July 31, 2013

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

RE: EB-2013- 0202 – Union Gas Limited
2014-2018 Incentive Regulation Application, Evidence and Settlement Agreement

Dear Ms. Walli,

Union Gas Limited ("Union") is requesting the approval of the Ontario Energy Board (the "Board") for a multi-year Incentive Regulation Mechanism ("IRM") that will be used to set Union's regulated distribution, transportation and storage rates over the 2014 to 2018 period.

The proposed IRM parameters are the product of a comprehensive Settlement Agreement (the "Agreement") between Union and stakeholders which is attached at Exhibit A, Tab 2. The stakeholders who are party to the Agreement ("Stakeholders") have reviewed and support the evidence which is attached at Exhibit A, Tab 1. The Stakeholders are parties who participated in Union's 2008-2012 IRM proceeding and in the annual rate proceedings throughout the last IRM term.

Although Union and Stakeholders reached a comprehensive Agreement, it is acknowledged that Notice will be required and that other parties may be interested in participating in the regulatory approval process associated with Union's 2014-2018 IRM. A panel of Union witnesses will be available to address any questions or concerns from the Board or such other interested parties when the Agreement is presented to the Board.

Union respectfully requests that the Board expedite both the Notice and the presentation of the Agreement. This would allow Union, assuming the Board accepts the Agreement, to file for approval of 2014 rates in time to implement them for January 1, 2014.

P. O. Box 2001, 50 Keil Drive North, Chatham, ON, N7M 5M1 www.uniongas.com
Union Gas Limited

If you have any questions, please contact me at 519-436-5476.

Yours truly,

Chris Ripley
Manager, Regulatory Applications

cc: George Vegh, McCarthy Tetrault
EB-2011-0210 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 approving an incentive rate mechanism to determine rates for the distribution and transmission and storage of gas effective January 1, 2014;

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. Union hereby applies to the Ontario Energy Board ("OEB"), pursuant to section 36 of the Ontario Energy Board Act, 1998 (the "Act") for an order approving a multi-year incentive rate mechanism ("IRM") to determine rates for the regulated distribution, transmission and storage of gas effective January 1, 2014. Union seeks an IRM pursuant to a comprehensive Settlement Agreement between stakeholders and Union:

   (a) which applies to the base rates approved by the OEB commencing January 1, 2013 in EB-2011-0210, as adjusted to reflect the upfront productivity commitment of $4.5 million and the annual $3.152 million increase related to deferred taxes over the IRM term;

(b) in which the annual rate escalation is limited by a price cap index ("PCI"), where PCI growth is driven by an inflation factor ("GDP IPI FDD"), less a productivity factor of 60% of GDP IPI FDD;

(c) which exists for a 5 year term ending December 31, 2018;

(d) which has a provision for earnings sharing;

(e) which continues to pass-through routine gas commodity and other costs;

(f) which allows for non-routine cost adjustments for matters outside of the utility's control, including criteria for non-discretionary capital projects; and

(g) which maintains the existing level of service to customers.

4. Union also applies for an order to establish the following deferral accounts effective January 1, 2014:

- Normalized Average Consumption Deferral Account (179-XXX)
- Tax Variance Deferral Account (179-XXX)
- Unaccounted for Gas ("UFG") Volume Variance Deferral Account (179-XXX)

5. Union also applies to the OEB for such interim orders approving interim rates and accounting orders as may from time to time appear appropriate or necessary.

6. Union further applies to the OEB for all necessary orders and directions to provide for pre-hearing and hearing procedures for the determination of this application.

7. This application is supported by a comprehensive settlement agreement and supporting reports.

8. 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.

9. The address of service for Union is:

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

Telephone: (519) 436-5476

Fax: (519) 436-4641

- and -

McCarthy Tetrault LLP
Suite 5300, TD Bank Tower
P.O. Box 48
66 Wellington Street West
Toronto, Ontario
M5K 1E6
Attention: George Vegh

Telephone: (416) 601-7709

Fax: (416) 868-0673

DATED: July 31, 2013

UNION GAS LIMITED

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TAB 1

1.0 INTRODUCTION

Union Gas Limited ("Union") is requesting the approval of the Ontario Energy Board ("Board") for a multi-year Incentive Regulation Mechanism ("IRM") that will be used to set Union's regulated distribution, transportation and storage rates over the 2014 to 2018 period. The purpose of this evidence is to support that request. With the exception of the changes outlined in this evidence, Union's 2014-2018 IRM is consistent with the IRM approved by the Board and in place over the 2008-2012 period.

A summary of the proposed 2014-2018 IRM parameters is found at Table 1 below:

Table 1
Union Price Cap Plan Proposal Summary

Parameter	2008-2012 Approved IRM	2014- 2018 Proposed IRM
Base Rate Adjustments	2007 Board-approved revenues adjustments: 1. Decrease base revenues by $1.9 million to levelize deferred taxes over the 2008-2012 period; 2. Decrease base revenues by $1.0 million for reduction in regulatory budget; 3. Increase S&T margins by $4.3 million; and, 4. Reduce base revenues by $1.6 million related to GDAR.	2013 Board-approved revenues adjustments: 1. Increase base revenues by $3.152 million to levelize deferred taxes over the 2014-2018 period; 2. Decrease base revenues by $4.5 million as a further upfront productivity commitment by Union; and, 3. No adjustments related to Winter Warmth/LEAP during the IRM term.
Rate Mechanism	Price Cap Index	Price Cap Index
Inflation Factor (I)	GDP IPI FDD Canada index (average of annualized quarterly changes of the last four quarters – Q2 to Q2)	GDP IPI FDD Canada index (average of annualized quarterly changes of the last four quarters – Q2 to Q2)

Productivity Factor (X)	Fixed at 1.82% for each year of the IRM term	60% of GDP IPI FDD for each year of the IRM term
Weather Methodology	2007 Board-approved 55:45 blend of 30-year average and 20-year declining trend weather methodology	2013 Board-approved 50:50 blend of 30-year average and 20-year declining trend weather methodology
Normalized Average Use Factor (NAC)	Rates adjusted annually to reflect changes in General Service normalized average use (AU)	Rates adjusted annually to reflect changes in General Service normalized average consumption (NAC) (including LRAM for General Service rate classes)
Y Factors	Pass through treatment for: • Upstream gas costs • Upstream transportation costs • Incremental DSM costs • LRAM volume reductions (for all rate classes) • Elimination of the Long-term Storage Premium per the NGEIR Decision	Pass through treatment for: • Upstream gas costs • Upstream transportation costs • Incremental DSM costs • LRAM volume reductions for contract rate classes
Y Factor: Major Capital Projects	No Y factor treatment	Y factor for Major Capital Projects that meet certain criteria set out in Exhibit A, Tab 2, Section 6.6 and described in more detail below. The Brantford-Kirkwall and Parkway D Compressor and the Parkway West projects (EB-2013-0074 and EB-2012-0433) as filed meet the criteria
Y Factor: Unaccounted For Gas (UFG) Volume Variances	No Y factor treatment	Y factor treatment for UFG volume variances with a symmetrical dead-band of +/- $5.0 million around amounts built into rates
Z Factors	Z factor treatment for certain non-routine adjustments subject to criteria including a materiality threshold of $1.5 million	Z factor treatment for certain non-routine adjustments subject to criteria including a materiality threshold of $4.0 million. Z factor criteria amended to reflect EB-2011-0277 Decision

Tax Changes	50/50 sharing of tax changes	50/50 sharing of tax changes and establish a deferral account to capture amounts for disposition
Term of Plan	5 years starting in 2008	5 years starting in 2014
Earnings Sharing Mechanism	Earnings Sharing Mechanism above benchmark ROE adjusted annually using the Board's formula. Earnings Sharing Mechanism: 0-200 bps – No sharing 201-300 bps – 50:50 sharing Over 300 bps – 90:10 in favour of ratepayers	Earnings Sharing Mechanism above the 2013 Board-approved ROE of 8.93% for each year of the IRM. Earnings Sharing Mechanism: 0-100 bps – No sharing 101-200 bps – 50:50 sharing Over 200 bps – 90:10 in favour of ratepayers
Off-Ramps	Initial off-ramp if normalized utility earnings exceed 300 bps in any year of the IRM. The initial off-ramp was replaced with 90:10 sharing of utility earnings in excess of 300 bps in favour of ratepayers	No off-ramp
Marketing Flexibility	Flexibility to develop new services subject to Board approval	Flexibility to develop new services subject to Board approval
Reporting	• RRR filings made available • 18 financial schedules for prior actual year	• RRR filings made available • 18 financial schedules for prior actual year • Unregulated Plant Continuity • Service Quality Indicator Results • Audited financial statements for utility operations

Annual Stakeholder Meeting	None	Annual funded stakeholder meeting that will: • Review prior year's financial statements • Explain market conditions and trends • Present the gas supply plan • Present new major capital projects • Present results of customer surveys
Rate Setting Processes	• File annual rate setting application by September 30 using IR mechanism including PCI, Y factors, approved Z factors and AU • File annual application for disposition of non-commodity deferral account and earnings sharing balances • File Quarterly Rate Adjustment Mechanism per EB-2008-0106	• File annual rate setting application by September 30 using IR mechanism including PCI, Y factors, approved Z factors and NAC • File annual application for disposition of non-commodity deferral account and earnings sharing balances • File Quarterly Rate Adjustment Mechanism per EB-2008-0106
Rebasing	Full cost of service filing for 2013 regardless of whether or not to be used for rate setting	Full cost of service filing for 2019 regardless of whether or not to be used for rate setting. Subject to agreement to extend the IRM term

As demonstrated by Table 1 above, Union's proposed 2014-2018 IRM is consistent with its prior IRM. The main differences are:

- An X factor that is a percentage of GDP IPPI FDD rather than a fixed inflationary adjustment;
- Y factor treatment for major capital projects and certain UFG volume variances;
- Smaller dead-band for earnings sharing; and,

- Annual funded stakeholder information sessions.

Although there are other minor differences between the prior IRM and the proposed IRM, the differences summarized above are the most significant. Each component of Union's proposed IRM is discussed in more detail below.

The proposed IRM parameters are the product of a comprehensive Settlement Agreement (the "Agreement") between Union and stakeholders. The stakeholders who are party to the Agreement ("Stakeholders") have reviewed Union's evidence. While the historical narrative and third party studies included in the evidence were not the subject of detailed consideration and discussion amongst the parties, the Stakeholders support Union's view that, taken as a whole, the evidence is supportive of the Agreement.

Specifically, this evidence provides:

1. A description of the Stakeholder consultation process that, ultimately, resulted in the Agreement provided at Exhibit A, Tab 2;
2. A description of the principles underpinning IRM as set out in the Natural Gas Forum Report and the conclusions found in Pacific Economics Group's ("PEG) *Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans (EB-2011-0052);*

3. A description of the 2014-2018 IRM parameters, including the resulting estimated rate impacts;
4. The results of a review of IRMs in other jurisdictions and how Union's proposed IRM compares. The review was prepared by London Economics International ("LEI") and is found at Exhibit A, Tab 1, Appendix A; and,
5. The results of a survey of Union's residential customers about the acceptability of inflationary rate increases. The survey was conducted by NRG Research Group and is found at Exhibit A, Tab 1, Appendix B.

2.0 STAKEHOLDER CONSULTATION PROCESS

As indicated above, Union's proposed 2014-2018 IRM is a product of comprehensive settlement discussions between Union and Stakeholders. On April 29, 2013, Union convened a meeting with Stakeholders to present its 2014-2018 IRM proposals. Those invited were intervenors that participated in Union's 2013 Rebasing Proceeding (EB-2011-0210) and representatives of Board Staff. This initial stakeholder meeting was facilitated by Mr. Ken Rosenberg, who was retained by Union to perform this function. The purpose of the meeting was to inform Stakeholders of Union's proposals and provide an opportunity for Stakeholders to ask questions to better understand those proposals. A copy of the slides used at that meeting are included at Exhibit A, Tab 2, Appendix A. The slides describe the original Union proposals for 2014-2018 rates.

At the end of the April 29, 2013 meeting, it was determined that further meetings would be held, which occurred on May 23, June 10, June 11, June 17 and July 15, 2013. Union also agreed that if Stakeholders had further questions related to Union's proposals, they could submit those questions and Union would respond in writing. Union received further information requests from the Building Owners and Managers Association of the Greater Toronto Area, the London Property Management Association, Canadian Manufacturers and Exporters, the Federation of Rental-housing Property of Ontario and Energy Probe. The responses to these information requests are found in Exhibit A, Tab 2, Appendix B. In addition, during the course of the 5 full days of settlement meetings, Union representatives provided oral responses to the many follow-up questions which Settlement Conference participants posed to obtain a clear understanding of Union's written responses to information requests. With the exception of the July 15, 2013 meeting, Mr. Ken Rosenberg also facilitated all further discussions.

At the May 23, 2013 meeting, Union responded to further information requests from Stakeholders. It was also determined in the May 23 meeting that the further discussions in June and July would take the form of a Settlement Conference with a view to agreeing on some or all of Union's IRM proposals. Parties agreed that all discussions would be subject to the Board's Settlement Conference Guidelines.

Settlement negotiations between Union and Stakeholders took place on June 10, June 11, June 17 and July 15, 2013. The product of those negotiations is the comprehensive settlement of the IRM parameters by which Union would set rates over the 2014-2018 period, subject to the determination of certain issues as set forth in Exhibit A, Tab 2, Section 13.3.

As indicated above, the Stakeholders invited to the initial meeting on April 29, 2013, were those that intervened in Union 2013 Rebasing Proceeding (EB-2011-0210). Specifically, the intervenors that participated in the IRM discussions were:

1. Association of Power Producers of Ontario (“APPrO”);
2. Building Owners and Managers Association of the Greater Toronto Area (“BOMA”);
3. Canadian Manufacturers and Exporters (“CME”);
4. Consumers Council of Canada (“CCC”);
5. Energy Probe Research Foundation (“Energy Probe”);
6. Federation of Rental-housing Providers of Ontario (“FRPO”);
7. Industrial Gas Users Association (“IGUA”);
8. City of Kitchener (“Kitchener”);
9. London Property Management Association (“LPMA”);
10. Ontario Association of Physical Plant Administrators (“OAPPA”);
11. School Energy Coalition (“SEC”);
12. Six Nations Natural Gas (“Six Nations”);
13. TransCanada PipeLines Limited (“TCPL”); and,
14. Vulnerable Energy Consumers Coalition (“VECC”)

Representing a broad range of interests, these same stakeholders were also a party to Union’s EB-2011-0210 Settlement Agreement. Further, these parties, with the exception of FRPO, also participated fully in the negotiation of Union’s last IRM (EB-2007-0606) and in the proceeding that amended the 2008-2012 earnings sharing mechanism (EB-2009-0101). Many of these stakeholders also actively participate in electricity policy and rate proceedings. Accordingly, both individually and collectively, these stakeholders are well-experienced regulatory participants who represent the legitimate interests of Union's ratepayers.

3.0 UNION'S 2008-2012 IRM MET THE BOARD'S OBJECTIVES

In the Natural Gas Forum ("NGF"), the Board's focus on rate regulation was in response to stakeholder concerns about perceived inefficiencies in the cost-of-service ratemaking framework. The primary concerns centred on a resource-intensive hearing process and weak incentives for utilities to perform efficiently.

In its March 30, 2005 report entitled "Natural Gas Regulation in Ontario: A Renewed Policy Framework, Report on the Ontario Energy Board Natural Gas Forum" (the "NGF Report"), on p. 18 the Board stated that an acceptable ratemaking framework must:

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.

After reviewing broad questions related to the appropriate ratemaking framework, the Board concluded that incentive regulation ("IR") would be an effective ratemaking framework for natural gas utilities in Ontario. The Board said a comprehensive IR model would reduce the regulatory burden while establishing an appropriate balance of risks and rewards for the utilities.

The primary key to the success of IR was that customers share in the benefits of the efficiencies generated by the utilities:

> ***"****The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet its criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities – to the benefit of customers and shareholders. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario. The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan." (p. 22 of the NGF Report)*

The NGF Report also noted that an IR framework would provide utilities the opportunity to generate efficiencies during the term of the plan, with an up-front sharing of these efficiencies through a productivity factor. Rebasing at the end of the IR term would ensure sustainable efficiencies were built into the new base rates on which another IR framework would be built. In order to benefit from incentive regulation during the term, utilities would have to achieve greater efficiencies than that which had already been shared with customers in each year of the plan.

