Accordingly, Union includes a planned amount of 9.3 PJ of unutilized capacity that generates a cost of $10.5 million of UDC in the Gas Supply Plan.

The details of Union's Gas Supply Plan are filed with the Board in evidence during any cost of service review, most recently in EB-2011-0210[4]. In addition, Union updates and reviews its Gas supply plan with Senior Management when a new demand forecast is created, typically on an annual basis.

[4] EB-2011-0210, Exhibit D1, Tab 1, and Tab 2 of Exhibits D3, D4, D5, D6.

6/ DEVELOPMENT OF THE UPSTREAM TRANSPORTATION PORTFOLIO

As supply and transportation market options change, so does Union's gas supply mix and how gas is transported to Ontario. Unchanged, however, is Union's application of the gas supply planning principles described earlier and the requirement to ensure secure, reliable supplies to serve its customers at prudently incurred costs. Each time Union considers a new supply basin or new upstream transportation capacity or renews existing transportation capacity, the cost alternatives are considered wherever options are available. A landed cost analysis is completed and filed when a new transportation path is contracted for, in accordance with the Board-approved EB-2005-0520 Settlement Agreement.

Until the 1950's, Union sourced its natural gas supplies through local Ontario production, manufactured gas, and imported U. S. Supplies. In the late 1950s, the construction of the TCPL Mainline connected western Canadian supplies to eastern Canadian consuming markets. By the 1990's, up to 90% of Union's system supply portfolio was sourced from western Canada, and was predominantly transported to Ontario via TCPL.

Through the 1990's, Union introduced more supply diversity into the Union South portfolio to increase diversity and take advantage of economic supply options from U.S. locations (i.e. Panhandle, Vector**).**

Today, production from mature North American natural gas basins is in decline while new production basins have emerged. This shift in where natural gas is being produced is changing the way natural gas has been traditionally transported in North America, impacting the flow of natural gas on the pipeline grid. For customers in eastern North America, less natural gas is available to flow east from the WCSB[5]. This has resulted in a fundamental shift from long haul transportation to short haul transportation as natural gas is sourced closer to market areas. For example, Union has turned back portions of its TCPL long haul firm transportation service in favour of U.S. supplies to serve the Union SSMDA and has also contracted for alternative TCPL short haul transportation routes (such as Niagara to Kirkwall). Union's upstream transportation portfolio includes a number of pipelines in the U.S. and Canada. Union's current supply mix is shown in the following supply charts included as Figure 4 and Figure 5.

[5] "ST98-2012 Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012-2021", dated June 2012

Figure 4

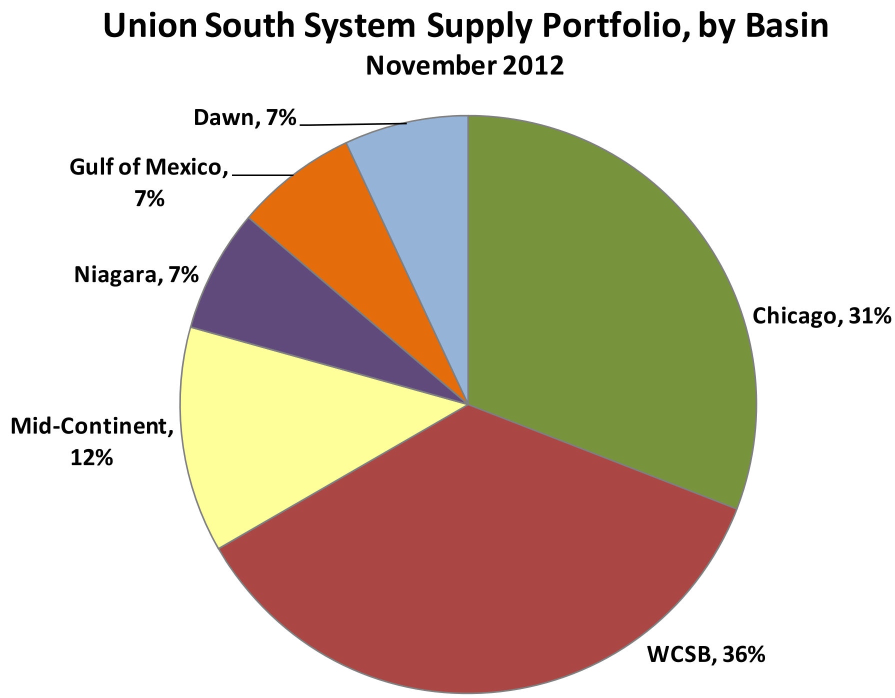
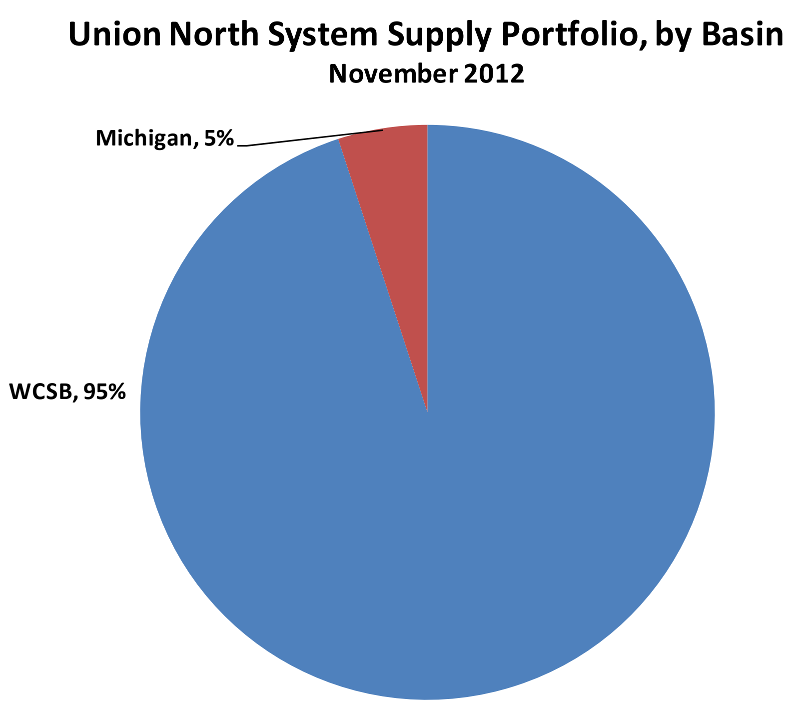


Figure 5



Union North remains predominantly sourced through TCPL from the WCSB. The following describes the services Union uses on the TCPL system that are reflected in the Gas Supply Plan.

TCPL Long haul Firm Transportation Capacity

Union holds long haul firm upstream transportation contracts on TCPL and sources supply at Empress to meet annual, seasonal and design day requirements. Union's contracts for long haul firm upstream capacity guarantee continued access on those transportation paths with the following benefits:

1. Contracts have either a long-term contractual commitment or an annual renewal provision. This provides the certainty that Union will continue to be able to meet its customer commitments on a sustained, long term basis.
2. Firm long haul contracts on TCPL are necessary in order to be eligible to contract for STS.
3. Firm long haul transportation provides access to diversion services which are included in the Gas Supply Plan and facilitates the assignment of capacity to DP customers.

All of these features are important in ensuring Union can efficiently serve its customers. The TCPL long haul firm upstream capacity is fully utilized on design day.

TCPL Storage Transportation Service ("STS")

STS is only available to TCPL long haul firm shippers and is an important component of the Union North portfolio. STS allows Union North customers access to storage at Dawn and is divided into STS injection rights and STS withdrawal rights.

STS injection rights allow for excess gas landing in a delivery area on a given day to move to Dawn or Parkway. At Parkway, Union can then move that gas to storage on the Dawn-Parkway system. STS withdrawal rights allow for stored gas to be withdrawn from storage later and moved from Dawn or Parkway back into the various delivery areas in Union North where gas is required. Union combines capacity on its own Dawn-Parkway system with the TCPL STS services to provide this requirement. The use of STS reduces costs by reducing the amount of firm long haul transportation capacity that would otherwise be required.

There are several aspects of STS that provide benefits in the overall management of the Union North portfolio:

1. Union uses TCPL STS injection rights to deliver excess delivered supplies on firm pipe to Dawn that are not required to meet market demand in the summer (through Parkway and Dawn) and withdraws supply from storage to meet market demand (through Parkway and Dawn) in the winter. This helps manage price fluctuations of supply and reduces the need to hold incremental long haul firm transportation capacity. The STS withdrawal rights are a key part of the upstream services used to meet a design day.

2. The STS allows pooling of STS contractual rights. STS pooling rights allow Union to take excess STS capacity in one delivery area and apply it to another delivery area in Union North subject to contractual arrangements. This is a unique and valuable feature of STS. Pooling rights provide Union with additional flexibility to serve the individual delivery areas in Union North and further reduces costs.
3. The STS also provides four additional nomination windows that allow flexibility intra-day to manage demand fluctuations and balancing costs on TCPL. This flexibility results in lower Limited Balancing Agreement ("LBA") costs on TCPL. Union is required to maintain an LBA in each delivery area in Union North for the purposes of balancing daily nominations to the market demand for all customers. The LBA tolerances are limited and the costs escalate the higher the daily and cumulative imbalance in the LBA.

When structuring the Gas Supply Plan, SENDOUT balances demands between supply on firm transportation capacity and STS withdrawals in the winter to determine which assets are required to serve the delivery area in a given month. TCPL STS withdrawals are fully utilized on design day. As part of the STS, TCPL tracks the nominal storage balance between the amount of gas injected into storage using STS and the amount withdrawn from storage using STS. If more gas is withdrawn from storage then injected, a surcharge or penalty applies.

TCPL Short haul Firm Transportation Capacity

Union holds short haul firm transportation contracts on TCPL from Parkway to the Union EDA in order to transport withdrawals from storage to meet design day and seasonal requirements in the Union EDA. This capacity is also matched with Dawn-Parkway capacity on Union's system. This service supplements STS to the Union EDA and is needed to help meet design day requirements. The guaranteed renewal rights on these contracts ensure that Union will continue to be able to meet its customer commitments on a sustained basis. TCPL short haul firm transportation into the Union EDA is fully utilized on design day.

TCPL Upstream Diversions

Upstream diversions of long haul firm transportation TCPL capacity allow for gas to be directed to or 'dropped off' at a different delivery area that is in the path of the contracted capacity. For example, Union relies on TCPL Empress to Union CDA contract capacity to be diverted upstream to meet design day requirements in the Union North markets. Otherwise, this contract delivers supply to Union South.

Purchase of a Transportation Exchange Service as a Transportation Service

An alternative transportation service available for purchase in the marketplace is a third party transportation exchange. A transportation exchange is a service where gas is delivered by a party at one location and received by that same party at a second location. Third party marketers offer exchange services that allow Union to supply gas in one location and receive it at another location. Union may purchase exchanges as a transportation service in the gas supply portfolio in the absence of available firm pipeline transportation capacity. This happens infrequently and usually as a temporary service until firm pipeline options become available.

Transportation exchange services meet the need for transportation, however are more limited. Exchanges do not allow Union to divert gas or assign capacity. In addition, the availability and cost of transportation exchanges is market driven. Typically, transportation exchanges are short term in length and do not include guaranteed renewal rights.

An example of where Union would purchase a transportation exchange service is illustrated by the Parkway to Union CDA transportation exchange. Union requires a firm transportation service from Parkway to Union CDA. TCPL did not offer the firm transportation capacity between Parkway and Union's CDA on either an annual or winter season basis. In order to transport gas supply from Parkway to Union CDA, Union currently uses a third party transportation exchange to meet its transportation requirements for the winter season.

Other TCPL Services

There are other transportation services available from TCPL that are not included in the Gas Supply Plan as they do not support the planning principles or provide the necessary service features. They are short term firm transportation ("STFT") and interruptible transportation ("IT").

TCPL Short-term Firm Transportation ("STFT")

The Gas Supply Plan does not rely on STFT service as this service does not meet Union's planning principles and exposes Union North customers to incremental service and price risk within the transportation portfolio. STFT can only be contracted for a minimum of seven days and a maximum of 364 days. There is no service flexibility attached to the service. Specifically, STFT is not a viable option for the Gas Supply Plan because it lacks the following:

- renewal rights;
- guaranteed availability;
- service flexibility
- access to STS; and,
- price certainty

Lack of renewal rights

The TCPL STFT service does not offer renewal rights nor guaranteed access to future capacity and as a result, Union would be required to bid into the STFT open season each year. Under the current system, it would be mid-to-late July at the earliest before Union would be awarded the required capacity for Union North delivery areas beginning

November 1 of the upcoming winter season, if capacity was available. The renewal risk related to STFT would create significant uncertainty in serving specific delivery areas.

No Guaranteed Availability

There is no guarantee that STFT capacity between any two points will be available in the future. As the market dynamics continue to evolve, both TCPL and Shippers may contract differently. There are a number of recent market events that may limit the availability of STFT on the TCPL system.

1. TCPL issued an open season for firm transport capacity non renewable (FTNR). This open season outlined TCPL delivery areas where firm transportation capacity will only be available until November 2015.
2. TCPL has announced a binding open season to support a conversion of a large portion of the Mainline natural gas capacity to an oil pipeline. TCPL has stated that:

   "After the transfer, there will continue to be sufficient capacity to meet current firm transportation requirements on the vast majority of the Mainline. However, current firm requirements exceed the capacity that would be available after the transfer by approximately 300 TJ/d to the Union EDA and export points east of and including Iroquois."[6]

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[6] TransCanada Pipelines Ltd. Non-Critical Notice issued April 2, 2013

Due to these developments, the risk related to Union accessing the STFT capacity when and where it is needed would create significant uncertainty in serving specific delivery areas.

Lack of service flexibility

The STFT service does not include the same flexibility features as firm service such as diversions, alternate receipt points and assignments. Union's Gas Supply Plan relies on diversions to manage costs and also requires assignments to facilitate direct purchase in Union North. In the absence of the right to divert gas, the only options to balance would be to use Interruptible Transportation ("IT") or to park the gas in the LBA for the specific delivery area. These options are either less reliable or cost more than diversions.

Lack of access to STS

As previously described, in Union North, TCPL's STS plays an important role in both balancing the annual supplies and demands as well as meeting design day needs. Shippers of STFT service are not eligible for STS. Meeting Union North market demands through STFT alone would require purchasing more supply and transportation capacity in the winter months when both are typically in higher demand and more expensive.

Lack of Price Certainty

STFT is a biddable service with a floor price equal to the FT service and with no maximum price for the service. In TCPL's RH-003-2011 Reasons for Decision issued in

March 2013, TCPL is encouraged by the National Energy Board (NEB) to price STFT as a premium service.

> *"STFT and ST-SN offer firm service for shorter periods of time. Due to their greater flexibility, we see short term services as premium services." (page 132, Item 8.3, Views of the Board)*

Participants bid on quantity, price and term, and capacity is awarded based on aggregate revenue to TCPL. To increase the likelihood that Union is awarded the required capacity, Union may be required to bid at values well in excess of the posted TCPL tolls.

In EB-2012-0451, Exhibit A, Tab 3, Enbridge also highlighted their concerns regarding reliance on unsecured supplies particularly peaking supplies and DP delivered supplies and the availability of STFT in the future. Enbridge has indicated the GTA Project is, in part, driven by their desire to reduce reliance on peaking supplies and STFT and source additional supply from Dawn and Niagara. The GTA Project is expected to provide significant enhancements to Enbridge's gas supply portfolio by improving supply diversity and flexibility, mitigating risk associated with non-renewable transport services such as STFT, and reducing gas supply costs.

Interruptible Transportation ("IT")

Similar to STFT services, IT services do not meet the guiding principles and the use of IT services would expose Union's system sales and DP customers to incremental risk.

FT-RAM has not been included in the Gas Supply Plan as its use relies on interruptible services and does not support Union's guiding principles of providing reliable and secure service. IT services would be at risk of curtailment and as such, are not included in the Plan. During the winter of 2012/2013, long-haul paths that were nominated on IT service into Union's delivery areas were interrupted on five different days.

FT-RAM is only available if firm TCPL transportation capacity is left empty. The resulting RAM credits must be used in the month they are generated to offset the cost of any IT. The minimum IT charge is equal to or greater than the FT commodity toll for the same transportation path. Therefore there is no benefit to system sales and bundled DP rate payers as a result of leaving the firm transportation capacity empty, generating the FT-RAM credit and flowing IT. This act of flowing IT would only increase the risk to system sales and bundled DP customers, without any corresponding savings. In addition, IT transport is a biddable service, meaning that the cost would fluctuate and could be more expensive than FT service. IT is not a viable option for the Gas Supply Plan because it lacks the following:

- renewal rights;
- guaranteed availability;
- service flexibility
- access to STS; and
- price certainty.

7/ OTHER TRANSPORTATION SERVICES HELD BY UNION

In addition to the services noted above, Union has other services that are not included in the Gas Supply Plan. There are services or contracts that are used for operational purposes (i.e. interruptible transportation, LBA with TCPL) or for security of supply (i.e. Bluewater River Crossing Contract). Union may also contract for services specifically designed to support S&T and paid for by S&T. These contracts and services are not described in this evidence.

8/ ONGOING MANAGEMENT OF THE GAS SUPPLY PLAN

Once the Gas Supply Plan is finalized, Union monitors actual activity relative to the Plan on a monthly basis. Variances from the forecast inventory position at February 28, March 31, and at October 31 relative to the Plan (for example, consumption variances from plan) are managed either through spot gas supply purchases, (if demand is greater than planned) or reducing gas supply purchases (if demand is less than planned). Any unutilized transportation capacity is released and sold into the secondary market to recover market value to minimize the cost of UDC. If this available short-term capacity was not sold, the cost to customers would be the total demand charge of unutilized transportation capacity.

As described in Exhibit A, Tab 1, Union's actual UDC in 2012 was 24.4 PJ. The level of UDC in excess of planned levels in 2012 was largely due to significantly warmer than normal weather in winter 2011/2012, partially offset by DP customers in Union South returning to system supply. Union was able to reduce the actual UDC cost by approximately 60% by releasing and selling this capacity in the secondary market. These actions resulted in actual total UDC costs less than the total level approved in rates.

The Gas Supply function is primarily focussed on two things: 1) determining what size the portfolio of services and assets must be to meet customer requirements; and 2) attaining an efficient combination of supply and transportation services and assets to meet these requirements. In completing both of these functions, the Gas Supply department focuses on applying the guiding principles to ensure customers receive the appropriate service.

This function is separate and distinct from S&T. This separation is necessary and appropriate to ensuring that the Gas Supply Plan only meets in-franchise customer requirements, and is not influenced by potential S&T opportunities.

S&T considers current market conditions and opportunities through the year and will market assets which are temporarily available to earn revenue. S&T may use the assets differently than what Gas Supply contemplated, however, any risk associated with these transactions is managed by S&T and any cost consequences impact S&T revenue. This is described in more detail in Exhibit B, Tab 2.

Gas Supply continues to purchase the supply at the planned locations and relies on the gas arriving at the various locations on Union's system to meet customer demand when it is needed.

9/ SUMMARY AND CONCLUSION

Union establishes a Gas Supply Plan that is right sized to meet firm system sales and bundled customer demands with a diverse, flexible and cost effective portfolio of firm services and assets. Union's integrated supply planning process incorporates demand related items such as customer growth, normalized weather, design day requirements, customer consumption patterns and economic outlooks. Union plans and contracts for services and assets to provide an efficient combination of upstream transportation, supply purchases, and storage assets to serve system sales and bundled DP customers' annual, seasonal and design day gas delivery requirements. Union adheres to the gas supply guiding principles to ensure the assets procured on behalf of customers are robust, secure, diverse and reliable to meet firm customer demands. The suggestion in Union's Rebasing proceeding (EB-2011-0210) that Union has contracted for excessive upstream gas transportation services in the Gas Supply Plan to the detriment of the ratepayer is simply unfounded and untrue. Union's portfolio does not have capacity in excess of that necessary to meet system sales and bundled DP customers firm requirements.

As supply and transportation market options change, so does Union's supply mix and how it is transported to Ontario. Union continues to proactively evaluate new supply and transportation options for Union North and Union South customers. Unchanged, however, is Union's application of the gas supply planning principles and the requirement to ensure secure, reliable supplies to serve its customers at prudently incurred costs.

TAB 4

RATE IMPACTS OF UNION'S PROPOSED TREATMENT OF TRANSPORTATION EXCHANGE REVENUE IN 2012

The purpose of this evidence is to compare the rate impacts of Union's proposal to treat FT-RAM related transportation exchange revenues ("FT-RAM revenue") as utility earnings subject to earnings sharing with the alternative gas cost deferral treatment, as approved by the Board in its EB-2012-0087 Decision.

Union's proposal to include net FT-RAM revenue in utility earnings subject to sharing results in a net debit deferral balance of $15.9 million and an earnings sharing credit of $15.7 million. A description of how the deferral balances and earnings sharing amount are allocated to rate classes is provided in Exhibit A, Tab 3.

Under the alternative EB-2012-0087 gas cost deferral treatment, 90% of the net FT-RAM revenue less applicable unaccounted for gas ("UFG") and compressor fuel costs is included in the Upstream Transportation FT-RAM Optimization Deferral Account (179-130) as a gas cost reduction. The UFG and compressor fuel costs deducted total $0.6 million. The result is a credit balance in this account of $33.0 million. The rest of the deferral account balances remain the same. Overall, there is a net credit deferral balance of $17.0 million and no earnings sharing.

The net FT-RAM revenue included in the Upstream Transportation FT-RAM Optimization Deferral Account also includes revenue associated with Union's Dawn to Parkway transmission system. As discussed in Exhibit B, Tab 2, some exchanges use the Dawn to Parkway system as well as upstream transportation capacity and, therefore, the revenue earned on these transactions includes value for Dawn to Parkway transportation. It is Union's view that Dawn to Parkway transportation revenue associated with transportation exchanges should not be deferred and should be treated as utility revenue in the same way that other, stand alone, Dawn to Parkway transportation revenue is treated.

In 2013, as a result of the Board's EB-2011-0210 Decision that 90% of all optimization revenues net of costs shall accrue to ratepayers, Union is tracking Dawn to Parkway revenue separate from revenue related to upstream transportation optimization. These revenues will not be included in the Upstream Transportation Optimization Deferral Account (179-131) established pursuant to the Board's EB-2011-0210 Decision. Union will file an application to dispose of 2013 deferral account balances in 2014.

In 2012, Union did not separately track the Dawn to Parkway transportation component of these exchanges because at the time Union entered into the transactions it was Union's belief that 2012 exchange revenue would be treated in a manner consistent with Union's IRM parameters and the treatment of exchange revenue in 2008, 2009 and 2010. In other words, there was no reason for Union to track Dawn to Parkway revenue included in the transaction separately because all transportation exchange revenue was considered utility revenue. While Union did not separately track the revenue, it is Union's estimate that the Dawn to Parkway transportation margin is approximately $1 million per year.

Since transportation exchange activity is underpinned by the upstream transportation portfolio, as well as Union's transmission system and purchased assets, it is appropriate to include net FT-RAM revenue in the utility earnings subject to sharing, as all ratepayers benefit from earnings sharing. Specifically, Union South bundled direct purchase customers, Union North transportation service customers and ex-franchise customers realize a benefit under Union's proposal. That is, the rate impacts are either higher credits, or lower debits than under the alternative gas cost deferral treatment.

In the alternative gas cost deferral treatment, only Union South sales service and Union North sales service and bundled direct purchase customers realize a benefit. That is, the rate impacts are either higher credits, or lower debits than under Union's proposal.

The total rate class impacts associated with both Union's proposal and the alternative treatment are provided in Schedule 1. Column (e) shows the difference between the two treatments. Where there is a positive number in column (e), the rate class benefits more from Union's proposal than the alternative treatment. Where there is a negative number in column (e), the rate class benefits more from the alternative treatment than Union's proposal.

The estimated bill impacts associated with both Union's proposal and the alternative treatment are provided in Schedule 2. Column (f) shows the difference between the two treatments. Where there is a positive number in column (f), the ratepayer benefits more from Union's proposal than the alternative treatment. Where there is a negative number in column (f), the ratepayer benefits more from the alternative treatment than Union's proposal.

Union has presented preliminary impacts of Union's proposal compared to the alternative gas cost deferral treatment to various customer groups (APPrO, CME and IGUA). A copy of the presentation is provided in Appendix A.

SCHEDULE 1

UNION GAS LIMITED
Calculation of 2012 Deferral Impacts by Rate Class

Line No.	Rate Class	Particulars ($)	Customers (a)	Consumption (10^3m^3) (b)		Earnings Sharing (c)	FT-RAM Deferral (d)	Difference (e) = (d-c)
	Union South							
1	M1	Sales Service		1,985,247	(1)	4,008,467	(4,936,769)	(8,945,237)
2		Direct Purchase		247,631	(1)	266,330	966,506	700,175
3				2,232,879	(1)	4,274,798	(3,970,263)	(8,245,061)
4	M2	Sales Service		412,655	(1)	1,070,472	(1,459,254)	(2,529,726)
5		Direct Purchase		385,090	(1)	635,587	1,098,844	463,257
6				797,745	(1)	1,706,059	(360,410)	(2,066,469)
7	M4	Sales Service	15	20,353	(2)	97,564	30,845	(66,719)
8		Direct Purchase	146	408,288	(2)	1,753,575	1,997,268	243,693
9			161	428,641	(2)	1,851,140	2,028,113	176,973
10	M5	Sales Service	10	19,039	(2)	21,573	(45,849)	(67,423)
11		Direct Purchase	134	451,207	(2)	286,303	436,827	150,524
12			144	470,246	(2)	307,876	390,978	83,102
13	M7	Direct Purchase	4	141,165	(2)	(361,267)	(202,623)	158,644
14			4	141,165	(2)	(361,267)	(202,623)	158,644
15	M9	Direct Purchase	3	57,878	(2)	(3,960)	9,330	13,291
16			3	57,878	(2)	(3,960)	9,330	13,291
17	M10	Sales Service	3	118	(2)	20	(59)	(79)
18		Direct Purchase	1	79	(2)	(26)	228	254
19			4	197	(2)	(6)	169	175
20	T1	Direct Purchase	60	5,023,637	(2)	1,956,488	2,734,706	778,218
21			60	5,023,637	(2)	1,956,488	2,734,706	778,218
22	T3	Direct Purchase	1	239,361	(2)	3,876	97,624	93,748
23			1	239,361	(2)	3,876	97,624	93,748
24	**Total Union South**	**Sales Service**				**5,198,097**	**(6,411,086)**	**(11,609,183)**
25		**Direct Purchase**				**4,536,906**	**7,138,710**	**2,601,804**
26						**9,735,003**	**727,624**	**(9,007,380)**
	Union North							
27	Rate 01	Sales Service & Bundled T		714,975	(1)	(5,131,651)	(11,907,714)	(6,776,063)
28				714,975	(1)	(5,131,651)	(11,907,714)	(6,776,063)
29	Rate 10	Sales Service & Bundled T		241,642	(1)	(2,463,032)	(5,819,038)	(3,356,006)
30		T-Service		427	(1)	(2,823)	(1,943)	880
31				242,068	(1)	(2,465,855)	(5,820,981)	(3,355,126)
32	Rate 20	Sales Service	2	6,471	(2)	(1,992)	(101,753)	(99,761)
33		Bundled DP	18	96,026	(2)	(29,558)	(1,509,969)	(1,480,411)
34		T-Service	36	552,219	(2)	458,914	676,916	218,003
35			56	654,716	(2)	427,364	(934,806)	(1,362,170)
36	Rate 100	T-Service	17	1,912,232	(2)	374,384	716,413	342,029
37			17	1,912,232	(2)	374,384	716,413	342,029
38	Rate 25	Sales Service	58	44,659	(2)	(18,576)	(280,969)	(262,394)
39		T-Service	43	162,978	(2)	(67,790)	23,267	91,058
40			101	207,636	(2)	(86,366)	(257,702)	(171,336)
41	**Total Union North**	**Sales Service & Bundled T**				**(7,644,809)**	**(19,619,444)**	**(11,974,635)**
42		**T-Service**				**762,685**	**1,414,654**	**651,090**
43						**(6,882,124)**	**(18,204,789)**	**(11,323,545)**

Notes:
(1) Based on forecast consumption for the period October 1, 2013 to March 31, 2014.
(2) Based on 2012 actual annual volume.