It was within this context that Union, through the EB-2007-0606 Settlement Agreement, implemented its 2008-2012 IRM.

3.1 ASSESSMENT OF UNION GAS LIMITED AND ENBRIDGE GAS DISTRIBUTION INC. INCENTIVE REGULATION PLANS

In February 2011, the Board initiated a "preliminary assessment" of the IR plans of Enbridge Gas Distribution Inc. ("Enbridge") and Union that were approved for the period 2008-2012 (EB-2011-0052). The Board retained PEG to complete the assessment. To develop a complete and thorough assessment, PEG was required to evaluate the impact of each company's IR plan on its gas delivery rates, cost and productivity trends, financial indicators, and service quality performance. In addition, PEG was asked to identify specific challenges, opportunities and information gaps relevant to the IR plans.

PEG's analysis focused on the Board's key criteria identified for an effective ratemaking framework. They included:

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

In its report dated September 2011, PEG concluded that Union's IRM approved for the 2008-2012 period successfully met each of these criteria. Although minor improvements/enhancements were identified (e.g. what/how data is collected during the IR term and how it's organized at the Board), overall, PEG was supportive of Union's IRM. As stated in the executive summary, an IR plan designed like Union's could better strengthen performance incentives, to the ultimate benefit of both customers and shareholders.

The analysis indicated that the IR plan encouraged Union to control costs more effectively and generate productivity and efficiency improvements while sharing those benefits with ratepayers. As stated at p. 7 of the PEG report,

> *"The overall thrust of our analysis of prices, earnings and TFP is that IR has generated win-win outcomes for customers and shareholders."*

<u>4.0 UNION'S 2014-2018 IRM PROPOSAL</u>

Union's 2014-2018 IRM proposal continues to support the objectives set out in the NGF Report. Those objectives are:

1. To establish incentives for sustainable efficiency improvements that benefit customers and shareholders;
2. To ensure appropriate quality of service for customers; and,
3. To create an environment that is conducive to investment, to the benefit of customers and shareholders.

In addition, when developing the 2014-2018 IRM, Union was also guided by the following:

1. To provide an incentive to continue to be more productive, including both cost efficiency and revenue enhancement opportunities;
2. To construct a framework that is similar to the past price cap mechanism, as familiarity by all parties would facilitate the discovery/settlement/regulatory approval processes;
3. To provide for modest, predictable rate increases;
4. To better address the alignment of, and stakeholder expectations for, the appropriate level of productivity incentive and reward;
5. To address certain items that cannot be managed within a price cap framework going forward;
6. To meet or exceed all customer service measures; and,
7. To meet investor expectations.

4.1 2014-2018 PROPOSED PARAMETERS

The purpose of this section is to provide more detail on the proposed parameters for Union's 2014-2018 IRM. This section is organized in the same manner as the Agreement provided at Exhibit A, Tab 2.

4.1.2 IRM PRICING FRAMEWORK

Consistent with Union's 2008-2012 IRM, Union would determine regulated distribution, transmission and storage rates over the IRM term using a multi-year PCI where rates are a function of:

- An inflation factor (I);
- A productivity factor (X);
- Certain non-routine adjustments (Z factors);
- Certain predetermined pass-throughs (Y factors); and,
- An adjustment for normalized average consumption (NAC).

The method by which rates would be determined using the factors and adjustments above is detailed at Exhibit A, Tab 2, Section 1.1.

In Union's view, a price cap framework best addresses one of the two items that matter most to customers: the price they pay for distribution, transmission and storage services. The other important consideration for customers is quality of service, which will continue to be monitored and reported to the Board through the RRR. A price cap provides greater incentives for the utility to implement comprehensive, longer-term productivity improvements compared to cost-of-service regulation. It also provides Union the flexibility to respond to a changing energy marketplace by encouraging the development of new services on a timely basis and changes to existing services when required while maintaining regulatory oversight.

Price cap parameters that are known in advance will result in more stable and predictable rates than a revenue cap mechanism. Unlike a revenue cap, a price cap does not focus on the revenue generated from the utility's activity. A price cap focuses on service prices. The formula works not by restricting revenues or by looking at what the utility's costs are, but by limiting the prices to a pre-determined amount set in relation to inflation and an expectation of productivity improvements.

4.2.2 BASE RATES

Union's 2013 rates (EB-2011-0210), subject to two adjustments, would be the basis on which rates would be set each year over the IRM term. Union's 2013 Board-approved rates meet the Board's requirements for a robust set of cost-based rates, established through a transparent review to serve as the basis for an IRM. Prior to setting 2014 rates, the first year of the IRM, Union's 2013 Board-approved revenue would be adjusted for:

1. The deferred tax drawdown; and,
2. An upfront productivity commitment by Union.

4.2.2.1 DEFERRED TAX DRAWDOWN ADJUSTMENT

Union would adjust its 2013 Board-approved revenue by $3.152 million (Exhibit A, Tab 2, Section 1.2.1.) This amount represents the levelized difference between the credit to ratepayers for deferred taxes included in Board-approved 2013 rates and the lower credits that are owed to ratepayers over the term of the IRM.

In 1997, Union changed its accounting for income taxes for utility operations from the tax allocation (or accrual) method to flow-through (or cash-basis) tax accounting. The change to flow-through tax accounting was adopted for rate-making purposes on a prospective basis in EBRO 493/494 (Union’s 1997 rate case). The tax allocation method of tax accounting used for rate-making purposes prior to EBRO 493/494 resulted in an accumulated deferred tax balance. In the EBRO 499 (Union’s 1999 rate case) settlement agreement, parties agreed that the accumulated deferred tax balance would be used to reduce Union’s cost of service in future years.

Union is required to include the amounts in its deferral account balances in the determination of taxable income. This creates a temporary timing difference between when amounts are accumulated in deferral accounts and when these amounts are disposed of to customers. As the deferral account balances change, the corresponding deferred income tax balances also changes. The deferred income tax balances are non-utility (i.e. not included in the calculation of rate base and revenue requirement). The temporary differences reverse themselves when the accumulated deferrals are disposed of to customers. This reversal results in no net impact to customers arising from these temporary differences.

For the proposed IRM, consistent with the adjustment mechanism applied during the 2008-2012 IRM, Union would adjust Board-approved revenue to reflect the difference between the deferred tax credit in 2013 base rates and the average of the deferred tax drawdown over the 2014-2018 IRM. The purpose of this adjustment is to provide a levelized tax benefit over the 2014-2018 period. At the end of that period, ratepayers and Union would be in the same position as they would have been without the normalization adjustment but without the inter-year volatility.

Union's 2013 rates contain a deferred tax credit of $15.169 million. The remaining accumulated deferred tax balance to be credited to customers after 2013 is $64.094 million. Without adjusting the deferred tax credit in rates during the IRM term, Union would over-refund the accumulated deferred tax balance which would then have to be collected from customers upon rebasing. Accordingly, an adjustment should be made to avoid this circumstance.

As shown at Table 3, for the proposed 2014-2018 IRM, the levelized amount would be $12.819 million (i.e. $64.094 million accumulated balance / 5 years), requiring a base rate increase of $2.350 million (i.e. $15.169 million in rates less $12.821 million levelized credit) ($3.154 million pre-tax).

Table 3
Amortization of Accumulated Deferred Tax Balance (2014-2018)

Line No.	Particulars ($000s)	2013	2014	2015	2016	2017	2018
1	Drawdown amount	15,169	13,465	13,555	13,101	13,141	10,832
2	Difference from 2013		(1,704)	(1,613)	(2,068)	(2,028)	(4,337)
3	Tax Rate – Board Approved	25.50%	25.50%	25.50%	25.50%	25.50%	25.50%
4	Pre-tax rev. requirement impact (1)		(2,287)	(2,166)	(2,776)	(2,722)	(5,822)
5	Average		(3,154)				

Notes:

(1) Line 2/(1-Line 3)

4.2.2.2 UPFRONT PRODUCTIVITY ADJUSTMENT

Union would reduce the 2013 Board-approved revenue by an upfront productivity commitment of $4.5 million. This adjustment is in addition to the annual productivity factor discussed below in section 4.4. As a result of this adjustment, Union would be incented to seek further productivity savings of $4.5 million. This adjustment would be allocated to rate classes in proportion to the allocation of Administrative and General Operating and Maintenance costs included in 2013 Board-approved rates.

4.2.2.3 WINTER WARMTH PROGRAM/LOW INCOME ENERGY ASSISTANCE PROGRAM ("LEAP") FUNDING

The Winter Warmth initiative is designed to provide financial support for natural gas customers who are unable to pay their gas bills. Union's contribution to Winter Warmth was mandated as a result of a settlement reached in a Late Payment Penalty Litigation proceeding (EB-2008-0417). As part of that settlement, a Winter Warmth trust fund was established. Union was, and continues to be, required to direct amounts from this fund on an annual basis to support low-income customers. The program provides grants to low-income residents who have Union Gas accounts in arrears or are faced with the threat of disconnection because of special circumstances that have led to their arrears. The initiative was created as a means to protect these customers from losing heat and warmth during the winter months. The Winter Warmth program is delivered through a network of local agencies across Union's franchise area with oversight provided by the local United Way agency.

Similar to Winter Warmth, the Low-income Energy Assistance Program ("LEAP") was established by the Board in 2011 for all electricity and natural gas distributors to assist low-income customers. The Board determined an appropriate funding level to be the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000. In Union's case, 0.12% of Union's distribution revenue is approximately $835,000. It should be noted that as per the Board's direction, Union is not currently required to participate in the LEAP program as it already contributes to Winter Warmth. However, once the Winter Warmth trust fund is exhausted, Union will then be required to provide funding through the Board-mandated LEAP.

Union has seen a significant increase in Winter Warmth program use since 2008. Consequently, the Winter Warmth fund is being used more quickly than originally forecast. If the Late Payment Penalty settlement funds are depleted over the term of the IRM, Union would pay but not seek to adjust rates to reflect the Board's Winter Warmth Program/LEAP funding requirements until the end of the IRM term.

4.3 INFLATION FACTOR

Union would continue the use of the quarterly Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD") Canada index as the inflation factor. Union also believes it is appropriate to use this inflation measure instead of an industry-specific inflation factor. The rationale noted on pgs. 12-13 of the June 2007 PEG report remains relevant today:

> *"Macroeconomic inflation measures have noteworthy advantages over industry-specific measures in rate adjustment indexes. One is that they are available from respected and impartial sources such as the Federal government. Customers are more familiar with them, and this facilitates acceptance of rate indexing generally. There is no need to go through the chore of annual index calculations. Controversies over the design of an industry-specific price index are side stepped."*

Union is proposing that the calculation of the annual inflation factor for the 2014-2018 IRM be the same as that used for the 2008-2012 IRM. Union would calculate the inflation rate to be used in its annual rate application as the average of the 4 quarters, ending in June each year (Q2 to

Q2). For example, the inflation factor used to set rates for 2014 would be based on the actual change in GDP IPPI FDD from Q2 2012 to Q2 2013, which is usually available by the end of August. For the purpose of calculating the rate impacts in this evidence and the Agreement, Union has assumed an annual inflation factor for each year of 1.63%, which is the average change in GDP IPI FDD from Q4 2011 to Q4 2012. This assumption would be updated for the rate application and order for rates effective January 1, 2014.

4.4 PRODUCTIVITY (X) FACTOR

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. Under the IRM framework, base rates, net of Y factors, were increased/decreased by the inflation factor less productivity, or I – X. For example, 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.

As shown in Table 4, over the 2008 to 2012 period, there was a net reduction in rates of $2.947 million over the term of Union's last IRM as a result of the annual price cap adjustment. This means that, to the extent that operating costs over the prior IRM term increased as a result of inflation, those increases were managed by a combination of cost efficiencies and/or revenue increases.

Table 4
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)

A number of cost efficiency measures have already been implemented in rates in Union's 2013 rebasing proceeding (EB-2011-0210), and revenue growth opportunities have been greatly reduced. In addition, Union experiences short-term revenue volatility during periods of low inflation when coupled with a fixed productivity factor. Accordingly, Union requires modest, predictable rate increases in order to manage expected cost pressures over the 2014-2018 period. Union's 2014-2018 IRM would include an annual X factor, inclusive of any stretch factor, expressed as a percentage of inflation, of 60%. This approach results in an annual net rate escalation factor, before the impact of Y and Z factors and earnings sharing, of 40% of GDP IPI FDD, or approximately $6.0 million based on an inflation factor of 1.63%. The combination of a base rate reduction associated with an additional productivity commitment, and an annual net inflator of 40% of GDP IPI FDD, ensures that customers' expectations of in-franchise delivery rate increases being no more than inflation can be readily met.

4.5 Weather Normal Methodology

Union's Board-approved current weather normal method is a 50:50 blended method that combines the 20-year declining trend method with the 30-year average method, as directed by the Board in its EB-2011-0210 Decision. Union would continue to use that normalization methodology over the term of its proposed IRM.

4.6 Normalized Average Consumption Adjustment

During the 2014–2018 IRM, Union will adjust rates annually for the changes in normalized average consumption ("NAC"), rather than average use ("AU"), to capture actual volumetric changes in the General Service rate classes. NAC incorporates all volume changes, including changes due to AU (efficiency gains) and DSM activities (LRAM).

Union is also proposing to establish a Normalized Average Consumption deferral account to capture the variance between the forecast NAC in rates and what is observed on an actual basis for the same year. As proposed, this deferral account would be disposed of annually through the non-commodity deferral accounts and earnings sharing proceeding.

<u>Background</u>

During the 2008–2012 IRM, volumetric consumption changes in the General Service rate classes were captured in two ways:

1. An AU adjustment to rates and a deferral account that captured the difference between the actual AU and the AU in rates; and,
2. A Lost Revenue Adjustment Mechanism ("LRAM") adjustment to rates and a deferral account that captured actual LRAM.

In hindsight, annual AU volume adjustment in rates and the AU deferral account during the 2008-2012 IRM was an overly-complex mechanism. The AU formed part of the annual rate adjustment for General Service rates as AU was a component in the annual rate adjustment formula.

The complexity arose from several sources:

1. The AU factor or target required estimation based upon an historical 3-year average percent change in average use that was lagged two years;
2. The AU deferral account was the second part of annual rate adjustment process. The AU deferral account was a true-up step of the initial rate adjustment made at the beginning of the year that was set by the AU factor; and,
3. To calculate AU, Union was required to start with the NAC for each rate class, determine the impacts of the DSM program (LRAM), then gross up the NAC volumes to remove the LRAM impacts. The DSM volumes (LRAM) were then captured as part of the annual volumetric adjustment to rates and the LRAM deferral account.

Changes for 2014-2018

Union would adjust rates for the changes in NAC, rather than in AU, as a means to capture volumetric changes in the General Service rate classes. NAC incorporates all volume changes, including changes due to average use (efficiency gains) or the impact of DSM activities, which simplifies the overall process. NAC is weather normalized.

Similar to the AU adjustment during the 2008–2012 IRM, Union would adjust the volumes used to calculate rates through the annual rate setting application. Union would adjust the volumes in rates based on the last known actual NAC. For example, for 2014 rates, which would be filed in the fall of 2013, Union proposes to adjust rates for the actual 2012 NAC. The lag is required because Union would not have the actual 2013 NAC at the time of the filing.

As noted earlier, to ensure that neither ratepayers nor Union win or lose with respect to NAC, Union will true-up NAC through a deferral account by comparing the actual NAC to the NAC in rates. For example, for 2014 rates, Union would compare the NAC included in rates (2012 actual NAC) to the actual NAC in 2014. The LRAM adjustment previously made to General Service rate classes would now be included in that NAC adjustment. The LRAM deferral account would continue to exist for the contract rate classes.

4.7 Y FACTORS

Y factors are costs associated with specific items that are subject to deferral account treatment, are passed through to customers, and are not subject to escalation. As was the case in Union's 2008-2012 IRM, Union would treat the following items as Y factors:

- Cost of gas and upstream transportation costs as defined in EB-2011-0210;
- DSM budget changes as determined in EB-2011-0327 and any subsequent Board proceeding; and,
- LRAM for the contract rate classes.

In addition, Union's 2014-2018 IRM would include Y factor treatment for:

- Unaccounted-for gas volume variances; and,
- Major capital additions.

4.7.1 COST OF GAS AND UPSTREAM TRANSPORTATION

The cost of gas supply, upstream transportation and gas supply balancing would continue to be passed through to customers through the Quarterly Rate Adjustment Mechanism ("QRAM"), including the prospective disposition of gas supply-related deferral accounts. The Board developed guidelines in EB-2008-0106 to standardize the QRAM process.

4.7.2 DEMAND SIDE MANAGEMENT ("DSM")

On January 31, 2012, Union filed its overall 2012-2014 DSM Plan Settlement Agreement (EB-2011-0327). The agreement, which was approved by the Board in February, 2012, included a large industrial DSM program for 2012 only. As part of the agreement, Union committed to file a new application supporting a large industrial Rate T1 and Rate 100 DSM plan for 2013 and 2014. Union developed and filed a new large industrial DSM plan for the years 2013 and 2014 on August 31, 2012 (EB-2012-0337). On p. 8 of its EB-2012-0337 Decision and Order dated March 19, 2013, the Board found Union's 2013 and 2014 overall DSM budgets to be appropriate.

Consistent with the EB-2011-0327 settlement agreement, to determine the total DSM budget forecast for 2013 and 2014, Union used the four-quarter rolling average of the GDP IPI FDD, released at the end of August of the prior calendar year, as the budget escalator. Union's 2013 total DSM budget is $31.6 million. Union escalated the 2012 budget using an inflation factor of 2.22% calculated using the four-quarter rolling average of the GDP IPI FDD as at Q2 2012. For illustrative purposes, if the same inflation factor of 2.22% is assumed to apply to 2014, the 2014 DSM budget would be $32.3 million.

4.7.3 LOST REVENUE ADJUSTMENT MECHANISM (”LRAM”)

Union’s DSM programs result in volume consumption reductions for all rate classes. During Union’s 2008-2012 IRM, Union adjusted the volumes to calculate rates through the annual rate setting application to capture the LRAM volume impacts for all rate classes.

For the 2014-2018 IRM, Union would continue this process for the contract rate classes. As noted in Section 4.6 above, Union would adjust the volume to calculate rates for General Service rate classes using NAC during the 2014-2018 IRM, which includes the LRAM volumes.

4.7.4 UNACCOUNTED FOR GAS (UFG) VOLUME VARIANCES

UFG represents 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 could include leakage or other actual unmeasured 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.

The total cost of UFG is comprised of two elements: a percentage of throughput volume that determines the UFG volume, and the Board-approved weighted average cost of gas (“WACOG”). Changes to WACOG and the corresponding impact on the total cost of UFG using the Board-approved UFG volume are captured in Union’s QRAM. Historically, UFG volume variances have not been deferred.

As part of Union's 2014-2018 IRM, total UFG cost changes resulting from a difference between the UFG volume included in rates and the actual UFG volume would be recorded in a new UFG volume deferral account. The amount to be recorded in the UFG volume deferral account would be calculated using the most recent Board-approved WACOG. The amount of the UFG volume deferral account to be cleared to customers would be subject to a symmetrical dead-band of $5 million, with amounts within such dead-band being to Union's account only.

The Board approved a total cost of $14.7 million for UFG in 2013 base rates (EB-2011-0210) calculated by multiplying the Board-approved total UFG volume of 70,253 10^3m^3 by a WACOG of $210.506/ 10^3m^3 (the cost of gas used in Union's January 1, 2013 QRAM). This means that for 2014 UFG, a volume variance less than $9.7 million or greater than $19.7 million would be subject to deferral. To illustrate, if the volume variance is $25.7 million, $6 million would be deferred and recovered from ratepayers.

4.7.5 MAJOR CAPITAL ADDITIONS

Union would include a capital pass-through mechanism in its 2014-2018 IRM. This mechanism is intended to adjust rates during the IRM term to reflect the associated impacts of significant capital investments made throughout the IRM term deemed "not-business-as-usual". "Not-business-as-usual" refers to capital expenditures that are significant and cannot be managed within Union's Board-approved capital budget.

At the time Union was developing its 2014-2018 IRM proposals, it identified three major facility expansion projects that it considered "not-business-as-usual" that it proposed to pass-through when the facilities go in to service. The projects Union identified were i) the development at the Parkway West site; ii) the Brantford-Kirkwall transmission pipeline and Parkway D compressor station; and, iii) the Burlington-Oakville transmission pipeline. The Parkway West project and the Brantford-Kirkwall pipeline/Parkway D compressor station are currently the subjects of Leave-to-Construct applications (EB-2012-0433 and EB-2013-0074). The Burlington-Oakville transmission pipeline Leave-to-Construct application has yet to be filed. As context, the Parkway West project and Brantford-Kirkwall/Parkway D projects have associated capital expenditures of $203 million and $204 million, respectively, and are the largest capital projects in Union's history by a significant measure.

Through discussions with Stakeholders, Union has developed eight criteria, which, if met by a major capital project, would be included in rates during the IRM term. Both the Parkway West and Brantford-Kirkwall/Parkway D projects currently meet the criteria. Although application for approval of the Burlington-Oakville transmission pipeline has not been filed, Union expects that it will also qualify for capital pass-through, subject to the outcome of that Leave-to-Construct proceeding.

The key features of the major capital pass-through mechanism would be:

- Any qualifying project must exceed two financial thresholds, related to both revenue shortfall and capital cost;
- Any qualifying project would be subject to a full regulatory review, either in a Leave-to-Construct proceeding or in a rates proceeding, but prior to being included in rates; and,
- Any qualifying project would be subject to both annual revenue requirement true-ups during the IRM term and an end-of-term qualification assessment.

As a result, significant new capital projects can be made to serve customers on a timely basis, and included in rates when the project is used or useful.

The criteria that must be met for any capital project to quality for Y factor treatment are as follows:

i) A minimum increase, or a minimum decrease, of $5 million in net delivery revenue requirement for a single new project (the "Rate Impact Threshold"). For the purposes of making this determination, capital costs are those costs relating to that capital project as defined under the applicable accounting rules. The net delivery revenue requirement associated with a capital project for any given year is the costs associated with incremental operating and maintenance expenses, depreciation expense, municipal property taxes expense, incremental long-term debt costs, and required return and income taxes net of any incremental delivery revenues arising from, associated with, or enabled by the project. Should the net delivery revenue requirement exceed the Rate Impact Threshold in any year, the project would meet the Rate Impact Threshold criterion. The rate adjustment for each year would be based on the forecast net delivery revenue requirement impacts for each specific year, subject to true-up to actual as discussed in section (viii) below.

To determine the net delivery revenue requirement for any year, the following parameters would be applied:

- Depreciation expense would be calculated using the 2013 Board-approved depreciation rates;
- The required return would assume a capital structure of 64% long-term debt and 36% common equity;
- The incremental long-term debt cost would be calculated based on expected financing costs for the incremental borrowing required by the project, at market rates in effect at the time the project is approved;
- The return would be calculated using the 2013 Board-approved return on equity of 8.93%;
- The income and other taxes related to the equity component of the return would be calculated using the 2013 Board-approved tax rate of 25.5%;
- The incremental delivery revenues associated with the project would be calculated as an offset to the delivery revenue requirement;

- For the in-service year, all components of the calculation except taxes (but including, without limitation, depreciation, cost of debt, and return) would be calculated only for the period from the month of in-service to the end of the year; and,
- These parameters would not change during the IRM term.

ii) The capital cost of the project, using the same capitalization policies as were in place for the purposes of the 2013 Board-approved (EB-2011-0210) revenue requirement, must exceed $50 million. Provided, however, that in the event that Union is required to change its accounting standard from USGAAP to any other standard (including IFRS), and as a result its capitalization policies must change, the capitalization policies under the new accounting standard would apply;

iii) The project is outside the base rates on which this incentive regulation framework is set;

iv) The project must be needed to serve customers and/or to maintain system safety, reliability or integrity, and cannot reasonably be delayed, and is demonstrated to be the most cost-effective manner of achieving the project's objective relative to the reasonably available alternatives;

v) The project would be identified to stakeholders and the Board as soon as possible, including in that year’s stakeholder review session where practical (see Section 12.2);

vi) The project would be subject to a full regulatory review equivalent to a Leave-to-Construct proceeding, in which the applicant must demonstrate need, safety or reliability purposes, and economic viability prior to inclusion in rates. For any project that requires Leave-to-Construct approval of the Board, the full regulatory review would be conducted in that proceeding. For any project that does not require Leave-to-Construct approval of the Board, Union commits to filing its annual rate adjustment application with the Board by July 1 of the year prior to the rate impacts of the project going into effect, to allow sufficient time for a full regulatory review of the project in its rates application;

vii) Subject to direction otherwise from the Board, Union would allocate the net revenue requirement using the 2013 Board-approved cost allocation methodologies. Any party, including Union, may take any position with respect to the proposed allocation for any particular capital project during review of the project, or its rate impacts, by the Board; and,

viii) The project would include a deferral account request to capture any differences between the forecast annual net delivery revenue requirement and the actual net delivery revenue requirement for each year of the IRM term for which the project is included in rates. The true-up will occur annually during the period the project is subject to Y factor treatment. Furthermore, if, at the end of the 2018 year, the actual net delivery revenue requirement, for any year the project has been in service, has not exceeded the $5 million minimum, the project would be deemed not to have qualified, and all amounts collected thereon would be refunded/charged to ratepayers through the mechanism of an End-of-IRM-term true-up deferral account.

4.8 Z FACTORS

A Z factor provides for rate adjustments intended to safeguard customers and the gas utility against unexpected material costs that are outside of management's control, out of the realm of the basic undertaking of a utility and not included in the proposed price cap. As was the case in the 2008-2012 IRM, Z factors would be subject to five criteria. The criteria are the same as those agreed to in the EB-2007-0606 Settlement Agreement with two modifications. First, the second criterion has been expanded to refer to the Board's EB-2011-0277 Decision on Union's request for Z factor approval of the costs associated with Sewer Lateral Cross Bores. Second, the materiality threshold has been increased to $4.0 million.

For prospective or historical cost increases/decreases to qualify for pass through as a Z factor, the cost increases/decreases must:

1. causally relate to an external event that is beyond the control of utility's management;
2. result from, or relate to, a type of risk:
    a. for which a prudent utility would not be expected to take risk mitigation steps; and,
    b. which is out of the realm of the basic undertaking of the utility (per EB-2011-0277 Decision, page 13).

3. not otherwise be reflected in the price cap index;
4. be prudently incurred; and,
5. meet the materiality threshold of $4.0 million of annual net delivery revenue requirement impact per Z factor event.

4.9 TAXES

Union would maintain an equal and symmetrical sharing of tax changes over the IRM term. Specifically, this involves the 50:50 sharing of the impact of tax changes, as applied to the tax level reflected in 2013 base rates. Treating 50% of tax changes as a Z factor is consistent with the Board's findings in its EB-2007-0606/EB-2007-0615 Decision (dated July 31, 2008).

Union would treat tax changes in the same manner as that used during the 2008-2012 IRM. Union would continue to calculate the variance between current year tax rates and calculation methods/rules to those used in current Board-approved rates and calculation methods/rates. This variance would be allocated to rate classes using the 2013 Board-approved rate base as the allocation factor.

Any variance between taxes using the actual rates and calculation methods/rules and the approved rates and calculation methods/rules in Union's rates would be captured in a new deferral account.

5.0 TERM OF THE PLAN

The term of the IRM would be five years commencing January 1, 2014 and ending December 31, 2018. A 5-year term would allow Union sufficient incentive and time to implement changes where the productivity benefits are realized over multi-year periods. In addition, achieving productivity improvements frequently involves incurring implementation costs. The term of a price cap plan must be long enough to justify incurring the implementation costs required to pursue the productivity improvements.

6.0 EARNINGS SHARING, BENCHMARK ROE AND OFF-RAMPS

To provide incentives for Union to seek productivity gains, either through achieving cost efficiencies or increasing revenue, while at the same time providing an opportunity for ratepayers to benefit from those initiatives during the IRM term, the 2014-2018 IRM would have an earnings sharing mechanism ("ESM") similar to Union's last IRM.

If, in any calendar year, Union's actual utility return on equity ("ROE") is more than 100 basis points over the 2013 Board-approved ROE of 8.93%, then excess earnings between 100 basis points and 200 basis points would be shared 50/50 between Union and its customers. If, in any calendar year, Union's actual utility ROE is more than 200 basis points over the 2013 Board-approved ROE of 8.93%, then such earnings in excess of 200 basis points would be shared 90/10 between customers and Union (i.e., customers would be credited 90% and Union would be credited 10%). For the purposes of the ESM, Union would calculate its earnings using the regulatory rules prescribed by the Board from time to time, and would not make any material changes in accounting practices that have the effect of either reducing or increasing utility earnings. All revenues that would be included in revenues in a cost-of-service application would be included in the earnings calculation, and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost-of-service application would be included in the earnings calculation.

The DSM-related Shared Savings Mechanism ("SSM"), the Lost Revenue Adjustment Mechanism ("LRAM"), and the storage-related deferral accounts are outside of the ESM identified above.

This ESM is comparable to Union's last ESM, where Union shared 50:50 with ratepayers, earnings in excess of 200 bps above the ROE, calculated annually using the Board's ROE formula underpinning 2007 Board-approved rates. Earnings in excess of 300 bps above the benchmark ROE were shared 90:10 in favour of ratepayers. Therefore, the two changes from the last IRM would be:

- the earnings above the Board-approved ROE that are attributable solely to the Company have been reduced from 200 bps to 100 bps (often known as a "dead-band"); and,
- the Board-approved ROE in rates and the ROE used for the purposes of calculating the ESM are fixed at the 2013 Board-approved level of 8.93% for the term of the IRM.

In the 2008-2012 IRM, the ROE was fixed in rates at the 2007 Board-approved level while it floated annually using the Board's ROE formula for the earnings sharing thresholds. Fixing the ROE for both rates and earnings sharing allows the Company's performance during the IRM term to be measured against a single ROE benchmark.

In light of the ESM and the other parameters (X factor, major capital addition pass-through, UFG volume deferral account), the 2014-2018 IRM would have no off-ramp. This is consistent with the 2008-2012 IRM.

7.0 REPORTING AND RECORD KEEPING REQUIREMENT ("RRR")

Union would maintain the same RRR financial reporting requirements for the 2014-2018 IRM as it had for the 2008-2012 IRM. Union would prepare and distribute annually during the 2014-2018 IRM, utility information for the most recent historical year. The information would include the schedules provided during Union's 2008-2012 IRM plus three additional schedules (items 19, 20 and 21 below). The schedules are:

1. Calculation of revenue deficiency / (sufficiency);
2. Statement of utility income;
3. Statement of earnings before interest and taxes;
4. Summary of cost of capital;
5. Total weather normalized throughput volume by service type and rate class;

6. Total actual (non-weather normalized) throughput volumes by service type and rate class;
7. Total weather normalized gas sales revenue by service type and rate class;
8. Total actual (non-weather normalized) gas sales revenue by service type and rate class;
9. Delivery revenue by service type and rate class and service class;
10. Total customers by service type and rate class;
11. Summary revenue from regulated storage and transportation;
12. Other revenue;
13. Operating and maintenance expense by cost type (actuals only);
14. Calculation of utility income taxes;
15. Calculation of capital cost allowance;
16. Provision for depreciation, amortization and depletion;
17. Capital budget analysis by function;
18. Statement of utility rate base (actuals only);
19. Unregulated Continuity of Property, Plant and Equipment, and Unregulated Continuity of Accumulated Depreciation;
20. Service Quality Indicators per the RRR; and,
21. Audited financial statements for utility operations.

8.0 ANNUAL GENERAL MEETING

Union believes that it is in the best interest of all parties to have more detailed and frequent engagement with intervenors and the Board to help ensure a greater understanding and transparency of its overall operations during the IRM term. To help accomplish this goal, Union would host an annual, funded stakeholder meeting to:

1. Review the previous year's financial results (e.g. earnings, capital spending) and other key operating parameters (e.g. SQI performance) for the most recently completed year;
2. Present and explain market conditions and expected changes/trends, and the impact these may have on regulated operations;
3. Present and review the gas supply plan for the coming year;
4. Present new capital projects that meet the major capital addition pass-through criteria as defined in Section 4.7.4; and,
5. Present the results of any customer surveys undertaken during the year.

Union would file all information resulting from this annual meeting with the Board and ensure it is available to any party not able to attend the annual stakeholder meeting. Union would plan to schedule these meetings sometime in April. This timing would follow the public release of year-end financial results but would be prior to filing the application for the annual disposition of the non-commodity deferral account balances (including any earnings sharing).