SCHEDULE 2

UNION GAS LIMITED
Calculation of 2012 Deferral Impacts for Customers within each Rate Class

Line No.	Particulars	Rate Component	Volume for 2012 Deferral Disposition (m^3) (a)		Earnings Sharing: Unit Rate for Recovery/(Refund) (cents/m^3) (b)	Earnings Sharing: Bill Impact ($) (c) = (a x b) / 100	FT-RAM Deferral: Unit Rate for Recovery/(Refund) (cents/m^3) (d)	FT-RAM Deferral: Bill Impact ($) (e) = (a x d) / 100	Difference ($) (f) = (e - c)
1	Average Rate 01	Delivery	1,733	(1)	(0.3399)	(5.89)	0.0379	0.66	
2	Annual Volume of 2,200 m³	Commodity	1,733	(1)	-	-	-	-	
3		Transportation	1,733	(1)	(0.3779)	(6.55)	(1.7034)	(29.51)	
4					(0.7178)	(12.44)	(1.6655)	(28.85)	
5	Sales Service					(12.44)		(28.85)	(16.42)
6	Direct Purchase Bundled T					(12.44)		(28.85)	(16.42)
7	Small Rate 10	Delivery	43,200	(1)	(0.6614)	(285.73)	(0.4552)	(196.65)	
8	Annual Volume of 60,000 m³	Commodity	43,200	(1)	-	-	-	-	
9		Transportation	43,200	(1)	(0.3578)	(154.57)	(1.9529)	(843.66)	
10					(1.0192)	(440.30)	(2.4081)	(1,040.31)	
11	Sales Service					(440.30)		(1,040.31)	(600.01)
12	Direct Purchase Bundled T					(440.30)		(1,040.31)	(600.01)
13	T-Service					(285.73)		(196.65)	89.08
14	Average Rate 10	Delivery	66,961	(1)	(0.6614)	(442.88)	(0.4552)	(304.81)	
15	Annual Volume of 93,000 m³	Commodity	66,961	(1)	-	-	-	-	
16		Transportation	66,961	(1)	(0.3578)	(239.59)	(1.9529)	(1,307.68)	
17					(1.0192)	(682.47)	(2.4081)	(1,612.49)	
18	Sales Service					(682.47)		(1,612.49)	(930.02)
19	Direct Purchase Bundled T					(682.47)		(1,612.49)	(930.02)
20	T-service					(442.88)		(304.81)	138.07
21	Large Rate 10	Delivery	180,001	(1)	(0.6614)	(1,190.53)	(0.4552)	(819.37)	
22	Annual Volume of 250,000 m³	Commodity	180,001	(1)	-	-	-	-	
23		Transportation	180,001	(1)	(0.3578)	(644.05)	(1.9529)	(3,515.25)	
24					(1.0192)	(1,834.57)	(2.4081)	(4,334.62)	
25	Sales Service					(1,834.57)		(4,334.62)	(2,500.04)
26	Direct Purchase Bundled T					(1,834.57)		(4,334.62)	(2,500.04)
27	T-Service					(1,190.53)		(819.37)	371.16
28	Small Rate 20	Delivery	3,000,000	(2)	0.0710	2,130.00	0.1105	3,315.00	
29		Commodity	3,000,000	(2)	-	-	-	-	
30		Transportation	3,000,000	(2)	(0.1018)	(3,052.68)	(1.6829)	(50,487.40)	
31					(0.0308)	(922.68)	(1.5724)	(47,172.40)	
32	Sales Service					(922.68)		(47,172.40)	(46,249.72)
33	Direct Purchase Bundled T					(922.68)		(47,172.40)	(46,249.72)
34	T-Service					2,130.00		3,315.00	1,185.00
35	Average Rate 20	Delivery	11,691,000	(2)	0.0710	8,300.61	0.1105	12,918.56	
36		Commodity	11,691,000	(2)	-	-	-	-	
37		Transportation	11,691,000	(2)	(0.1018)	(11,896.30)	(1.6829)	(196,749.39)	
38					(0.0308)	(3,595.69)	(1.5724)	(183,830.84)	
39	Sales Service					(3,595.69)		(183,830.84)	(180,235.15)
40	Direct Purchase Bundled T					(3,595.69)		(183,830.84)	(180,235.15)
41	T-service					8,300.61		12,918.56	4,617.95
42	Large Rate 20	Delivery	15,000,000	(2)	0.0710	10,650.00	0.1105	16,575.00	
43		Commodity	15,000,000	(2)	-	-	-	-	
44		Transportation	15,000,000	(2)	(0.1018)	(15,263.40)	(1.6829)	(252,436.99)	
45					(0.0308)	(4,613.40)	(1.5724)	(235,861.99)	
46	Sales Service					(4,613.40)		(235,861.99)	(231,248.59)
47	Direct Purchase Bundled T					(4,613.40)		(235,861.99)	(231,248.59)
48	T-Service					10,650.00		16,575.00	5,925.00
49	Average Rate 25	Delivery	2,055,000	(2)	(0.0416)	(854.88)	0.0143	293.87	
50		Commodity	2,055,000	(2)	-	-	-	-	
51		Transportation	2,055,000	(2)	-	-	(0.6434)	(13,221.87)	
52					(0.0416)	(854.88)	(0.6291)	(12,928.01)	
53	Sales Service					(854.88)		(12,928.01)	(12,073.13)
54	T-Service					(854.88)		293.87	1,148.75
55	Small Rate 100	Delivery	27,000,000	(2)	0.0195	5,265.00	0.0374	10,098.00	
56	T-Service				0.0195	5,265.00	0.0374	10,098.00	4,833.00
57	Average Rate 100	Delivery	112,484,000	(2)	0.0195	21,934.38	0.0374	42,069.02	
58	T-service				0.0195	21,934.38	0.0374	42,069.02	20,134.64
59	Large Rate 100	Delivery	486,300,000	(2)	0.0195	94,828.50	0.0374	181,876.20	
60	T-Service				0.0195	94,828.50	0.0374	181,876.20	87,047.70

Notes:
(1) Based on average consumption per customer, for the period October 1, 2013 to March 31, 2014.
(2) Based on annual volumes.

UNION GAS LIMITED
Calculation of 2012 Deferral Impacts for Customers within each Rate Class

Line No.	Particulars	Rate Component	Volume for 2012 Deferral Disposition (m^3) (a)		Earnings Sharing: Unit Rate for Recovery/(Refund) (cents/m^3) (b)	Earnings Sharing: Bill Impact ($) (c) = (a x b) / 100	FT-RAM Deferral: Unit Rate for Recovery/(Refund) (cents/m^3) (d)	FT-RAM Deferral: Bill Impact ($) (e) = (a x d) / 100	Difference ($) (f) = (e - c)
1	Average Rate M1	Delivery	1,679	(1)	0.1076	1.81	0.3903	6.55	
2	Annual Volume of 2,200 m³	Commodity	1,679	(1)	0.0944	1.58	(0.6389)	(10.72)	
3					0.2020	3.39	(0.2486)	(4.17)	
4	Sales Service					3.39		(4.17)	(7.56)
5	Direct Purchase					1.81		6.55	4.75
6	Small Rate M2	Delivery	45,840	(1)	0.1650	75.64	0.2853	130.78	
7	Annual Volume of 60,000 m³	Commodity	45,840	(1)	0.0944	43.27	(0.6389)	(292.87)	
8					0.2594	118.91	(0.3536)	(162.09)	
9	Sales Service					118.91		(162.09)	(281.00)
10	Direct Purchase					75.64		130.78	55.15
11	Average Rate M2	Delivery	55,772	(1)	0.1650	92.02	0.2853	159.12	
12	Annual Volume of 73,000 m³	Commodity	55,772	(1)	0.0944	52.65	(0.6389)	(356.33)	
13					0.2594	144.67	(0.3536)	(197.21)	
14	Sales Service					144.67		(197.21)	(341.88)
15	Direct Purchase					92.02		159.12	67.09
16	Large Rate M2	Delivery	191,000	(1)	0.1650	315.15	0.2853	544.92	
17	Annual Volume of 250,000 m³	Commodity	191,000	(1)	0.0944	180.30	(0.6389)	(1,220.30)	
18					0.2594	495.45	(0.3536)	(675.38)	
19	Sales Service					495.45		(675.38)	(1,170.83)
20	Direct Purchase					315.15		544.92	229.77
21	Small Rate M4	Delivery	875,000	(2)	0.4295	3,758.13	0.4892	4,280.50	
22		Commodity	875,000	(2)	0.0499	436.28	(0.3376)	(2,954.29)	
23					0.4794	4,194.41	0.1516	1,326.21	
24	Sales Service					4,194.41		1,326.21	(2,868.19)
25	Direct Purchase					3,758.13		4,280.50	522.38
26	Average Rate M4	Delivery	2,662,000	(2)	0.4295	11,433.29	0.4892	13,022.50	
27		Commodity	2,662,000	(2)	0.0499	1,327.29	(0.3376)	(8,987.78)	
28					0.4794	12,760.58	0.1516	4,034.72	
29	Sales Service					12,760.58		4,034.72	(8,725.86)
30	Direct Purchase					11,433.29		13,022.50	1,589.21
31	Large Rate M4	Delivery	4,019,000	(2)	0.4295	17,261.61	0.4892	19,660.95	
32		Commodity	4,019,000	(2)	0.0499	2,003.90	(0.3376)	(13,569.46)	
33					0.4794	19,265.50	0.1516	6,091.49	
34	Sales Service					19,265.50		6,091.49	(13,174.01)
35	Direct Purchase					17,261.61		19,660.95	2,399.34
36	Small Rate M5	Delivery	825,000	(2)	0.0635	523.88	0.0968	798.60	
37		Commodity	825,000	(2)	0.0499	411.35	(0.3376)	(2,785.47)	
38					0.1134	935.22	(0.2408)	(1,986.87)	
39	Sales Service					935.22		(1,986.87)	(2,922.09)
40	Direct Purchase					523.88		798.60	274.73
41	Average Rate M5	Delivery	3,266,000	(2)	0.0635	2,073.91	0.0968	3,161.49	
42		Commodity	3,266,000	(2)	0.0499	1,628.45	(0.3376)	(11,027.08)	
43					0.1134	3,702.36	(0.2408)	(7,865.60)	
44	Sales Service					3,702.36		(7,865.60)	(11,567.95)
45	Direct Purchase					2,073.91		3,161.49	1,087.58
46	Large Rate M5	Delivery	11,004,000	(2)	0.0635	6,987.54	0.0968	10,651.87	
47		Commodity	11,004,000	(2)	0.0499	5,486.66	(0.3376)	(37,153.10)	
48					0.1134	12,474.20	(0.2408)	(26,501.23)	
49	Sales Service					12,474.20		(26,501.23)	(38,975.43)
50	Direct Purchase					6,987.54		10,651.87	3,664.33
51	Small Rate M7	Delivery	28,327,000	(2)	(0.2559)	(72,488.79)	(0.1435)	(40,649.25)	
52	Direct Purchase				(0.2559)	(72,488.79)	(0.1435)	(40,649.25)	31,839.55
53	Average Rate M7	Delivery	35,291,000	(2)	(0.2559)	(90,309.67)	(0.1435)	(50,642.59)	
54	Direct Purchase				(0.2559)	(90,309.67)	(0.1435)	(50,642.59)	39,667.08
55	Large Rate M7	Delivery	45,238,000	(2)	(0.2559)	(115,764.04)	(0.1435)	(64,916.53)	
56	Direct Purchase				(0.2559)	(115,764.04)	(0.1435)	(64,916.53)	50,847.51

Notes:
(1) Based on average consumption per customer, for the period October 1, 2013 to March 31, 2014.
(2) Based on annual volumes.

UNION GAS LIMITED

Calculation of 2012 Deferral Impacts for Customers within each Rate Class

Line No.	Particulars	Rate Component	Volume for 2012 Deferral Disposition (m^3)		Earnings Sharing: Unit Rate for Recovery/(Refund) (cents/m^3)	Earnings Sharing: Bill Impact ($)	FT-RAM Deferral: Unit Rate for Recovery/(Refund) (cents/m^3)	FT-RAM Deferral: Bill Impact ($)	Difference ($)
			(a)		(b)	(c) = (a x b) / 100	(d)	(e) = (a x d) / 100	(f) = (e - c)
1	Small Rate T1	Delivery	7,537,000	(2)	0.0389	2,931.89	0.0544	4,100.13	
2	Direct Purchase				0.0389	2,931.89	0.0544	4,100.13	1,168.24
3	Average Rate T1	Delivery	82,265,000	(2)	0.0389	32,001.09	0.0544	44,752.16	
4	Direct Purchase				0.0389	32,001.09	0.0544	44,752.16	12,751.08
5	Large Rate T1	Delivery	197,789,850	(2)	0.0389	76,940.25	0.0544	107,597.68	
6	Direct Purchase				0.0389	76,940.25	0.0544	107,597.68	30,657.43
7	Largest Rate T1	Delivery	628,870,000	(2)	0.0389	244,630.43	0.0544	342,105.28	
8	Direct Purchase				0.0389	244,630.43	0.0544	342,105.28	97,474.85

Notes:
(1) Based on average consumption per customer, for the period October 1, 2013 to March 31, 2014.
(2) Based on annual volumes.

APPENDIX A

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Treatment of Exchange Revenues within the 2012 Earnings Sharing and Disposition of Deferral Accounts and Other Balances Proceeding

March 2013

Key Messages

- ✓Exchange revenues and costs are properly accounted for within utility earnings
- ✓Including the revenue and costs in 2012 utility earnings results in earnings sharing which benefits all ratepayers and partially offsets net debit balances of deferral accounts
- ✓This treatment is consistent with how exchange revenues were treated in 2008-2010
- ✓This treatment is consistent with the structure of the Incentive Regulation Mechanism, and with the balance of benefits and risks
- ✓Any other treatment is retroactive ratemaking

Evidence Overview

- To be filed late April/early May
- Proposes 2012 exchange revenues be included in utility earnings subject to sharing, as they were in 2008-2010
- Addresses the treatment of RAM exchange revenue in the context of Incentive Regulation, and the balance of benefits and risks
- Responds to the Gas Supply directive from the 2013 Rate Case
- Addresses the impact of previous Decisions in the wholesale market
- Requests approval of final balances for all 2012 deferral accounts and an order for final disposition of these balances
- Requests approval of the customer portion of earnings sharing in 2012 and the proposed disposition of that amount to Union's customers

Union's proposal results in earnings sharing, which is shared with all ratepayers

Deferral Balances and Earnings Sharing – Union Proposal

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- Total preliminary Deferral Account balance debit of approximately $16 million
- Main drivers ($ millions):
    - DSM incentives and variance accounts $ 11
    - One time pension charge on transition to US GAAP $ 8
    - Short term storage and other balancing services $ 2
    - Average use per customer $ (4)
- Preliminary Earnings Sharing credit of approximately $15 million primarily due to net exchange revenues

Union's proposal results in a net debit to ratepayers of $1 million

Deferral Balances and Earnings Sharing – RAM Exchange Revenues Deferred

- Total preliminary Deferral Account balance credit of approximately $17 million
- Main drivers ($ millions):

RAM related exchange revenue	$ (33)
DSM incentives and variance accounts	$ 11
One time pension charge on transition to US GAAP	$ 8
Short term storage and other balancing services	$ 2
Average use per customer	$ (4)

- Earnings Sharing is not triggered

Impacts – Union South

Rate Class	Particulars ($)	Estimated Rate Class Impact: Earnings Sharing (a)	RAM Deferral (b)	Difference (c) = (b-a)
M4	Sales Service	98,325	18,593	(79,732)
	Direct Purchase	1,740,306	1,978,637	238,331
		1,838,631	1,997,230	158,599
M5	Sales Service	21,762	(57,723)	(79,484)
	Direct Purchase	259,236	406,449	147,213
		280,998	348,726	67,729
M7	Direct Purchase	(372,387)	(217,233)	155,153
T1	Direct Purchase	1,970,331	2,731,422	761,091

On the whole, these rate classes benefit more from including exchange revenue in utility earnings than in a RAM Deferral Account

Impacts – Union North

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Rate Class	Particulars ($)	Estimated Rate Class Impact Earnings Sharing (a)	 RAM Deferral (b)	Difference (c) = (b-a)
20	T-Service	494,280	707,485	213,206
25	T-Service	(65,784)	23,271	89,056
100	T-Service	390,299	724,805	334,506

On the whole, these rate classes benefit more from including exchange revenue in utility earnings than in a RAM Deferral Account

Estimated Regulatory Timeline

Stage	Date
Application	Late April/early May
Interrogatory Responses	June
Settlement Negotiations	July/August
Hearing	August/September
Board Decision	In time for implementation with October QRAM

Appendix

Union North General Service

Particulars ($)	Estimated Bill Impact: Earnings Sharing (a)	Estimated Bill Impact: RAM Deferral (b)	Bill Variance (c) = (b - a)
Rate 01			
Average			
Sales & Bundled DP	(12.65)	(31.15)	(18.50)
Rate 10			
Small			
Sales & Bundled DP	(494.90)	(1,152.63)	(657.73)
T-Service	(335.84)	(245.29)	90.55
Average			
Sales & Bundled DP	(767.11)	(1,786.59)	(1,019.48)
T-service	(520.55)	(380.20)	140.35
Large			
Sales & Bundled DP	(2,062.10)	(4,802.62)	(2,740.52)
T-Service	(1,399.33)	(1,022.05)	377.28

Union North Contract

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Particulars ($)	Estimated Bill Impact Earnings Sharing (a)	RAM Deferral (b)	Bill Variance (c) = (b - a)
Rate 20			
Small			
Sales & Bundled DP	(593)	(48,998)	(48,406)
T-Service	2,430	3,591	1,161
Average			
Sales & Bundled DP	(2,310)	(190,947)	(188,637)
T-service	9,470	13,994	4,524
Large			
Sales & Bundled DP	(2,964)	(244,992)	(242,029)
T-Service	12,150	17,955	5,805
Rate 25			
Average			
Sales	(830)	(13,522)	(12,692)
T-service	(830)	294	1,124
Rate 100			
Small	5,508	10,233	4,725
Average	22,947	42,631	19,685
Large	99,205	184,308	85,103
T-Service only			

Union South General Service

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Particulars ($)	Estimated Bill Impact		
	Earnings Sharing	RAM Deferral	Bill Variance
	(a)	(b)	(c) = (b - a)
Rate M1			
Average			
Sales Service	4.39	(5.79)	(10.18)
Direct Purchase	2.51	7.18	4.67
Rate M2			
Small			
Sales Service	125.56	(222.60)	(348.15)
Direct Purchase	74.31	131.79	57.48
Average			
Sales Service	152.76	(270.83)	(423.59)
Direct Purchase	90.41	160.34	69.94
Large			
Sales Service	523.15	(927.50)	(1,450.65)
Direct Purchase	309.61	549.13	239.51

Union South Contract Mid Market – Sales & DP

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Particulars ($)	Estimated Bill Impact		
	Earnings Sharing	RAM Deferral	Bill Variance
	(a)	(b)	(c) = (b - a)
Rate M4			
Small			
Sales Service	4,227	799	(3,427)
Direct Purchase	3,729	4,240	511
Average			
Sales Service	12,859	2,431	(10,427)
Direct Purchase	11,345	12,900	1,555
Large			
Sales Service	19,414	3,671	(15,743)
Direct Purchase	17,129	19,476	2,347
Rate M5			
Small			
Sales Service	943	(2,501)	(3,444)
Direct Purchase	474	743	269
Average			
Sales Service	3,735	(9,901)	(13,636)
Direct Purchase	1,878	2,943	1,065
Large			
Sales Service	12,583	(33,360)	(45,943)
Direct Purchase	6,327	9,915	3,587

Union South Contract
Large Market – DP Only

Particulars ($)	Estimated Bill Impact: Earnings Sharing	RAM Deferral	Bill Variance
	(a)	(b)	(c) = (b - a)
Rate M7			
Small	(74,727)	(43,595)	31,131
Average	(93,098)	(54,313)	38,785
Large	(119,338)	(69,621)	49,717
Direct Purchase only			
Rate T1			
Small	3,007	4,168	1,161
Average	32,824	45,493	12,669
Large	78,918	109,378	30,460
Largest	250,919	347,765	96,846
Direct Purchase only			

TAB 5

UNION'S RESPONSE TO THE BOARD'S EB-2011-0210 DIRECTIVE TO REVIEW THE GAS SUPPLY PLANNING PROCESS

The purpose of this evidence is to review the Board's Gas Supply directive in EB-2011-0210, to describe how Union responded to the directive and to provide Union's response to the recommendations provided.

In Union's 2013 Rebasing proceeding, EB-2011-0210, the Board approved Union's 2013 Gas Supply Plan as filed. However, the Board expressed concerns with the gas supply planning process, planning methodology and resulting Gas Supply Plan, in light of Union's optimization activities during its incentive regulation term. The Board questioned whether Union's optimization activities became a driver of the Gas Supply Plan, rather than a consequence of it.

At p. 40 of the EB-2011-0210 Decision, the Board ordered Union to:

> *"file with the Board an expert, independent review of its gas supply plan, its gas supply planning process, and gas supply planning methodology."*

Within its Decision, the Board also ordered Union to provide Intervenors and Board staff with an opportunity to review the Request for Proposals ("RFP") prior to its issuance. The Board provided a list of items to be included in the purpose of the review (p. 41).

In November 2012, Union drafted a RFP based on the list of items in the Decision. The draft RFP was sent to the EB-2011-0210 intervenors for comment on November 30, 2012. Union received comments from the City of Kitchener, the Federation of Rental-housing Providers of Ontario, the Canadian Manufacturers and Exporters and TransCanada Pipelines Limited on December 5, 2012. Union responded to the comments on December 8, 2012. On December 10, 2012 Union sent the RFP to 13 consultants with the scope of work separated into the following three tasks:

Task 1: Gas Supply Planning Principles and Processes

- Verify that Union's gas supply planning process, methodology, and plan reflects appropriate planning principles, including a reference to cost.
- Determine whether planning principles are objectively applied and result in a gas supply plan that is "right sized".
- Determine whether the peak day in the North and South Delivery Areas are appropriately/consistently reflected in the gas supply plan, and if not, recommend remedial action.
- Determine whether Union is conducting sufficient due diligence with respect to the cost benefit analysis associated with de-contracting a particular gas transportation route and re-contracting on an alternative route, and recommend remedial action, if required.

- Determine whether Union is using the transportation portion of the gas supply portfolio to favour the transportation paths of entities in which Union or its parent has (or will have in the future) an economic interest, and recommend remedial action, if required.

Task 2: Peak (Design) Day Practice

- Determine whether Union's differing peak-day methodologies in the North and South Delivery Areas are appropriate, and if not, recommend alternative approaches.
- Recommend whether the two approaches should be aligned.
- Compare the methodology of determining the peak design day, based on the coldest day in the last 50 years, with other heat-sensitive distributors in North America.

Task 3: Cost Allocation/Rate Design and Deferral Accounting

- Examine the cost allocation and rate design used by Union to allocate the cost of gas supply to in-franchise customers in the North and South to ensure that it is appropriate and reflects regulatory principles.
- Examine the structure of the current natural gas supply deferral and variance accounts, with a view to simplifying and standardizing these accounts in the North and South Delivery Areas.

- Determine whether the structure and text of the various natural gas supply deferral and variance accounts is consistent with the principles of the Decisions and Orders that provided the authorization for these accounts and consistent

Union received seven bids in response to the RFP. Three consultants bid on all three tasks, two consultants bid on tasks 1 and 2, and two consultants bid on tasks 2 and 3. Union awarded Tasks 1 and 2 to Sussex Economic Advisors ("Sussex") and Task 3 to Concentric Energy Advisors ("Concentric").

Sussex issued its report to Union on April 20, 2013. Concentric issued its report to Union on April 20, 2013. The reports can be found at Exhibit C, Tab 2 and Tab 3.

In the EB-2011-0210 Decision, the Board ordered that the results of the Gas Supply Plan review were to be subject to a stakeholder information process and then filed with the Board. The Sussex and Concentric reports were sent to the EB-2011-0210 intervenors on April 20, 2013 and then presented to stakeholders at a meeting on April 24, 2013. At the stakeholder session, Sussex and Concentric presented their findings and responded to questions.

Union's Response to the Sussex Report Recommendations

In its report filed at Exhibit C, Tab 2 Sussex reviews Union's gas supply planning processes, specifically Union's guiding principles, design day demand forecast, implementation of the plan and contracting/transportation path decision process. Sussex concludes: Union's guiding principles are sound and similar to other LDCs; Union's design day demand forecasting is appropriate, consistent and aligned between Union North and Union South, and similar to other LDCs; Union's gas supply portfolio reflects the circumstances of each area and is right-sized; Union's approach to de-contracting/re-contracting is reasonable and similar to other LDCs; and Union's optimization approach is reasonable and consistent with approaches of other LDCs.

In addition to its conclusions, Sussex also provides recommendations for various aspects of Union's Gas Supply planning processes. The recommendations include:

- Design Day Demand Forecasting
    - Increased documentation across departments;
    - An annual review process of the prior year's results;
    - A review/evaluation of whether different data sets should be analyzed; and
    - Use of the coldest observed temperature in Union South for the design day standard

- Gas Supply Plan
    - Increased documentation of the Gas Supply Plan including the underpinning assumptions and how the Plan conforms to the planning principles, circulated via memorandum
    - A summary of regulatory and market drivers that provides context for stakeholders should be included
- Contracting Practices
    - Continued use of known information in the contracting decision process, with the addition of scenarios around the base case
    - Documentation of the alternatives analyzed and not analyzed
    - Review of whether the SENDOUT model could be used to augment the landed cost analysis
    - Development of a process to review the cost of service, rate level and rate design for St. Clair Pipeline and Bluewater Pipeline

Union accepts Sussex's recommendations as they relate to: the documentation and analysis of the design day process and review; the development of a Gas Supply Plan memorandum or narrative; the common process regarding contracting; and the periodic review of the St. Clair and Bluewater contracts.

With respect to the recommendation to change the Union South design day standard from 44 degree days to 43.1 degree days, Union has reviewed and accepts the recommendation.

EXHIBIT C

TAB 1

THE SECONDARY NATURAL GAS MARKET IN ONTARIO

Prepared by Stephen M. Acker
May 7, 2013

Introduction

The October 31, 1985 Agreement on Natural Gas Markets and Pricing (the "Halloween Agreement") marked a fundamental change in the way Ontario natural gas consumers were able to purchase their natural gas supplies. No longer tied to the Local Distribution Companies ("LDC's"), consumers were free to purchase their natural gas from whomever they chose. From the early days of natural gas commodity price deregulation, where consumers were largely only able to purchase gas supply at the Empress, Alberta inlet into the TransCanada Pipeline System ("TCPL"), to today's environment where Ontario natural gas consumers are free to purchase gas supply at any number of points on the North American natural gas pipeline grid, the Direct Purchase Market for natural gas has evolved into one of the more efficient commodity markets in North America.

Today, Ontario natural gas consumers are not only free to purchase natural gas from suppliers of their choosing, including the LDC, but they are also free to purchase natural gas under a myriad of prices, terms, and at multiple locations. This is the legacy of the Halloween Agreement, and its success is due in large part to the existence of the secondary market for natural gas transportation and transportation services in Ontario. An active and competitive secondary market for natural gas supply and transportation services ensures that both the supply and transportation of natural gas will be the result of agreements reached between willing sellers and willing buyers. From the earliest days of deregulation where producers competed amongst themselves to sell natural gas to the largest industrial end users and LDCs at Empress, to today's environment where producers, pipelines, agents, brokers, marketers, industrials of all sizes, commercial operations, electricity producers, institutions, municipalities, and LDCs are all involved in the buying, selling, and/or transporting of natural gas, the foundation for this activity has been an increasingly active and efficient secondary market for natural gas transportation and associated transportation services. As the North American pipeline industry has evolved over the last 25 plus years, and as the value of subscribing for and holding firm transportation has alternated between positive and negative, the constant and continued participation of LDCs in the holding, and maximizing the value, of pipeline transportation has facilitated the secondary markets. By default, it has also supported the continued ability of Ontario natural gas consumers to benefit from having multiple, competitively priced options for natural gas supply.

Ontario Natural Gas Market Participants

In sharp contrast to the pre-Halloween Agreement era, when the Ontario LDCs, and therefore the Ontario gas consumers, had effectively one supply source (Western Canada), one supplier (LDC), and one price (regulated), today's Ontario natural gas market has multiple supply sources, multiple suppliers, and multiple, freely negotiated prices. To better appreciate the current

Ontario natural gas market, one needs to know who the players are, and what roles they perform:

1. **<u>Producers:</u>** Regardless of their geographic location, producers are defined as entities primarily involved in the exploration for, and production of, natural gas. Producers sell their discovered natural gas and reinvest the proceeds back into further exploration. Producers may choose to sell their natural gas anonymously on an exchange such as NGX, or directly to LDCs, Producer Marketers, Direct Purchase End Users, or Marketers/Traders. If selling to customers not located near the source of production, the Producer assumes the responsibility and cost of securing incremental transportation required to get the natural gas to the point of sale, with an expectation of increasing the ultimate price received.

2. **<u>End Users</u>**: Entities that consume (burn) the purchased natural gas. Typically LDCs, municipalities, and other entities that resell/redistribute natural gas, such as residential/retail aggregators, are considered as end users. End users not located at or near the production sources for natural gas must either have the gas transported to the point of purchase, or contract in some fashion for transportation services to move the purchased gas on their behalf.