9.0 RATE SETTING FILINGS

To set annual rates during the 2014-2018 IRM, Union would file the following information annually:

1. Union would file an application for approval of any Z factor adjustments, the pricing of any new regulated services, and/or for any other adjustments for which advance approval from the Board is required, in a time frame that would enable these issues to be resolved in sufficient time to be reflected prospectively in the next year's rates.
2. Union would file a draft rate order with supporting documentation by September 30 which reflects the impact of the PCI, Y factors, approved Z factors and NAC. The documentation would be in sufficient detail to allow the Board to issue a procedural order, such that a final rate order could be issued by December 15 for implementation by January 1; and,
3. As soon as reasonably possible following the public release of Union's annual audited financial statements, Union would apply (as it does now) for the disposition of actual year-end non-commodity deferral account balances. (This would coincide with the filing of an annual earnings sharing calculation as described in Section 6.0). Union would use its best efforts to file its application and pursue the regulatory process such that, after the Board's decision, Union would be able to implement all rate adjustments associated with the deferral account disposition at the time of its July 1 QRAM. Union would continue to adjust gas supply commodity and upstream transportation costs through the QRAM mechanism as approved in EB-2008-0106.

10.0 OTHER ISSUES

There are four issues that will be the subject of further discussion and regulatory process. They are:

1. M1/M2 and R01/R10 Volume breakpoint;
2. Parkway obligation;
3. Gas Supply Plan Studies; and,
4. M5/T3 cost allocation rate design.

Union was ordered to address the M1/M2 and R01/R10 Volume breakpoint by the Board in its EB-2011-0210 Decision. A working group has been formed. Union will file sufficient evidence on cost allocation and rate design with respect to these rate classes to allow the Board to adjudicate the issue in the EB-2013-0202 proceeding or in the 2014 rates proceeding.

In the EB-2011-0210 Settlement Agreement, parties agreed to establish a Parkway Obligation Working Group. Union was directed to report to the Board on the status of this working group as part of the 2014 rates proceeding. Union will file sufficient evidence on this issue, and its position on whether or not changes should be made, to allow the Board to adjudicate the issue in the 2014 rates proceeding.

In its EB-2011-0210 Decision, the Board directed Union to hire a consultant to review its gas supply plan and the cost allocation of the gas supply costs. Union contracted with Sussex

Economic Advisors ("Sussex") and Concentric Energy Advisors ("Concentric") to review and provide reports on Union's gas supply plan and the allocation of costs associated with the gas supply plan. Union filed the Sussex and Concentric reports in its 2012 Deferrals and Earnings Sharing Disposition proceeding (EB-2013-0109). Any changes required following the review of the gas supply plan reports in EB-2013-0109 would be implemented per the Board's decision in that proceeding.

Certain intervenors expressed concerns about the M5 and T3 cost allocation and rate design. As part of EB-2013-0202 or Union's 2014 rates proceeding, parties will have an opportunity to review and, if appropriate, to lead evidence on the M5 and T3 cost allocation and rate design as approved by the Board in EB-2011-0210.

11.0 REBASING

Union would (subject to any subsequent agreement of all parties to extend the IRM term) prepare a full cost-of-service filing at the time of rebasing, regardless of whether Union applies to set rates for 2019 on a cost-of-service basis or not.

At the time of rebasing, Union would provide 2013-2017 actual, 2018 bridge and 2019 forecast information. In addition, Union would provide historical plant continuity information for 2012, 2013, 2014, 2015 and 2016 similar to the information provided in the EB-2011-0210 proceeding at Exhibits B6/T1 & T2/S 1 – 5.

12.0 ESTIMATED RATE IMPACTS OVER THE 2014-2018 IRM

Based on the evidence above, Union has calculated rate impacts for the in-franchise and ex-franchise rate classes for each year of the 2014-2018 IRM. The assumptions and rate impacts, exclusive of any pass-through updates (e.g. inflation, Y factors), can be found in the Settlement Agreement, Exhibit A, Tab 2, Appendix C.

For Union South, based on the assumptions listed at page 1 of Appendix C, the total bill impact for the average residential customer in Rate M1 as shown at page 8 of Appendix C is estimated to increase by 1.3% over the proposed 5-year IRM term. This amounts to an estimated 2.6% increase to the total delivery charge over the IRM term.

For the Union South contract rate classes, the estimated rate impacts over the IRM term range between -8.1% to 7.8% and are shown at pages 5, 6 and 7 of Appendix C.

For Union North, based on the assumptions listed at page 1 of Appendix C, the total bill impact for the average residential customer in Rate 01 as shown at page 8 of Appendix C is estimated to decrease by 0.8% over the proposed 5-year IRM term. This amounts to an estimated 0.6% decrease to the total delivery charge over the IRM term.

For the Union North contract rate classes, the estimated rate impacts over the IRM term range between -4.0% to 2.8% and are shown at pages 5, 6 and 7 of Appendix C.

For all in-franchise rate classes, the forecast annual percent rate change is less than the average actual inflation rate of 1.8% that occurred over the 2008-2012 IRM term.

13.0 LONDON ECONOMICS INTERNATIONAL REPORT

Union retained London Economics International LLC ("LEI") to review Union's 2014-2018 IRM proposals and compare those proposals to IRM models and approaches approved in the regulatory jurisdictions of other North American distribution utilities. In addition, LEI reviewed the Agreement and provided comments as an Addendum in their report. LEI's report (the "Report") can be found at Appendix A. LEI concluded that Union's proposals and the Agreement are consistent with the Board's objectives as outlined in the Ontario Energy Board Act, 1998 and with the principles set out in the Board's Natural Gas Forum Report.

LEI's review of other distribution utilities focused on the major components of an IRM framework including:

- The use of an inflation factor;
- Productivity trends and X factors;
- The pass-through of capital project costs;
- The treatment of unaccounted for gas ("UFG");

- The use of Z factors to recover extraordinary costs;
- The use of earnings sharing mechanisms ("ESM"); and,
- The use of commonly-tracked service quality indicators ("SQI").

Inflation Factor

LEI reviewed inflation factors in other jurisdictions and Ontario and found that there is no clear trend favouring the selection of an economy-wide inflation factor (e.g. GDP IPI FDD) compared to other composite measures (e.g. average earnings plus economy-wide measures). However, Union's proposed and settled use of GDP IPI FDD is consistent with practices in Ontario, including Union's 2008-2012 IRM.

Productivity and X factor

LEI reviewed productivity factors in other jurisdictions and found that:

> *"Productivity investments, like other investment types, face declining marginal returns; as the most attractive opportunities are exhausted, less remunerative alternatives are harvested, until ultimately the frequency of productivity enhancing activities slows. Well-run utilities which have already made strides in improving efficiency may find it harder and harder to continue to do so at the same rate." p. 25*

LEI's finding is consistent with Union's situation. During Union's 2008-2012 IRM, Union undertook and completed productivity improvements in each year of the IRM term. As a result, Union is faced with the increasingly difficult task of finding productivity projects that result in cost savings or incremental revenues that exceed the cost of the project.

LEI noted that, compared to Union's initial proposal of an X factor of 0%, the Agreement, at Section 3, incorporates a positive productivity factor which is expressed as a percentage of inflation (60% of GDP IPI FDD). This ensures that, excluding pass-through adjustments, customers' rates increase by only a proportion of inflation. Thus, in real terms, customers will be facing decreasing rates (before accounting for necessary pass-through elements). LEI notes that the initially-proposed X factor of 0% is consistent with recent industry experiences, including the Total Factor Productivity study completed by PEG for the Board with respect to electricity distributors (Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board, May 2013). As the Agreement includes a positive productivity factor, LEI states:

> *"The Agreement obligates Union to further improve productivity, and provides a more than reasonable balance between the interests of consumers and the industry viability." p. 53*

UFG

LEI reviewed the accounting practices for UFG in other jurisdictions and Ontario with the principle that the utility and consumers should not be at significant risk for pass-through costs such as UFG. In LEI's jurisdictional review, they found that other distributors had deferral accounts, adjustment mechanisms or tracking mechanisms to reconcile the forecast UFG costs and the actual UFG costs.

Union did not have a UFG true-up mechanism for its 2008-2012 IRM.

LEI found that Union's proposal for a UFG deferral account that would capture the difference between forecast UFG costs and actual UFG costs to be consistent with standard regulatory practice, in that it supports cost recovery and meets the Board's objectives of maintaining a financially-viable distribution company and protecting consumers with respect to price.

As part of the Agreement, there would be a symmetrical dead-band of $5.0 million for the UFG deferral account (See Section 6.5 of the Agreement). As part their Addendum, LEI believes that the mechanics of a UFG deferral account with a $5 million dead-band are consistent with the principles and objectives noted above.

<u>Treatment of Capital Costs</u>

LEI reviewed the treatment of major capital projects during an IRM term in other jurisdictions and Ontario and concluded that:

> *"IR frameworks often include rate adjustment mechanisms outside the I-X framework. These mechanisms have a range of criteria so as balance the need to protect consumers against inappropriate cost pass-throughs against the need for a utility to be able to invest prudently and recover its return on investment including in circumstances where it has no discretion regarding the investment." p. 36*

Further, LEI noted that:

> *" ... certain capital projects may be treated outside the I-X annual adjustment framework recognizing that this framework cannot cater for large and outside the norm capital expenditures and/or situations where the utility has no discretion." p. 36*

LEI's review included capital cost treatment in Ontario, including the Board's Report titled: *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*. The fourth generation of incentive regulation for electricity distributors includes an Incremental Capital Module ("ICM"), which is intended to set thresholds for "non-discretionary" capital expenditures.

Union proposes to treat major capital projects as Y factors, subject to qualifying criteria. LEI concluded at p. 39 of their Report that Union's proposed Y factor treatment for major capital projects is consistent with capital pass-through regulatory principles in Ontario and other jurisdictions in that the project must be approved by the Board, Union must demonstrate the need for the project, and the costs will only be passed through when the projects are in-service. Further, LEI concluded that the application of qualifying criteria is similar to the ICM applied by the Board in the electricity sector.

The Agreement, at Section 6.6, outlines the criteria that capital projects must meet to qualify for rate recovery. LEI concluded, at p. 55 of the Report, that the major capital additions criteria in Section 6.6 are reasonable and continue to meet the objectives and principles discussed above.

Z Factors

LEI reviewed the used of Z factors for the treatment of unknown or unforeseen costs in other jurisdictions and Ontario and concluded that most utilities have Z factor criteria to determine whether a cost should be approved for rate recovery.

Union originally proposed to maintain the same Z factor criteria that were approved in Union's 2008-2012 IRM. LEI found that Union's proposed criteria were consistent with the OEB principles and IRM frameworks in other jurisdictions.

The Agreement, at Section 8, describes the Z factor criteria for Union's 2014-2018 IRM. The two changes between the proposed and settled criteria are: including eligible cost increases/decreases (prospective and historical) to qualify for pass-through, and increasing the eligibility threshold from $1.5 million to $4.0 million. LEI concluded that the increase in the threshold benefits ratepayers as it increases the costs Union must absorb before it can pass through costs via a Z factor adjustment.

ESM

LEI reviewed the ESMs in other jurisdictions and Ontario, concluding that many jurisdictions do not have ESMs, including the electricity distributors in Ontario. However, Union's historical use of its ESM is consistent with ESMs in other jurisdictions.

Union originally proposed to reduce the earnings sharing dead-band, from 200 bps for its 2008-2012 IRM, to 100 bps for its 2014-2018 IRM. LEI noted:

> *"The reduction in deadband offsets the reduced X-factor impact for customers and aligns productivity incentives for Union. The asymmetrical nature of the proposed arrangement provides additional efficiency incentives for Union to improve its performance as it must absorb any cost pressures in order to maintain its ROE." p. 45*

The Agreement, at Section 11.1, describes the ESM for Union's 2014-2018 IRM. The dead-band remains at 100 bps, but the earnings are shared 50:50 for earnings between 100 bps and 200 bps above the allowed ROE, and 90:10 in favour of ratepayers for earnings over 200 bps. LEI concluded that:

> *"The ESM arrangement in the Agreement is more generous towards ratepayers, as compared to the initial proposal described in the report" p.55*

<u>SQIs</u>

LEI reviewed SQIs, primarily industry-specific benchmarks related to operations and reliability, customer service and safety, in other jurisdictions and Ontario and found that about half of the jurisdictions have SQI reporting requirements.

Union originally proposed to maintain the same Board-approved SQI reporting, identical to the SQI reporting in Union's 2008-2012 IRM. This same reporting is reflected in the Agreement at Section 12.1. LEI found the SQIs to be consistent with other jurisdictions that have SQI reporting.

14.0 CUSTOMER SURVEY

Union retained NRG Research Group to complete a 2013 utility pricing parameters study to understand ratepayers' attitudes toward price stability and predictability in natural gas delivery charges. This study was completed in the form of a telephone survey in May and June 2013 with the target group being Union's residential customer base. The study can be found at Appendix B.

The key survey results are largely aligned with Union's expectations. A total of 62% of the respondents agreed it would be acceptable for Union to increase its delivery charges for each of the 5 years of the IRM term by no more than the general inflation rate. With respect to rate stability and predictability, 49% agreed that "stable" delivery charges meant that delivery rates could change but not by a large degree. Further, 68% either "strongly agreed" or "somewhat agreed" that stable delivery charges would allow them to more effectively budget their overall household costs.

Knowing delivery charges in advance was also seen as a benefit. A total of 30% viewed this as being "very beneficial", whereas another 38% saw this as being "somewhat beneficial". When asked to best describe their opinion about stabilizing delivery charges, 38% said they would prefer stable rates for all charges on their bill (not just delivery charges). A total of 42% agreed that working to stabilize delivery charges is better than doing nothing at all.

The Agreement would result in in-franchise delivery rate increases being less than or equal to inflation for all rate classes over the 5-year IRM term. Further, the IRM framework provides a pricing framework that would result in stable and predictable rates over the 5-year term.

15.0 SUMMARY

The appropriate incentive regulation model for Union is a price cap framework. The parameters of this framework, as contained in the Agreement filed at Exhibit A, Tab 2, meet the Board's objectives for incentive regulation. The parameters are supported by Union and a wide range of experienced stakeholders who represent Union's ratepayers. The parameters are well within the range of reasonable incentive regulation parameters as approved by regulators in other jurisdictions. The parameters are consistent with the last IRM approved by the Board, and meet most customers' expectations for future rate increases. The estimated impact of the parameters is an annual net adjustment to in-franchise delivery rates of less than inflation as shown at Appendix C of the Settlement Agreement. The annual increase over the 5-year term beginning January 1, 2014 would allow Union to make economic and efficient investments in required infrastructure, attach new customers and grow throughput volumes. Union requests the Board's approval of the multi-year Incentive Regulation Mechanism as formulated by the Settlement Agreement.

APPENDIX A

Review of Union Gas Limited's proposed incentive ratemaking plan and case study analysis of North American gas distribution utilities

Prepared for Union Gas Limited ("Union") by London Economics International LLC ("LEI")[1]

July 17th, 2013

LEI was engaged by Union to review Union's proposed 2014 to 2018 incentive ratemaking ("IR") plan as presented to stakeholders on April 29th, 2013 and to examine case studies of approaches to IR applied to other North American gas distribution utilities. In the case study analysis, Union particularly requested LEI to examine approaches to a set list of ratemaking parameters: productivity and X-factor trends, alternative approaches to designing an I-X framework, approaches to establishing inflation factors, approaches in other jurisdictions to applying an Earnings Sharing Mechanism ("ESM"), use of capital trackers for unknown costs, appropriateness of deferral accounts for unaccounted-for gas ("UFG"), and service quality indicators ("SQIs") and how they are measured.

LEI finds that Union's proposed 2014 to 2018 plan is consistent with the Ontario Energy Board's ("OEB") objectives and the general application of IR principles, as reflected in the case studies. Evidence suggests that productivity growth is slowing across gas utilities and more generally the utility sector, though economic cycles also play a role in productivity trends. LEI's case study analysis demonstrates that a one size fits all approach is not appropriate for designing IR plan parameters.

ADDENDUM – LEI was subsequently requested by Union to provide comments on Union's draft Settlement Agreement. In summary, LEI finds that the proposed Settlement Agreement provides improved benefits for ratepayers when compared with the original proposal. In particular, the I-X adjustment mechanism will support decreases in real rates aside from adjustments for other factors and the two step asymmetrical ESM ultimately provides ratepayers with the most generous sharing arrangements of any of the case studies examined by LEI.

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[1] The development of this report was supervised by Mr. A.J. Goulding, President, LEI.