3. **<u>LDCs:</u>** LDCs are a distinct form of end user for one very important reason; LDCs have more than just a purely economic criteria when contracting for pipeline transportation. As the supplier of natural gas to, and supplier of last resort for, their General Service

customers, all LDCs are guided by one overriding principle; to secure and provide a fully reliable supply of natural gas at reasonable prices while maintaining portfolio diversity. LDCs contract for upstream transportation in order (1) to diversify supply and promote new supply sources, (2) to meet normal and peak day demands, and (3) to provide service and supply throughout the franchise in a safe and reliable manner. These various drivers may at times result in LDCs contracting for transportation that may appear to the outsider to be uneconomic, and for that reason local utility regulators regularly assess the prudency of a LDC's transportation and gas supply contracting practices.

4. **Marketers:** There are two categories of Marketers; Producer Marketers and Direct Marketers.

    a. Producer Marketers: These Producers make investments in personnel and assets in order to add incremental value to their production in the hope of selling at a price greater than the local, daily priced option. Assets usually consist of some combination of storage and transportation and are acquired on both the Primary and Secondary Markets. Some Producer Marketers will purchase third party supply from others, generally Producers, in order to increase the volume of natural gas they have for sale.

    b. Direct Marketers: These entities are similar to Producer Marketers except for the fact that they do not explore for or produce natural gas. Direct Marketers are solely in the business of buying and selling natural gas for a profit, and will contract for assets or services only if they increase the probability of making a profit. Direct Marketers tend to sell mostly to End Users and LDCs and can be described as being in the risk management business; they purchase natural gas and/or associated services and hope to resell them at a profit.

5. **Traders:** These entities exist solely for the purpose of buying and selling natural gas for a profit. Traders will operate at any and all locations that offer them that opportunity and they generally do not discriminate between customers, except on credit strength. Traders will buy and sell to and from all market participants, including other Traders, and do not discriminate between electronic and physical sales, except on the basis of price. Traders will attempt to capitalize on the difference in price between buying and selling at two different geographic locations, if they can "cover" the spread between the two locations at a cost less than the current market value. Traders generally accomplish this feat by participating in the Secondary Transportation Market.

    One important fact that must always be kept in mind when discussing an efficiently operating commodity market - there are only two participants that cannot be replaced or done without: the Producer and the End User. Any and all participants in the industry who get between these two do so for one reason only - to make a profit, either by speculating on the price of the commodity itself, <u>or by providing a service to others at a price greater than the costs they incur.</u> If the opportunity to make a positive return on their investment disappears, the *industry participants in the value chain between production and consumption will re-deploy both their financial and intellectual capital elsewhere.*

Liquidity and Depth

One of the most important contributions that Marketers and Traders bring to the Ontario Natural Gas Market is liquidity and depth. Liquidity and depth exist when there are a sufficient number of buyers and sellers willing to transact such that the difference between the price a buyer is willing to pay and the price a seller is willing to accept is very small (the bid/offer spread), and when any one transaction will have a limited effect on the price of a subsequent transaction. In the North American natural gas industry, the NYMEX Henry Hub Market is the most liquid and deep. In Canada, the AECO Market Hub in Alberta is the most liquid and deep, and the Ontario located Dawn Market Hub the next most liquid and deep. Liquidity is important to both buyers and sellers of natural gas because it ensures that they are always able to buy or sell natural gas; there exists many buyers and sellers willing to conduct the exact same transaction at the exact same time. In Ontario, for example, if there were no liquidity at the Dawn Market Hub, no buyer, be it LDC or traditional end user, would be confident that they would be able to buy natural gas as needed. If there were only one buyer at the Dawn Market Hub, no seller would be confident that they were receiving a fair and competitive price for their gas supply.

The Dawn Market Hub is liquid for a variety of reasons:

1. **Access:** There are a number of transportation options for accessing the Dawn Market Hub, including TCPL, Alliance/Vector, Great Lakes Gas Transmission, Panhandle, Trunkline/Panhandle, National Fuel/TCPL, and ANR/Enbridge.
2. **Storage:** There is an active and competitive natural gas storage market, both at the Dawn Market Hub and in the surrounding area (i.e. Michigan)
3. **Sellers:** There are at any one time, a number of Producer Marketers, Direct Marketers, and Traders willing sell natural gas.
4. **Buyers:** There are at any one time a number of Producer Marketers, Direct Marketers, Traders, LDCs, Power Generators, Large Industrials and various other End Users willing to buy natural gas.

A critical fact to consider when discussing the liquidity of the Dawn Market Hub is that, for all intents and purposes, there is no native natural gas production in the immediate area; in order for any market participant to deliver gas to, or move gas away from, the Dawn Market Hub, they need access to some sort of transportation, either in their own name, or provided as a service by others. Some participants also choose to contract for storage services in order to balance their buying and selling obligations and/or to take advantage of anticipated movements in the price of natural gas.

In addition to the Dawn Market Hub, there are a number of other pricing points in Ontario where natural gas transactions can and do regularly occur, including the Western Delivery Area, the Northern Delivery Area, the Central Delivery Area, the Eastern Delivery Area, the Sault Ste. Marie Delivery Area, and Parkway. Each of these points is, to varying degrees, less liquid and deep than the Dawn Market Hub for the very reasons previously mentioned; there are fewer physical options for accessing these points, and there are fewer buyers and sellers transacting at these points. One result of this lower level of liquidity and depth is that the market price for natural gas is less discoverable by market participants, and therefore is more volatile. Volatility does increase the odds of either the buyer or the seller being unhappy with the price they may receive or pay for their natural gas. However, the proximity of these points to the liquidity of the Dawn Market Hub reduces location differentials when compared to both the AECO Market Hub and Henry Hub Market.

Prices are generally more transparent when based on liquid and deep pricing points located closer to the point of sale. Specifically, if a point of purchase is easily connected to the Dawn Market Hub by either accessible pipeline transport or exchange services, the spread between Dawn and this point will be less than it otherwise would be if the point were more isolated.

In order to have a vibrant, competitive, and transparent market place for natural gas, liquidity and depth are critical, and in order to have liquidity and depth, all the market players have to have a reason to participate, and that reason is usually that the price at which natural gas is bought or sold is acceptable to both parties in a transaction. In Ontario, one major reason for the increasing liquidity and depth of the Dawn Market Hub, and to a lesser extent, the surrounding points of sale in Ontario, is the existence of an active secondary market, which would not exist if not for the commitments made by some industry participants to offer and contract for natural gas transportation services. Because of their obligation to serve, and the subsequent size of their supply requirements, LDCs are usually the largest investors in assets, both transportation and storage. This statement is borne out by the fact that currently, among the largest volume contractors for firm, term TCPL transportation, Union transportation to serve ex-franchise, and Union storage are the Ontario LDCs, the Québec LDC GMi, and the U.S North East/New England LDCs, with more than 6 bcf/d of natural gas leaving the Dawn Market Hub to serve ex-Union Ontario, Québec, New England and Mid-West customers.

Secondary Markets

A secondary market in natural gas transportation, sometimes referred to as an aftermarket, facilitates transactions between willing parties, sometimes outside of a regulated environment, at least in Canada. One result of a secondary market in natural gas transportation is that it provides for instant and independent valuation of an asset or service - the marketplace willingly decides the worth based upon supply and demand and freely negotiated transactions.

If one uses TCPL service as an example, the primary market consists of those shippers who have contracted directly with TCPL and obligated themselves to pay the National Energy Board (NEB) approved toll for the service that they have purchased. To date, the price that TCPL may charge for that service could only be changed if approved by the NEB after a prescribed regulatory process. TCPL may create and offer new services to the marketplace, but the tolls for those services had to be approved by the NEB.

Again using TCPL service as an example, the secondary TCPL market consists of the TCPL contracted shippers (who are obligated to pay to TCPL the NEB approved toll) and any other party willing to pay that shipper to move gas between two points, either by providing a service, such as an exchange, or by temporarily transferring title to the TCPL capacity at a price agreeable to both parties. The price at which either of these two transaction occurs may be more or less than the applicable NEB regulated toll. To summarize, the market value of the pipeline capacity in question may be positive or negative when compared to the regulated cost of the same piece of capacity. The result of a single transaction as described is that the original owner of the TCPL capacity has realized value if the spread is greater than the regulated cost, or the original owner has mitigated at least a portion of a notional loss if the value received (spread) is less than the regulated cost.

The current Ontario secondary natural gas transportation market participants include Producers, End Users, including Power Generators, Large Industrials and Institutions, LDCs, Marketers, and Traders as described above. Again, one needs to remember that an efficient and liquid Ontario natural gas marketplace needs all of these participants in order to survive in a largely unregulated commodity market such as the Ontario Direct Purchase Natural Gas Market. (*The Ontario Direct Purchase Natural Gas Market is defined as consisting of those natural gas consumers who do not purchase their natural gas supply directly from an LDC.*) If the secondary market in Ontario were to disappear, or even diminish, it is likely that the decreased potential to transact profitably would cause Marketers and Traders to re-evaluate their continued participation. This departure from the marketplace would result in a dramatic decrease in liquidity, depth, and price transparency in the Ontario natural gas marketplace, likely resulting in higher natural gas prices, to the detriment of both Ontario LDCs and Ontario Direct Purchase End Users.

A logical question to be asked at this point would be, “Who ultimately benefits from an active and healthy secondary market for transportation and storage services in Ontario?”

The short answer is the Ontario natural gas End User, whether General Service or Direct Purchase supplied. Of course Marketers and Traders also benefit, but they do so only when serving the ultimate beneficiaries, the End Users.

I. The Ontario LDC General Service customers benefit from an active and healthy secondary market because their LDC is able to generate revenue from the efficient use of prudently acquired assets that may not otherwise be fully utilized at all times. How these revenues are treated is left to the discretion of the regulator. The point to be made here is that if there were not a secondary market for transportation services in Ontario, the LDC General Service customer would be paying more for their completely bundled services.

II. The Dawn Market Hub benefits from increased liquidity which results in:
   a. More reasonable and competitive prices.
   b. Ontario Power Generators and Larger Industrials are able to purchase very large volumes on short notice.

III. The Ontario Direct Purchase End Users benefit from an active and healthy secondary market because they have choices:
   a. A choice of where to purchase their gas supply: Empress, Dawn, Parkway, EDA, CDA, NDA, Chicago etc.
   b. A choice of whether to directly contract to transport their gas supply themselves or to have another party provide the service.

The decisions an Ontario Direct Purchase End user makes will be primarily driven by cost - which combination of purchase location and necessary transportation will result in the lowest delivered gas cost possible? Without an active and healthy secondary market in transportation and storage services, the Direct Purchase End User would only have one choice; contract for the regulated transportation necessary to move gas from the purchase point to the LDC City Gate, regardless of the economics of that decision.

This was the situation immediately post the Halloween Agreement. The commodity was deregulated, but the secondary market for transportation was in its infancy. Marketers and Traders quickly identified the value of accessing transportation held by others (LDCs and Large Industrials) and when bundled with gas supply, created increased liquidity and services at points across the Canadian pipeline system. LDCs and Large Industrials were then presented with an option to generate incremental revenue through the more efficient use of their transportation assets.

> *While both LDCs and Direct Purchase End user have options when looking to purchase natural gas at more liquid points such as Empress and Dawn, at the less liquid points such NDA, WDA, EDA etc., it is often necessary for these players to contract directly with TCPL for service to ensure consistent, reliable supply. Holders of transportation to these less liquid points are a prime source of secondary market transport, especially during periods of reduced demand. An example would be releasing this transportation to a third party (Marketer/Trader) in return for that party obligating itself to supply natural gas to the LDC/Direct Purchase End User on agreed to terms and price. The*

Marketer/Trader is then free to use the transport in whatever fashion they choose in an attempt to make a profit - hopefully by selling natural gas to another industry participant at a profit. Again, it is important to remember that the Marketer/Trader will only participate in any particular market if there exists a reasonable expectation of making a profit at an acceptable level of risk. Marketers/Traders live and die by managing price risk, which is their business, while LDCs and Direct Purchase End Users generally try to avoid price risk. If a Marketer/Trader is willing to provide a service (transport and/or gas supply) at a price acceptable to a LDC or Direct Purchase End User, then a deal is concluded and the risk of failure to perform lies with the Marketer/Trader; this usually means that whatever assets required to perform are either acquired in the secondary market, or a subsequent deal is done with another industry participant willing to transact with the Marketer/Trader. It is easy to understand how the term "daisy chain" can be applied to situations as described above. There may be any number of parties in between the original seller and buyer of the natural gas in question, the majority of whom are attempting to sell natural gas or transportation service at a price higher than they paid for the same thing. The LDC/Direct Purchase End User is primarily concerned with receiving the service or supply contracted at the price negotiated.

A vibrant, efficient, and competitive secondary market for transportation services benefits all of the participants in the Ontario natural gas industry. The benefits of such a secondary market would not exist if the contracted holders of natural gas pipeline contracts did not outright release their temporarily underutilized capacity or use such capacity to provide services to others. One only needs to look at the list of current shippers on the TCPL and Union systems to see that LDCs are by far the largest holders of transportation and as such, their continued participation in the secondary market is critical to its existence.

Exchange Services

The secondary natural gas market in Ontario has been loosely defined as the use of transportation and storage assets, for purposes other than their original intent, to provide a service to a third party. Whether transportation assets are released outright to third parties, or used by their original holders to provide a service to a third party, the vast majority of incremental value is created by providing an exchange. An exchange is an agreement whereby the holder of transportation agrees to accept gas from a third party, at a specific location and over a specific period of time, and to give a similar quantity of gas to the same third party at another location over the same period of time. One party will usually pay the other party for this service.

A simple example of an exchange would be Party A delivering a specific volume of gas at Empress over a specific time period to Union Gas, and Union Gas giving a like volume of gas to Party A at Parkway over the same specific time period. In this example, Party A would pay Union Gas an agreed to price for this service, while Union Gas would be obligated to pay TCPL the NEB approved toll for the temporarily underutilized Empress to Parkway service; the two prices would not necessarily be equal.

Because Union Gas' firm, term Empress to Parkway TCPL service currently has diversion rights associated with it, Union Gas might subsequently choose to divert its service to another delivery point on the TCPL system in order to transact an exchange for Party B, while simultaneously sourcing gas at Parkway in order to fulfill its original obligation to Party A. This second scenario illustrates how a single Union Gas temporarily underutilized transportation asset can be leveraged to conclude two incremental transactions, thereby increasing overall liquidity in the marketplace while generating increased revenue for Union Gas.

The second scenario described above required Union Gas to divert its TCPL service from its primary delivery point to a secondary point on the TCPL system in order to conclude the specific transaction. Under the current TCPL Tariff only Firm Service ("FT") contracts can be diverted from their primary delivery points. TCPL services such as Interruptible Transport ("IT") and Short Term Firm Transport ("STFT") do not have these diversion rights and as such, in isolation, do not have much secondary market value - they are restricted to one receipt point and one delivery point and they cannot be released to other parties. The ability to divert FT service has inherent value and therefore secondary market participants usually have an interest in acquiring such service, if the price is acceptable. That being said, both IT and STFT can be used to provide an exchange, but each is restricted to the contracted receipt and delivery points.

A unique feature of FT service on TCPL, at least currently, is Firm Transportation Risk Alleviation Mechanism ("FT-RAM"). Long haul, FT shippers on TCPL are able to apply credits generated from unutilized demand charges against the cost incurred for any contracted IT service. Shippers are free to contract IT services between any two points they choose. Because FT-RAM is a service intended to increase value to long haul TCPL FT shippers, FT-RAM has a value that can be realized by certain parties. For example, a FT shipper with TCPL service between Empress and Parkway might outright release that service to a Marketer/Trader who would not utilize the service, but apply the subsequently generated FT-RAM credits against IT service contracted that would be utilized to transact with a third party. Meanwhile, the original party would cut costs that would have otherwise been incurred. Again, one sees how this single piece of TCPL transport can be used to increase overall liquidity in the marketplace.

Another example of how the inherent value of TCPL long haul FT service can be unlocked through FT-RAM is where the original contract holder of the service applies earned credits against its own contracted IT service which could be used to generate revenue by providing an exchange service to a third party. Market liquidity is increased because a transaction has taken place that might not have otherwise. As described above, the likelihood of several subsequent transactions occurring as a result of the original exchange cannot be ignored.

Exchanges increase liquidity and benefit all participants in the Ontario natural gas marketplace, as follows:

- **<u>Producers</u>** benefit because Marketers/Traders are incented to compete for produced natural gas.
- **<u>Direct Purchase Customers</u>** benefit because there are more options for competitively sourcing their required gas supply. For those Direct Purchase End

users that hold their own TCPL FT, there are multiple parties competing to optimize their transportation service. For very large volume purchasers such as Power Generators and Large Industrials, there is increased confidence that required volumes will be available when needed. All end users benefit whenever the LDC is able to realize increased revenue that is shared with its ratepayers and shareholders.

- **LDCs** benefit because they are able to generate revenue from the more efficient use of their contracted transportation assets, either by outright release of the service that may be temporarily underutilized, or by using the FT-RAM credits generated by the asset to provide an exchange service that generates revenue that can be shared by ratepayers and shareholders.
- **Marketers/Traders** benefit because they are able to use exchanges in order to buy and sell natural gas at a variety of geographic points without having to make long term commitments to pipeline companies. Without access to exchanges and/or released pipeline capacity Marketers/Traders would have reduced opportunities to provide services to Direct Purchase End Users, and hence have less opportunity to earn a profit. As mentioned above, without the prospect of earning a profit, Marketers/Traders will look elsewhere for that opportunity and the marketplace will risk having lost the very participants that create and maintain market liquidity and depth.

The FT-RAM service provides increased opportunity for shippers to optimize the value of contracted capacity. As the holder of FT service monetizes the value of the FT-RAM feature, all Ontario market participants benefit from the increased secondary market transactions through increased liquidity, depth, and price transparency. As holders of large amounts of FT service, Ontario LDCs are able to earn increased revenues that can be shared as directed by the regulator.

Marketers/Traders

Marketers/Traders have been identified as essential market participants largely responsible for the existence of a vibrant and healthy secondary market in Ontario. Unlike other participants, Marketers/Traders have no vested interest in either natural gas production or consumption, except to the extent that they can possibly profit by the buying and selling of the commodioty. The only reason for a Producer, LDC, or a Direct Purchase End User to deal with a Marketer/Trader is that the Marketer/Trader is offering a service, for a price, that the Producer, LDC, and/or Direct Purchase End User deems attractive. These services usually consist of buying or selling natural gas at locations, terms, and prices deemed competitive. Since LDCs are prohibited from offering many of the services Marketers/Traders are able to provide, such as the in-franchise selling of natural gas at fixed prices over fixed terms, the Marketer/Trader provides an essential service to all market participants. Again, the critical point to appreciate is that the Marketer/Trader will only create and offer services as long as there exists the prospect of having access to assets and services that can generate a profit. The major factor in attracting Marketers/Traders is liquidity and depth at and close to points such as the Dawn Market Hub.

Exchanges are the backbone of the secondary natural gas marketplace in Ontario, and access to transportation services is the backbone of a natural gas exchange. The parties most likely to contract and hold firm, term transportation are the LDCs, whose mandate includes sourcing and securing diverse and reliable gas supply at competitive prices, and larger End Users desiring to manage supply and price risk themselves. Due to the ever changing market value of transportation, and the term and credit commitments required by pipeline companies such as TCPL, Marketers/Traders seldom contract for firm, term transportation services directly from pipeline companies. This is especially true during periods when the regulated toll for TCPL services is greater than the market spread between the same two points; if Marketers/Traders are not able to acquire assets at close to their current market value, they will not participate in the market and less gas will flow. Marketers/Traders generally prefer to deal in the secondary marketplace because they are able to negotiate both term and price for the assets or services desired. Marketers/Traders then repackage supply, transport (services), and market for resale. It is this repackaging that brings new products and services to the marketplace and to the extent that Marketers/Traders compete amongst themselves for supply, transport (services), and market, then liquidity and price transparency results, to the benefit of all market participants. To the extent that Marketers/Traders are not able to access any one of supply, transport (services), or market, they will look for other markets where all three are available. In the Ontario marketplace supply and market are available. The third requirement, transportation (services), is only available as long as the holders of the firm transportation contracts are willing, able, and incented to make transportation (services) available. If the holders of the firm transportation contracts do not make them available in some fashion to the secondary marketplace, then Marketers/Traders have little prospect of packaging deals attractive to their customers and will look elsewhere for that opportunity. IT and STFT services alone are not sufficiently flexible for Marketers/Traders to rely solely on their availability. The secondary marketplace will consequently be less robust, liquid, and transparent, and the price of natural gas for all industry participants will be set in a less competitive environment.

Optimization

The Ontario Energy Board (the "OEB" or the "Board") defines optimization as "… any market-based opportunity to extract value from the upstream supply portfolio held … to service in-franchise bundled customers, including, but not limited to, all FT-RAM activities and exchanges."[1] If one assumes that it is appropriate for all asset owners to attempt to extract full value from and for their assets, then it is entirely appropriate for the holders of firm, term transportation on TCPL to pursue opportunities to realize such value, and a vibrant, healthy, and competitive secondary market is a direct result of that opportunity. In addition to the Ontario LDCs, Union Gas Limited and Enbridge Gas Distribution, the Québec LDC GMi and the vast majority of the U.S. Northeast and New England based LDCs all optimize their TCPL and/or Union firm transportation, either through outright releases or by way of providing exchange services. All of these concerns are currently incented in some fashion to attempt to realize incremental value from their assets while ensuring that they meet their over-riding mandates

[1] EB-2011-0210, Decision and Order, October 24, 2012, page 39.

to serve their General Service Customers. While incentives may certainly vary between jurisdictions, without incentive, the increased commitment of time and energy, and the assumption of the increased risks are not worth the investment. Again, without the opportunity for periodically underutilized assets to be provided to the marketplace, liquidity will diminish.

If all holders of firm, term TCPL transportation were to contract for the levels of service they deemed necessary to meet their respective requirements, (including meeting peak day demands), but were then not to optimize the capacity, several scenarios would unfold:

- Producers would choose to sell their product where the netback price is the highest, and this might result in less firm, term TCPL service to Ontario being contracted. If this were to happen, then potentially less natural gas supply would be drawn to Ontario and the competitiveness of the marketplace would be negatively impacted.
- Direct Purchase End Users would be severely limited in their options to decrease the overall delivered cost of their natural gas supply, since fewer counterparties would be competing to supply their needs.
- LDCs would continue to meet their mandate of securing and providing diverse and reliable supply, however the net, incremental benefits currently being realized would be much diminished.
- Marketers/Traders would have fewer options available to them to provide prices and services attractive to the marketplace. If Marketers/Traders were to exit the Ontario

marketplace, then Direct Purchase End Users would have less opportunity to access exchanges with a result being less competitive natural gas service.

Natural gas asset optimization is justified because it fosters competition, resulting in increased liquidity and price transparency, both of which contribute to a vibrant and healthy natural gas market in Ontario. If the owners of assets are not incented in some fashion to optimize their assets, or to have some other party optimize on their behalf, then the marketplace is less efficient, and all End Users are worse off.

Conclusion

The author has attempted to describe how the existence of a vibrant and healthy secondary market for transportation and related services is vital to the continued success of the Ontario natural gas market. From the days prior to the Halloween Agreement, when Ontario end users had effectively no choice but to purchase their natural gas from their regulated LDC, to the present day where end users are offered a multitude of gas supply and transportation options, the evolution of the secondary market for transportation and services has been a critical part of that success. The ability for transportation holders to release or optimize their pipeline capacity supports an efficient secondary market where holders are able to earn incremental revenue while counterparties are able to extract value from otherwise temporarily underutilized assets, resulting in a more efficient marketplace with a broader range of services and pricing options being offered to all participants.

By its very definition, optimization creates risk - an asset is being used for a purpose other than its original intention, and there needs to be an incentive to do so. While the value of incentives may vary amongst market participants, their complete absence would result in less optimization due to inadequate return potential for the level of risk accepted when undertaking optimization.

The author has described how the involvement of Marketers and Traders in the Ontario natural gas market has benefited all participants by bringing competition to the gas supply business, and competition results in increased market liquidity, depth, and price transparency for all. If Marketers and Traders do not have a reasonable expectation of earning a profit from their activities, they will look elsewhere for that opportunity, and the Ontario marketplace will suffer.

Access to assets and services that can be repackaged and sold to the marketplace is the backbone of the Marketing and Trading business, and in order to gain such access, the holders of the assets needs to be incented to negotiate. Traditionally the largest contractor for upstream transportation, the Ontario LDCs have been the natural counterparty to Marketers and Traders seeking access to assets and related services. Without some incentive to optimize their assets, it is reasonable to assume that the level of LDC transport optimization would diminish, with the effect being decreased competition and the resulting negative effects.

The Ontario Energy Board has already recognized that some level of incentive for the LDC is appropriate in order to facilitate the optimization of prudently acquired utility assets.[2] The issue at hand is what the repercussions to the Ontario natural gas marketplace would be if the

[2] EB-2011-0210, Decision and Order, October 24, 2012, page 39.

holders of transportation assets were not inclined to optimize their assets. The level of competition to buy and sell natural gas in Ontario would decline, and the positive effects of competition, that being a more reasonable, transparent, and competitive price for natural gas would be lessened.

Stephen M. Acker

Mr. Acker recently retired as Vice President, Marketing & Origination with BP Canada Energy Group ULC (BP Canada) where he was responsible for BP's natural gas marketing and asset origination in Eastern Canada and the U.S. New England/North East.

Mr. Acker worked in the oil and gas industry for almost 32 years, joining Dome Petroleum Limited in 1981. Dome merged with Amoco Canada Petroleum Company in 1988, and BP acquired Amoco in 1998.

Prior to his moving into natural gas marketing in 1990, Mr. Acker held numerous industry positions related to Beaufort Sea Development, Northern Offshore Drilling, Corporate Finance, Investor Relations, Corporate Aviation, and has spent time as Manager, Marketing and Public Relations for Les Chantiers Davie Shipbuilding in Lévis (Québec).

Mr. Acker's early natural gas experience included short and long term supply planning, market research and analysis, customer service, and marketing support. Mr. Acker assumed responsibility for marketing and asset origination in Eastern Canada and the US Northeast/New England markets in the mid-1990s, growing the department from a single employee to a team ultimately consisting of seven employees. Customer accounts grew over this time from five to more than one hundred in both Canada and the United States, and included Local Distribution Companies, Institutions, Municipalities, Power Generators, Industrials of varying sizes, Commercial Operations, and Retail Market Aggregators. Gas volumes marketed at times exceeded 500 mmcf/d.

The team Mr. Acker oversaw not only was responsible for the sale of natural gas to end users, but in conjunction with the Company's natural gas traders, identified and acquired physical assets such as pipeline transportation and storage that could be exploited for the benefit of both the Company and its customers.

Over the years Mr. Acker has spoken publically at numerous natural gas industry functions and has appeared before both the National Energy Board and the Ontario Energy Board

Mr. Acker is a graduate of Dalhousie University in Halifax, Nova Scotia., holding a Bachelor of Science and a Masters in Business Administration.

TAB 2

Filed: 2013-05-08
EB-2013-0109
Exhibit C
Tab 2

SUSSEX
ECONOMIC ADVISORS

Union Gas

Gas Supply Planning Review

April, 2013

Prepared by

Sussex Economic Advisors, LLC

Executive Summary

Sussex Economic Advisors, LLC ("Sussex") was retained by Union Gas ("Union" or the "Company") to review their gas supply planning practices. Specifically, pursuant to an Ontario Energy Board Decision ("OEB") and Order in EB-2011-0210, Sussex reviewed the following Union gas supply planning activities:

- Guiding Principles
- Design Day Demand Forecast
- Implementation of the Plan
- Contracting/Transportation Path Decision Process

In addition to the above issues outlined by the OEB, Sussex also reviewed the Union approach with respect to extracting value from gas supply assets (i.e., upstream transportation capacity contracts).

The Sussex approach, with respect to this assignment, consisted of on-site meetings with various Union departments involved in the development and implementation of the gas supply plan and associated inputs; a review of gas supply planning documentation (e.g., Excel spreadsheets and SENDOUT model runs) and a benchmarking analysis comprised of over 20 local distribution companies ("LDCs") located in Canada and the U.S.

The following is a summary of our major conclusions and recommendations, which are discussed in detail herein.

Conclusions

- The Union primary gas supply planning principles of reliability and cost are reasonable, similar to other LDCs, and are reflected in the gas supply plan.
- The Union approach regarding design day demand forecasting (i.e., extreme cold weather conditions and a firm customer usage factor per degree day) is appropriate, similar to other LDCs, and reflected in the gas supply plan.
- The design day demand forecasting approach for Union North and Union South is consistent and aligned. Sussex recognizes that the Union North forecasted design day demand becomes a direct input into the gas supply design day plan, while the Union South forecasted design day demand is an input into the storage and transmission

system plan; however, the process used to develop the Union North and Union South design day demand forecast is similar.

- The Union gas supply portfolio for Union North and Union South reflects the circumstances of each area; specifically, Union North is comprised of a non-contiguous service territory with the TransCanada ("TCPL") Mainline providing the physical connections across the service territory. Conversely, Union South is a contiguous service territory with access to significant underground storage, transmission assets, as well as the Dawn Hub. Because of the differing circumstances, Union North relies on the TCPL Mainline services to meet the gas supply planning principles; while Union South uses underground storage and access to various natural gas supply transportation paths to meet the gas supply planning principles. The resultant gas supply portfolios for Union North and Union South are reasonable and appropriately sized.
- The Union approach to decontracting/recontracting is comprised of data gathering, quantitative and qualitative analysis, and documentation. This approach is consistent with the contract evaluation approach used by other LDCs, is similar to the Union Incremental Transportation Contracting Analysis,[1] and is reasonable.
- With respect to whether Union is using the transportation portion of the gas supply portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex understands that Union contracts with St. Clair Pipelines LP (an affiliate) for certain capacity that is used for overall security of supply. Sussex further understands that the St. Clair Pipeline LP agreements (St. Clair Pipeline and Bluewater Pipeline) are the only capacity contracts Union has with an affiliate. Therefore, given the role of St. Clair Pipeline LP in the Union gas supply portfolio (i.e., security of supply) Sussex understands that the Union capacity agreement with St. Clair Pipeline LP has not been subjected to or included in any Union transportation path analysis.
- On the broader issue of whether Union could use the transportation portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex recommends Union utilize the Incremental Transportation Contracting Analysis framework (i.e., description of path, rationale for including path in the portfolio, benefit analysis with a discussion of how the path conforms to the gas supply planning

[1] As outlined in the EB-2005-0520 Settlement Agreement, Union utilizes an Incremental Transportation Contracting Analysis for any new or extensions to existing upstream transportation agreements with a term of one year or greater.

principles, and landed cost analysis) augmented by our recommendations for all contracting decisions, regardless of whether that contract decision is for decontracting, recontracting or incremental capacity. This approach would be applied irrespective of the entity owning the upstream pipeline/project, and as a result would provide sufficient analysis and documentation as to why Union pursued a certain strategy regarding a transportation path decision.

- Finally, while there are various alternatives used by LDCs to extract value from gas supply portfolio assets, the current approach utilized by Union leverages the core competencies of the Gas Supply and Storage & Transmission groups, is consistent with other approaches used by LDCs (e.g., asset management arrangements), and is reasonable.

Recommendations

- Regarding the design day demand forecasting process, Sussex recommends:
  - In general, Union should increase the level of documentation across departments with respect to the demand forecasting and gas supply planning processes.
  - The design day demand forecasting team (which is a cross-functional undertaking) should develop an annual review process regarding the weather and consumption data from the prior year; performance of the trend line; and any changes in the process or data, responsibilities/people, events/business conditions that could impact the process/results.
  - Review and evaluate whether different data sets, regarding the design day demand forecast should be analyzed (e.g., multiple winter periods, subsets of multiple winter periods).[2]
  - For Union South, the coldest observed temperature should be used to develop the design day weather standard. This would result in Union North and Union South having a consistent and similar approach regarding design day weather standards. If this recommendation is adopted for Union South, the design day weather standard would be 43.1 degree days rather than the current value of 44 degree days.

[2] It is important to note that Sussex is not recommending a change in the methodology rather Union should have a process in place to annually evaluate different data periods to assess whether a change in methodology should be investigated.

- Regarding the development of the gas supply plan, Sussex recommends:
  - Union should develop a gas supply plan memorandum that includes the following: (i) summary of the current natural gas market situation; (ii) the results of the design day demand forecast with a discussion of the underpinning assumptions; (iii) an overview of the current gas supply portfolio; and (iv) identification of near term portfolio decisions and a description of how the Union strategy for the specific portfolio decision conforms to the gas supply planning principles.
  - The Union gas supply plan should include a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g., RH-003-2011); physical infrastructure projects that will likely impact Union; and implications associated with gas supply basins as a high level discussion of these regulatory and market drivers in the Union gas supply plan will provide market context for Union's stakeholders.
- Regarding Union's contracting practices, Sussex recommends:
  - Union should continue to use known information (e.g., current approved tolls) in the contracting decision process to reduce the subjectivity of the analysis; however, Union should develop scenarios around the base case.
  - Union should provide documentation supporting the choice of alternatives analyzed and not analyzed (e.g., Path A was not reviewed as there is no capacity available on that pipeline). The documentation requirements are similar to the practices described in the Union Incremental Transportation Contracting Analysis as augmented by the Sussex recommendations.
  - Review and evaluate whether the SENDOUT model could be used to augment the landed cost analysis. Although the landed cost analysis is a straightforward analysis for pipeline options that will be dispatched at 100% load factor; the exercise of modeling contract options in SENDOUT may, in of itself, be a useful process, as the attributes of the path need to be understood in order to be modeled.
  - The Sussex recommendations with respect to contracting decisions apply to all Union contract/transportation path decisions regardless of the entity owning the upstream pipeline/project.
  - Union should establish a process to review the cost of service, rate level, and rate design for St. Clair Pipeline and Bluewater Pipeline. Specifically, every three

years or pursuant to a significant National Energy Board ("NEB") filing by either St. Clair Pipeline or Bluewater Pipeline, Union should undertake a review of the current pipeline situation and, depending on the outcome of that review, initiate negotiations with the pipeline or submit a complaint to the NEB.

Introduction

Sussex Economic Advisors LLC ("Sussex")[3] was retained by Union Gas ("Union" or the "Company") to review their Gas Supply Planning functions pursuant to an Ontario Energy Board ("OEB") Decision and Order in EB-2011-0210; and to review Union's approach with respect to the management of gas supply transportation/capacity contracts.

Specifically, in the EB-2011-0210 Decision and Order the OEB provided the following direction to the Company: "Accordingly, the Board orders Union, prior to its next rates proceeding (cost of service or incentive regulation), to file with the Board an expert, independent review of its gas supply plan, its gas supply planning process and gas supply planning methodology."[4] In addition, the OEB outlined eleven specific elements[5] that should be included in the independent review; eight of those elements[6] are addressed by Sussex herein.

This report is organized and presented in the same sequence as the typical gas supply planning process. In general, an LDC gas supply planning and portfolio management process follows a logical sequence of activities, primarily: (i) development and communication of gas supply planning objectives and principles; (ii) forecast of natural gas demand for certain time periods including peak demand under design weather conditions; (iii) plan and implement a gas supply strategy (e.g., level and type of resources to meet the forecasted demand) while adhering to the stated gas supply planning objectives and principles; and (iv) on-going management of the gas supply portfolio assets.

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3 Sussex Economic Advisors, LLC is a management and economic advisory firm providing consulting services to regulated industries such as natural gas, electricity, water, and thermal energy distribution. The firm's Partners have held senior positions in utility companies, competitive energy suppliers, management consulting firms and business focused academic institutions. Our Consulting Staff, Executive Advisors, and Affiliated Experts have substantial experience and training in matters relating to regulatory strategy and policy development, natural gas infrastructure development and open season processes, gas supply planning and capacity portfolio optimizing, energy market analysis and assessments, financial and economic analysis, rate proceedings and regulatory compliance, due diligence and valuation, and management reviews and audits. Sussex has a substantial list of clients including natural gas distribution companies, electric utilities, combination utilities, electric transmission providers, natural gas pipeline companies, municipal utilities, and non-regulated energy market participants. Summary biographies for the Sussex project team assigned to the Union gas supply planning project are provided in Appendix A.

4 Ontario Energy Board, EB-2011-0210 Decision and Order, P. 40

5 Ibid, P. 41

6 The remaining elements are addressed in a separate report issued by another consulting firm.

The following chart lists the primary LDC gas supply planning activities and identifies the section where Sussex addresses certain of the elements outlined by the OEB in the EB-2011-0210 Decision and Order:

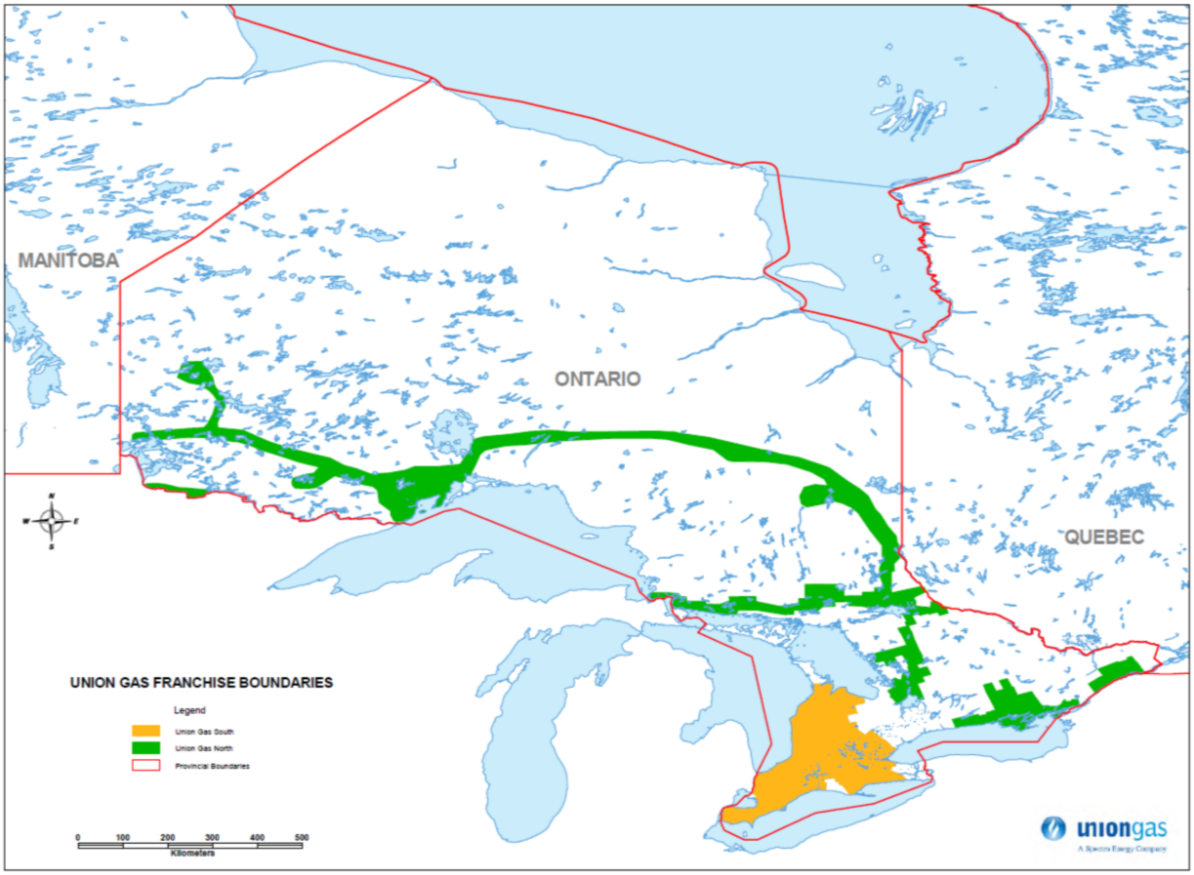
Gas Supply Planning Activity	EB-2011-0210 Report Elements
Develop Gas Supply Planning Principles	1. Verify that Union's gas supply planning process, methodology, and plan reflects appropriate planning principles, including a reference to cost.
Design Day Demand Forecast	3. Determine whether Union's differing peak-day methodologies in the North and South Delivery Areas are appropriate, and if not, recommend alternative approaches. 4. Recommend whether the two approaches should be aligned. 5. Compare the methodology of determining the peak design day, based on the coldest day in the last 50 years, with other heat-sensitive distributors in North America.
Develop Gas Supply Plan	2. Determine if the planning principles are objectively applied and result in a gas supply plan that is "right sized". 6. Determine whether the peak day in the North and South Delivery Areas are appropriately/consistently reflected in the gas supply plan, and if not, recommend remedial action.
On-going Management	7. Determine whether Union is conducting sufficient due diligence with respect to the cost benefit analysis associated with decontracting a particular gas transportation route and recontracting on an alternative route, and recommend remedial action, if required. 8. Determine whether Union is using the transportation portion of the gas supply portfolio to favor the transportation paths of entities in which Union or its parent has (or will have in the future) an economic interest, and recommend remedial action, if required.

Prior to the evaluation of the Union gas supply planning process, the report includes a brief overview of the Company and certain Union gas supply planning geographical areas to provide necessary background information, context, and perspective. In addition, the report briefly outlines our approach and analysis regarding the Union gas supply planning process.

Union Gas Overview

Union provides natural gas service to almost 1.4 million customers in over 400 communities across northern, southwestern and eastern Ontario. In addition, Union provides third party storage and transmission service to a variety of customers located in Ontario, Quebec, the U.S. Northeast and other geographic locations. The Union storage, transmission and distribution network has an annual throughput of about 1,300 PJ of which approximately 500 PJ is distributed within the Union service territory. Natural gas consumption in the Union service territory has been growing at approximately 1% per year and the customer base is predominantly residential and small commercial customers (i.e., end users that do not have alternative fuel capability and the associated consumption is very weather sensitive).

From a gas supply planning perspective, the Union service territory has two distinct geographic regions, Union North and Union South. Union North comprises the Union service territory from the Manitoba border running east and south through Ontario and includes the Cornwall region just east of the Greater Toronto Area ("GTA"), while Union South consists of the region east of Windsor in southwest Ontario running northeast to London and including the area just west of the GTA and down to the Hamilton Region. Union South represents approximately 75% of the total number of Union distribution customers and is experiencing higher growth than Union North. The following map depicts the general geographical location of Union North and Union South:



As illustrated by the above map, Union North is a geographically dispersed non-contiguous service area where the TransCanada ("TCPL") Mainline provides the sole feed of natural gas and physically connects the various service regions. Conversely, the Union South service territory is contiguous and the Company has a significant asset position in this region including on-system underground storage, transmission infrastructure and direct access to the Dawn Natural Gas Trading Hub ("Dawn Hub"). As discussed in more detail herein, the Union North and Union South distinctions (e.g., contiguous v. non-contiguous service territories and the availability of Union gas supply assets) frame the gas supply planning process for the Company.

Sussex Project Approach

To evaluate the Union gas supply planning process, Sussex utilized various data gathering approaches including:

- On-site meetings with representatives from applicable Union departments[7] involved in: (i) the preparation of the design day demand forecast; (ii) the development of the gas supply plan; and (iii) the implementation and management of the gas supply plan.
- Reviewing various Union gas supply planning documents, spreadsheets, SENDOUT model runs, and other relevant material (e.g., EB-2011-0210 submissions and transcripts).
- Conducting an LDC benchmarking analysis, which consisted of a review of certain Canadian and U.S. LDC gas supply plan materials.

In addition to our research and analysis the Sussex observations, conclusions and recommendations regarding the Union gas supply planning process are also based on the collective gas supply planning experience and judgment of the Sussex project team.

As discussed above, the Sussex analysis regarding the Union gas supply plan is organized in a similar manner to how an LDC would generally develop a gas supply plan and manage the resultant portfolio. Specifically, an LDC gas supply plan and portfolio management process follows a logical sequence of steps and is comprised of four major activities:

1. Develop and communicate the gas supply planning objectives and principles.
2. Prepare a design day demand forecast, which guides the level of resource requirements.
3. Develop the gas supply plan within the stated objective and principles.
4. On-going management of the gas supply portfolio.

While these four activities are comprised of various tasks and analyses, they are generally representative of the gas supply planning approach utilized by LDCs. However, the individual LDC gas supply plan will reflect the unique circumstances and situation of that LDC. It is important to note that as market circumstances and regulatory requirements change the LDC approach regarding the four major gas supply planning activities would also change.

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[7] Sussex met with several Union departments and areas including: Gas Supply Acquisitions, Gas Supply Planning, Transportation Acquisition, Capacity Management & Utilization, Storage & Transportation Sales, Gas Control, Storage Planning, Distribution Planning, System Planning, Finance, and Regulatory Affairs.

Gas Supply Plan Review – Principles

The first activity in a gas supply planning process is to develop and communicate the gas supply plan objectives and principles. These objectives and principles provide the framework and structure for the remaining three activities (i.e., design day demand forecast, gas supply portfolio development, and management of the gas supply plan and associated resources). As part of our review of the Union gas supply planning principles, Sussex addresses the first element from the OEB Decision and Order in EB-2011-0210, specifically:

- Verify that Union's gas supply planning process, methodology and plan reflects appropriate planning principles, including a reference to cost.

The Sussex analysis regarding the first gas supply planning activity (i.e., principles and objectives) is comprised of three steps: (i) document the current Union gas supply planning principles; (ii) evaluate the Union gas supply plan principles; and (iii) compare the Union gas supply principles to other LDCs.

In terms of the first step (i.e., documentation), the Union gas supply planning principles were defined in EB-2011-0210 as follows: "the Gas Supply Planning Process is guided by a set of principles that are intended to ensure that customers receive secure, diverse gas supply at prudently incurred cost. These principles are:

1. Ensure secure and reliable gas supply to Union's service territory;
2. Minimize risk by diversifying contract terms, supply basins and upstream pipelines;
3. Encourage new sources of supply as well as new infrastructure to Union's service territory;
4. Meet planned peak-day and seasonal gas delivery requirements; and
5. Deliver gas to various receipt points on Union's system to maintain system integrity.[8]

In addition, the Union Gas Supply planning principles were further discussed in the EB-2011-0210 proceeding. Specifically, Union provided the following context regarding gas supply planning principles: "Gas Supply is guided by a number of key principles. These principles ensure that Union's customers receive a secure and reliable gas supply at a prudently and

8 EB-2011-0210, Exhibit D1, Tab 1, P. 2 of 16.

reasonably incurred cost. These long-standing principles are filed in our current evidence…and the OEB has actually endorsed these in some of those past proceedings."[9]

Although Union lists five gas supply planning principles, the discussion during the EB-2011-0210 proceeding narrows the focus of the principles to the major drivers of an LDC portfolio (i.e., reliability and cost). The remaining Union gas supply planning principles provide guidance on how to achieve reliability from a demand perspective (e.g., meet the design day demand and support system integrity through gas supply deliveries); and from a gas supply perspective (e.g., diversity of gas supply basins and pipeline delivery paths, and encouraging new sources of gas supply/infrastructure).

The reliability of service to firm customers, who are high priority end users (e.g., home heating residential customers or small to medium commercial customers such as hospitals and private businesses), is the primary objective of an LDC's design day gas supply portfolio. This primary objective of reliable service under extreme cold weather conditions is balanced with the cost of the gas supply portfolio needed to provide that service. LDCs typically balance the objectives of reliability and reasonable cost by developing a diversified and flexible asset portfolio that can respond to not only on-system demand fluctuations but also upstream gas supply/capacity issues or opportunities. Although the concept of gas supply diversity can have different meanings and be accomplished using various approaches, the development of shale gas basins, particularly in the market area, has placed an added emphasis on portfolio diversity/flexibility in the furtherance of the primary gas supply planning objectives (i.e., reliability and reasonable cost).

Regarding the second step (i.e., evaluate the Union gas supply planning principles), the Union gas supply planning principles recognize not only the need for reliable service (i.e., provide service during extreme cold weather conditions), which is of particular importance given Union's customer segment profile (i.e., residential and small commercial customers), but also how to achieve the stated goal of reliability at a reasonable cost (i.e., through diversification of delivery paths and sources, contract for a variety of pipeline services, staggered contract termination dates, and meeting the supply requirements[10] of the geographically diverse Union service

9 OEB, EB-2011-0210 Hearing Transcripts, July 13, 2012, Volume 3, P. 6-7.

10 The gas supply requirements of the diverse Union system include providing sufficient pipeline capacity and supply to support on-system demand and pressure needs.

territory). In addition, the Union gas supply planning principles recognize the importance of new natural gas supply sources and infrastructure to the Union service area as the continued viability of the Dawn Hub and the utilization of the Union storage and transmission assets provide benefits to the Union distribution customers as well as the broader market that utilizes those resources.

The third step in the Sussex analysis of the Union gas supply planning principles was to review the gas supply planning principles of other LDCs. Although gas supply planning principles will likely reflect the circumstances of the individual LDC, the following excerpts from certain LDC planning documents provide insight to LDC gas supply planning principles:

- "The NSTAR Gas resource planning process is designed to ensure a reliable energy supply for its customers with a minimum impact on the environment and at the lowest cost taking into consideration important non-price factors such as reliability, flexibility and diversity."[11]
- "The Company's forecast methodology supports its supply planning goals of ensuring that: (1) its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the coldest planning day ("design day"); and (2) it maintains sufficient supplies under contract and in storage (underground storage, LNG and propane) to meet customers' requirements over the coldest planning year ("design year")."[12]
- "Cascade's resource planning continues to focus on ensuring that the Company can meet the needs of our firm gas sales customers in a way that minimizes costs over the long term…Integrated Resource Plan provides the strategic direction guiding the Company's long-term resource acquisition process."[13]
- "Pursuit of a best-cost portfolio allows CMA to provide its customers with reliable service at a reasonable cost. The Company's overall portfolio objective is supported by a number of specific resource planning objectives, which are summarized as follows: (1) reduce portfolio costs; (2) maintain portfolio security/reliability (which includes enhancing diversity across pipelines and supply basins); (3) provide contract flexibility; and (4) acquire viable resources."[14]

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[11] NSTAR Gas Company, 2012 Forecast and Supply Plan filed February 10, 2012, P. 7.

[12] Long-Range Resource and Requirements Plan of Boston Gas Company and Colonial Gas Company for the forecast period 2012/13 to 2013/17 filed February 21, 2013, P. 6.

[13] Cascade Natural Gas Corporation, 2012 Integrated Resource Plan filed December 14, 2012, PP. 5 and 9.

[14] Columbia Gas of Massachusetts, 2011 Forecast and Supply Plan filed September 19, 2011, P. 59.

- "In its GCR plan, the Company takes into consideration the importance of taking actions to assure that our customers receive reliable and reasonably priced natural gas supplies for their needs. The Company utilizes a consistent planning methodology with defined risk parameters to assure customers service is not unreasonably jeopardized."[15]

As illustrated by the gas supply planning objectives and principles of the various LDCs reviewed, the Union gas supply planning principles address similar themes (i.e., reliability and cost); outline approaches to achieve these objectives (e.g., gas supply and pipeline diversity, and support new sources of supply and infrastructure); and, based on the experience and judgment of the Sussex project team, are reasonable.

15 Consumers Energy Company, Gas Cost Recovery Plan, Direct Testimony of Michael A. McKimmy filed December 27, 2012, P. 3.

Gas Supply Plan Review – Design Day

Once the gas supply planning principles have been established, the next activity in the LDC gas supply planning process is the development of the design day demand forecast for firm customers. As part of the Union design day demand forecast review, Sussex will address Elements three, four and five from the OEB Decision and Order in EB-2011-0210, specifically:

- Determine if Union's differing peak-day methodologies in the North and South Delivery Areas are appropriate, and if not, recommend alternative approaches.
- Recommend whether the two approaches should be aligned.
- Compare the methodology of determining the peak design day, based on the coldest day in the last 50 years, with other heat-sensitive distributors in North America.

The Sussex analysis, with respect to the process utilized by Union to forecast design day demand, consists of five steps: (i) general definition, purpose and approach regarding LDC design day forecasts; (ii) summary of the current approach utilized by Union to forecast design day demand for Union North and Union South; (iii) benchmark the Union design day demand forecast process to the design day demand forecasting process used by other LDCs; (iv) Sussex observations and conclusions regarding the appropriateness of the Union design day demand forecasting process and address the issue of Union North and Union South forecast alignment; and (v) Sussex process recommendations.

With respect to the first step (i.e., general definition, purpose and approach regarding LDC design day demand forecasts), Sussex provides a brief overview of the role and importance of design day demand forecasting in the development of the LDC gas supply portfolio followed by a summary of the components of an LDC design day demand forecast.

In general, an LDC develops a gas supply portfolio to meet design day demand, which is the forecasted demand for firm customers during an extreme cold weather day. The following representative excerpts from other LDC planning documents with respect to design day demand not only provide similar definitions of design/peak day demand but also underline the importance of design/peak day demand in the LDC's gas supply/infrastructure plan:

- "Peak demand, or the maximum gas that our customers require at a single point in time, drives infrastructure investment because we must build to that demand even if it is a relatively infrequent occurrence to ensure reliable gas service when it is most needed."[16]

- "The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system."[17]
- "[Design day demand is] the greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements."[18]
- "The primary objective of the design peak day forecast is to ensure sufficient supply under extreme and potentially dangerously cold conditions."[19]
- "Gas system design criteria are used to size pipeline, storage, and contractual commitments to maintain gas system reliability. Standard practice in the gas utility industry is to correlate peak day demand with certain operating conditions, most notably ambient temperature."[20]

There are generally two main drivers regarding an LDC design day demand forecast: (i) the weather standard (i.e., what is the expected degree day that will be utilized in the design day demand forecast); and (ii) the calculated firm customer use per degree day factor. The LDC design day demand forecast is the result of applying the calculated firm customer use per degree day factor to the design day weather standard resulting in an estimate of firm customer consumption under extreme cold weather conditions. The forecast of design day demand is of particular importance to LDCs that have a high concentration of residential and small commercial customers that rely on the LDC for heating requirements as these segments will have significant usage under extreme cold weather conditions and no alternative fuel capability.

The second step in the Sussex analysis was to document the current approach utilized by Union to forecast the design day demand for Union North and Union South.

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16 Consolidated Edison, Gas Long Range Plan 2010-2030, December 2010, P. 33.

17 Long-Range Resource and Requirements Plan of Boston Gas Company and Colonial Gas Company for the forecast period 2012/13 to 2013/17 filed February 21, 2013, P. 25.

18 Cascade Natural Gas Corporation, 2012 Integrated Resource Plan filed December 14, 2012, P. 148.

19 Consumers Energy Company, Gas Cost Recovery Plan, Direct Testimony of Jonathon J. Guscinski filed December 27, 2012, P. 3.

20 Enbridge Gas Distribution Rate Application, EB-2011-0354, Exhibit D2, Tab 4, Schedule 1, P.1.

Union North – Design Day Demand Forecast Process

The Union approach to forecasting design day demand for Union North is similar to the general LDC design day forecasting approach outlined above (i.e., develop a design day weather standard and a calculated firm customer use per degree day factor). In terms of the design day weather standard for Union North, the Company utilizes a coldest observed methodology (i.e., the design day weather standard is the actual coldest temperature observed over a period of time). Specifically, for the development of the design day demand requirements for the gas supply plan, the thirteen Union North temperature zones used by the Union Distribution Planning group are aggregated into six gas supply planning areas. The following chart illustrates the mapping of the thirteen temperature zones into the six gas supply planning areas (when multiple temperature zones are mapped into one gas supply planning area, Sussex has underlined which temperature zone weather is utilized for gas supply planning purposes):

Distribution Planning Temperature Zone		Gas Supply Planning Areas
Fort Frances	→	Manitoba Delivery Area
Kenora <u>ThunderBay</u>	→	Western Delivery Area
Kapuskasing Timmins Earlton <u>Sudbury</u> NorthBay	→	Northern Delivery Area
Sault Ste. Marie	→	Sault Ste. Marie Delivery Area
Muskoka/Gravenhurst	→	North Central Delivery Area
Trenton <u>Kingston</u> Cornwall	→	Eastern Delivery Area

As shown by the above chart, there are certain gas supply planning areas that are comprised of one temperature zone (e.g., the Manitoba, Sault Ste. Marie, and North Central Delivery Areas); and there are other gas supply planning areas that are comprised of several temperature zones (e.g., the Western, Northern and Eastern Delivery Areas).