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1 Introduction

1.1 Incentive ratemaking ("IR") frameworks and key components

IR frameworks are an alternative to traditional cost of service regulation. IR has a number of advantages over cost of service regulation, including: (i) better alignment of incentives between regulated companies and the objectives of ratepayers; (ii) reducing the overall regulatory burden (by allowing the regulatory, customer representatives and the utility to focus on broader industry trends and sectoral matters other than detailed, line by line cost of service reviews); and (iii) improving the predictability of treatment for companies on regulatory issues, and spurring companies to seek out innovative business and operational practices (as they have greater confidence that they will retain a portion of efficiency gains). IR frameworks are becoming the norm in jurisdictions worldwide, and can have one or more of the following elements:

- a ***cap on rates*** (either price cap or revenue cap);
- an ***annual adjustment mechanism***, which is generally designed to adjust the rate cap for inflationary pressures faced by a utility and also to provide some form of efficiency incentive. It may take the form I-X, where I is the inflation factor and the X-factor reflects an efficiency incentive;
- ***Y-factor*** for passing through specifically defined capital and operating costs that cannot be adequately catered for within the rate cap framework, for example, due to difficulties in forecasting costs or outside historical norm expenses. There may also be an element where management has limited or no discretion when it comes to incurring these costs. Y-factors may vary in the range of costs they cover and similarly defined measures can be called cost pass-throughs, riders, K (capital) factors or trackers;
- ***Z-factor*** to recover extraordinary costs that are outside the company's ability to control or forecast and are outside the rate cap framework. The Z-factor allows for adjustment in case events occur that: (i) are perceived as beyond the reasonable control of utility management; (ii) were neither foreseen nor foreseeable at the time a formula was set; and (iii) have a significant impact on company finances;
- An ***earnings sharing mechanisms ("ESM")***, which is designed so that if the formulae-driven price adjustments (rate cap times annual adjustment mechanism) results in a too wide divergence between prices and costs, the extra-normal earnings (or losses) are shared amongst the company and its customers rather than retained (or absorbed) entirely by the company. ESM can be symmetrical or asymmetrical (i.e. customers sharing only in gains and not losses); and
- Performance or ***service quality indicators ("SQIs")***, which are often used concurrently with efficiency incentives, to ensure any cost reductions implemented by the utility do not lead to deteriorating service quality.

Each of the above elements is discussed in extensive detail in the report.

1.2 Union Gas Limited ("Union") proposal

Union is currently preparing its 2014 to 2018 IR plan and is applying the same overarching framework as its 2008 to 2012 IR plan,[2] that is: a price cap with an I-X annual adjustment mechanism and an adjustment for changes in elements such as average use, as well as Y-factors and Z-factors. The proposed IR plan will also contain an ESM and SQIs.

The main parameters of the 2014 to 2018 plan remain largely unchanged, with the following key exceptions:

- the proposed X-factor is 0% compared to 1.82% in the previous IR plan; and
- a smaller asymmetrical dead-band of +100 basis points compared with +200 basis points previously for the ESM.

Union presented the proposed elements to stakeholders at a consultation session on April 29th, 2013.

1.3 Scope of work

Union asked London Economics International LLC ("LEI") to consider how the 2014 to 2018 IR plan proposal presented to stakeholders:

- aligns with the Ontario Energy Board's ("OEB") objectives, which focus on industry viability, competition, reliability of supply and protecting interests of consumers with regards to price; and
- more generally compares with ratemaking approaches applied to other North American gas distribution utilities which operate under similar rate cap and annual adjustment mechanisms.

Union also specifically requested the case study analysis examine historical trends and best practice in the following parameters:

- ***inflation factors***: approaches to establishing the I-factor or applying inflation adjustments which are consistent with concepts of transparency and precedent in Ontario;
- ***productivity and X-factor trends***: methodology of estimating the expected productivity gains, and how these estimates (or actual productivity trends) have evolved during the IR regime implementation;
- ***appropriateness of deferral accounts for unaccounted-for gas (Y-factors)***: application of deferral accounts to account for changes in unaccounted-for gas;

[2] The rebasing year is 2013 and this was part of a separate review process.

- ***treatment of capital projects (referred to as Y-factors)***: how unknown capital expenditures are treated under an IR regime, where unknown refers to uncertainty around the final costs rather than the status of the project itself. Further clarity on the types of projects which would be covered under this category was provided in the draft Settlement Agreement;

- ***treatment of unforeseen events (referred to as Z-factors)***: how unknown expenditures, which may arise of the term of the plan, are provided for under the IR plan;

- ***ESM:*** approaches in other jurisdictions to applying ESMs; and

- ***SQIs and how they are measured***: different service quality indicators that are commonly tracked for the utilities under IR regimes (such as standards for customer service, meter reading, emergency response etc.) and how such SQIs are utilized for the IR processes.

This very specific analysis was required to identify: alternative parameter designs that Union could apply; trends in productivity growth, notably how this is incorporated into an X-factor number, to see if there are broader trends in declining productivity growth as being proposed by Union through its reduced X-factor; and consider whether parameters being applied by Union were generally consistent with IR practices in other jurisdictions.

1.4 Summary of findings

Because I-X is not the only form of IR, LEI has applied a broad definition of IR and reviewed a range of ratemaking plans with differing incentive characteristics. California, Maine and Massachusetts have a long (though not continuous) history of I-X regulation. Alberta and British Columbia have also been included as Canadian jurisdictions applying an IR form of ratemaking regulation to gas utilities. To further explore elements of Union's proposed framework, LEI also surveyed a further eleven gas distribution utilities in the US operating under various regulatory frameworks. The targeted utilities have customer numbers in the range 800,000 to two million, which compares with Union's estimated 1.4 million[3] customers.

The LEI case study and other analysis found that:

- ***inflation factors*** – economy-wide, e.g. Gross Domestic Product Implicit Price Index ("GDP-IPI") or composite measures are used (e.g. average earnings plus economy-wide measures). There is no clear trend favoring one approach over another and Union's proposed use of the Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD") measure is consistent with practices in Ontario, approaches applied by other jurisdictions and reflects simplicity;

[3] Union Gas website http://www.uniongas.com/about-us (accessed 17 June 2013)

- ***productivity and X-factor trends*** – productivity growth is slowing across the utility's industry; slow productivity growth is consistent with the 0% X-factor proposed by Union;
- ***alternative approaches to designing an I-X framework*** – instead of applying an X-factor, some jurisdictions apply a fixed 'stretch factor', for example, by adjusting the I-factor downwards by a ratio to incorporate productivity, or by putting a cap and floor on changes in the consumer price index ("CPI"), or setting a CPI plus target to reflect economic circumstances. Should Union wish to consider providing ratepayers with some form of 'efficiency dividend' and hold rates steady in real terms for the expenditure components covered by the adjustment mechanism then Union could consider one of these alternative approaches;[4]
- ***deferral accounts for unaccounted-for gas (Y-factors)*** – all ratemaking plans reviewed except one provide a mechanism to recover costs for unaccounted-for gas. The mechanisms may vary and not all involve use of deferral accounts. However, the principles are the same: cost recovery for utilities and only pass-through of actual costs to customers. Union's proposal is consistent with these principles;
- ***treatment of capital projects (Y-factors)*** – all ratemaking plans reviewed with an I-X framework provide for treatment of some types of capital projects outside the I-X framework, except for the case of a startup, which is not applicable to Union. The mechanisms may vary but generally revolve around one or more of the following principles: clear project definition; demonstration of 'need'; and thresholds under which a utility cannot apply for a pass-through. Union's proposal is consistent with these principles;
- ***treatment of unforeseen events (Z-factors)*** – most jurisdictions have some form of treatment for costs arising from unforeseen events. These are not open-ended and generally have mechanisms to encourage utility efficiency and minimize costs for consumers, such as a threshold below which costs cannot be passed through and/or scrutiny by the regulator. Furthermore, they may be limited to a specific list of events. LEI finds that Union's proposal to maintain its existing criteria is consistent with approaches applied in other jurisdictions and provides for tight controls and therefore limitations around what unforeseen costs can be passed through to customers;
- ***ESM*** – these are commonly applied to the electricity distribution industry and are also observed in the gas distribution sector, for example, Fortis BC, Bangor Gas (Maine), and Consolidated Edison Company of New York. Union's ESM is generous to ratepayers in that it is asymmetrical and will provide Union with strong efficiency incentives as it is not proposing to share losses with ratepayers; and

[4] As discussed later in Section 12 (Addendum), after discussions with stakeholders for the forthcoming period, Union has ultimately agreed to an inflation coefficient mechanism to set the X-factor, whereby the X-factor = 60% of the I-factor.

- ***service quality indicators*** – these are commonly applied and fall into three broad categories: customer service, safety and network performance, such as reliability. Union's proposal is consistent with the indicators applied in other jurisdictions.

Overall, LEI finds that Union's 2014 to 2018 IR plan is in line with OEB objectives and application of the above parameters is consistent with the approaches taken by similar North American gas distribution businesses operating under IR frameworks. Union's proposal for a reduced X-factor is consistent with declining productivity trends across the gas distribution industry in North America as well as the electricity industry in Ontario.

There is significant variation across and within jurisdictions in the detailed design of the above-mentioned parameters. Provided common sense economic principles are followed, there is no 'ideal' parameter design that will fit all utilities proposing an IR plan. Variations in parameter values reflect the need for practical solutions to meet regulatory objectives while recognizing territory- or business-specific challenges.

1.5 List of acronyms

AU	Average use
AUC	Alberta Utilities Commission
BCUC	British Columbia Utilities Commission
bp	Basis points
CPI	Consumer price index
CPUC	California Public Utilities Commission
DPU	Department of Public Utilities
DSM	Demand side management
ESM	Earnings sharing mechanism
GAAP	Generally accepted accounting principles
GDP IPD	Gross domestic product implicit price deflator
GDP IPI	Gross domestic product implicit price index
GDP IPI FDD	Gross domestic product implicit price index final domestic demand
GDP PI	Gross domestic product price index
FEI	Fortis BC Energy Inc.
ICC	Illinois Commerce Commission
ICM	Incremental capital module

IFRS	International financial reporting standards
IR	Incentive ratemaking
LEI	London Economics International LLC
MFP	Multifactor productivity
NAC	Normalized average consumption
NAICS	North American Industry Classification Systems
OEB	Ontario Energy Board
PBR	Performance-based ratemaking
QRAM	Quarterly rate adjustment mechanism
ROE	Return on equity
RRR	Reporting and record keeping requirements
SDG&E	San Diego Gas and Electric
SQI	Service quality indicators
StatsCan	Statistics Canada
TFP	Total factor productivity
TIRF	Targeted infrastructure recovery factor
UFG	Unaccounted-for gas
WACOG	Weighted average cost of gas

2 Background to Union's 2014 to 2018 plan and OEB objectives

This section sets out Union's 2014 to 2018 ratemaking plan and the broader context, notably the OEB's objectives and approach to ratemaking, in which Union's plan is being prepared. This context is important for informing LEI's evaluation of each of the individual parameters in Union's plan and how the plan meets the ratemaking regulatory framework applied by the OEB.

2.1 Introduction to Union's 2014 to 2018 plan

Union is now preparing for its next IR cycle for the proposed period of 2014 through 2018. The 2014 to 2018 IR plan will primarily apply the same framework as the 2008 to 2012 IR plan, that is: a price cap index which is adjusted annually for inflation, productivity, unknown costs, pass-through costs and changes in average use.

The price cap annual adjustment mechanism is equal to "I – X + Z + Y + AU", where:

- prices are permitted to increase by an inflation rate ("I")[5] less the productivity factor ("X"), which is designed to reflect and encourage improvements in efficiency/productivity;
- AU is the average use factor, applied to adjust rates reflecting the impact of changes in average use per general service customer on a class by class basis;[6]
- the 'Y' factor represents certain pre-determined cost pass-throughs (including upstream gas and transportation costs, incremental demand side management ("DSM") costs and volume reductions and storage margin sharing changes) and capital projects that are pre-specified or meet certain criteria; and
- the 'Z' factor includes certain non-routine adjustments that are not adjusted by the price cap index but are passed through to rates, including elements such as changes in costs beyond the control of management not reflected in the price cap index.[7]

The key elements of Union's proposed 2014-2018 IR plan are summarized in Figure 1. This table also highlights where changes are being proposed, as compared with the 2008-2012 IR plan.

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[5] The I factor being proposed is actual year-over-year change in the annualized average of four quarters (using Q2 to Q2) of Statistics Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand.

[6] This is achieved by reducing the volume used to determine rates by the average of the most recent three years' actual weather normalized volume loss (using the 55/45 blended weather method, updated annually) per general service customer within each rate class. This methodology is similar to how the volume losses associated with DSM are handled when rates are determined.

[7] In the 2008 to 2012 IR plan, the cost pass-throughs were limited by a materiality threshold of $1.5 million annually per Z-factor event. Source: *Board Decision EB-2007-0606 Jan 17th, 2008 includes Union Jan 2008 Settlement Agreement* http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0606/dec_union_enbridge_20080117.pdf; Page 17

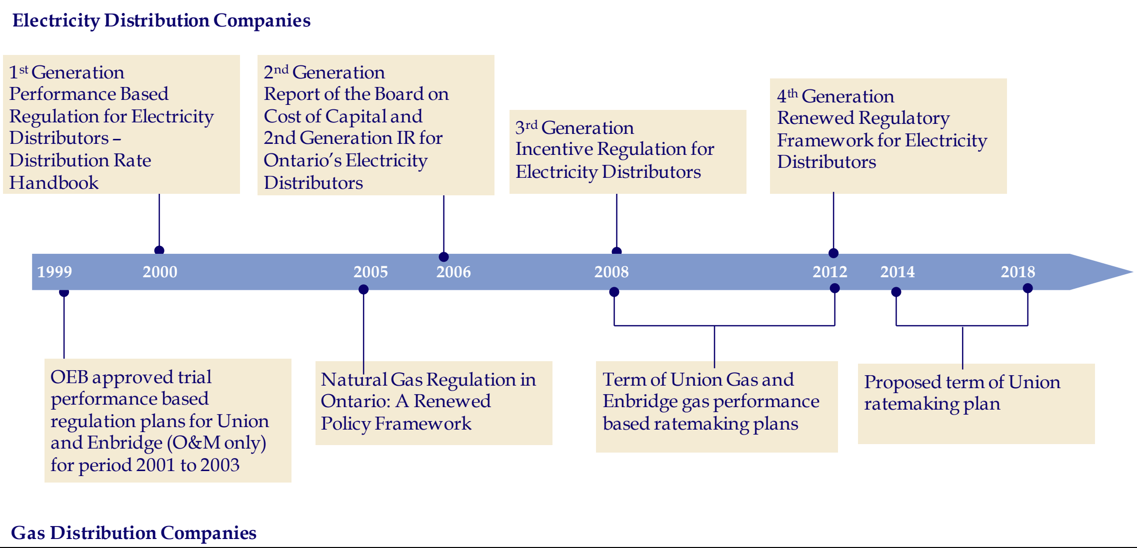
Figure 1. Summary of Union's 2014-2018 IR plan as initially proposed

Key components	*Proposed changes*
X- factor	*No (or zero) X-factor compared to previous fixed X-factor of 1.82%*
Earnings sharing mechanism	*Smaller dead-band (100 bps) with 50/50 sharing beyond that, as compared to 200 bps over approved ROE*
Capital cost treatment	*Separately for larger defined projects (worth capital costs of $25 million or more per project) and projects which meet set criteria*
ROE synchronization	*Pass-through mechanism for annual adjustment to ROE per formula to match ROE in rates to that used for ESM*
Unaccounted for gas	*Deferral account for unaccounted for gas volume*
Exchange revenue sharing	*Net exchange revenues to be treated as revenues and 50/50 sharing of variances being proposed*
Z-factor	*In addition to maintaining existing criteria, adding an adjustment for 2015 rates and parameters for any changes due to OEB Cost of Capital review in 2014*
Off-ramp	*Address misalignment of productivity incentive/reward; regulated utility earnings exceeded the allowed ROE by 300 bps for two consecutive years*
Annual stakeholder information sessions	*Being proposed to explain financial results, sources of earnings, any new activities, and changes in market conditions, including review of gas supply plan*

2.2 OEB's approach to IR regulation and application of objectives

The OEB has been regulating gas distribution business prices since its establishment in the 1960s and electricity distribution business prices since the late 1990s. Since assuming regulation of electricity distribution, the OEB's preference has been to apply IR to encourage efficiency, applied in the form of a rate cap (price or revenue) and annual adjustment mechanism. The annual adjustment has generally been based on an I-X escalation mechanism, where the X-factor represents industry productivity, usually based on historical total factor productivity ("TFP") growth rates, and a utility-specific "stretch" factor. This approach has been applied across electricity and gas distribution, with a longer and more continuous history of application in the electricity sector (see Figure 2).

Figure 2. Ontario history of performance-based ratemaking for electricity and gas



Most recently (2008 to 2012), in the case of gas distribution utilities, the I-X adjustment factors have been applied differently. Union's X-factor was a fixed annual percentage of 1.82%, which fell within a range of historical TFP values presented by expert witness testimonies at the time. By contrast, Enbridge's I-X adjustment applied an X-factor that was set as a percentage of the I-factor and adjusted each year with the resulting implied X-factor fluctuating between 0.396% and 1.365%, depending on the value of the I-factor.[8]

In relation to regulation of the Ontario natural gas sector, the OEB's guiding objectives include:[9]

- facilitating competition in the sale of gas to users;
- protecting the interests of consumers with respect to prices and the reliability and quality of gas service;
- facilitating rational expansion of transmission and distribution systems;
- facilitating rational development and safe operation of gas storage;
- promoting energy conservation and energy efficiency in accordance with the policies of the Government of Ontario; and
- facilitating the maintenance of a financially-viable gas industry for the transmission, distribution and storage of gas.

The OEB has undertaken work[10] over the past decade to streamline gas utility regulation and has established a framework that has the following features:

- establishes incentives for sustainable efficiency improvements that benefit customers and shareholders;
- ensures appropriate quality of service for customers; and
- creates an environment that is conducive to investment, to the benefit of customers and shareholders.

As subsequent sections demonstrate, Union's proposal is consistent with the OEB's objectives with regards to the regulation of the gas sector.

[8] The implied X factors varied and were 0.816% in 2008, 0.693% in 2009, 1.365% in 2010, 0.396% in 2011, and 1.032% in 2012, significantly less than Union's fixed X-factor of 1.82% in each year.

[9] These are the objectives set out in the *Ontario Energy Board Act, 1998*

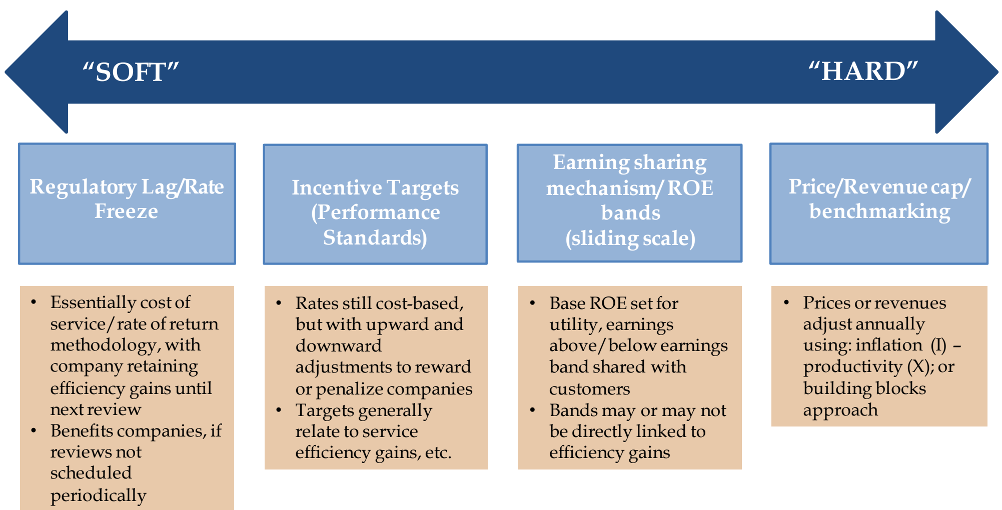
[10] OEB (2005) *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* Report on the Ontario Energy Board Natural Gas Forum http://www.ontarioenergyboard.ca/documents/consultation_ontariogasmarket_report_300305.pdf

3 Ratemaking practices – case study and survey observations

Broadly, IR can be thought of as a spectrum ranging from "soft" frameworks such as regulatory lag, rate freezes and efficiency audits/reviews to "hard" frameworks such as the setting of price or revenue caps, which are formulaic and pre-determined to increase by inflation less an efficiency component or productivity target (see Figure 3). In between there is a range of tools available to a regulator to encourage improvements in a utility's operating performance. These tools may often be combined and should not be considered independent and mutually exclusive.

While conceptually straightforward, ratemaking can be challenging to apply in practice. 'Real world' considerations need to be taken into account, such as: the need for simplicity and transparency; the limitations in translating theoretical concepts such as the economic theory behind TFP growth into feasible numbers applicable to ratemaking, due to data or other constraints; and the circumstances faced by a particular utility at the time of a rate review and into the future.

Figure 3. Continuum of Incentive Regulation Mechanisms



Source: Adapted from LEI (2011) *Performance based rate making in Canada: best practice, key principles and lessons learned in forming a regulatory regime*

It can be helpful to review experience elsewhere in order to demonstrate an IR proposal is consistent with best practice. To further inform LEI's examination of Union's 2014-2018 ratemaking plan, LEI undertook detailed case study analysis of seven utility plans,[11] where 'hard' frameworks (usually I-X regimes) were applied. LEI also undertook a high level survey

[11] The Alberta Utilities Commission ("AUC") undertook a single, combined proceeding for electricity and gas distribution companies. LEI reviewed the two Alberta gas distribution companies (ATCO Gas and AltaGas) separately to assess for any possible difference in treatment. However, given the outcomes were largely the same, for simplicity they are treated as one case study throughout the remainder of the document. Likewise, for Massachusetts, where treatment within the jurisdiction is the same, they are labeled as Massachusetts.

of eleven other utility plans using various regulatory frameworks to provide a more in-depth analysis given the limited extent to which a hard I-X framework is applied in North America. While not all utilities operate under 'hard' frameworks, many of the same elements or regulatory "tools" (e.g. ESMs, regulatory lags and performance standards) are commonly applied.

In summary, the case studies (summarized in Figure 4) and survey analysis (presented in Appendix B) showed one or more of the IR elements being proposed by Union has been applied by most of the gas distribution utilities studied. The approach being taken by Union is well within the range of industry practice. The case study review and survey analysis highlights that although the implementation details may vary, common overarching approaches and principles are applied. When it comes to setting rates, there is a strong focus on productivity and cost containment albeit this is taking place in an environment of slowing productivity growth. The key themes to emerge are as follows:

- one size does not fit all in the design of ratemaking parameters, for example, selection of the I-factor or approach to managing cost recovery for unaccounted-for gas ("UFG") can vary;
- service quality is commonly tracked using various standard indicators; and
- variations in approaches to applying ratemaking parameters are not significant so long as the underlying objectives or principles are met; that is, efficiency is encouraged and rate parameters meet design criteria such as transparency and simplicity.

Figure 4. Summary of regulatory approaches from case study analysis

	Rate cap	X-factor/ productivity	I-factor	Treatment of unknown costs	ESM	Mechanisms for treatment of unaccounted for gas	Service quality indicators
Alberta (ATCO Gas and AltaGas)	Revenue per customer	1.16% (inc 0.2% stretch factor)	Composite (average weekly earnings and CPI)	Z factor with conditions and only for certain types of events	N/a	Separate rate rider	Yes
British Columbia - Fortis BC	Revenue	0.50%	Composite (average weekly earnings and CPI)	Pass through for certain events	Yes 50:50 for earnings above/below ROE	Pass through at cost on quarterly basis with reconciliations between actual and forecast managed through a deferral account	Yes
California - SDG&E	Revenue	Not explicit but assumed to be - 0.75%	CPI Urban	Application needs to be filed for review of costs should they arise	N/a	Fixed cost balancing account	Yes
Maine - Bangor Gas	Price	0.50%	GDP PI	No due to high ROE	Yes 50:50 for earnings above ROE of 15%	No due to high ROE	N/a
Massachusetts - Berkshire Gas	Price	Annual consumer dividend in form of 1% reduction in I factor	GDP PI	Exogenous factors above a minimum threshold of $65,000	N/a	Semi annual adjustment	Yes
Massachusetts - New England Gas Co	Revenue per customer	Not specific but must demonstrate productivity improvements to receive inflation adjustment	GDP IPD	Not specifically mentioned	N/a	Semi annual adjustment	Yes

Note: FortisBC's framework is currently a proposal for consideration before the British Columbia Utilities Commission ("BCUC").

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In the remainder of this section, LEI provides a more detailed explanation of how the case study and survey utilities were selected and then examines how these utilities have practically applied each of the ratemaking parameters.

3.1 Approach to case study selection

LEI looked at seven case study utilities in five jurisdictions where an I-X framework had been formerly applied. A further eleven companies were surveyed to review ratemaking approaches more generally given the relatively small number of jurisdictions applying an I-X framework. Most (nine) of the companies surveyed operated under some form of price or revenue cap with no formal annual adjustment mechanism and only adjustments for specific costs. Where rates are frozen, an implicit I-X regime can be said to be in place where I=X; in other words, I-X=0. Therefore rates did not increase between rate periods except where there may be some specially identified adjustments for capital trackers, riders or other pass-throughs. One of the surveyed utilities applied a framework similar to the case studies. This was not described as an X-factor but had the same effect. One of the companies surveyed had annual cost of service reviews.

The seven case studies were selected from jurisdictions where a history of I-X regulation was available, even if this was not continuous. Variations may have occurred in the approaches taken but a 'hard' form of IR has been applied, notably in California, Maine and Massachusetts in the US. The selection of these case studies also reflected that utilities from these jurisdictions are often included in TFP gas industry studies undertaken for benchmarking Ontario gas distribution utilities. Alberta and British Columbia are included in the case study analysis as examples of Canadian jurisdictions applying I-X regulation even though Alberta has only recently started applying this form of IR.

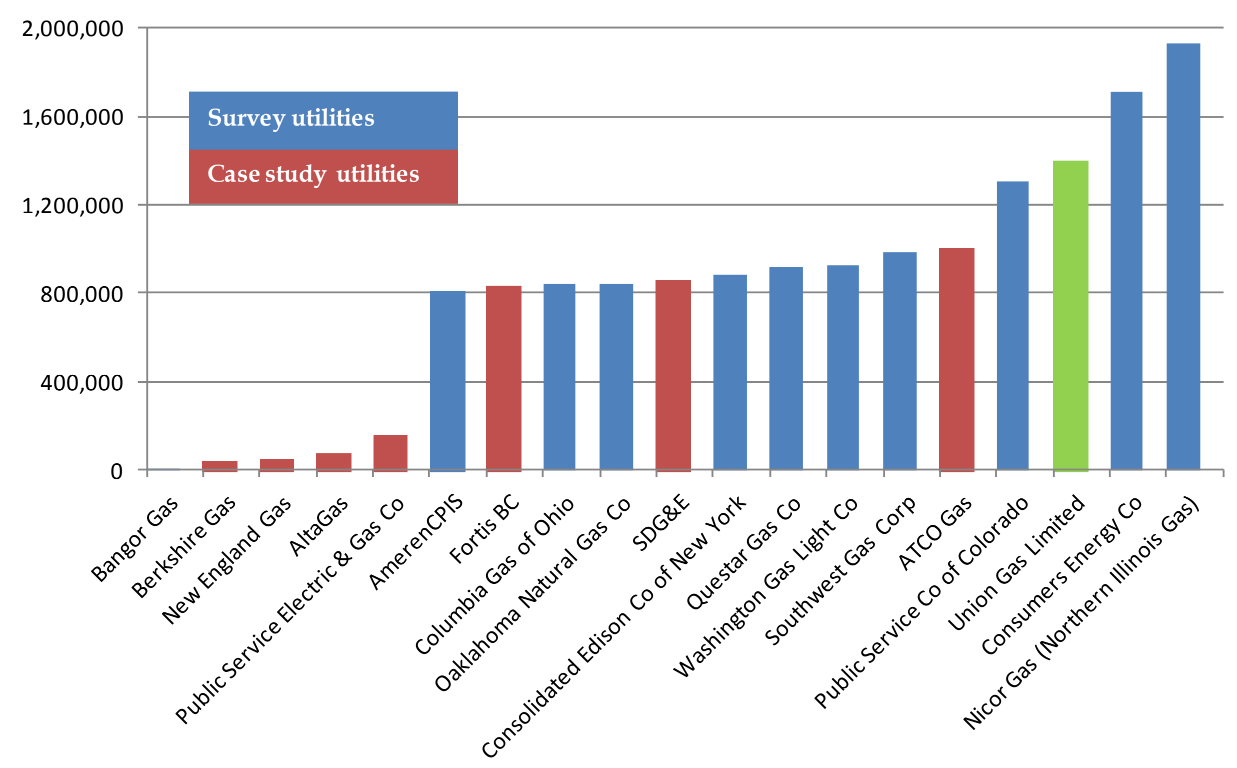
Some of the case studies had relatively small numbers of customers when compared with Union's 1.4 million customers. However, as the focus here is on design parameters, LEI has included the case studies as they reflect relevant examples of I-X regulation. Figure 5 presents the customer numbers for each of the case study and survey gas distribution utilities.

Outside of North America, the most noteworthy international jurisdictions to have a long and continuous history of IR application are Australia and the UK. IR in these jurisdictions has been applied not only to gas distribution, but also electricity, water and transport, among other sectors. Where appropriate lessons can be drawn from these jurisdictions, particularly around productivity analysis, they have been included in the observations in the relevant sections. However, as their approach to I-X (known as building blocks) is different from that currently practiced in Ontario and being proposed by Union for its next generation of IR, a detailed analysis has not been included.

As indicated earlier, to provide broader information on approaches across North America for the parameters that Union requested be investigated, LEI surveyed a further eleven gas distribution utilities across a range of jurisdictions with customer numbers ranging from 800,000 to two million, a range which encompasses Union's 1.4 million customers (see Appendix B for details).

Of these additional utilities, nine applied a form of IR where revenue or price increases were limited in some way (e.g. rate freezes), requiring the company to manage its costs within the cap albeit there may be some adjustments for specified projects. Only one had annual cost of service reviews. The majority (seven) had service quality indicator obligations; three had implemented ESMs.

Figure 5. Case study and survey gas companies – customer numbers



4 IR Framework – Rate cap (revenue or price) with annual adjustments (I-X)

4.1 Theoretical underpinnings

The rate cap sets the maximum price or revenue that a utility can recover and may be adjusted annually, often by an I-X formula.[12] This trend was also evident in the survey utilities with only three applying a price cap. The approach to annual adjustment mechanisms is more varied with the case study jurisdictions all applying a variant of the I-X formula.

At its simplest, there are two key principles embedded in the I-X formula. First, it allows a utility to be compensated for general inflationary costs so that the utility has the opportunity to earn a fair return. Second, it provides an incentive for a utility to contain costs, for example by improving efficiency. The adjustment downwards of the I-factor by an efficiency incentive measure, the X-factor, means that the utility will only be able to increase prices by less than inflation. There may be nominal rate increases if the X-factor is less than the I-factor, however, this mechanism results in customers facing a decrease in real rates so long as the X-factor takes a positive value.[13]

It is also important to note that the selection of the X-factor and the I-factor is inter-dependent. If the I-factor used is an input-based index, then the X-factor will simply reflect the productivity growth of the industry and can be adjusted to account for recent historical firm performance. If an output-based price index is used, such as the CPI or GDP deflator, then the index will reflect the effects of economy-wide productivity, and the X-factor is interpreted as the difference between the productivity growth rates of the industry and the overall economy.

The approach to calculating the X-factor can be highly technical and is often based on TFP studies in North American I-X IR regimes. TFP studies present a variety of empirical approaches, but they all share a common goal, which is to document the observed historical change in inputs and outputs over a given period of time, thereby capturing average trends in productivity over time. TFP studies, while potentially providing an indication of past performance, provide little insight into what is achievable in the future. Furthermore, TFP studies and the empirical results depend on the available historical data, length of the time series, selection process and assumptions made around data variables used to represent inputs and outputs, as well as the specific empirical techniques chosen. The results can also be the subject of much debate between regulators, utilities, intervenors and other parties.

[12] As presented earlier in Figure 4, a majority (five) of the case study utilities apply a form of revenue cap reflecting a move towards decoupling prices from revenues as average use per customer is declining.

[13] Rates may rise in real terms due to other elements of the formula. For example, rates may rise due to capital expenditure required to maintain reliable service.