For each of the six gas supply planning areas and the associated temperature zone (e.g., Western Delivery Area and Thunder Bay temperature zone), Union uses the coldest observed temperature in that area/zone as the design day weather standard. The following table summarizes the design day weather standard by area/zone and to provide context Sussex has included other extreme cold temperature observations for each area/zone:

HIGHEST DAILY DEGREE DAYS

	THUNDER BAY		FORT FRANCES		S.S. MARIE		MUSKOKA		SUDBURY		KINGSTON	
Temperature Zone	3		1		8		10		7		12	
Gas Supply Zone	WDA		MDA		SSMDA		NCDA		NDA		EDA	
Design Day	1/29/1951	51.6	2/1/1996	54.7	1/15/1994	48.2	1/15/1994	49.0	1/3/1981	51.9	1/3/1981	47.1
	2/1/1996	51.6										
# Within 2 Degree Days	5		2		3		7		3		2	
	1/16/2005	51.0	1/18/1994	53.5	1/3/1981	47.6	1/20/1942	48.9	1/15/1994	51.8	1/9/1947	45.5
	1/9/1982	51.0	1/16/2005	52.8	2/1/1962	47.2	1/23/1976	48.3	1/8/1968	50.9	1/9/1968	45.5
	1/19/1985	50.7			2/17/1979	46.6	2/15/1943	48.1	1/18/1982	50.3		
	1/4/1968	50.1					1/3/1981	48.0				
	1/14/1972	50.0					2/11/1979	47.7				
							1/8/1968	47.5				
							1/18/1997	47.5				

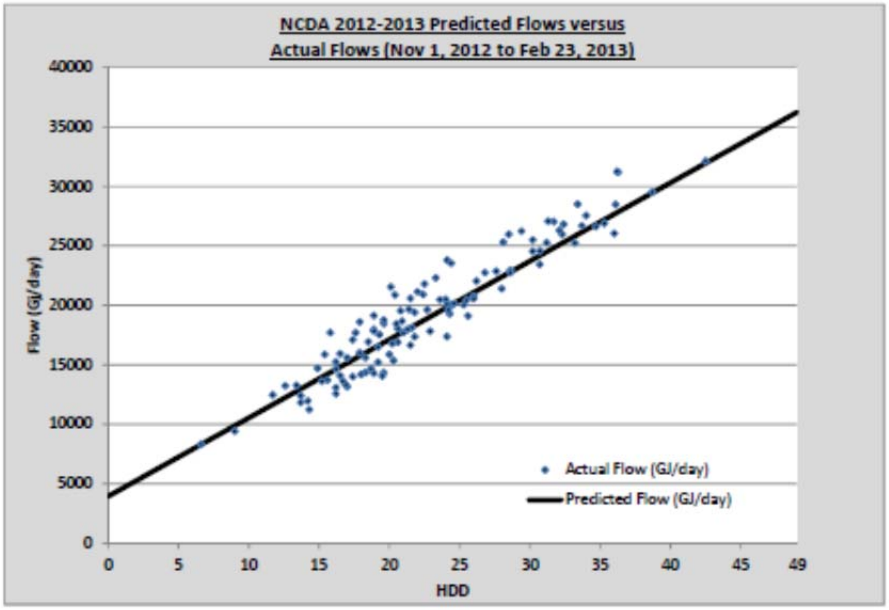
Source: Union Gas

As indicated by the above table, each gas supply planning area has observations that are within two degree days of the coldest observed temperature/degree day indicating that the coldest observed temperature/degree day is not an outlier relative to the data set.

The second component of the Union North design day demand forecast is the calculation of the firm customer use per degree day factor.[21] Specifically, the Company develops a trend line using the daily firm customer consumption from the prior winter and the associated daily degree day data. Stated differently, for each of the six gas supply planning areas Union calculates daily firm customer demand for the prior winter period (interruptible and T-service consumption and weekend/holiday data are removed from the series) and, in conjunction with daily degree day data, a trend line is developed.

Next, Union extrapolates the calculated trend line to the coldest observed temperature resulting in the estimated design day demand for each gas supply planning area. Please find below an illustrative example of the degree day data and trend line calculation developed by Union for the North Central Delivery Area ("NCDA"):

[21] Please note that the calculated firm customer use per degree day factor is for certain customer segments (e.g., general service) while for other customers Union may use a contracted amount.



Based on the design day weather standard of 49 degree days for the NCDA, the expected design day demand is just under 40 TJ.

Finally, the design day demand is increased by the winter season growth factor developed by the Union Demand Forecasting group. By way of example, if the design day demand estimate for the NCDA is 40 TJ and the Demand Forecasting group is projecting a 1% winter season growth factor the forecasted design day demand for the NCDA is 40.4 TJ.

The following table provides the Union 2012/2013 design day demand forecast[22] for the gas supply zones in Union North:

Supply Zone	TJ/Day
Manitoba Delivery Area ("MDA")	14
Western Delivery Area ("WDA")	85
Northern Delivery Area ("NDA")	284
Sault STE. Marie Delivery Area ("SSMDA")	115
North Central Delivery Area ("NCDA")	40
Eastern Delivery Area ("EDA")	251
Total	789

[22] The design day demand forecast includes T-service firm contract demand, Bundled Firm Service demand, and T-service storage redelivery demands.

As illustrated by the above table, the projected design day demand for Union North is approximately 789 TJ, with the NDA and EDA gas supply zones representing almost 70% of the projected Union North design day demand.

Union South – Design Day Demand Forecast Process

The Union approach to forecasting design day demand for Union South is similar to not only the general LDC approach but also to the Company approach utilized for Union North. Specifically, for Union South the Company utilizes a coldest observed approach as the design day weather standard and a calculated firm customer use per degree day factor.

In terms of the design day weather standard, Union currently uses weather information for the London Airport as the temperature data for Union South. The following table is a summary of the coldest observed temperatures at the London Airport from 1953 to 2013:

Date	Degree Day
10-Jan-82	43.1
18-Jan-94	42.8
19-Jan-94	42.6
20-Jan-85	42.1
15-Jan-72	41.4

Although the coldest observed weather is 43.1 degree days, Union utilizes a 44 degree day for the design day weather standard for Union South. While the documentation associated with the 44 degree day is not informative regarding its relationship to the coldest observed temperature, it is our understanding that the 44 degree day was established based on a review of the coldest temperatures observed. Similar to Union North, there are several degree day observations within one or two degree days of the coldest observed (i.e., the 43.1 degree day) indicating that the coldest observed temperature is not an outlier relative to the overall data series.

The next component of the Union South design day demand forecast is the development of the trend line (i.e., the daily firm customer load relative to daily degree days).[23] Similar to Union North, the Company collects the daily consumption from the prior winter; removes interruptible load and holiday/weekend observations; and, in conjunction with the daily degree day observations calculates a trend line. The trend line is then extrapolated to the design day weather standard and the design day demand forecast is estimated. Finally, the design day demand forecast is increased based on the Union South growth forecast developed by the Demand Forecasting group.

The following table is a summary of the Union design day demand forecast for Union South:[24]

Supply Zone	**TJ/Day**
Dawn to Parkway (D-P) System (Incl. D-P fuel)	1,662
Dawn to Sarnia Industrial System	417
Dawn to Panhandle System	439
Dawn to Low Pressure Market (Sarnia N&S and London Lines)	31
Dawn Fuel (Incl. 'Company Used' gas)	34
Total	**2,583**

As illustrated by the above table, the design day demand forecast for Union South is approximately 2,583 TJ.

However, unlike Union North the design day demand estimate is not communicated to Gas Supply. Rather it is one of the inputs to the storage and transmission system planning model. As discussed above, Union South, unlike Union North, is a contiguous service territory with significant on-system assets such as underground storage facilities, transmission lines and the Dawn Hub. As a result of these physical assets, the design day demand forecast is utilized by Union as part of an integrated physical natural gas delivery plan that includes: storage volumes required to meet a Union South design day on February 28, natural gas supply delivery requirements at Dawn and Parkway for Union and other third parties; and potential Union South winter peaking requirements on the Dawn to Parkway transmission system.

23 Please note that the calculated firm customer use per degree day factor is for certain customer segments (e.g., general service) while for other customer segments Union may use a contracted amount.

24 The design day demand forecast includes system sales, Bundled Direct Purchase, T-service and unbundled customers.

The third step in the Sussex design day demand analysis is to review the results of the benchmarking analysis regarding LDC design day demand forecasting. Specifically, Sussex reviewed design day demand forecasts for 21 companies representing 64 separate business units or planning regions located in Canada or the northeast, mid-west and western United States.[25] With respect to the design day demand forecasting process, Sussex focused our benchmarking analysis on weather standards utilized (e.g., coldest observed temperature for the design day); the calculation of design day demand (e.g., trend line) and the growth factor calculation.

In terms of the weather standard, there are two main approaches utilized by LDCs for determining design day weather. The first approach is to use the coldest observed temperature over a certain period of time while the second approach is to use probability (i.e., frequency of occurrence). If the coldest observed approach is utilized, the time period of the data series is usually thirty to forty years. Some utilities, however, relied on historical weather data stretching much further back. For example, ConEd of New York relies upon a peak day which was experienced in 1934.[26] If the probability approach was utilized, the frequency of occurrence ranged from one in five years to one in ninety years and the underlying data series ranged from ten to over fifty years.[27] Overall, twelve of the companies reviewed use coldest observed, seven use frequency of occurrence and two rely on other methodologies.[28]

In addition to the design day weather standard, the Sussex benchmarking analysis also reviewed the process utilized by various LDCs to calculate design day demand per degree day and the approach used to project design day demand growth. While the LDCs reviewed may have different equation components regarding design day demand per degree day the vast majority utilize a regression analysis whereby historical daily consumption and degree days are

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[25] The benchmarking analysis is attached as Appendix C.

[26] Based on discussions with ConEd of New York.

[27] For example, NSTAR Gas Company reviewed ten years of historical weather data. *See*, NSTAR Gas Company, 2012 Forecast and Supply Plan filed February 10, 2012, P. 58. Additionally, Enbridge Gas Distribution reviewed over fifty years of historical weather data (January 1953 to September 2010 for the Central and Eastern divisions). *See*, Enbridge Gas Distribution, Rate Application filed January 1, 2012, Exhibit D1, Tab 2, Schedule 3, P. 8. The remaining companies (for which the length of the dataset was reported) fell within a range of 34 to 43 years.

[28] Other methodologies include: (1) a Monte Carlo analysis to determine normal weather and then use two standard deviations (assuming a normal distribution) to determine the design day and (2) a form of cost benefit analysis.

evaluated and a trend line is developed. Regarding the design day demand growth factor, the majority of the LDCs reviewed, utilize the annual demand growth developed as part of the LDC corporate demand projections and apply that same factor to the design day demand forecast.

The fourth step in the Sussex review of the Union design day forecast process consists of certain observations and conclusions based on our review of the Union approach, the LDC benchmarking analysis and the collective experience and judgment of the Sussex project team, specifically:

- The approach utilized by Union to forecast design day demand for Union North and Union South is consistent (i.e., aligned) and includes similar steps: (i) use of the coldest observed as the weather planning standard; (ii) develop a trend line using the most recent daily winter data and degree days; and (iii) extrapolate the trend line to the weather planning standard to determine design day load.
- The approach used by Union for design day demand forecasting is similar to the LDCs reviewed in the benchmarking analysis (i.e., develop a weather standard, calculate use per degree day, and project design day demand based on the combination).
- The use of the coldest temperature observed is reasonable as Union has experienced weather close to the coldest observed in all the gas supply planning areas; and it is consistent with the practice of the LDCs in the Sussex benchmarking analysis. The following table is a summary of the design day weather standard used by the LDCs in the Sussex benchmarking analysis.

Peak Day Planning Approach	Number of Companies Utilizing Approach
Coldest Day Observed	12
Frequency of Occurrence	7
Other	2

- Sussex recognizes that the Union North design day demand becomes a direct input to the gas supply design day plan, while the Union South design day demand is an input to the storage and transmission system plan; however, the process used to develop the Union North and Union South design day demand forecast is consistent and aligned.
- Overall, the Union methodology for forecasting design day demand is appropriate; and, the Company approach with respect to forecasting design day demand for Union North and Union South is consistent and aligned.

Lastly, based on our review of the Union design day demand forecast process, the LDC benchmarking analysis and the experience of the project team, Sussex has the following process recommendations:

- While the design day demand planning process is well documented within each Union department/group, the process should be documented across the departments/groups; specifically, Union should develop a high level flow chart that outlines the information flow needed to develop the design day demand forecast and associated departmental/group responsibilities.
- Prior to the start of the annual gas supply planning process, the departments/groups involved in peak day demand estimation should meet and kick off the design day demand process with: (i) a review of the results from the prior year (e.g., coldest degree day observations, associated demand on those days; performance of the trend line); (ii) any changes in the process, data, responsibilities/people, events/business conditions that could impact the process/results; (iii) schedule for completion; and (iv) communication of final work product.
- Once the design day demand forecast is completed a de-brief meeting should be held to discuss process changes or issues that need to be addressed.
- As part of the design day demand forecasting process, Union should review and evaluate whether different data sets, with regard to the design day demand forecast, should be analyzed (e.g., multiple winter periods, or subsets of multiple winter periods); it is important to note that Sussex is not recommending a change in the methodology being utilized, rather Union should have a process in place to annually evaluate different data sets and/or time periods to assess whether a change in methodology should be investigated.
- Finally, Union South should utilize the actual coldest observed temperature (i.e., 43.1 degree days) and not the current value of 44 degree days in the calculation of the Union South design day demand. The use of the actual coldest observed temperature for Union South would result in a consistent approach for determining the design day weather standard for both Union North and Union South.

Gas Supply Plan Review – Develop Gas Supply Plan

After the preparation of the design day demand forecast the next activity in an LDC gas supply planning process is the development of a gas supply plan that is consistent with the first two activities (i.e., gas supply planning principles and the design day demand forecast). Specifically, the LDC in this activity will develop a gas supply plan that conforms to the gas supply planning objectives and principles while meeting the forecasted design day demand. In this section, Sussex will address Elements two and six from the OEB Decision and Order in EB-2011-0210:

- Determine if the planning principles are objectively applied and the result is a gas supply plan that is "right sized".
- Determine whether the peak day in the North and South Delivery Areas are appropriately reflected in the gas supply plan, and if not, recommend remedial action.

The Sussex analysis of the Union gas supply plan development consists of the following steps: (i) an overview of the current gas supply portfolios for Union North and Union South and the major considerations in the development of the respective portfolios; (ii) our observations and conclusions regarding the Union gas supply plan development; and (iii) the Sussex recommendations.

The Union North gas supply portfolio primarily consists of Western Canadian Sedimentary Basin ("WCSB") gas supply and TCPL Mainline transportation contracts. Union augments this primary source of gas supply with a limited volume from MichCon that is transported on Great Lakes Gas Transmission to the TCPL Mainline; and underground storage transported on Union transmission to the TCPL Mainline at Parkway for redelivery on the TCPL Mainline to Union North.

In terms of TCPL Mainline services,[29] Union contracts for long haul long term firm transport on the TCPL Mainline (Mainline LTFT);[30] and, as a result, Union has access to certain TCPL

[29] Please see Appendix B for a summary of certain TCPL Mainline service offerings.
[30] TCPL Mainline offers long term (i.e., 365 days or greater) and short term (i.e., less than 365 days) transportation service.

Mainline LTFT transportation service attributes (FT-RAM)[31] and other TCPL Mainline service offerings (e.g., storage transportation service ("STS")). The TCPL Mainline LTFT service provides Union with a firm right to renew thus ensuring that Union North customers will have access to firm capacity at NEB approved tolls from the only pipeline option to feed the service territory. Under the TCPL Mainline LTFT terms of service, Union also has the option of in-path deliveries thus enabling Union to provide service under extreme weather conditions, at no additional cost, to delivery areas that are upstream of the primary delivery area in the specific TCPL Mainline LTFT contract.

Another aspect of the TCPL Mainline LTFT service is the ability of the customer (e.g., Union) to contract for STS.[32] The main benefit of the LTFT and STS service combination is described by TCPL as follows: "Allows a Firm Transportation (FT) contract holder, in combination with their STS contract to meet seasonal market and storage requirements and still keep a high load factor. Offers numerous flexibility features including guaranteed renewal rights, additional nomination windows to better balance daily gas supply and consumption, and RAM credits to maximize the value of the contract."[33]

Sussex understands that Union utilizes the TCPL Mainline LTFT to meet the demand requirements of Union North and when the demand is less than the Union North Mainline LTFT capacity, Union, using the STS service, injects those volumes to storage. In the winter period, Union is able to withdraw the previously injected gas supply from STS to meet winter seasonal demand requirements. Not only does the TCPL Mainline LTFT and STS service combination allow for high utilization of the Union North LTFT capacity (e.g., where feasible Union plans for 100% contract utilization for nine to ten months per year), but it also provides customers with a potential natural gas price benefit (i.e., a physical hedge). Stated differently, Union is able to purchase natural gas in the summer period, inject into storage, then withdraw that natural gas priced at summer price indices to serve winter peak season load.

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31 FT-RAM is currently an attribute of the long term long haul service that provides Union with several benefits including reduced interruptible transportation costs and increased market value of unutilized capacity.

32 To be eligible for STS service, the TCPL Mainline customer must have a long haul LTFT contract to a market point.

33 TransCanada Mainline website.

STS also provides Union North with additional nomination flexibility as this service has four additional nomination windows with two of those nomination windows during the night, which facilitates daily load balancing and minimization of balancing costs.[34] Finally, STS service can be pooled across certain Northern delivery areas thus adding flexibility to the Union North portfolio; in other words the STS contracted capacity by delivery area (e.g., NDA) can be shared across certain delivery areas (e.g., NDA and NCDA) thus providing inter-delivery area flexibility.

In addition to reviewing the Union gas supply portfolio developed to meet Union North requirements, Sussex also reviewed whether the Company had contracted for an appropriate level of resources to meet the forecasted design day demand requirements. Specifically, for the six gas supply delivery areas, Sussex reviewed the Union North level of gas supply assets planned to meet the forecasted design day demand. The following table is a summary of the design day demand forecast and the associated portfolio to meet the individual gas supply planning areas in Union North:

[34] Sussex understands that Union has estimated approximately $5 to $7.5 million of avoided load balancing cost for the 2011/2012 period as a result of STS.

Winter 2012/2013 Northern Firm Design Day Demand in TJ's/Day

	Delivery Area						
	MDA	WDA	SSMDA	NDA	NCDA	EDA	Total
Design Day - Degree Day	54.7	51.6	48.2	51.9	49.0	47.1	
Design Day Demand by Delivery Area	14	85	115	284	40	251	789
Composed of:							
T-Service Firm Contract Demand	9	10	80	126	3	98	326
Union Responsible							
Bundled Firm Service Demand	5	75	34	149	37	154	454
T-Service Storage Redelivery Demand	-	-	-	9	-	-	9
Firm Demand - Union Responsible	5	75	34	158	37	154	463
Capacity & Supply to meet Firm Demand - Union Responsible							
Upstream Transportation - Capacity							
TCPL L/H from Empress	4	37	8	49	9	59	166
Supply - Upstream Transportation							
Union	3	27	4	34	5	42	115
Direct Purchase	1	10	4	15	4	17	51
	4	37	8	49	9	59	166
Redelivery from Storage							
TCPL STS Withdrawals - contracted	-	31	35	48	14	69	197
TCPL STS Withdrawals - pooled	-	-	(9)	3	14	(9)	-
TCPL STS Withdrawals - flowed		31	26	52	28	60	197
TCPL S/H from Parkway	-	-	-	-	-	35	35
		31	26	52	28	95	232
Supply from Upstream Transport & Storage	5	68	34	101	37	154	398
Firm Demand	**5**	**75**	**34**	**158**	**37**	**154**	**463**
Supply from Upstream Transport & Storage	**5**	**68**	**34**	**101**	**37**	**154**	**398**
Excess/(shortfall) by Delivery Area	**(1)**	**(7)**		**(57)**			**(65)**
Excess/(shortfall) by delivery area	**(1)**	**(7)**		**(57)**			**(65)**
Supply from Other Sources							
Diversions - from Union South transport portfolio							
TCPL Empress - Union CDA	1	7	-	57	-	-	65
Excess/(shortfall) by Delivery Area	-	-	-	-	-	-	-

As illustrated by the above table, the design day demand for Union North is approximately 789 TJ[35] of which 41% or 326 TJ is associated with T-Service Firm Contract Demand[36] and approximately 59% or 463 TJ is attributed to Bundled Firm Service demand or T-Service storage redelivery demand.

To meet the forecasted design day demand associated with Union firm gas supply requirements (i.e., 463 TJ), the Union portfolio is comprised of: 36% TCPL Mainline long haul capacity; 43%

35 This value is the same estimate developed and reported in the Gas Supply Review – Design Day Demand section for Union North.

36 T-Service customers are typically large industrial customers that hold their own contract for upstream pipeline capacity, but Union provides a storage service to these customers.

from redelivery of STS volumes; 8% from a short haul service on the TCPL Mainline; and 13% from a diversion of a TCPL Mainline contract that is primarily used to deliver gas supply to Union South.

The Union South gas supply portfolio, unlike Union North, has access to diverse supply basins and/or market area hubs such as the WCSB, Gulf of Mexico, Rockies, Marcellus/Utica shale, Chicago Hub, and Dawn Hub. As a result, Union South has various pipeline options including the following contracted delivery paths:

- TCPL Mainline ➔ Parkway
- Trunkline ➔ Panhandle ➔ Ojibway
- Alliance Pipeline ➔ Vector Pipeline ➔ Dawn
- Chicago Hub ➔ Vector Pipeline ➔ Dawn
- Panhandle Eastern Pipe Line ➔ Ojibway
- Niagara ➔ TCPL Mainline ➔ Kirkwall

In addition to the various pipeline delivery options and paths, Union South has access to significant on-system underground storage and associated transmission facilities as well as the Dawn Hub. With respect to pipeline services for Union South, the Company has a variety of contracts including TCPL Mainline LTFT to the CDA, TCPL Mainline short-haul transportation services as well as firm service on other upstream pipelines including Alliance, Vector and Panhandle Eastern. Given the significant underground natural gas storage volume and the direct access to the Dawn Hub, the Union South upstream pipeline contracts are utilized at 100% load factor (i.e., no unabsorbed demand charges on a planned basis).

Similar to the analysis of Union North, please find below a summary of Union South design day demand, and the resources utilized to serve that demand:

Union South Design Day Demand* and Resources (TJ/day)	
Union South Demand	2,583
Supply	
Storage at Dawn	1,238
Non-obligated (e.g., Power Plants)	197
TCPL Empress to CDA	70
Trunkline	21
Panhandle	26
TCPL Niagara	21
Ontario Parkway	522
Alliance/Vector	85
Vector	85
Ontario Dawn	288
Customer Supplied Fuel	30
Total Supply	**2,583**
*Includes system sales, Bundled Direct Purchase, T-service, Unbundled	

As illustrated by the above table, the forecasted design day demand for Union South is approximately 2,583 TJ (which includes system sales, bundled direct purchase, T-service and unbundled customers). The forecasted design day demand volume (i.e., 2,583 TJ) is provided as an input to the Union storage and transmission system plan; and the resultant plan is developed based on pipeline capacity, delivered gas supplies, and storage volume.[37]

To meet the forecasted design day demand, Union has approximately 50% of the volume being delivered from Dawn Storage; while the other 50% is comprised of upstream pipeline capacity or delivered volumes.

Based on our analysis and evaluation regarding the development of the gas supply plan, Sussex has the following observations and conclusions:

[37] The 2,583 TJ value is the same estimate developed and reported in the Gas Supply Review – Design Day Demand section for Union South; and General Service represents approximately 55% of the 2,583 TJ, while contract customers reflect about 45%.

- The Union gas supply plan for Union North and Union South appropriately reflects the forecasted design day demand for each area. Stated differently, the forecasted design day requirements as discussed above in the Gas Supply Plan Review – Design Day section are included and appropriately reflected in the development of the Union Gas Supply Plan.
- The Union gas supply plan is developed for each region based on the specific circumstances and situation for Union North and Union South. Union North, given its reliance on the TCPL Mainline has sufficient capacity under contract to serve the design day demand and incorporates the flexibility of the diverse TCPL Mainline service offerings to provide natural gas storage benefits to Union North. The gas supply plan developed for Union South appropriately leverages the physical on-system storage and transmission assets as well as access to Dawn Hub, thus allowing the upstream pipeline capacity for Union South to be utilized at 100% load factor on a planned basis.
- Although Union North and Union South portfolios are developed to meet the requirements of each region there are certain assets that can provide service to both delivery areas:
    - The Union South portfolio has long haul long term firm capacity on the TCPL Mainline (Empress to CDA), which can provide gas supply to Union South or to "with-in" path delivery areas in Union North.
    - Union North has access to Union storage and transmission assets as there is approximately 290 TJ/day withdrawn at Dawn to meet the Union North design day demand.

Finally, Sussex has developed the following recommendations regarding the Union gas supply plan development.

- Gas Supply Plan Memorandum
    - Once the gas supply plan has been developed (i.e., the models have been updated and the new results calculated), Union should develop a summary memorandum that provides a narrative discussion regarding: (i) general market conditions and drivers with respect to natural gas demand and supply; (ii) the results and process used to develop the Union North and Union South design day demand forecasts; (iii) the assumptions underpinning the results; (iv) an overview of the current Union gas supply portfolio for Union North and Union South; (v) identification of near term portfolio decisions; and (vi) describe how the

Union strategy regarding the identified portfolio decisions conforms to the gas supply planning principles.

  - The gas supply plan narrative should be circulated and reviewed both within the gas supply area but also in certain supporting departments such as Storage Planning, Distribution Planning, and Regulatory.

- Regulatory and Market Implications
  - The Union gas supply plan should also provide a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g., RH-003-2011) that may influence Union gas supply decisions. Stated differently, the results of major regulatory changes that will influence upstream pipeline services and costs should be included and discussed in the Union gas supply plan.
  - The Union gas supply plan should provide a summary of physical infrastructure projects or gas supply/pipeline options that may impact the Union gas supply plan. While the potential infrastructure projects will have specific regulatory processes, discussing these projects and gas supply drivers at a high level in the Union gas supply plan will provide market context for Union stakeholders.
  - The Union gas supply plan should include research and analysis regarding the gas supply portfolio implications associated with gas supply basin trends and evaluate potential impacts on the Union gas supply portfolio. The additional narrative would allow the Union stakeholders to better understand the rationale underpinning certain gas supply strategies.

Gas Supply Plan Review – Contracting

The last activity in the gas supply planning process is the on-going management of the gas supply portfolio (e.g., contracting decision analysis). As part of our review of the Union gas supply contracting/transportation path practices, Sussex addresses Elements seven and eight from the OEB Decision and Order in EB-2011-0210:

- Determine whether Union is conducting sufficient due diligence with respect to the cost benefit analysis associated with decontracting a particular gas transportation route and recontracting on an alternative route and recommended remedial action, if required.
- Determine whether Union is using the transportation portion of the gas supply portfolio to favor the transportation paths of entities in which Union or its parent has (or will have in the future) an economic interest, and recommend remedial action if required.

When an LDC is analyzing a transportation contracting decision, and assuming that the volume required has not changed, there are three general options that are evaluated:

- Recontract for the same path
- Recontract for a different path on the same pipeline
- Recontract on a different pipeline/path

The LDC contract analysis generally includes: (i) data gathering; (ii) quantitative modeling of the options; (iii) evaluating qualitative factors; and (iv) documenting the decision analysis and process. The Sussex analysis of the Union contracting practices evaluates the Union approach with respect to transportation contracting based on the typical LDC approach (i.e., data gathering, modeling, documentation).

Regarding the first step (i.e., data gathering), the Union Gas Supply Group is active in various information gathering activities including: attending energy conferences, market participant meetings, access to industry publications and data, and contracting for third party consulting reports. The Union gas supply group also conducts requests for proposals associated with natural gas purchases thus acquiring market information and price signals. In addition, Union has an active regulatory group that is involved in upstream pipeline regulatory proceedings, thus providing gas supply with current pipeline filings and submissions.

With respect to the second step (i.e., quantitative modeling), Union utilizes two approaches to evaluate contracts/transportation path decisions. First, Union uses a landed cost analysis to evaluate the delivered cost of transportation path options. In a landed cost analysis, Union identifies the various components of each path; develops cost/price assumptions for the various components; and calculates a delivered cost of transporting natural gas from the transportation path gas supply source to the Union market area. The following example illustrates the landed cost approach:

1	**2**	**3**	**4**		**3 + 4**
Path	**Gas Supply Basin**	**Gas Supply Cost**	**Pipeline 1**	**Pipeline 2**	**Total**
A	Rockies	Henry Hub + x	$D	N/A	Henry Hub + x + $D = A Total
B	Gulf of Mexico	Henry Hub + y	$E	$F	Henry Hub + y + $E + $F = B Total

As shown by the above table, Path A consists of a Rockies gas supply priced at Henry Hub plus a basis of x and is transported on Pipeline 1 for a landed cost comprised of the gas supply cost and the toll for Pipeline 1. Path B consists of a Gulf of Mexico gas supply transported on both Pipeline 1 and 2 for a landed cost of gas supply cost plus transport on Pipeline 1 and 2.

The landed cost approach assumes that the pipeline components are costed at 100% load factor (i.e., the transportation path is used every day at full volume). This type of analysis allows the alternative paths to be evaluated in a straight forward and transparent manner.

In addition to the landed cost analysis, Union may also utilize the SENDOUT model to evaluate a transportation path that is not expected to be utilized at 100% load factor. The SENDOUT model, which is an optimization tool, allows Union to evaluate how alternative transportation paths influence the overall gas supply portfolio. Using an optimization model, such as SENDOUT, allows Union to evaluate the total cost of the portfolio as the model considers the inter-relationships of the numerous contract parameters of the individual resources. Specifically, Union has modeled the gas supply portfolio in SENDOUT and has included the following inputs: maximum daily quantity ("MDQ"), tolls and fuel rates, and demand estimates.