4.2 Practice in other jurisdictions

Given the challenges of deriving an X-factor, regulatory decisions and settlement agreements have sometimes sought to embed the key principles of the I-X formula in ratemaking plans, while moving away from relying solely on historical TFP studies, although these can still be important for informing decisions.

Figure 6 presents examples of I-X being set as: (i) inflation factor plus an X-factor (where X-factor is positive 1% in the case of Berkshire Gas Company, and negative 0.75% in the case of San Diego Gas & Electric ("SDG&E"); (ii) inflation with a cap and floor on the maximum and minimum increase, and an inflation coefficient mechanism (whereby the X-factor is < 100% of the inflation factor), converting I-X to I*X.

These approaches have a number of benefits relative to cost of service regimes, notably they still provide: (i) strong incentives for utilities to improve efficiency as they cap costs; (ii) an opportunity for the utility to earn a fair return; and (iii) simplicity, so that all stakeholders can understand the approach being taken.

The survey analysis (Appendix B) showed that many (nine) jurisdictions effectively apply an (I-X) of 0 by setting rate freezes or not adjusting rates between regulatory periods; that is, the X-factor is implicity set equal to the I-factor. There may still be some adjustment for capital trackers for specific projects, riders for gas costs and adjustements for unknown costs just as there would be under an explicit I-X IR framework.

Figure 6. Selection of alternative approaches to embedding productivity in the I-X formula

Regulator	Utility and ratemaking period	Approach	Regulator comment
CPUC	SDGE (2012-2015)	CPI plus 75 basis points	Reflects current economic circumstances plus consistency with previous decisions
CPUC	SDGE (2004-2007)	CPI with a cap and floor on the maximum and minimum increase	CPUC recognizes that this approach displaces the use of a productivity factor and a stretch factor and finds it to be a reasonable compromise of their litigated positions.
MA DPU	Berkshire Gas Company (2002-current)	Annual price adjustment (including an inflation adjustment) that provides a guaranteed annual consumer dividend (in the form of an annual 1% reduction to the GDP inflator)	Regulator notes that customers have enjoyed rate stability and predictability as a result of the price cap mechanism
OEB	Enbridge (2008-2012)	Inflation coefficient	I-factor adjusted downwards by a percentage factor in lieu of the inclusion of an 'X factor' and/or a 'stretch factor'

4.3 Why Union proposal is appropriate

Union's proposed IR framework, a price cap with annual adjustments for inflation, efficiency and changes in customers, as well as adjustments for Y- and Z-factors is a commonly used framework in ratemaking. This framework provides efficiency incentives as Union must operate within the price cap arrangement and has limitations on the extent to which it can pass-through any costs outside the framework to ratepayers, i.e., via Y- and Z-factors. LEI's assessment of each of the individual elements is discussed below.

In relation to the IR framework, the trend in gas utility regulation is to apply revenue caps rather than price caps reflecting changes in average customer consumption. Union is proposing to maintain the price cap arrangement; however, there will also be adjustments for average customer use, this therefore achieves similar objectives as a revenue cap framework. Union will still have the opportunity to earn a fair return in the face of declining average consumption, as the price cap will have an adjustment element for customer use. Therefore, Union's proposal to adopt a price cap framework is consistent with industry trends.

5 I-factor (inflation factor)

5.1 Theoretical underpinnings

The I-factor allows a utility to maintain the required level of revenue to compensate for general increases in costs, as measured by inflation, which are beyond its control.

> **Summary of I-factor approaches**
>
> - Economy-wide inflation measure (e.g. CPI or GDP-IPI)
> - Composite measure (e.g. based on combination of independent and public wage and price index measures)

There are three primary considerations when assessing which index to choose: first, does any particular index or combination of indices more appropriately reflect the company's observed cost behavior than another? The index should also be exogenous to the business, that is, the business itself should not be able to influence the level of the index itself. Second, does the index rely on readily available public data from a reliable source? Additional considerations under this criteria would be that the index be available on a timely basis, and not subject to continuous revision. Third, is the index generally accepted by ratepayers as being a reasonable estimation for how overall costs in the economy change over time? Is it transparent and easily understood? A further fourth issue might be referred to as "theoretical cost congruence," and refers to the extent that the index components consist of goods and/or services that the utility actually buys. While it may not be possible to satisfy each of these criteria perfectly, index selection can reasonably take each into account.

To meet these considerations, there are generally two broad types of approaches to determining the I-factor: using an economy-wide measure of inflation such as the CPI or GDP IPI; or creating a composite measure of inflation based on a combination of wages and general inflation. Both these approaches meet the second consideration. That is, they are transparent, independent of the business and not subject to continuous revision. The choice of I-factor also informs the form of productivity analysis used to develop the X-factor.

5.2 Practice in other jurisdictions

Jurisdictions applying (or that have applied) I-X regulation use either CPI or GDP IPI as an economy-wide I-factor, depending on their needs and circumstances. In lieu of explicitly using an economy-wide measure alone, Alberta is applying a composite index based on average weekly earnings and CPI, as can be seen in Figure 7, and FortisBC has also proposed a composite index.

The survey analysis (see Appendix B) identified that where inflation adjustments were applied (only one company) an economy-wide measure was used, the GDP price deflator. The approach of using an economy-wide measure, while more independent from a company's own behavior, may not reflect changes in a company's observed costs to the same extent as a composite measure, although this can be partially addressed by using GDP IPI rather than CPI if only a single measure is used. However, an economy wide approach may be generally more accepted by ratepayers as a reasonable estimate of changes in the overall economy and cost pressures more likely to be faced by consumers. This was the argument highlighted by the California Public Utilities Commission ("CPUC") in selecting an economy wide (CPI) measure rather than a more utility-specific measure (see Section 13.3.3).

Figure 7. Examples of I-factor approaches

Alberta	*Composite weighted index based on Average Weekly Earnings (55%) and CPI (45%)*
British Columbia	*2014 to 2018: Proposed composite based on Average Weekly Earnings and CPI;* *2004 to 2009: CPI*
California (SDG&E)	*2012-2015: CPI-Urban (US Bureau of Labor Statistics);* *2008-2012: Not applied*
Maine (Bangor Gas Co.)	*GDP IPI*
Massachusetts	*GDP IPI: Berkshire Gas since 2002* *Other utilities (New England Gas - no inflation adjustment applied)*

5.3 I-factor experience in Ontario

In the Ontario gas sector, previous IR plans have used GDP IPI FDD published by Statistics Canada ("StatsCan") as the I-factor.[14,15] However, in the Ontario electricity sector, for the first generation of IR (2001-2006),[16] the OEB approved an I-factor that tracked the composite inflation trends for the utilities' specific inputs across three categories: labor, materials and capital. For the second generation (2007-2009),[17] the OEB preferred to use the macroeconomic measure of inflation and approved the use of GDP IPI FDD as published by StatsCan. The same index was approved for the third generation IR[18] (2009-2013) as well.

[14] OEB. Decision with Reasons. Application by Union Gas Limited for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission, and storage of gas for periods commencing January 1, 2001, and January 1, 2002. September, 20, 2002

[15] OEB. Decision. Application by Union Gas Limited for an Order or Orders approving or fixing a multi-year incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008. January 17, 2008

[16] OEB. Electricity Distribution Rate Handbook. November 3, 2000

[17] OEB. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2006

[18] OEB. Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008

For the forthcoming fourth generation of IR (starting from 2014),[19] the OEB is proposing that inflation will depend on the ratemaking framework chosen by the electricity utility. For utilities choosing fourth generation IR or the annual IR approach a composite index will be used. The composite index will be a utilities industry specific input price index (final determination to be made after stakeholder consultations), which is similar in theory to the input-focused industry inflation indices used in Alberta and proposed by FortisBC. Where a utility chooses a customized ratemaking approach, then the I-factor will be informed by both the utility's and the OEB's analysis of inflation.

5.4 Why Union's proposal is reasonable

Union proposes to use the same I-factor index for its 2014-2018 ratemaking plan as it did in its previous IR plan. This I-factor is calculated based on the actual year-over-year change in the annualized average of four quarters (using Q2 to Q2) of StatsCan's GDP IPI FDD.

Canadian gas utilities in Alberta and BC (as are electricity utilities in Ontario) are using I-factor composite measures which specifically reflect labor costs as well as CPI. However, the US utilities examined by LEI under a 'hard' I-X IR framework use a GDP based measure except for SDG&E, which uses a CPI measure. The use of GDP IPI or CPI inflation measures may be less reflective of a utility's own cost experience, but these measures have the advantage of being robust, transparent, widely used and well understood/accepted by consumers.

Either index approach, industry-wide or composite, would meet OEB criteria as they:

- support a financially-viable gas distribution industry by allowing a utility to recover costs beyond its control; and
- protect the interests of consumers with respect to prices by containing price rises to measures that are consistent with inflationary pressures being faced across the economy.

LEI finds that Union's proposed approach is reasonable as the measure it proposes to use:

- reasonably takes into account the generic requirements of an index for the purposes of providing a reasonable balance between consumer protection and providing the utility with an opportunity to earn a fair return. That is, the GDP IPI FDD measure:
    - broadly reflects the cost pressures faced by Union, and the index cannot be influenced by Union. As with any generic measure, it will only be a proxy for the cost pressures faced by Union but it still provides Union with the opportunity to recover inflationary pressure costs while also providing incentives for Union to manage its costs within the limit imposed by the index;
    - is transparent and publicly available; and

[19] OEB. Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. October 18, 2012

    - acceptable to ratepayers, as reflected in its adoption in previous Ontario gas sector and electricity sector (second and third generation) IR plans
- meets OEB objectives; and
- is consistent with industry practice.

6 Productivity - X-factor, historical TFP and productivity trends

6.1 Theoretical underpinnings

The X-factor sets the efficiency performance incentives for a utility. Generally, an X-factor should take into consideration the levels of productivity a utility has already achieved, observed levels of productivity at similar entities, the rate at which productivity is expected to be able to increase in the future, and the capability of that specific utility (if well-run) to achieve similar levels of productivity growth.[20]

Productivity investments, like other investment types, face declining marginal returns; as the most attractive opportunities are exhausted, less remunerative alternatives are harvested, until ultimately the frequency of productivity enhancing activities slows. Well-run utilities which have already made strides in improving efficiency may find it harder and harder to continue to do so at the same rate.

As discussed earlier in Section 4.1, the I- and X-factors cannot be considered in isolation; it is the final 'output' of the formula (I-X) which sets the performance incentive for a utility. In short, where the X-factor is above 0, a utility must make productivity improvements in order to absorb any cost pressures from inflation. At the same time, an X-factor of 0 does not mean that a utility is getting less efficient; it may simply imply that the utility has already achieved an optimum level of productivity, or in making capital investments anticipates that its inputs will be growing faster than outputs over the term of the plan.

6.2 Practice in other jurisdictions

US historical data (presented in Figure 8) indicates a downward trend in productivity across electricity and combined electricity and gas utilities. Declining productivity growth trends can be due to a variety of factors, including the pace of technological change, the timing for its adoption, changing demand patterns, general economic conditions, regulatory changes, demographics etc.

Furthermore analysts must be mindful of the impact of diminishing returns. If historical TFP studies are used for guidance, the economically justifiable productivity target for the future represented by the X-factor is likely to fall below those levels implied by actually achieved productivity trends in the past, reflecting the fact that efficiency gains may be more difficult to achieve as the most evident operational changes are deployed and the overall economic environment remains challenging.

Although Figure 8 presents TFP trends in both electric and combined electric and gas utilities, LEI believes that the electric and gas utilities have similar institutional characteristics and cost

[20] While classic regulatory theory suggests that the X-factor should reflect only industry trends, this ignores practical considerations such as the need for regulators to consider issues of financial stability and the limitations of productivity studies themselves.

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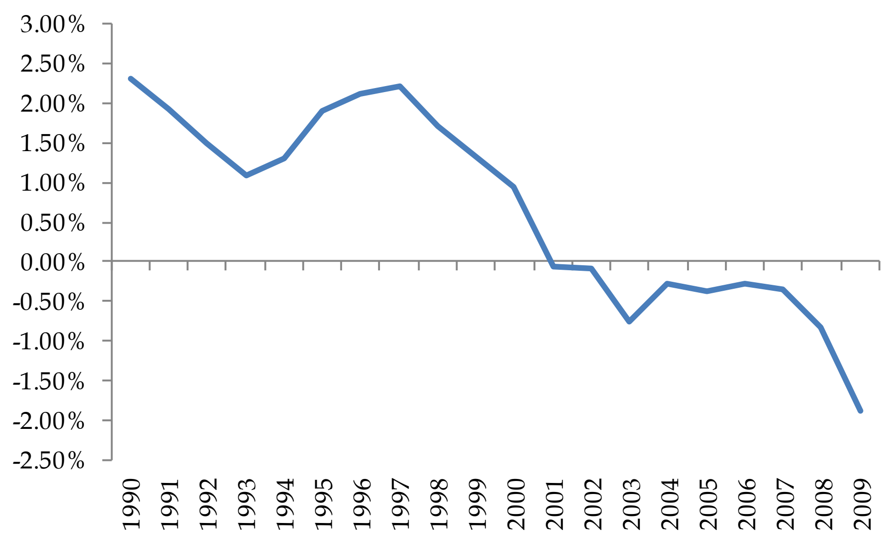
drivers, such as commercial and regulatory requirements, level of capital intensity, labor and operational and maintenance issues etc., resulting in comparable productivity growth trends. This is also consistent with Alberta Utilities Commission's observations in its recent natural gas performance-based ratemaking ("PBR") decision: "*Based on the evidence in this proceeding, and because of the similarities in the institutional framework, business environment and regulatory requirements between the gas and electric distribution industries, the Commission finds that TFP research from one industry can be used to estimate productivity growth for firms in the other industry when transparent and robust data for both industries are not available*."[21]

Figure 8. US utilities* TFP trends over last 20 years (5-year rolling averages)



** Utilities include electric and combined gas and electric; Source: adapted by LEI from 'Total Factor Productivity Study for use in Alberta Utilities Commission ("AUC") Proceeding 566 – Rate Regulation Initiative.' Prepared by AUC Consultants. December 30, 2010.*

6.2.1 TFP trends observed in case studies

It is questionable whether substantial incremental productivity gains can be reasonable expected where IR has been in place for extensive periods and the least cost and/or most effective projects have already been implemented. To explore this issue further, LEI has also examined TFP studies submitted as part of ratemaking processes as well as broader productivity trends across the Canadian energy sector, particularly the gas distribution sector.

The requirement to look at broader measures of productivity has been necessitated by the limited long-term experience of jurisdictions applying an I-X approach to rate regulation. The OEB is one of the only North American jurisdictions with a history of consistently applying I-X incentive ratemaking. The OEB's application of I-X for the electricity sector has been regularly

[21] AUC Decision 2012-237 – Rate Regulation Initiative. September 12, 2012

applied, that is a rate cap and annual adjustment mechanism, since it began regulating electricity distributor rates in 2001.[22] Gas utilities are entering their second round of I-X IR, although there was an earlier period when a similar ratemaking framework was trialed in the early 2000s (see Figure 2).

Both the UK and Australia have also applied IR to the gas distribution sector for extensive periods – in the UK for over 20 years and in Australia just under 20 years. The form of IR used in the UK and Australia is also a price or revenue cap, although the X-factor is determined by way of a building blocks rather than exclusive reliance on TFP studies, as the case has been in North American 'I-X' plans. Specifically, the X-factor in the UK and Australia embeds productivity within the forward looking analysis of required revenues, although TFP studies and benchmarking are still used to assess whether the forward looking analysis of required revenues is reasonable. More importantly, in these jurisdictions, achieved productivity can still be observed and tracked to look at how trends have changed over time.

Overall productivity trends appear to be declining, however, some caution needs to be taken in interpreting these results as there could be a number of factors driving the observed decline in achieved productivity in addition to diminishing returns, including economic cycles.

6.2.2 X-factor and TFP trends across North American utilities from ratemaking processes

TFP studies submitted as part of ratemaking processes for gas and electric utilities suggest that productivity growth rates are slowing for gas and electricity utilities in North America. Some notable examples are presented in Figure 9. LEI was not asked to perform its own TFP study for North America gas distribution sector, nor to opine on the validity of the studies mentioned below, and includes these for the purposes of illustrating declining productivity trends and where appropriate how this impacts the X-factor.