With respect to the third step (i.e., evaluate qualitative factors), Union considers various qualitative factors in contracting decisions such as supply basin diversity, contract terms, and pipeline diversity. These qualitative factors are discussed in more detail below when Sussex reviews the Union Incremental Transportation Contracting Analysis.

Regarding the fourth step (i.e., documentation), Sussex reviewed documentation associated with certain Union gas supply contracting/transportation decisions including:

- Alliance Pipeline renewal decision
- 2011-2012 system and supply plan proposed transportation additions
- SSMDA via MichCon proposed transportation additions
- CTHI/CPMI capacity renewal – Union MDA

Sussex reviewed the Union management presentations for each of the identified decisions to verify that sufficient information had been gathered regarding each decision; alternative options had been identified and modeled; and the decisions were documented. The following table is a summary of our findings:

Decision	**Data Gathering**	**Quantitative Analysis**	**Documentation**
Alliance Renewal	Included Alliance depreciation surcharge, tolls and used ICF gas price forecast	Landed cost approach as path flows at 100% load factor	Management Presentation
Proposed 2011-2012 Transport Additions	Included gas price forecast from ICE, toll and fuel information	Landed cost analysis as path would flow at 100% load factor	Management Presentation
SSMDA via MichCon	Included gas price forecast from ICE, tolls and fuel	Landed cost and annual cost comparison	Management Presentation
Union MDA/CTHI/CPMI	Focused on volume as no other pipeline alternative is available	Focus of analysis was on MDQ level; demand data reviewed	Management Presentation

As illustrated by the above table, the Union contracting decisions reviewed by Sussex addressed issues typically covered by an LDC contract analysis (i.e., data gathering, modeling, and documentation).

In addition to the contracting decisions summarized in the matrix above, Sussex reviewed the process used by Union to evaluate new or incremental capacity contracts. Specifically, for new or incremental transportation paths Union uses the Incremental Transportation Contracting

Analysis, which was first outlined in EB-2005-0520. As part of the Incremental Transportation Capacity Analysis Union utilizes the following evaluation process:

- Description of the new or incremental transportation path;
- Provide written rationale describing why Union is entering into this new transportation path;
- Describe all relevant transportation contract parameters including: provider, term, price and receipt/delivery points;
- Quantitative comparison of the landed cost to alternatives; and
- Quantitative and/or qualitative consideration of additional factors considered relevant by Union, including: security of supply, supply basin diversity, contract term diversity, pipeline operator diversity, terms and conditions and demand charge/commodity charge structure.

The process outlined for Incremental Transportation Capacity Analysis is consistent with the LDC process described above (i.e., data gathering, quantitative modeling, qualitative considerations and documentation).

With respect to whether Union is using the transportation portion of the gas supply portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex understands that Union contracts with St. Clair Pipelines LP (an affiliate) for certain capacity that is used for overall security of supply. Sussex further understands the St. Clair Pipeline LP agreements (St. Clair Pipeline and Bluewater Pipeline) are the only capacity contracts Union has with an affiliate. Therefore, given the role of St. Clair Pipeline LP in the Union gas supply portfolio (i.e., security of supply) Sussex understand the Union capacity agreement with St. Clair Pipeline LP has not been subjected to or included in any Union transportation path analysis.

On the broader issue of whether Union could use the transportation portfolio to favor transportation paths in which Union or the parent may have an interest, Sussex recommends Union utilize the Incremental Transportation Contracting Analysis framework augmented by our recommendations for all contracting decisions, regardless of whether that contract decision is for decontracting, recontracting or incremental capacity. This approach would be applied irrespective of the entity owning the upstream pipeline/project, and as a result would provide sufficient analysis and documentation as to why Union pursued a certain strategy regarding a transportation path decision.

Sussex has the following additional recommendations regarding the Union contract/transportation path evaluation process:

- It is important for Union to continue to use known information (e.g., current approved tolls) to reduce the subjectivity of the analysis; however, a range of inputs should also be considered to increase the robustness of the analysis. Stated differently, Union should develop scenarios around the base case.
- Union should provide documentation supporting the choice of alternatives analyzed and not analyzed (e.g., Path A was not reviewed as there is no capacity available on that pipeline). The documentation requirements are similar to general LDC contracting practices and the Union Incremental Transportation Contracting Analysis process discussed above.
- Review and evaluate whether the SENDOUT model could be used to augment the landed cost analysis. Sussex appreciates that the landed cost analysis at 100% load factor is more straightforward analysis for pipeline options that will be dispatched at maximum capacity value every day; however, the exercise of modeling the contract option in SENDOUT may, in of itself, be a useful process, as the attributes of the path need to be understood in order to be modeled.
- The Sussex recommendations with respect to contracting decisions apply to all Union contract/transportation path decisions regardless of the entity owning the upstream pipeline/project.
- Union should establish a process to review the cost of service, rate level, and rate design for St. Clair Pipeline and Bluewater Pipeline. Specifically, every three years or pursuant to a significant NEB filing by either St. Clair Pipeline or Bluewater Pipeline, Union should undertake a review of the current pipeline situation and, depending on the outcome of that review, initiate negotiations with the pipeline or submit a complaint to the NEB.
- Finally, although the OEB Decision and Order in EB-2011-0210 did not address whether an LDC contracting analysis should consider the broader implications of that contract decision on third parties, Sussex recommends that if Union attempts to incorporate such an analysis the focus of that broader evaluation should be directional impact assessments and not detailed quantification of costs and benefits. Specifically, given the supply/market footprint and diverse service areas of the infrastructure that provides natural gas to Union and the various downstream customer segments, a detailed cost

and benefit analysis will need to rely on many assumptions associated with markets and regulatory activities that may be difficult to estimate and the result from such an analysis may or may not inform the contract decision for Union and its customers.

Gas Supply Plan Review – Organization

In addition to the gas supply plan elements identified by the OEB in EB-2011-0210, Sussex also reviewed the Union practices associated with gas supply portfolio asset optimization. Specifically, once a gas supply plan has been developed and the contracts/assets are in place for a certain period of time (e.g., season or multi-year), LDCs will typically identify and undertake activities and opportunities to leverage the assets that are not being used to serve firm customers (i.e., asset optimization).

The process or range of activities utilized by an LDC to extract value from the gas supply portfolio can range from the straight forward (i.e., daily assignment of transportation contracts) to the more complicated (i.e., structured products to serve the need of a particular market participant). As expected, the value derived from an LDC gas supply portfolio will be related to the level of activity and products/services provided to the market.

In general, there are three options used by LDCs to extract value from gas supply assets: (i) LDC managed activity; (ii) third party asset manager; and (iii) non-regulated affiliated asset manager.

When a third-party or a non-regulated affiliated asset manager is utilized to extract value from the LDC portfolio, the LDC assigns an asset or a portfolio of assets to the asset manager and in return, the LDC receives a payment based on the activity of the asset manager. There are various payment structures for asset management arrangements, including:

- The asset manager pays a fixed fee for the use of the LDC's assets;
- The asset manager provides an upfront payment and shares any additional value with the LDC at a pre-arranged percentage; or
- The asset manager shares the value earned with the LDC based on a pre-arranged percentage.

The value received by the LDC under an asset management arrangement could vary significantly based on: (i) the competitiveness of the marketplace with respect to asset managers; (ii) the timing of the transaction and whether the forward natural gas prices and/or basis is trending up or down; and (iii) the assets provided by the LDC to the asset manager (i.e., one path on a specific pipeline or various assets such as transportation on several pipelines and underground storage).

In addition to the variability in the value derived from asset management arrangements, this approach may also results in a decrease of “in-house” knowledge and expertise, thus impacting the overall capability of the LDC. Stated differently, the “out-sourcing” of the value extraction activities could reduce the expertise and knowledge of the “in-house” LDC personnel.

The other option with respect to asset management is for the LDC to perform these activities “in-house” and compete with other market participants such as energy marketing companies. Under this approach, the LDC is active in the market and has direct participation resulting in market insights and information; however, the LDC may lack the scale and scope of other energy market participants as those firms may have more innovative deal structures or greater incentives to extract value. For example, a non-regulated energy marketing company has an incentive to develop innovative and creative products and services to grow revenue, margins and profit; and as a result of this financial incentive, the energy marketer is more likely to maximize the value of the LDC assets as compared to general LDC activity. In addition, the energy marketer is able to add assets to existing or expected positions and thereby bundle the combined or integrated assets to extract more value.

The Union approach to extracting value from the gas supply portfolio is a hybrid of the two approaches and leverages the Union assets and positions. Specifically, Union has storage and transmission assets that are offered to market participants by the Storage and Transmission Sales Group (‘S&T”) at various time periods (e.g., daily, seasonal or multi-year); and as such, the S&T sales group is in the energy marketplace on a continuous basis. By including the gas supply assets with the S&T existing positions, Union is able to provide market participants with structured products that optimize the assets on an integrated basis; and provide value that would likely not be extracted had the gas supply assets been managed on a standalone basis. The S&T Group essentially operates as an asset manager within the regulated organization.

The attributes of the Union approach include:

- The gas supply group is focused on developing a portfolio that meets the forecasted demand over not just the upcoming year but over the long term. As such, the gas supply group is focused on medium and long-term portfolio decisions that meet the gas supply planning principles, not on short term value extraction.

- The S&T sales group, on the other hand, is focused on near term asset utilization and optimization (i.e., extracting the most value from the current asset positions).
- As both functions are within the utility, the OEB has the ability to review transactions and activity in a fairly detailed and transparent process.
- Union, as an active market participant, provides structured services to the marketplace thus providing another alternative to meet the needs of market participants (i.e., Union is able to structure products and services for a variety of market participants including: end users, retail energy marketers and wholesale market participants).
- The incentive for S&T to extract value from the gas supply portfolio assets create a healthy tension between S&T (i.e., market driven) and the Union Gas Control group (i.e., reliability and system integrity driven).
- Changing market dynamics may result in new products and structures that will continuously require risk/reward evaluation, thus requiring the need for Union to continue to develop quantitative analytical skills and analysis.

In summary, while there are various alternatives used by LDCs to extract value from the gas supply portfolio assets the main differences in approach are: "in-house" v. "out-sourced" and value drivers (e.g., incentives). The current approach utilized by Union to extract value leverages the core competencies of Gas Supply and S&T, is consistent with other approaches used by LDCs (e.g., asset management arrangements), and, based on the experience of the Sussex project team, is reasonable.

Sussex Team Bios

James M. Stephens, Partner

Mr. Stephens has twenty-five years of experience in the energy industry and he has held senior management positions at consulting firms, energy marketing companies and natural gas utilities. Most recently, Mr. Stephens served as Senior Vice President for Concentric Energy Advisors, Inc. He has assisted numerous clients with regulatory policy strategy/tactics and energy market analyses/assessments including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure (e.g., pipeline expansions); the evaluation of new markets/opportunities (e.g., distributed LNG); market entry/exit strategies (e.g., service territory or product/service expansions); market implications of new energy infrastructure (e.g., LNG facilities and pipelines); integrated resource plans (e.g., natural gas demand forecasting and resource portfolio analysis); natural gas supply portfolio evaluation and optimization (e.g., asset management agreements); and management prudence (e.g., implementation of risk management/portfolio strategies). In addition to his consulting experience, Mr. Stephens served as the President of a retail energy marketing firm where he was responsible for all aspects of business unit management including front, mid and back office functions. Mr. Stephens was also responsible for the Gas Supply Procurement and Portfolio Optimization function for a local distribution company. Mr. Stephens holds a B.S. in Management and an M.B.A. with a concentration in Operations Management from Bentley College.

Peter Newman, Executive Advisor

Mr. Newman, who is an Executive Advisor with Sussex, has over thirty-five years of experience in various natural gas supply management roles for WE Energies. Specifically, Mr. Newman was responsible for managing all the natural gas supply functions including: long term supply planning and acquisition; natural gas purchasing strategies and execution; capacity portfolio optimization; development and implementation of risk management objectives and policies; and management of the gas control function. In addition, Mr. Newman participated in numerous Federal Energy Regulatory Commission proceedings with respect to natural gas pipeline expansions, rate proceedings, new services and other regulatory issues. Mr. Newman was also a key member of the management team that developed and built the Guardian Pipeline and, in that role, Mr. Newman contributed to a variety of activities, including: market development and project management, developing and implementing the open season process, market assessment, regulatory strategy and proceedings, capacity marketing and tariff development. Mr. Newman is an engineering graduate of the University of Wisconsin-Platteville.

Jim Voss, Executive Advisor

Mr. Voss, who is an Executive Advisor with Sussex, has twenty-five years of experience in the natural gas industry having held management positions at major Midwestern LDCs as well as unregulated energy marketing firms. He has extensive background and knowledge of gas trading and asset optimization, nominating and scheduling operations, pipeline-LDC system interfaces, gas supply portfolio planning, and related Federal and State regulatory oversight. Mr. Voss is a graduate of the University of Wisconsin-Madison with a Masters in Finance from the University of Wisconsin-Milwaukee.

Adam Perry, Managing Consultant

Mr. Perry's experience in the energy industry is wide-ranging, including work related to regulatory proceedings, rate design, cost of service, cost of capital and financial valuations. His regulatory work has involved development of minimum filing requirements, demand forecasts, return on equity analyses, class cost of service and allocation factor analyses, and market-based rates evaluations. In addition, Mr. Perry has developed expert testimony, prepared financial models for valuation purposes, and performed regulatory and market research. Mr. Perry holds a B.S. in Economics from Northeastern University, where he graduated magna cum laude and was a member of the Omicron Delta Epsilon Society.

TCPL Mainline Services

Service	Description	Access	Toll / Price	Toll Type	Renewal Rights	Key Features and Benefits
FT Firm Transportation	• Firm service with a primary receipt point and primary delivery point • Term: minimum of 1 year; no maximum	• Open Season • Awarded based on term x toll	• 100% load factor FT toll • Empress to Union-EDA o Demand: $63.84842/GJ/ month or $2.099/GJ/day o Commodity: $0.14377/GJ	• Monthly demand and commodity	• Renewal minimum 1 year • 6 months notice required	• Will build for service • Secure and reliable daily deliveries • Guaranteed renewal rights • Alternate Receipt Point and Diversion rights • Shifts (i.e., temporary receipt and/or delivery points) – minimum duration of 3 months • Assignment rights • RAM credits on long-haul and linked short-haul
STFT Short Term Firm Transportation	• A short term firm service with a primary receipt point and primary delivery point • Term: specified number of days not less than 7 consecutive days, monthly periods, or	• Open Season • Shippers bid quantity, price and term • Awarded based on aggregate revenue	• Biddable • Bid floor price = 100% load factor FT toll • No maximum • Toll is fixed for the term of the contract • Empress to Union-EDA o STFT Minimum Toll: $2.2429/GJ	• Bid price daily demand equivalent	• n/a	• Will not build for service • Fills short term and seasonal transportation needs on a firm basis; has the same reliability as FT service • No Alternate Receipt Point and Diversion rights • No Shifts • No Assignment rights • No RAM • Receipts allowed from certain delivery areas

Service	Description	Access	Toll / Price	Toll Type	Renewal Rights	Key Features and Benefits
	combination of consecutive monthly periods (i.e., Block Periods) up to 1 year less 1 day					
STS Storage Transportation Service	• Firm service allowing for injections and withdrawals at storage locations • Requires the STS contract holder to also hold a long-haul FT contract to their market point • Term: minimum of 1 year; no maximum	• Open Season • Awarded based on term x toll • Must also hold a long-haul FT contract to the market point	• STS toll	• Monthly demand and commodity	• Renewal minimum 1 year • 6 months notice required	• Will build for service • Guaranteed renewal rights • No Alternate Receipt Point and Diversion rights • No Shifts • No Assignments • STS RAM credits (seasonal) • Ability to convert to STS-L • Additional Nomination Windows to balance daily gas supply and consumption

Sources: TCPL Mainline Customer Express website (http://www.transcanada.com/customerexpress/2773.html) and Company Tariff

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
Enbridge Gas Distribution	Central	Ontario					
Enbridge Gas Distribution	Eastern	Ontario					
Enbridge Gas Distribution	Niagara	Ontario					
Enbridge Gas Distribution	TOTAL	Ontario	1,957,733	404,670,766	3,506,040	Multi-Peak Design Criteria, which, in addition to incorporating the single peak day weather criteria, include statistical conditions about weather applied to other days in the winter season. Relies upon probability of occurrence to determine the peak days.	Peak day demand is derived from the HDDs for peak day, and potentially other weather variables, assumed within the Design Criteria. However, the Company's current Design Criteria does not include weather variables other than HDDs.
Centra Gas Manitoba	TOTAL	Manitoba	266,699	65,898,545	456,184	Coldest winter day experienced	
FortisBC	Columbia	British Columbia			26,539		
FortisBC	Coastal	British Columbia			860,618		
FortisBC	Ft. Nelson	British Columbia			5,687		
FortisBC	Inland	British Columbia			275,815		
FortisBC	Whistler	British Columbia			6,635		
FortisBC	TOTAL	British Columbia	841,000	108,430,263	1,175,293	Probability of occurrence	Usage per degree day.
Gaz Métro	Quebec	Quebec			1,261,561	Coldest day in last 20 years	
NSTAR	Cambridge	Massachusetts	52,032	9,485,379			
NSTAR	Framingham	Massachusetts	63,282	10,925,112			
NSTAR	New Bedford	Massachusetts	63,636	7,820,545			
NSTAR	Worcester	Massachusetts	89,472	13,402,977			
NSTAR	TOTAL	Massachusetts	268,422	41,634,013	412,000	Probability of occurrence	Develop NSTAR Gas Forecast Sendout/EDD Factors by Division and Month factors for each division.
National Grid	Boston Gas	Massachusetts	606,159	81,629,143	954,000		
National Grid	Essex Gas	Massachusetts	50,835	6,460,769	71,000		
National Grid	Colonial Gas - Lowell	Massachusetts	88,911	12,359,614	149,000		
National Grid	Colonial Gas - Cape Cod	Massachusetts	105,795	10,360,869	114,000		
National Grid	TOTAL	Massachusetts	851,700	110,810,395	1,107,897	Probability of occurrence	The Company developed the reference year sendout using regression equations of its Primary Firm Load Sendout (those sales classes for which the Company must plan its interstate pipeline capacity portfolio) based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
Bay State Gas d/b/a Columbia Gas of MA	Brockton	Massachusetts	147,028	20,581,514	241,320		

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
Bay State Gas d/b/a Columbia Gas of MA	Lawrence	Massachusetts	45,807	6,763,865	72,676		
Bay State Gas d/b/a Columbia Gas of MA	Springfield	Massachusetts	101,001	12,854,268	136,374		
Bay State Gas d/b/a Columbia Gas of MA	TOTAL	Massachusetts	293,836	40,199,647		Probability of occurrence	Forecast design day demand for each division is derived from a daily demand model that uses data for all days in April 2010 through March 2011 with 10 or more EDDs.
Southern Connecticut Gas	TOTAL	Connecticut	165,000	28,939,000	281,255	Coldest day in last 30 years	SCG uses a multiple regression model for determining peak day gas requirements (design day sendout). The model utilizes daily weather information, lagged daily weather information, and firm sendout for SCG's service area. The assumed design day and lagged EDD variables used to calculated the design day sendout are 68 EDDs and 60 EDDs, respectively.
Connecticut Natural Gas	Hartford	Connecticut			277,611		
Connecticut Natural Gas	Greenwich	Connecticut			39,182		
Connecticut Natural Gas	TOTAL	Connecticut	155,000	31,148,000	316,793	Coldest day in last 30 years	CNG uses a multiple regression model for determining peak day gas requirements (design day sendout). The model utilizes daily weather information, lagged daily weather information, and firm send out for each of CNG's service areas (Hartford and Greenwich).
Yankee Gas	TOTAL	Connecticut	209,952	47,571,000	396,494	Coldest day in last 30 years	Based on the highest heating degree day occurrence (75 EHDD) in the Reference Case, Design Weather Forecast.
National Grid	Narragansett Electric Company	Rhode Island	250,000	34,023,000	308,000	First, the Company performed a Monte Carlo analysis of normal weather conditions. Design Day = Normal Day + 2 standard deviations. Second, the Company performed a cost/benefit analysis.	The Company developed the reference year sendout using regression equations based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
National Grid	Brooklyn Union Gas (Long Island)	New York	553,000		949,942		
National Grid	Brooklyn Union Gas (New York City)	New York	1,200,000		1,399,830		

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
National Grid	TOTAL	New York	1,753,000			Coldest day observed	The Company developed the reference year sendout using regression equations based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
National Grid	Niagara Mohawk	New York	588,452	145,128,000		Coldest day observed	The Company developed the reference year sendout using regression equations of its Primary Firm Load Sendout (those sales classes for which the Company must plan its interstate pipeline capacity portfolio) based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement. This regression equation captures the observed characteristics of the Company's sendout requirements. The observed characteristics include the following: (1) sendout requirements are directly related to HDD; (2) sendout requirements are affected by HDDs that occur over a multiday period; and (3) sendout requirements differ by day of the week.
Consolidated Edison	ConEd of New York	New York	1,101,100	247,000,000	1,090,909	Coldest day observed	Peak day consumption for firm customers is calculated by determining the previous winter's peak, by regressing each day's firm consumption from November 15 through March 15, excluding weekends and holidays to a 0 degree day.
Northern Utilities	Maine	Maine	26,500	9,025,493	52,353		
Northern Utilities	New Hampshire	New Hampshire	28,000	7,333,889	52,778		
Northern Utilities	TOTAL	Total System	54,500	16,359,382		Probability of occurrence. The 20 year average and standard deviation of the peak day was calculated and used to calculate the Design Day EDD associated with a 1-in-33 year probability of occurrence.	To determine the Planning Load associated with Design Day weather in each Division, a daily Design Day model was developed for each Division. Similar to the daily Planning Load model developed for Normal Year and Design Year, the dependent variable was historical daily Planning Load for the period May 1, 2009 through March 31, 2011 by Division and the independent variables included weather and other variables (e.g., day of the week). The preliminary Design Day Planning Load was then calibrated using the adjustment factors associated with Design Year January for each forecast year for the Base Case, High Growth, and Low Growth scenarios.
National Grid	EnergyNorth Natural Gas	New Hampshire	87,000	12,782,786	138,401	Monte Carlo analysis of average daily temperature as the variable to be modeled and HDD, which is a linear transformation of average daily temperature (Determines Normal Day/Year). Design Day/Year = Normal Day/Year + 2 Standard Deviations.	The Company developed the reference year sendout using regression equations based on the prior April to March time period. The level of the Company's sendout in the reference year served as the "springboard" to which incremental sendout was added. Using the design day weather planning standard, the Company determined the design day sendout requirement.
Michigan Consolidated Gas	Detroit/Ann Arbor	Michigan			1,383,000		
Michigan Consolidated Gas	Grand Rapids	Michigan			557,000		
Michigan Consolidated Gas	Upper Peninsula	Michigan			86,000		
Michigan Consolidated Gas	Traverse City	Michigan			120,000		
Michigan Consolidated Gas	Alpena	Michigan			94,000		
Michigan Consolidated Gas	TOTAL	Michigan	1,213,521	151,500,000	2,240,000	MichCon plans for an end-of-month peak day based on the coldest historical temperatures from the 22nd of that month to the 7th of the following month. It is possible for an end of March peak day temperature to occur through the end of the first week in April when storage balances are at their minimums.	MichCon serves its peak day requirements around critical end-of-month demand. MichCon's peak day demand model examines the design weather at sixteen different locations and condenses them down to five primary demand locations. End-of-month peak demand in January, February, and March 2013 at these five primary demand locations are calculated using statewide weather.

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
Consumers Energy	TOTAL	Michigan	1,713,239	287,142,000	3,437,000	Coldest day since 1960	There are three primary steps in the peak day forecast development methodology. In step 1 of the design peak day sendout forecast method, the linear regression of city gate sendouts versus Wind Adjusted Weighted Degree Day ("WAWDD") is performed. Then an adjustment is used to implement allowance for potential variance in design peak day sendouts by calculating the 4% probability line. The city gate sendout represented by this 4% probability line at 80 WAWDD is then used in later steps instead of the city gate sendout represented by the linear regression line. In the second step, historical results of step 1 are directly compared using linear regression to historical weather adjusted system sendouts for the winter time period of January alone, due to it having the strongest correlation of the four selected winter time periods evaluated. This linear regression equation is then used to estimate non-electric 80 WAWDD design peak day sendouts for the five year planning period based on the gas sendout forecasts for January in the Corporate Gas Deliveries forecast with the addition of fuel use and system loss. After the additions in step 3, the estimated future 80 WAWDD peak day loads reflect the total peak day load connected to the Consumers gas transmission system. Estimates for future 65 WAWDD peak day and 50 WAWDD peak day loads can be determined by adjusting the results of step 2 downward with the appropriate weather sensitivity factor and then continuing with step 3 as normal. The Company also implements a floor mechanism which does not allow the design peak day sendout to go below the 80 WAWDD result from the most recent winter in the first forecast Plan year.
Cascade Natural Gas	Aberdeen	Washington	6,400	925,818	8,093		
Cascade Natural Gas	Bellingham	Washington	45,377	4,083,168	67,781		
Cascade Natural Gas	Bremerton	Washington	30,602	2,781,927	34,624		
Cascade Natural Gas	Kennewick	Washington	23,371	2,352,617	36,887		
Cascade Natural Gas	Longview	Washington	3,745	643,646	7,956		
Cascade Natural Gas	Moses Lake	Washington	2,505	391,348	7,736		
Cascade Natural Gas	Mount Vernon	Washington	40,297	3,733,543	48,805		
Cascade Natural Gas	Sunnyside	Washington	6,668	877,714	9,802		
Cascade Natural Gas	Walla Walla	Washington	11,663	993,260	15,804		
Cascade Natural Gas	Wenatchee	Washington	2,303	555,619	5,920		
Cascade Natural Gas	Yakima	Washington	22,631	2,639,888	30,276		
Cascade Natural Gas	Baker	Oregon	3,854	367,694	2,622		
Cascade Natural Gas	Bend	Oregon	43,648	4,630,960	56,796		
Cascade Natural Gas	Ontario	Oregon	4,474	448,181	3,043		
Cascade Natural Gas	Pendleton	Oregon	12,412	1,213,757	19,696		
Cascade Natural Gas	TOTAL	Total System	259,950	26,639,139	355,841	Coldest day in last 30 years	The peak day forecast is developed by adjusting the therm usage on the coldest day in recent history (January 5, 2004 at 56 HDD) upwards to an estimate of what therm usage would have been had that day been 61 HDD (December 21, 1990, the coldest day in the last 30 years). The therm usage is then applied to each district and escalated into the future at the forecast therm usage annual growth rate.
NW Natural	Albany	Oregon	40,191				
NW Natural	Astoria	Oregon	12,281				
NW Natural	Dalles	Oregon	5,476				
NW Natural	Eugene & Coos Bay	Oregon	39,882				
NW Natural	Lincoln City & Newport	Oregon	10,097				
NW Natural	Portland	Oregon	413,232				
NW Natural	Salem	Oregon	87,994				
NW Natural	Vancouver & Dalles	Washington	68,301				

Company	Division	State / Province	Number of Customers	Annual Sales / Throughput (Dth)	Peak Day Send-Out (Dth)	Peak Day Planning Approach	Peak Day Consumption Estimation Process
NW Natural	TOTAL	Total System	677,454		697,970	Coldest day in last 25 years	Daily use is separated into two components, base load and heat load. The base load component is assumed to be constant throughout the year and is independent of ambient temperatures. Base load represents demand for uses such as water heating and cooking. Heat load represents demand for space heating. Base load is calculated by performing a linear regression with daily use per customer as a function of HDDs, using customer usage data from the summer months of July, August, and September. For the non-summer months, the base load value is subtracted from the daily customer use data and the heat load factors are calculated. Peak day load is calculated by inputting the peak day HDDs in the two equations and adding the results together.
Pacific Gas & Electric	TOTAL	California	4,520,000		2,842,000	Probability of occurrence	The Abnormal Peak Day ("APD") core forecast is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under APD conditions.

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
Enbridge Gas Distribution	Central	Ontario			
Enbridge Gas Distribution	Eastern	Ontario			
Enbridge Gas Distribution	Niagara	Ontario			
Enbridge Gas Distribution	TOTAL	Ontario			
Centra Gas Manitoba	TOTAL	Manitoba			
FortisBC	Columbia	British Columbia			
FortisBC	Coastal	British Columbia			
FortisBC	Ft. Nelson	British Columbia			
FortisBC	Inland	British Columbia			
FortisBC	Whistler	British Columbia			
FortisBC	TOTAL	British Columbia	Growth rate based on underlying econometric models.	The objectives of the Annual Contracting Plan are: (1) To contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements. (2) To develop a portfolio mix which incorporates flexibility in the contracting of resources based on short term and long term planning, and evolving market dynamics.	
Gaz Métro	Quebec	Quebec			
NSTAR	Cambridge	Massachusetts			
NSTAR	Framingham	Massachusetts			
NSTAR	New Bedford	Massachusetts			
NSTAR	Worcester	Massachusetts			
NSTAR	TOTAL	Massachusetts		In addition to conducting a review of the historical frequency of occurrence associated with the five coldest winter periods and peak days for each division, the Company also reviewed recent changes in the natural gas industry that may affect the Company's selection of its design-planning standards. These factors include: (a) regulatory unbundling; (b) liquidity in market centers downstream of traditional production areas; and (c) the role of gas marketers.	The NSTAR Gas resource planning process is designed to ensure a reliable energy supply for its customers with a minimum impact on the environment and at the lowest cost, taking into consideration important non-price factors such as reliability, flexibility, and diversity.
National Grid	Boston Gas	Massachusetts			
National Grid	Essex Gas	Massachusetts			
National Grid	Colonial Gas - Lowell	Massachusetts			
National Grid	Colonial Gas - Cape Cod	Massachusetts			
National Grid	TOTAL	Massachusetts	Growth rate based on underlying econometric models.	The Department assesses the two major aspects of every gas company's supply plan: adequacy and cost; and the supply planning process. The Department's review of reliability, is included in the Department's consideration of adequacy. A supply planning process is critical in enabling a utility company to formulate a resource plan that achieves an adequate, least-cost, and low environmental impact supply for its customers. An appropriate supply planning process provides a gas company with an organized method of analyzing options, making decisions, and re-evaluating decisions in light of changed circumstances.	The Company's forecast methodology supports its supply planning goals of ensuring that: (1) its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the coldest planning day ("design day"); and (2) it maintains sufficient supplies under contract and in storage (underground storage, LNG and propane) to meet customers requirements over the coldest planning year ("design year").
Bay State Gas d/b/a Columbia Gas of MA	Brockton	Massachusetts			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
Bay State Gas d/b/a Columbia Gas of MA	Lawrence	Massachusetts			
Bay State Gas d/b/a Columbia Gas of MA	Springfield	Massachusetts			
Bay State Gas d/b/a Columbia Gas of MA	TOTAL	Massachusetts	Based on the assumptions that design day occurred on a day in January, the design day planning load requirements were calculated as part of the design year planning load requirements.		The F&SP details CMA's resource planning process and presents the Company's resource strategies based on its current forecast of customer requirements and present market conditions. The plan demonstrates that CMA's planning standards are appropriate and its resource strategies are in the best interests of its customers and result in a reliable, best-cost, long-range supply and capacity portfolio to meet the Company's forecasted firm demand. CMA's decision-making process requires the Company to establish appropriate goals and objectives. The primary goal of CMA's planning process is to acquire and manage all available resources in a manner that achieves a best-cost resource portfolio for its customers. A best-cost portfolio appropriately balances lower costs with other important non-cost criteria such as reliability, viability and flexibility. Pursuit of a best-cost portfolio allows CMA to provide its customers with reliable service at a reasonable cost. The Company's overall portfolio objective is supported by a number of specific resource planning objectives, which are summarized as follows: (1) reduce portfolio costs; (2) maintain portfolio security/reliability (which includes enhancing diversity across pipelines and supply basins); (3) provide contract flexibility; and (4) acquire viable resources.
Southern Connecticut Gas	TOTAL	Connecticut	Peak day demand projections are based upon the current base case scenario.		To describe its planning process to regulators, customers, and other interested parties. The Forecast is constantly changing as the industry and the markets change, and the report represents a single view of that Forecast at a particular point in time. Numerous scenarios continue to evolve from the Forecast and are used in the decision-making process.
Connecticut Natural Gas	Hartford	Connecticut			
Connecticut Natural Gas	Greenwich	Connecticut			
Connecticut Natural Gas	TOTAL	Connecticut	Peak day demand projections are based upon the current base case scenario.		To describe its planning process to regulators, customers, and other interested parties. The Forecast is constantly changing as the industry and the markets change, and the report represents a single view of that Forecast at a particular point in time. Numerous scenarios continue to evolve from the Forecast and are used in the decision-making process.
Yankee Gas	TOTAL	Connecticut	Peak day demand projections are based upon the current base case scenario.		
National Grid	Narragansett Electric Company	Rhode Island	Growth rate based on underlying econometric models.		This Supply Plan is designed to demonstrate that the Company's gas-resource planning process has resulted in a reliable resource portfolio to meet the combined forecasted needs of the Company's Rhode Island customers at least cost and to ensure that the Company maintains sufficient supply deliverability in its resource portfolio to meet customer requirements on the coldest planning day ("design day") and that it maintains sufficient supply under contract and in storage (underground storage, LNG and propane) to meet customers requirements over the coldest planning year ("design year").
National Grid	Brooklyn Union Gas (Long Island)	New York			
National Grid	Brooklyn Union Gas (New York City)	New York			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
National Grid	TOTAL	New York	Growth rate based on underlying econometric models.		
National Grid	Niagara Mohawk	New York	Growth rate based on underlying econometric models.		
Consolidated Edison	ConEd of New York	New York	Growth is based on forecasts for economic growth, transfers from interruptible to firm service, fuel switching and energy efficiency.		The gas forecast drives the timing and magnitude of the required investment in transmission and distribution infrastructure. Con Edison currently develops 10-year load forecasts to ensure that transmission and distribution infrastructure is adequate to support the economic growth of NYC and Westchester County. To develop the 20-year forecast for the Gas Long Range Plan, the existing forecast was extended based on a number of key driver sensitivities.
Northern Utilities	Maine	Maine			
Northern Utilities	New Hampshire	New Hampshire			
Northern Utilities	TOTAL	Total System	The preliminary Design Day Planning Load was calibrated using the adjustment factors associated with Design Year January for each forecast year for the Base Case, High Growth, and Low Growth scenarios.		The IRP is provided to explain the planning processes Northern uses to develop an adequate, reliable and economic portfolio and to allow the Public Utilities Commissions of Maine and New Hampshire to evaluate the reasonableness of those planning processes. The IRP relates solely to Northern's planning and contracting activities in support of the gas supply portfolio used to supply customers in the two states.
National Grid	EnergyNorth Natural Gas	New Hampshire	Growth rate based on underlying econometric models.	The Company's planning process ensures that it maintains a reliable resource portfolio and energy supply to meet the forecasted needs of its customers at the lowest possible cost.	The filing of IRPs helps promote communication between the utility and the Commission regarding the utility's supply needs and gas resource decisions. Integrated resource planning helps the Commission assess a utility's comprehensive supply-side and demand-side resources and the utility's ability to satisfy customer's short-term and long-term energy needs at the lowest overall cost consistent with maintaining supply reliability.
Michigan Consolidated Gas	Detroit/Ann Arbor	Michigan			
Michigan Consolidated Gas	Grand Rapids	Michigan			
Michigan Consolidated Gas	Upper Peninsula	Michigan			
Michigan Consolidated Gas	Traverse City	Michigan			
Michigan Consolidated Gas	Alpena	Michigan			
Michigan Consolidated Gas	TOTAL	Michigan			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
Consumers Energy	TOTAL	Michigan	Growth is based on gas sendout forecasts for January in the Corporate Gas Deliveries forecast with the addition of fuel use and system loss.	In its Gas Cost Recovery ("GCR") Plan, the Company takes into consideration the importance of taking actions to assure that our customers receive reliable and reasonably priced natural gas supplies for their needs. The Company utilizes a consistent planning methodology with defined risk parameters to assure customers service is not unreasonably jeopardized.	The primary objective of the design peak day forecast is to ensure sufficient supply under extreme and potentially dangerously cold conditions.
Cascade Natural Gas	Aberdeen	Washington			
Cascade Natural Gas	Bellingham	Washington			
Cascade Natural Gas	Bremerton	Washington			
Cascade Natural Gas	Kennewick	Washington			
Cascade Natural Gas	Longview	Washington			
Cascade Natural Gas	Moses Lake	Washington			
Cascade Natural Gas	Mount Vernon	Washington			
Cascade Natural Gas	Sunnyside	Washington			
Cascade Natural Gas	Walla Walla	Washington			
Cascade Natural Gas	Wenatchee	Washington			
Cascade Natural Gas	Yakima	Washington			
Cascade Natural Gas	Baker	Oregon			
Cascade Natural Gas	Bend	Oregon			
Cascade Natural Gas	Ontario	Oregon			
Cascade Natural Gas	Pendleton	Oregon			
Cascade Natural Gas	TOTAL	Total System	The underlying peak day forecast is calculated as the peak day therm usage applied to each district and escalated into the future at the forecast therm usage annual growth rate. This method rests on the assumption that core market load shape does not significantly change throughout the forecast horizon.	The plan provides a method for evaluating resources in terms of their costs and risk. Cascade's service territory covers about 32,000 square miles and extends over 700 highway miles from end to end, encompassing a diverse economic base as well as varying climatological areas. Cascade serves 96 communities throughout Washington and Oregon consisting of about 260,000 customers. All of the communities Cascade serves are small cities and towns. This makes Cascade unique in the gas distribution business in the Pacific Northwest.	The primary purpose of Cascade's long-term resource planning process has been, and continues to be, to inform and guide the Company's resource acquisition processes. In addition, to minimize costs over the long term for the Company's firm gas sales customers.
NW Natural	Albany	Oregon			
NW Natural	Astoria	Oregon			
NW Natural	Dalles	Oregon			
NW Natural	Eugene & Coos Bay	Oregon			
NW Natural	Lincoln City & Newport	Oregon			
NW Natural	Portland	Oregon			
NW Natural	Salem	Oregon			
NW Natural	Vancouver & Dalles	Washington			

Company	Division	State / Province	Growth Rates for Peak Day Load	Planning Factors/Processes	Objective of Plan
NW Natural	TOTAL	Total System	Forecast peak day demand relies upon the base case customer forecast, usage factors, and the design weather pattern.	The Company continues to use the same region-specific forecasts in its 2013 IRP as it used in past IRPs. The regions are defined as Vancouver & The Dalles (Washington), Albany, Astoria, Eugene & Coos Bay, The Dalles (Oregon), Lincoln City & Newport, Portland, and Salem. Each region is distinguished by unique weather, usage patterns, customer growth and resource availability. These eight regions also define the separate demand points along with supplies and distribution system connections.	The IRP defines the mix of natural gas supply and demand side measures designated to meet expected future demand and reliability requirements at the lowest reasonable cost to the utility and its ratepayers. Peak day demand is the primary driver of the resource plan. High peaking demand puts a premium on storage, while large base line volumes may drive more pipeline capacity. Meeting peak day load is of primary consideration for the IRP.
Pacific Gas & Electric	TOTAL	California	Growth rate based on underlying econometric models.		The 2012 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2030. The projections in the California Gas Report are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
Enbridge Gas Distribution	Central	Ontario	41.4	HDD (°C)	1:5			Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Enbridge Gas Distribution	Eastern	Ontario	48.2	HDD (°C)	1:5			Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Enbridge Gas Distribution	Niagara	Ontario	38.8	HDD (°C)	1:5			Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Enbridge Gas Distribution	TOTAL	Ontario					SENDOUT	Settlement decision in Enbridge Gas Distribution Rate Case (EB-2011-0354), see also application at Exhibit D1, Tab 2, Schedule 3
Centra Gas Manitoba	TOTAL	Manitoba	56.0	HDD (°C)				Centra Gas Manitoba 2013/14 General Rate Application, Transcript of Centra Gas Manitoba Transportation and Portfolio Application
FortisBC	Columbia	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Coastal	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Ft. Nelson	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Inland	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	Whistler	British Columbia						FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential)
FortisBC	TOTAL	British Columbia			1:20	The maximum forecasted consumption or demand of gas over a 24 hour period that can be expected.		FortisBC Executive Summary to 2012/13 Annual Contracting Plan (Confidential), Commercial Energy Consumers Association of BC Information Request 11.3
Gaz Métro	Quebec	Quebec	46.0	HDD (°C)				Peak Gas Day Analysis, May 2005
NSTAR	Cambridge	Massachusetts	80.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	Framingham	Massachusetts	85.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	New Bedford	Massachusetts	74.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	Worcester	Massachusetts	85.0	EDD (°F)	1:50			NSTAR Gas 2012 Forecast and Supply Plan
NSTAR	TOTAL	Massachusetts				The design day represents the single highest EDD the Company's resource portfolio must be structured to meet.	SENDOUT	
National Grid	Boston Gas	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	Essex Gas	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	Colonial Gas - Lowell	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	Colonial Gas - Cape Cod	Massachusetts						Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan
National Grid	TOTAL	Massachusetts	77.6	EDD (°F)	1:35.9	The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground-storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. In this filing, the Company defines its design day standard at 77.6 EDD with a probability of occurrence of once in 35.90 years, as a result of its on-going review of planning standards.	SENDOUT	Boston Gas and Colonial Gas 2013 Long-Range Resource and Requirements Plan, Final Order of the DPU dated May 7, 2012, Discussions with Company
Bay State Gas d/b/a Columbia Gas of MA	Brockton	Massachusetts	79.5	EDD (°F)	1:33			Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
Bay State Gas d/b/a Columbia Gas of MA	Lawrence	Massachusetts	80.5	EDD (^oF)	1:33			Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan
Bay State Gas d/b/a Columbia Gas of MA	Springfield	Massachusetts	78.6	EDD (^oF)	1:33			Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan
Bay State Gas d/b/a Columbia Gas of MA	TOTAL	Massachusetts				The design day standard represents extreme winter weather conditions that have a statistically defined probability of occurring on a very infrequent basis; the design day standard is used to assess the Company's plans to provide reliable service under extremely cold weather conditions.	SENDOUT	Bay State Gas Company 2011 Long Range Integrated Forecast and System Gas Supply Resource Plan
Southern Connecticut Gas	TOTAL	Connecticut	68.0	EDD (^oF)			SENDOUT	SCG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f), Company website
Connecticut Natural Gas	Hartford	Connecticut	75.0	EDD (^oF)				CNG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f)
Connecticut Natural Gas	Greenwich	Connecticut	68.0	EDD (^oF)				CNG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f)
Connecticut Natural Gas	TOTAL	Connecticut					SENDOUT	CNG 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f), Company website
Yankee Gas	TOTAL	Connecticut	75.0	EDD (^oF)			SENDOUT	Yankee Gas 2012 Biennial Forecast Demand & Supply, CT General Statutes (Title 16, Chapter 277, Section 16-32f)
National Grid	Narragansett Electric Company	Rhode Island	66.0	HDD (^oF)	1:40.69		SENDOUT	2011/12 to 2015/16 Long-Term Gas Supply Plan
National Grid	Brooklyn Union Gas (Long Island)	New York						Downstate Service Territory Technical Conference January 9, 2013
National Grid	Brooklyn Union Gas (New York City)	New York						Downstate Service Territory Technical Conference January 9, 2013

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
National Grid	TOTAL	New York						Discussions with Company
National Grid	Niagara Mohawk	New York	74.0	HDD (^oF)				Upstate Service Territory Technical Conference January 9, 2013, Gas Sales Forecast - Witness A. Leo Silvestrini - 12-G-0202, Discussions with Company
Consolidated Edison	ConEd of New York	New York	65.0	HDD (^oF)		Peak demand, or the maximum quantity of natural gas that our firm customers require at a single point in time, drives infrastructure investment because our system must be able to meet that demand even if it is a relatively infrequent occurrence. In our service territory, these peak demand periods occur only during the coldest winter days, often for only several hours over the span of a few days.		Technical Conference January 9, 2013, ICF Assessment of NYC Natural Gas Market Fundamentals and Life Cycle Fuel Emissions, ConEd Integrated Long-Range Plan 2012, ConEd Gas Long Range Plan 2010-2030 December 2010, Discussions with Company
Northern Utilities	Maine	Maine	78.9	EDD (^oF)	1:33			Northern Utilities 2011 Integrated Resource Plan
Northern Utilities	New Hampshire	New Hampshire	80.5	EDD (^oF)	1:33			Northern Utilities 2011 Integrated Resource Plan
Northern Utilities	TOTAL	Total System				The Design Day planning standard represents extreme weather conditions on a single day that has a statistically defined probability of occurring on a very infrequent basis.	SENDOUT	Northern Utilities 2011 Integrated Resource Plan
National Grid	EnergyNorth Natural Gas	New Hampshire	72.3	HDD (^oF)		Design day is an extreme weather event for which the Company must maintain adequate resources. The design day standard determines the most cost-effective amount of daily transportation capacity (both interstate and supplemental). The design day standard is based on the statistical distribution of the coldest day of each calendar year.	SENDOUT	National Grid NH 2010 Integrated Resource Plan, New Hampshire Public Utilities Commission Order No. 25,317, January 11, 2012
Michigan Consolidated Gas	Detroit/Ann Arbor	Michigan	69.0	HDD (^oF)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Grand Rapids	Michigan	72.0	HDD (^oF)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Upper Peninsula	Michigan		HDD (^oF)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Traverse City	Michigan	76.0	HDD (^oF)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	Alpena	Michigan	75.0	HDD (^oF)				MichCon Gas Cost Recovery Plan
Michigan Consolidated Gas	TOTAL	Michigan				The coldest mean average temperature MichCon can expect at each location as of January, February and March.		MichCon Gas Cost Recovery Plan

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
Consumers Energy	TOTAL	Michigan	80.0	HDD (°F) (Adjusted upward by 4 HDD due to wind)			SENDOUT	Consumers Energy Gas Cost Recovery Plan
Cascade Natural Gas	Aberdeen	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Bellingham	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Bremerton	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Kennewick	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Longview	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Moses Lake	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Mount Vernon	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Sunnyside	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Walla Walla	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Wenatchee	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Yakima	Washington						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Baker	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Bend	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Ontario	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	Pendleton	Oregon						Cascade Natural Gas Corporation 2012 Integrated Resource Plan
Cascade Natural Gas	TOTAL	Total System	61.0	HDD (°F)		The greatest total natural gas demand forecasted in a 24-hour period used as a basis for planning peak capacity requirements.	SENDOUT	Cascade Natural Gas Corporation 2012 Integrated Resource Plan
NW Natural	Albany	Oregon	54.5	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Astoria	Oregon	50.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Dalles	Oregon	62.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Eugene & Coos Bay	Oregon	52.2	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Lincoln City & Newport	Oregon	48.5	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Portland	Oregon	53.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Salem	Oregon	54.0	HDD (°F)				2013 Integrated Resource Plan
NW Natural	Vancouver & Dalles	Washington	54.7	HDD (°F)				2013 Integrated Resource Plan

Company	Division	State / Province	Design Day	Design Day (HDD or EDD?)	Design Day Probability	Definition of Peak Day	Optimization Software Used	Source
NW Natural	TOTAL	Total System	53.0	HDD (^oF)			SENDOUT	2013 Integrated Resource Plan
Pacific Gas & Electric	TOTAL	California	33.0	HDD (^oF)	1:90	A design day standard used to ensure reliable gas service to core customers.		2012 California Gas Report, PG&E Gas Transmission and Distribution Systems Capacity Planning Requirements 6/5/2012

TAB 3

Union Gas Limited
Gas Supply Plan Review

April 2013

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I. Overview

Union Gas Limited ("Union" or the "Company") is a Canadian natural gas utility that provides natural gas distribution, transmission, storage and related services to approximately 1.4 million residential, commercial and industrial customers in over 400 communities in northern, south western and eastern Ontario. The Company also provides natural gas storage and transmission services for other utilities and customers located outside of the Company's distribution service area. Union is regulated by the Ontario Energy Board ("OEB"). From a rate setting perspective, Union divides its service territory into two operations areas: (1) a Northern and Eastern Operations Area ("Union North"); and (2) a Southern Operations Area ("Union South").

In developing its gas supply plan, Union models all contracted upstream transportation capacity and storage assets to provide an integrated service across all delivery areas for its bundled customers. Union uses software known as SENDOUT (by Ventyx) to complete the gas supply plan. The gas supply planning process is guided by a set of principles that are intended to ensure that customers receive secure, reliable and diverse gas supply at a prudently incurred cost.

In October 2012, Union received a decision from the OEB on its 2013 rates proceeding (docket number EB-2011-0210). As part of that decision, the Board ordered Union to undertake an expert, independent review of its gas supply plan, its gas supply planning process, and gas supply planning methodology. That independent review consists of three parts: (1) Gas Supply Planning Principles and Processes; (2) Peak (Design) Day Practice; and (3) Cost Allocation/Rate Design and Deferral accounting. Pursuant to a Request for Proposal ("RFP"), Union engaged Concentric Energy Advisors ("Concentric") to provide the third portion of the review (*i.e.*, Cost Allocation/Rate Design and Deferral accounting).

In addition to the overview section, this report contains six other sections. Section II contains a description of the scope undertaken by Concentric. Sections III through VI provide descriptions of Concentric's approach and findings in three areas: (1) cost allocation and rate design (Sections III and IV); (2) deferral and variance account structure (Section V); and (3) the consistency of Union's deferral and variance accounts with approving decisions and orders (Section VI). Finally, Section VII contains Concentric's conclusions.

II. Scope

Per the RFP and the October 2012 Decision in docket number EB-2011-0210, the scope of the Cost Allocation/Rate Design and Deferral accounting review includes the following elements:

- Examine the cost allocation and rate design used by Union to allocate the cost of gas supply to in-franchise customers in Union North and Union South to ensure that it is appropriate and reflects regulatory principles;
- Examine the structure of the current natural gas supply deferral and variance accounts, with a view to simplifying and standardizing these accounts in the Union North and Union South Delivery Areas; and
- Determine whether the structure and text of the various natural gas supply deferral and variance accounts is consistent with the principles of the Decisions and Orders that provided

the authorization for these accounts and consistent with the findings of the Board in this proceeding, and recommend remedial action, if required.

The following sections contain Concentric's approach and findings in each of those scope areas.

III. Cost Allocation

a. Approach

Through interviews with Union and an evaluation of Union's cost allocation and rate design model, Concentric gained an understanding of and evaluated the principles used by Union in assigning costs to its rate classes.

In order to establish the cost responsibility of each rate class, a three step analysis is undertaken. The three steps are: (i) functionalization; (ii) classification; and (iii) allocation. The first step, functionalization, separates the expenses based on the characteristics of utility operation. The second step, classification, further separates the functionalized expenses into one of three cost defining characteristics: (i) customer related; (ii) demand or capacity related; or (iii) commodity related. The final step, allocation, assigns the functionalized and classified cost elements to the various rate classes. Costs are allocated on factors reflective of the cost element, *e.g.*, usage volumes are typically used to allocate commodity-related costs.

Union functionalizes its gas supply costs as purchase production, transmission or storage and groups its gas supply costs in the following categories for cost allocation purposes:

- Firm Supply Commodity
- Sales Service Landed Supply Cost
- Firm Transportation Demand
- Firm Transportation Commodity
- Firm Transportation Fuel
- Diversions
- Other Transportation (Ojibway/St. Clair)
- Third Party Storage and Storage Transportation Service ("STS")
- Other Supplies - UFG

b. Cost Allocation Methodologies

<u>Firm Supply Commodity</u>

These costs represent the firm supply commodity costs for Union North. These costs are allocated to Union North rate classes on the basis of system supply volumes. Bundled direct purchase and transportation service volumes are not included in the allocation as these customers supply their own gas.

The firm supply commodity costs are incurred on a volume-delivered basis and vary with changes in volumes. Allocation to classes on the basis of supply volumes reflects the cost incurrence basis and is an appropriate method of allocation.

Union South Sales Service Landed Supply Costs

These are landed supply costs for Union South. These costs are allocated to Union South rate classes on the basis of sales volumes. Direct purchase volumes are excluded as these customers provide their own gas supply.

The firm supply commodity costs are incurred on a volume-delivered basis and vary with changes in volumes. Allocation to classes on the basis of supply volumes reflects the cost incurrence basis and is an appropriate method of allocation.

Firm Transportation Demand

These are the firm transportation demand costs, primarily from TransCanada Pipeline ("TCPL"), incurred for Union North sales service and bundled direct purchase customers. These costs are allocated to Union North rate classes using a blended factor consisting of three parts. The first part allocates costs to Rate 25, North Large Volume Interruptible Service (for reference, a description of Union's rate classes is provided in Attachment A). The second part allocates a portion of the costs on a base load basis, and the third part allocates the remaining costs on an excess demand basis.

The Rate 25 winter volumes are priced at the 100 percent load factor derivative of the TCPL demand toll and these costs are subtracted from the total transportation demand costs. The costs net of the Rate 25 costs are then divided between base load costs and excess costs. The base load costs are determined as the ratio of Union North sales service and bundled direct purchase service average daily volumes by rate class to the total daily TCPL contract volumes. Excess demand costs are the total transportation demand costs net of the Rate 25 costs and the base load costs. Excess demand costs are allocated to the rate classes based on the difference between the rate class design day demand and the average daily demand for the class.

The use of a base and excess methodology for the allocation of demand costs is a recognized industry method. This method assigns a portion of the costs to customers' base service needs, and assigns additional costs based on the demands above the base level. This method is appropriate for Union because the Company must contract for firm transportation service to meet the customers' peak season needs, which are in excess of their average, or base, levels.

Firm Transportation Commodity

These costs are the transportation commodity costs (primarily TCPL costs) incurred to serve Union North sales service and bundled direct purchase customers. The allocation for these costs is a blended factor consisting of two parts. The first part allocates costs to Rate 25 and the second part allocates the remaining costs on the basis of sales service and bundled direct purchase volumes. The Rate 25 costs are determined based on this class's winter sales volumes multiplied by the TCPL commodity rates. The costs so determined are subtracted from the total to determine the costs for the firm rate classes. These net costs are allocated to rate classes on the basis of sales service and bundled direct purchase volumes, excluding transportation service volumes.

The firm transportation commodity costs are incurred on a volume delivered basis and vary with changes in volumes. Allocation to rate classes on the basis of sales volumes reflects the cost incurrence basis and is an appropriate method of allocation.

Firm Transportation Fuel

These costs are the TCPL transportation fuel costs incurred to serve Union North sales service customers. The allocation of these costs is a blended factor consisting of two parts. The first part allocates costs to Rate 25, and the second part allocates the remaining costs on the basis of firm sales service volumes. The Rate 25 costs are determined based on this class's winter sales volumes multiplied by the TCPL fuel rates. The costs so determined are subtracted from the total to determine the costs for the firm rate classes. These net costs are allocated to rate classes on the basis of firm sales service volumes excluding bundled direct purchase and transportation service volumes. Bundled direct purchase customers provide their own fuel at Empress and transportation service customers provide their own fuel and transportation to the delivery area.

The firm transportation fuel costs are incurred on a volume delivered basis and vary with changes in volume. Allocation to rate classes on the basis of sales service volumes reflects the cost incurrence basis and is an appropriate method of allocation.

Diversions

Diversion costs are the costs related to out of path transportation service on TCPL and are assignable to Union North sales service and bundled direct purchase customers. These costs are allocated on the same basis as Firm Transportation Demand costs, discussed above.

Diversion costs are firm transportation demand costs and are allocated on the same basis.

Other Transportation Costs (Ojibway/St. Clair)

These costs relate to the St. Clair and Bluewater river crossing. Union contracts for this capacity for the security of Union South supply. These costs are allocated based on the Ojibway/St. Clair design day demands. The Ojibway/St. Clair design day demands include both in-franchise and ex-franchise customers.

Allocation of transmission system costs on a demand basis is an accepted industry method as is the use of design day as the measure of demand.

Third Party Storage and Storage Transportation Service ("STS")

This cost category includes the STS costs Union incurs to meet the seasonal needs of Union North sales service and bundled direct purchase customers and the Third Party Storage, *i.e.*, Black Creek Storage, costs that serve both Union North and Union South.

STS demand costs are allocated to Union North rate classes based on a factor consisting of each class's design day demand in excess of its average daily demand. The average daily demand is equal to the class annual consumption volumes, excluding transportation service, divided by 365. The design day volumes for classes Rate 20 and Rate 100 are the sum of customers' contract demands. The design day volumes for classes Rate 01 and Rate 10 are calculated using a base load and heating use per degree day methodology.

Union incurs these storage and transportation costs in order to serve customers' peak season demands, which occur during the winter season. The use of an excess over average allocator is appropriate because Union must contract for storage service to meet customers' peak season needs, which are in excess of their average, or base, levels.

STS commodity costs are allocated to Union North rate classes on the basis of normalized winter sales volumes, excluding Rate 25 and transportation service volumes for the months of December through February.

Black Creek Storage costs are allocated on the basis of storage space. Total Union North space is allocated to the rate classes using the excess demand over average day demand discussed above in the Storage Deliverability section. Union South space is allocated on a "Aggregate Excess" method where the excess of the November to March winter season volumes over the average daily volumes during this same period is calculated for each in-franchise sales and bundled transportation rate class (firm and interruptible). The volumes for Rates T1, T2, and T3 are the contracted storage space amounts and the excess utility storage space (short-term storage) is the difference between forecasted in-franchise space requirements and the storage space reserved for in-franchise customers.

Unaccounted for Gas ("UFG")

Total Company UFG costs are functionalized to purchase production and storage based on total volumes and are classified as commodity costs. The costs allocated to purchase production are first directly assigned to ex-franchise rate classes (*i.e.*, M12, M13, M16 and C1) and Union North rate classes on a volumetric basis. Union North UFG costs are allocated to rate classes on the basis of normalized winter sales, excluding interruptible service (Rate 25). Union South UFG costs are allocated to rate classes on delivery volume basis.

Storage related UFG costs are allocated in proportion to the amount of gas injected and withdrawn from storage for each rate class.

There is difference in the allocation of UFG to Union North and Union South rate classes. Union explains that the use of normalized winter sales for the Union North allocation is based on a historic methodology used by Centra Gas before the merger with Union Gas. This allocation methodology recognized that Centra utilized Union's storage and transmission assets largely to meet the peak day requirements in Union North. Union has considered changing this allocation methodology but has not as the impact was not significant. Given that the impact of the change is not significant Concentric is not recommending a change at this time.

c. Findings

As noted above, Concentric's review of the allocation methods finds that the methods used by Union are appropriate, and consistent with regulatory principles and industry standards.

IV. Rate Design

a. Approach

Through interviews with Union and an evaluation of Union's cost allocation and rate design model, Concentric gained an understanding of and evaluated the principles used by Union in designing rates for its rate classes.

Union North

Union North has four zones: Fort Frances; Western; Northern; and Eastern with separate gas supply rates for each. The gas supply rates for Union North customers consist of three parts: gas commodity, transportation and storage. The gas commodity component is applicable to sales service customers only, while the transportation and storage components are applicable to sales service and bundled direct purchase customers.

<u>Gas Commodity Rate</u>

The gas commodity rate for Union North is adjusted quarterly based on a calculated Alberta Border Reference Price. The starting point for the calculation of the Alberta Border Reference Price is the 21-day average of the NYMEX one-year strip. The 21-day average of the NYMEX one-year strip is calculated based on a simple average of 21 consecutive days of the closing NYMEX price for the 12 month strip, ending no earlier than 30 days prior to the quarterly implementation date. Union then adds the Empress – NYMEX basis[1] and the foreign exchange differential[2] to determine the Alberta Border price for each month. These prices are applied to forecasted purchase volumes for the applicable month and the weighted average for the forecast period is the Alberta Border Reference Price. This price is the reference price for the North Purchased Gas Variance Account and Spot Gas Variance Account for incremental purchases made at Empress. The gas commodity rate also includes TCPL firm transportation fuel costs.

<u>Transportation and Storage Rates</u>

To serve customers in its four Northern rate zones Union incurs firm transportation and storage[3] costs over six TCPL rate zones. The TCPL tolls increase on a west to east basis. Having allocated the overall gas supply and transportation costs to its rate classes, Union must then derive rates to recover these costs, reflecting the cost differential of the transportation and storage services across the TCPL zones. Union uses calculated zone transportation cost differentials to do this.

<u>Zonal Differentials</u>

Transportation demand tolls applicable to each Union zone are summed and converted to a 100 percent load factor rate. Commodity tolls are added to the unitized demand rate for each zone to produce a total zone commodity rate on a 100 percent load factor basis. Zone differentials are then calculated using Fort Frances, the western most zone, as the base.

<u>Rates 01 and 10</u>

The zonal differentials are allocated to transportation and storage using the ratio of the 2013 Board Approved (EB-2011-0210) Rate 01 transportation and storage revenue requirement. These zonal differentials for each zone are applied to the total volumes in that zone to determine the total transport and storage cost differential by zone. The total zone cost differential is subtracted from

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1 Basis is the differential that exists at any time between the future or forward price for a given commodity and the comparable cash or spot price for the commodity.

2 To account for the difference between Canadian prices and U.S. dollar denominated NYMEX prices.

3 The storage costs are the third party and STS costs included in the cost of gas that are discussed in the cost allocation section.

the total transport and storage costs allocated to each class. These net transport and storage costs are the base costs incurred to serve all customers in all zones. Dividing these net costs by the total Union North volumes produces the base unit rate which is also the Fort Frances zone rate. Adding the zone differentials to the Fort Frances base produces the transport and storage unit rates for each successive zone.

Rate 20

Gas supply costs allocated to Rate 20 are recovered through a combination of demand and commodity charges. Sixty percent of the demand related transportation and storage costs allocated to Rate 20 are recovered as demand and 40 percent commodity. All commodity related transportation and storage costs are classified to the commodity rate for recovery.

Rate 20 demand and commodity charges are derived for each Union North zone using a zone differential approach with Fort Frances as the base. Transportation demand rates applicable to each Union zone are summed and zone differentials are then calculated using Fort Frances as the base. The zone differential rate is multiplied by the zone demand billing determinants to determine incremental zone costs. These incremental costs are subtracted from the total allocated demand costs to determine the base demand costs. The base demand costs are divided by the total demand determinants to determine the base rate. The demand zone differentials are added to this base rate to determine the demand rate for each zone.

The transport commodity zone differentials are used as the Rate 20 commodity rate differentials. The Rate 20 Commodity Transportation 2 volumes are priced against the calculated zone differentials to determine the second block base costs by zone. The remaining commodity classified costs are recovered over the Commodity Transportation 1 volumes. The zone differential rate is multiplied by the Commodity Transportation 1 billing determinants in each zone to determine incremental zone costs. These incremental costs are subtracted from the total Commodity Transportation 1 costs to determine the base costs for Commodity Transportation 1. These base costs are divided by the total Commodity Transportation 1 determinants to determine the base rate. The first block commodity zone differentials are added to this base rate to determine the Commodity Transportation 1 rate for each zone.

Rate 100

While there are no sales or bundled direct purchase customers taking service under this rate schedule, Union derives a rate for tariff purposes and does not allocate any transportation costs to this rate class. Gas supply costs allocated to Rate 100 are recovered through a combination of demand and commodity charges. Seventy percent of the demand related transportation and storage costs allocated to Rate 100 are recovered as demand and 30 percent as commodity. All commodity related transportation and storage costs are classified to the commodity rate for recovery.

Rate 100 demand and commodity charges are derived for each Union North zone using a zone differential approach with Fort Frances as the base. Transportation demand rates applicable to each Union North zone are summed and zone differentials are then calculated using Fort Frances as the base. The zone differential rate is multiplied by the zone demand billing determinants to determine incremental zone costs. These incremental costs are subtracted from the total allocated demand costs to determine the base demand costs. The base demand costs are divided by the total demand determinants to determine the base rate. The demand zone differentials are added to this base rate to determine the demand rate for each zone.

The transport commodity zone differentials are used as the Rate 100 commodity rate differentials. The Rate 100 Commodity Transportation 2 volumes are priced against the calculated zone differentials to determine the Commodity Transportation 2 base costs by zone. The remaining commodity classified costs are recovered over the Commodity Transportation 1 volumes. The zone differential rate is multiplied by the Commodity Transportation 1 billing determinants for each zone to determine incremental zone costs. These incremental costs are subtracted from the total Commodity Transportation 1 costs to determine the base costs. The Commodity Transportation 1 base commodity costs are divided by the total Commodity Transportation 1 determinants to determine the base rate. The commodity zone differentials are added to this base rate to determine the Commodity Transportation 1 rate for each zone.

Union South

The gas supply rates for Union South are applicable to sales service customers only and consist of two parts, gas commodity and transportation.

<u>Gas Commodity Rate</u>

The gas commodity rate for Union South is the Alberta Border Reference Price plus TCPL's Eastern Delivery Area firm transportation fuel costs.

<u>Transportation Sales Rate</u>

The Union South Transportation Sales Rate is the difference between the Southern Portfolio Cost Differential ("SPCD") and the 100 percent load factor TCPL Eastern Delivery Area toll. Union adjusts the transportation component to account for the fact that Union South is largely served with non-TCPL supplies. The SPCD is determined by comparing the projected cost of serving Union South sales service customers, based on the Union South Portfolio, to the cost of serving Union South sales service customers based on the Ontario Landed Reference Price. The Ontario Landed Reference Price is the Alberta Border Reference Price plus the 100 percent load factor TCPL Eastern Delivery Area tolls and fuel. This cost difference is divided by forecasted Union South sales to determine the SPCD reference price. The Ontario Landed Reference Price is the reference price for the South Purchased Gas Variance Account and the Spot Gas Variance Account for incremental purchases made at Dawn.

b. Findings

<u>Union North</u>

Union North is primarily served by gas sourced from western Canada and transported by TCPL. Establishing the gas commodity rate based on an average NYMEX price, plus basis and foreign exchange differential, reflects current Union gas contracting practices and provides appropriate gas costs to customers. To the extent Union revises its gas purchasing practices and sources of gas used to serve Union North customers the calculation of the reference price should be revisited.

Union North has four zones and Union incurs increasing third party transportation and storage costs to serve customers from west to east on its system. Union designs rates for each rate class in each zone to recover the overall costs allocated to the rate class. The zone differential approach used by Union recognizes the increase in cost incurrence from west to east across its system. This method establishes a base level of costs for the classes and adds additional costs to each zone using the increased third party tolls and the level of service required in the zone.

The zone differential approach is appropriate under the current circumstances where gas supply is primarily sourced from Alberta and flows west to Union's markets. However, if Union revises it gas portfolio and begins to source gas at locations closer to its markets the cost allocation and rate designs methodologies will need to be revisited.

Union South

The gas supply rate design for Union South is appropriate, reflecting Union's purchasing practices for serving Union South customers. The Alberta Border Reference Price plus the TCPL Eastern Delivery Area fuel costs provides a gas commodity rate in that it is based on an average NYMEX plus basis and the foreign exchange differential. The SPCD accounts for the difference in transportation costs between that incurred to serve Union South and TCPL service. Together the gas supply charge components provide an accurate representation of the cost of gas for Union South.

V. Deferral and Variance Account Structure

a. Approach

Concentric performed the following steps to examine the structure of the current Union North and Union South natural gas supply deferral and variance accounts, with a view to simplifying and standardizing these accounts. First, Concentric obtained from Union a list of the deferral and variance accounts used by the Company for costs related to gas supply and optimization. Concentric reviewed the text of each deferral and variance account to gain an understanding of the purpose and structure of each account. Second, Concentric reviewed accounting guidance from the Ontario Energy Board ("OEB") regarding the accounts used by Union to defer supply and optimization costs. Third, Concentric examined the structure of each account in order to evaluate whether there were ways in which each account could be simplified or standardized. Concentric's examination focused on: (a) whether the accounts were straightforward in their design and structure; (b) whether the accounts are adjusted regularly and automatically; (c) whether the types of costs captured in each account were appropriate and grouped in a reasonable manner; and (d) whether there were any trends in the accumulation of costs in the deferral and variance accounts that would suggest the accounts are not working as designed.

b. Deferral and Variance Account Overview

Union uses a Quarterly Rate Adjustment Mechanism ("QRAM") to adjust rates on a quarterly basis to reflect changes in the cost of natural gas supply to Union's customers. In the QRAM process, reference prices are updated based on 12-month forecasts, and rates are adjusted to reflect those updated reference prices, changes in deferrals, and other underlying changes in transportation costs and delivered volumes. Through the quarterly QRAM process, Union accomplishes the following:

- Sets the Alberta Border Reference Price for Union North gas supply;
- Sets the Ontario Landed Reference Price for Union South sales service customers;

- Sets the SPCD;
- Makes adjustments when underlying TCPL toll adjustments are approved by the National Energy Board ("NEB"); and
- Determines variances between natural gas supply costs and reference prices in order to record deferral amounts for prospective recovery and set unit rates for recovery of variances.

The QRAM methodology is relatively straightforward, and involves the use of an automatic, formulaic process to adjust rates. Separate Union North and Union South Purchase Gas Variance Accounts ("PGVAs") are used to capture and defer differences between actual costs and those recovered in rates. For Union North, only natural gas commodity costs are captured in the PGVA because Union provides transportation service to both sales service and direct purchase customers, so transportation related deferrals must be captured and disposed of separately from commodity costs, which are only charged to sales service customers. For Union South, both natural gas commodity and transportation costs are deferred in the PGVA, because Union does not provide transportation service to direct purchase customers, so the PGVA is entirely related to sales service customers.

Union uses a number of deferral and variance accounts to record differences between actual costs and revenues and those recovered in rates. Related to its supply function, Union uses seven deferral and variance accounts. Two accounts are used exclusively for Union North (account nos. 179-100 and 179-105), one account is used exclusively for Union South (179-106), and four accounts are used for both operations (179-107,[4] 179-108, 179-109, and 179-131). Attachment B to this report contains a list of these deferral and variance accounts, along with a description of each account. In addition, as required by the Board in docket number EB-2011-0210, Union has established a Gas Supply Optimization Variance Account (Account No. 179-131), a symmetrical account that will "capture the variance in the actual net revenues related to gas supply optimization activities and the amount built into rates."[5]

Union uses separate Union North and Union South PGVAs to avoid the need to allocate purchased gas costs between Union North and Union South customers, and take into account operational, rate design, and direct purchase offerings differences between Union North and Union South.[6] Union uses one inventory revaluation deferral account (*i.e.*, Account No. 179-109, "Accounting Entries for Inventory Revaluation Account") for both Union North and Union South customers because Union does not have separate Union North and Union South inventory. Deferrals in this account are allocated to Union North and Union South sales service customers on a volumetric basis.

Deferrals in the PGVAs are determined by comparing the actual price of natural gas and transportation costs to the reference prices (*i.e.*, the Alberta Border Reference Price for Union North gas supply, and the Ontario Landed Reference Price for Union South sales service customers). Deferrals are disposed of in the QRAM process, with deferral balances being recovered or refunded (as appropriate) over a rolling 12-month period.

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[4] Note, while this account (*i.e.*, 179-107 – Spot Gas Variance Account) is available to capture cost variances for both North and South spot gas purchases, it is typically only used for Northern spot gas purchases.
[5] Ontario Energy Board, Decision and Order EB-2011-0210, October 24, 2012.
[6] Union Gas Prefiled Evidence, EB-2008-0106, November 14, 2008, at 28.

Deferral Account Structure

Deferral account data presented in each QRAM cover a 24-month period: the prior 12 months, including nine months of actual data and three months of forecasted data, and the "QRAM Period," or the following 12 months, which are all presented on a forecasted basis. The amounts for prospective recovery in each deferral accounts have three components: (1) the change in 12-month deferral account projections, which is calculated as the current 12-month projection of monthly deferrals for the QRAM Period less the 12-month projection of monthly deferrals for the QRAM Period from the prior QRAM filing; (2) a true-up of deferral balances that represents the variance between projected and actual deferral balances for the months with actual data since the previous QRAM filing (*i.e.*, the most recently ended calendar quarter); and (3) a true-up of prospective recovery amounts that represents the variance between projected and actual prospective recovery for months with actual data since the previous QRAM filing. The true-up of prospective recovery amounts (*i.e.*, the third component, described above) is essentially a true-up for differences between forecasted and actual usage by customers.

The following is a description of the structure of each deferral and variance account:

- **North Transportation Tolls and Fuel** (Account No. 179-100): The deferral amount for recovery is calculated as the difference between the transportation tolls and fuel costs that are recovered through rates and actual transportation tolls and fuel costs.
- **North PGVA** (Account No. 179-105): The deferral amount for recovery is calculated as: the difference between (a) the forecasted purchase costs divided by forecasted volumes to determine a weighted average price for the QRAM Period, and (b) the quarterly reference price (*i.e.*, the Alberta Border Reference Price).
- **South PGVA** (Account No. 179-106): The deferral amount for recovery is calculated as: (1) the difference between (a) the forecasted purchase costs divided by forecasted volumes to determine a weighted average price for the QRAM Period, and (b) the quarterly reference price (*i.e.*, the Ontario Landed Reference Price); plus (2) the SPCD adjustment. The SPCD adjustment is intended to capture the cost benefit, for customers, of the supply diversity used by Union to serve Union South customers.
- **Spot Gas Variance Account** (Account No. 179-107): The deferral amount for recovery is calculated as the difference between the unit cost of spot gas purchased each month and the unit cost of gas included in rates, multiplied by the spot volumes purchased in excess of planned purchases.
- **Unabsorbed Demand Cost (UDC) Variance Account** (Account No. 179-108): The deferral amount for recovery is calculated as the difference between actual UDC and UDC actually recovered in rates.[7] The disposal of this account is done on an annual basis.
- **Inventory Revaluation** (Account No. 179-109): The deferral amount for recovery is calculated as: (a) the difference between the current Ontario Landed Reference Price and the previous approved Ontario Landed Reference Price, multiplied by (b) inventory levels.

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[7] Union does not forecast UDC costs in the South Gas Supply Plan, and thus there are no UDC costs in South rates. Any actual UDC incurred for South customers is incremental to costs recovered in rates.

- **Upstream Transportation Optimization** (Account No. 179-131): The deferral amount is equal to 90% of actual net revenue from gas supply optimization activities, and upstream transportation optimization revenues actually recovered in rates per the Decision and Order in docket number EB-2011-0210. The disposal of this account is done on an annual basis.

c. Findings

Concentric found the structure of the current natural gas supply deferral and variance accounts used by Union to be straightforward and applied with a high degree of automation. The accounts are structured at an appropriate level of detail to allow for transparency in the recording and disposal of deferrals, and the types of costs accumulated in each account are reasonable. For example, while Union could record commodity, transportation, inventory revaluation, and spot gas purchases variances in one account and then perform allocations across its operations areas and rate classes, the Company uses separate Union North and Union South PGVA accounts, and also separately records inventory revaluation and spot gas purchase variances, avoiding the need for additional allocation calculations.

In addition, Concentric found that there were no trends in the accumulation of costs in the deferral accounts that would indicate the accounts were not working as designed. Specifically, Concentric reviewed deferral account balances as of January 1, 2012, December 31, 2012, and February 28, 2013 (*i.e.*, the most recent month available as of Concentric's review), and noted that the deferral account balances did not appear to be significantly large or increasing significantly from period to period.

VI. Consistency of Deferral and Variance Accounts with Approving Decisions and Orders

a. Approach

To perform this element of the scope, Concentric first identified the relevant deferral and variance accounts and reviewed the text of each account. Second, Concentric compared the text of each account to the Decisions and Orders that provided the authorization for these accounts. Third, Concentric reviewed the findings of the Board in EB-2011-0210 to determine if any changes were made to the relevant deferral and variance accounts, and, if so, whether the accounts were consistent with the findings of the Board. Finally, Concentric evaluated the consistency of the deferral and variance accounts with regulatory principles and industry standards.

Concentric's examination focused on: (a) whether the text of the accounts are consistent with the approving Decisions and Orders; and (b) whether the accounts are consistent with regulatory principles and industry standards. As to regulatory principles, Concentric specifically assessed Union's deferral and variance accounts in terms of the timeliness with which costs are recovered, the frequency with which rates are adjusted for changes in variances, and whether any intergenerational issues might arise by virtue of the deferral of costs.

b. Findings

Attachment B to this report contains: (1) a table that lists the supply-related deferral accounts used by Union; (2) the text of each account that describes the charges to be recorded; (3) language from the Decisions and Orders that provided the authorization for each account; and (4) if applicable, the findings of the Board in EB-2011-0210 related to the supply-related accounts. As shown in

Attachment B, the text of each account is consistent with the authorizing language from the Board, and, where applicable, the findings of the Board in EB-2011-0210.

In addition, Concentric finds that the structure of Union's deferral and variance accounts is consistent with regulatory principles and industry standards as they relate to deferral and variance accounts. Specifically, the quarterly adjustment of deferrals under the QRAM process reasonably captures recent changes in market conditions while avoiding the additional costs that might be incurred from more frequent adjustment filings. In addition, the recovery of deferrals over the coming 12-month period ensures the timely recovery of Union's costs and/or refund of negative variances to customers while minimizing any intergenerational issues that could arise from longer deferrals.

VII. Conclusions

Concentric performed the following areas of review as part of our independent evaluation of Union's cost allocation and rate design and deferral accounting: (1) examined the cost allocation and rate design used by Union to allocate the cost of gas supply to Union North and Union South in-franchise customers to ensure that it is appropriate and reflects regulatory principles; (2) examined the structure of the current Union North and Union South natural gas supply deferral and variance accounts, with a view to simplifying and standardizing these accounts; and (3) determined whether the structure and text of the various natural gas supply deferral and variance accounts is consistent with the principles of the Decisions and Orders that provided the authorization for these accounts and consistent with the findings of the Board EB-2011-0210.

As documented throughout this report, Concentric determined that cost allocation and rate design used by Union is reasonable, the structure and the natural gas supply deferral and variance accounts is appropriate and straightforward, and the structure and text of the natural gas supply deferral and variance accounts is consistent with regulatory principles and industry standards in general, and the Board's Decisions and Orders specifically.

Union North In-Franchise

Rate 01A – North Small Volume General Firm Service (firm gas requirements less than 50,000 m^3/year) – sales, transportation, and bundled transportation services

Rate 10 – North Large Volume General Firm Service (firm gas requirements greater than 50,000 m^3/year) – sales, transportation, and bundled transportation services

Rate 20 – North Medium Volume Firm Service (total maximum daily requirements for firm or combined firm and interruptible service greater than 14,000 m^3/year) – sales, transportation, bundled transportation, and storage services

Rate 25 – North Large Volume Interruptible Service (total maximum daily interruptible requirement is 3,000 m^3 or greater or the interruptible portion of a maximum daily requirement for combined firm and interruptible service is 14,000 m^3 or greater) – sales and transportation services

Rate 30 – North Intermittent Gas Supply Service and Short Term Storage/Balancing Service

Rate 100 – North Large Volume High Load Factor Firm Service (total maximum daily requirement for firm service is 100,000 m3 or greater, and whose annual requirement for firm service is equal to or greater than its maximum daily requirement multiplied by 256) – sales, transportation, bundled transportation, and storage services

Rate S1 – North General Firm Service Storage Rates – transportation and storage services

Union South In-Franchise

Rate M1 – South Small Volume General Service Rate (total consumption less than 50,000 m^3/year)

Rate M2 – South Large Volume Service Rate (total consumption greater than 50,000 m^3/year)

Rate M4 – South Firm Commercial/Industrial Contract Rate (minimum term of one year that specifies a daily contracted demand between 4,800 m^3 and 140,870 m^3)

Rate M5A – South Interruptible Commercial/Industrial Contract (minimum term of one year that specifies a daily contracted demand between 4,800 m^3 and 140,870 m^3)

Rate M7 – South Special Large Volume Contract (minimum term of one year that specifies a combined maximum daily requirement for firm, interruptible and seasonal service of at least 140,870 m^3, and a qualifying annual volume of at least 28,327,840 m^3)

Rate M9 – South Large Wholesale Service (take or pay for a minimum of 2,000,000 m^3)

Rate M10 – South Small Wholesale Service (non-contract distributors)

Rate R1 – South Bundled Direct Purchase Contract Rate (for customers who enter into a Receipt Contract or Gas Purchase Contract for delivery and/or sale of gas to Union)

Rate T1 – South Storage and Transportation (annual transportation volume for combined firm and interruptible service is at least 2,500,000 m^3 or greater and has a daily firm contracted demand up to 140,870 m^3

Rate T2 – South Storage and Transportation (daily firm contracted demand of at least 140,870 m^3, and who enters into a Carriage Service Contract)

Rate T3 – South Storage and Transportation (minimum annual transportation of 700,000 m^3 or greater, and who enters into a Carriage Service Contract)

Rate U2 – South Unbundled Service (customers who enter into an Unbundled Service Contract for storage, and who contracts for Standard Peaking Service)

Ex-Franchise

Rate M12 – Transportation Service

Rate M13 – Transportation of Locally Produced Gas

Rate M16 – Storage Transportation Service

Rate C1 –Cross Franchise Transportation Service

Account	Account Name	Union Gas Text	Summary of Approving Decision Text
179-100	Transportation Tolls and Fuel – Northern and Eastern Operations Area	This account is applicable to the Northern and Eastern Operations of Union Gas Limited… [This account is used] [t]o record…the difference in costs between the actual per unit transportation and associated fuel costs and the forecast per unit transportation and associated fuel costs included in the rates as approved by the Board. [This account is also used] [t]o record…the charges that result from the Limited Balancing Agreement[, as well as] revenue from T-Service customers for load balancing service from the Limited Balancing Agreement.	Originally approved as the "TCPL Tolls and Fuel," this account records the difference in costs for Union North customers between the actual per unit tolls and associated fuel costs and the forecast per unit tolls and associated fuel costs included in rates as approved by the Board. This account originally was underpinned with 100% TCPL transportation. In docket number EB-2012-0087, the reference to "TCPL" was removed from the account in recognition that Union's northern supply portfolio now includes transportation on Michcon and GLGT. (EB-2003-0087)
179-105	North Purchase Gas Variance Account	This account is applicable to the Northern and Eastern Operations area of Union Gas Limited… [This account is used] [t]o record…the difference between the unit cost of gas purchased each month for the Northern and Eastern Operations area and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in the gas sales rates.	This account tracks the difference between the unit cost of the commodity used to serve Union North customers that is purchased each month and the unit cost of gas included in the gas sales rate as approved by the Board. Union North supply is underpinned with 100% TCPL transportation and deferred against the Alberta Border Reference Price. (EB-2003-0087)
179-106	South Purchase Gas Variance Account (South PGVA)	This account is applicable to the Southern Operations area of Union Gas Limited... [This account is used] [t]o record…the difference between the unit cost of gas purchased each month for Southern Operations and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.	This account tracks the difference between the delivered unit cost of gas purchased each month to serve Union South customers and the Ontario Landed Reference Price as approved by the Board. The Union South Portfolio is underpinned by gas delivered to Ontario using Alliance/Vector, Trunkline, and Northern TCPL supplies diverted to Southern customers, Ontario Production and planned spot purchases. Because the Union South Portfolio Cost will be different than the Ontario Landed Reference Price, credits/debits will accumulate in this account and be offset by the forecast SPCD. Supply costs are deferred against the Ontario Landed Reference Price. (EB-2003-0087)

Account	Account Name	Union Gas Text	Summary of Approving Decision Text
179-107	Spot Gas Variance Account	[This account is used] [t]o 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. [This account is also used] [t]o record…the approved gas supply charges recovered through the delivery component of rates.	This account tracks the cost consequence of any spot purchases in excess of planned spot volumes, using the Ontario Landed Reference Price. There is no spot gas for Union North customers in the Gas Supply Plan. For Union South customers, any price variance for planned spot purchases will be captured in the Union South PGVA.
179-108	Unabsorbed Demand Cost (UDC) Variance Account	[This account is used] [t]o record…the difference between the actual unabsorbed demand costs incurred by Union and the amount of unabsorbed demand charges included in rates as approved by the Board… [This account is also used] [t]o record… the benefit from the temporary assignment of unutilized capacity under Union's transportation contracts to the Northern and Eastern Operations Area. The benefit will be equal to the recovery of pipeline demand charges and other charges resulting from the temporary assignment of unutilized capacity that have been included in gas sale rates.	This account tracks any UDC incurred on behalf of Union North customers and Union South customers, where UDC is a flow through cost to customers. For Union North, Union forecasts UDC in the Gas Supply Plan and recovers UDC in Gas Supply Transportation Rates. Any UDC recovered from these customers as part of the transportation tolls will be credited to this account. If the UDC for Union North differs from the costs recovered in rates, then this cost will be recovered from/refunded to Union North bundled customers, subject to Board approval. For Union South, there are no UDC costs forecasted in the Gas Supply Plan, and thus no UDC costs in Union South rates. Any UDC incurred in Union South is incremental and recovered from Union South sales service customers. (EB-2003-0087)
179-109	Inventory Revaluation Account	[This account is used] [t]o record the decrease (increase) in the value of gas inventory available for sale to sales service customers due to changes in Union's weighted average cost of gas approved by the Board for rate making purposes.	This joint account tracks the change in value of gas inventory for both Union North and Union South sales service customers due to changes in Union's Ontario Landed Reference Price of gas as approved by the Board. Inventory revaluation amounts are calculated by applying the change in the Ontario Landed Reference Point to the sales service inventory volume at point in time of measurement. (EB-2003-0087)

Account	Account Name	Union Gas Text	Summary of Approving Decision Text
179-131	Upstream Transportation Optimization	Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act. This account records a debit as a receivable from customers and a reduction in cost of gas for the unit rate of optimization revenues refunded to in-franchise customers multiplied by the actual distribution transportation volumes. It records a credit as a payable to customers and a reduction in transportation revenue equal to the ratepayer portion (90%) of the actual net revenue from gas supply optimization activities.	The Board directs Union to establish a symmetrical variance account to capture the variance in actual net revenues related to gas supply optimization activities and the amount built into rates. This amount built into rates related to gas supply optimization is 90% of Union's 2013 forecast of base exchanges and 90% of half of Union's FT-RAM 2013 forecast. The balance in the account will be shared 90% to ratepayers and 10% to the shareholder on an annual basis. The Board also found that the disposition amounts will be allocated in the same manner as the gas supply optimization related margin amounts. (EB-2011-0210)