The slowing or zero growth productivity trends in the more recent gas utility TFP studies are also reflected in the latest electricity TFP study for Ontario.[23] The Ontario TFP study for electricity distributors (2002 to 2011) concludes that actual average TFP growth has been close to 0% based on two different methodologies (index-based and econometric) and recommended the OEB apply an X-factor of 0% and maximum stretch factor of 0.6% for future electricity IR plans. This compares with an X-factor of 0.72% and a maximum stretch factor of 0.6% in the previous round of electricity IR (3rd generation).

Similarly, in a recent (March 2013) study prepared by LEI for ENMAX Power,[24] LEI extended its TFP analysis of Ontario's electricity distribution companies, originally performed in 2007 and

[22] OEB (2012) *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, p.7

[23] "*Empirical Research in Support of Incentive Rates Setting in Ontario: Report to the Ontario Energy Board*" (2013) Lawrence Kaufmann, Dave Hovde, John Kalfayan and Kaja Rebane; May 2013

[24] "*Total Factor Productivity of Ontario's Electricity Distributors: Extended Study*": March 27, 2013; prepared by LEI for ENMAX Power Corporation as Additional Evidence for Formula Based Ratemaking Transmission Tariff Re-Opener Application (No. 1608905, Proceeding ID#2182) of October 15th, 2013

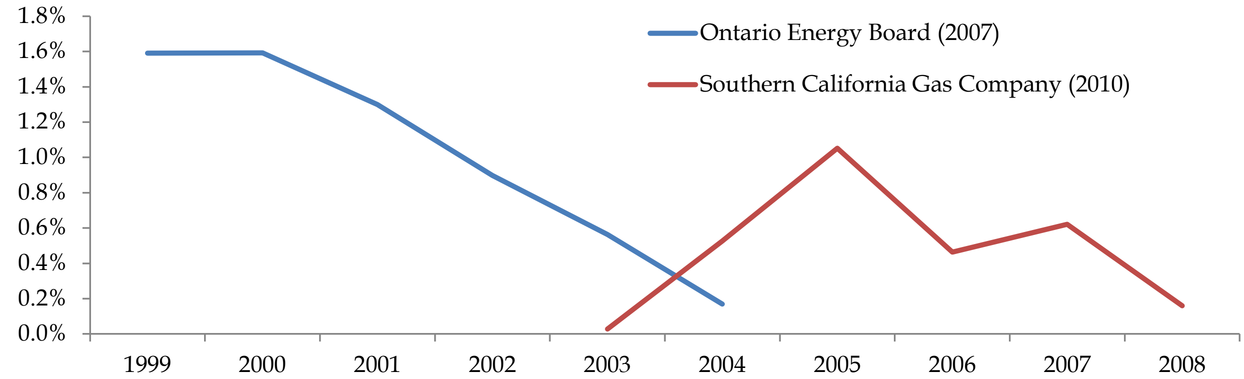
updated in 2009. The extended study suggested that, across five different scenarios tested, the average annual TFP growth rates ranged between -0.7% and -0.2% over the last ten years (2002-2011).

Figure 9. North American gas TFP studies for rate making proceedings

TFP Study	Details and where applicable X-factor implications
Price Cap Index Design for Ontario's Natural Gas Utilities (2007) Prepared for Ontario Energy Board by Mark Lowry, David Hovde, Lullit Getachew and Steve Fenrick	The study (1994 to 2004 data) shows US gas utilities had a growth rate of 0.87% in TFP. The final approved X-factor was 1.82%, based on a number of X-factor values proposed during the proceedings.
Direct Testimony of Mark Lowry on behalf of Southern California Gas Company (2010) Prepared Mark Lowry and David Hovde	Covers 34 US gas utilities' data from 1998 to 2008 and shows declining productivity from average of 1.18% per annum over entire study with growth of 0.99% per annum over the last 5 years. The study was not used to determine an X-factor as the rate making framework set a revenue cap with annual fixed revenue requirement adjustments. The study was prepared to meet a CPUC requirement that investor-owned utilities report on productivity trends in general rate case proceedings.
Total Factor Productivity Study for use in AUC Proceeding 566 – Rate Regulation Incentive (2010) Prepared by Jeff Makholm, Agustin Ros and Meredith Case	Covers 72 US combined gas/electricity and electricity companies from 1972 to 2009 and showed final results of 0.96%. The X-factor approved was 1.16% based on the analysis from the TFP study and a stretch factor of 0.2% (0.96%+0.2%=1.16%).
Estimating Total Factor Productivity (2013) Prepared for FortisBC Inc. by its consultants	Covers 95 US gas utilities for the period 2007 to 2011 and shows productivity is 0%. Despite the 0% productivity finding, FortisBC has proposed an X-factor of 0.5% as part of an overall package of measures to ensure continuity of productivity improvement.
Incentive Ratemaking Report (2013) Prepared for Enbridge Gas Distribution by James Coyne, James Simpson and Melissa Bartos	Covers 25 companies for the period 2000 to 2011 and shows TFP is -0.32% with a more efficient seven company subgroup recording a productivity of -0.01%. Based on this analysis a 0% X factor was applied to analyze Enbridge's plan.

Figure 10 presents five-year rolling average TFP growth rates across the two studies focusing on gas utilities only. Both studies suggest that the growth in productivity has largely dissipated and indicate declining trends approaching 0%. The study prepared for FortisBC Inc. does not include data to perform a similar 5-year rolling average analysis; it only covers the last five years and uses a different methodology to the first two studies. It surveys 95 US gas utilities for the period 2007 to 2011 and estimates productivity to be 0%.

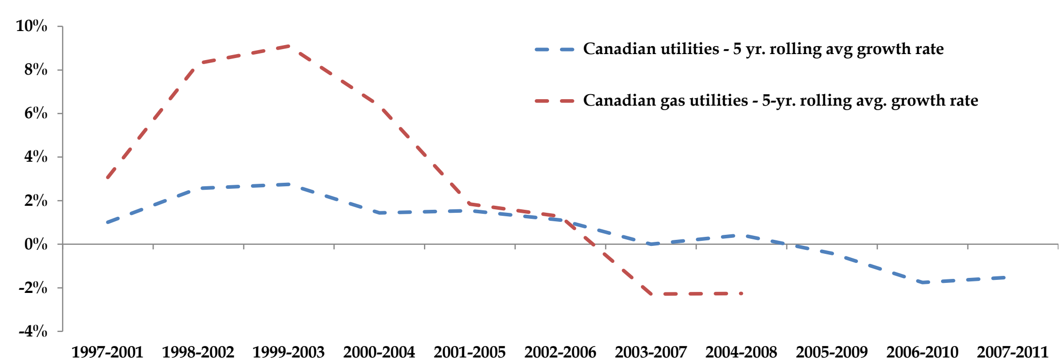
Figure 10. TFP growth rates (5-year rolling average) across gas utilities' TFP studies



6.2.3 TFP trends across the Canadian utilities sector

There has been a downward trend in the Multifactor Productivity ("MFP")[25] growth in Canada for the utilities sector[26] and gas utilities subsector (Figure 11).

Figure 11. Average TFP growth rate of the utilities sector and gas utilities subsector



Note: MFP data for the Canadian gas utilities sector is available until 2008 only

Source: Statistics Canada *(CANSIM Table 383-0021 for the Canadian utilities sector and CANSIM Table 383-0022 for the Canadian gas utilities subsector - Accessed on June 10, 2013)*

The MFP, which is the ratio of the real value of output over the combined input of capital and labor, is generally recognized by regulatory commissions as well as in economic literature and

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[25] Statistics Canada publishes annually an MFP index along with sector and sub-sector indices as a whole for the business sector. The sector indices use the North American Industry Classification Systems ("NAICS") where utilities is one of the sectors.

[26] The utilities sector is composed of two subsectors: (i) electric power generation, transmission, and distribution; and (ii) natural gas distribution, water, and other systems. While we recognize that these classifications include segments other than gas distribution, they are nonetheless illustrative of relevant trends.

empirical studies as an industry productivity index. According to StatsCan, over the last decade, the 5-year rolling average growth rate for the Canadian utilities sector MFP has decreased steadily from a high of 2.8% in 2003 to -1.5% in 2011. A similar trend can be seen for the gas utilities sector, where the 5-year rolling average MFP growth rate decreased from 9.1% in 2003 to -2.3% in 2008.[27]

6.2.4 TFP trends in Ontario

The downward trend in utilities sector productivity is also evident in Ontario, where incentive regulation has applied for electricity distribution since 2001 and gas distribution since 2008. The most recent data series[28] on the provincial MFP indices released by StatsCan show that there has been significant negative growth in the MFP for the Ontario utilities sector recently. The average MFP growth rates of Ontario utilities have also been negative for the most recent 13, 10, and 5 years through 2010, as presented in Figure 13.

Figure 12. MFP 5-yr rolling average growth rate for Ontario utilities sector (1998-2010)

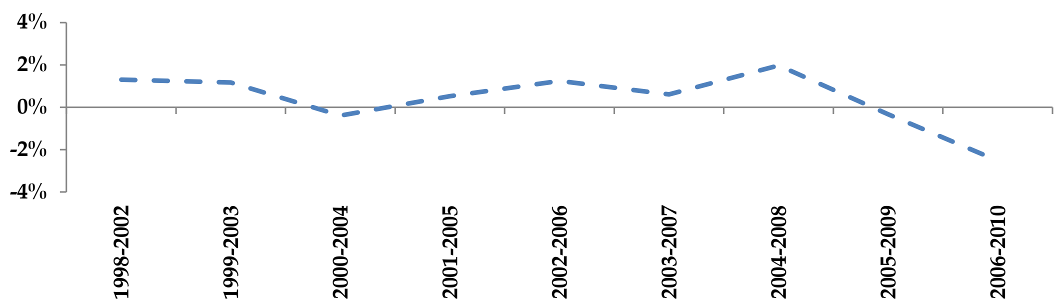

Figure 13. Average MFP growth rates for Ontario utilities sector

Province	13-Year Avg (1998-2010)	10-Year Avg (2001-2010)	5-Year Avg (2006-2010)
Ontario	-0.5%	-1.0%	-2.5%

Note: MFP data for the Ontario utilities sector is available from 1997 to 2010 only; Source: StatsCan *Table 383-0026* (Accessed on June 10, 2013)

6.2.5 TFP trends for international gas utilities

The trends observed in North America are consistent with trends in other jurisdictions applying IR. Overall, utility productivity trends in Australia are also declining with long-term MFP

[27] The CANSIM Table 383-0022 (MFP for Gas Utilities) has data until 2008 only. There is a three-year reporting lag for this dataset.

[28] The MFP dataset for the Canadian Utilities Sector, the CANSIM Table 383-0026 includes both the aggregate business sector as well as the major sectors such as utilities, mining and oil and gas extraction, manufacturing, and construction, to name a few. The data currently available is from 1997 to 2010 only.

growth for electricity, gas, water and waste services equaling -1.3% for the period from 1989-90 to 2011-12 and more recent shorter term (2007-08 to 2011-12) at -4.5%.[29] The Productivity Commission noted that structural factors have raised input costs without any corresponding increase in outputs as for the utilities sector "input use has risen to enhance the environment, amenity, safety and reliability of supply."[30]

6.3 Why Union's proposal is appropriate

Union's proposal to reduce the X-factor to 0% reflects its experience responding to productivity incentives in the past. Union is entering the 2014-2018 IR framework after having already taken steps to improve productivity.[31] During the previous plan term, consumers received real reductions in gas rates with the I-X formula (not accounting for other adjustments), which on occasions were negative as inflation was low.[32] Union's X-factor of 1.82% in its 2008-2012 plan was significantly above X-factors indicated by the studies examined earlier in Section 6.2.2. The highest gas industry productivity measure across these studies was 1.18%, as presented in the study for Southern California Gas Company.

Union's proposal for a 0% X-factor is consistent with more recent industry experience.[33] Declining trends in utility productivity are common across North America with increasing investment in non-revenue generating assets for safety and integrity as well as Government environmental policy driving the declines in productivity.[34]

Furthermore, Union's proposed X-factor will provide it with a more reasonable opportunity to earn a fair return, which is consistent with one of the key OEB objectives of maintaining a financially-viable gas industry. The I-X framework will continue to incentivize Union to improve efficiency, as Union will still need to operate within the constraints of a price cap, assuring that its costs increase by no more than inflation to achieve its allowed rate of return. It also needs to manage unknown costs by finding efficiency improvements, as any unknown costs under the Z-factor threshold (of $1.5 million)[35] must be absorbed by Union.

In this context, LEI finds that Union's proposed 0% X-factor provides a reasonable balance between the interests of the consumers and industry viability.

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[29] Productivity Commission (2013) *PC Productivity Update*, p.22

[30] Ibid. p.2

[31] A study for the OEB in 2007 estimated Union's average annual TFP growth rate to be over 2.4% for the period 1999-2005. Source: *Price Cap Index Design for Ontario's Natural Gas Utilities*; March 30th, 2007; Table 5

[32] As occurred in 2009, 2010 and 2011

[33] For example, a TFP study for the OEB recommended a 0% X-factor for electricity. The OEB has yet to make a decision in this matter. A TFP study for FortisBC recommended a 0% X-factor, although FortisBC has proposed a 0.5% X-factor, which is currently under consideration by BCUC.

[34] This is similar to the Australian experience see Section 6.2.5.

[35] Union is proposing to maintain existing Z-factor criteria (as the 2008-2012 plan)

Alternatively Union could consider one of the following approaches applied to determining the I-X annual adjustment such as:

- an inflation coefficient, where the I-X formula becomes a fixed percentage (less than 100%) of the I-factor, for example, the approach taken by Enbridge in its 2008-2012 ratemaking plan; or

- an 'efficiency dividend' approach, where the X-factor is set at an agreed fixed percentage. This is the approach currently being proposed by FortisBC, which is proposing a 0.5% X-factor, and Berkshire Gas Company, where a 1% reduction in the GDP inflator is applied.

The benefits of these approaches compared with Union's current proposal are that they provide stronger efficiency incentives and benefits to ratepayers through reductions in real rates. While productivity gains may be limited in the current environment as reflected in Union's 0% X-factor proposal and Union's approach as discussed above is entirely reasonable in this climate, the two alternative methods effectively become a 'stretch factor' for Union.[36]

[36] As noted earlier in footnote 4, after discussions with stakeholders, Union has ultimately agreed to an inflation coefficient mechanism to set the X-factor, whereby the X-factor = 60% of the I-factor.

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7 Cost pass-throughs for known projects or cost categories (Y-factors)

Arrangements for the pass-through of costs where the project or cost category is known and/or the costs are non-discretionary but the actual costs are not yet known (or cannot be reasonably estimated) is common practice. These arrangements can go by a variety of names, including the Y-factor, rider, capital tracker (of one or more years in duration) or pass-through. While they have different names, there are common principles applied to the design of these arrangements, although not all may necessarily apply. One or more of the principles that may apply are:

- to clearly define the purpose for the pass-through;
- to apply to capital costs which are anticipated, but where the actual costs may not be known at the time of the ratemaking application or where costs cannot be reasonably estimated thereby requiring some form of separate tracking mechanism;
- pass-throughs are subject to a high level of scrutiny and transparency as well as a strict approvals process;
- affected items are non-discretionary;
- no annual adjustment (i.e. I-X) mechanism applied to these items. Where the costs for recovery are not set on a regular basis upfront, there is often a reconciliation process so that a utility cannot over/under recover the costs of providing the service; and/or
- subject to a variety of 'cost controls' such as materiality thresholds or caps on expenditure.

While there is a wide number of projects or cost categories for which costs can be passed through, LEI was asked to focus on two categories – UFG and major capital projects.

7.1 Treatment of UFG

7.1.1 Theoretical underpinnings

To facilitate a financially-viable gas distribution industry and protect consumers with respect to price, the ratemaking framework needs to provide flexibility for a utility to be able to recover its costs while at the same time consumers should only pay for actual costs and the cost of administration with appropriate incentives. The utility should not be earning a significant profit on the cost of services which it is merely passing through to the consumer. In the gas distribution sector, one of the key pass-through costs faced by a utility on behalf of consumers is the cost of the gas itself, including all services associated with the supply of the gas, such as UFG or 'lost gas.'

The mechanisms applied to UFG through the ratemaking review process come under a variety of names (e.g. deferral accounts, balancing accounts, adjustment mechanisms, tracking mechanisms or riders) and focus on total gas supply costs (including UFG) or separate treatment of UFG. Alternatively, they can be formulaic approaches applied through administrative codes. Either way they generally have the same operating framework consisting of two steps. First, pass-through costs, such as gas supply (including UFG) or just UFG, are forecast so that tariff rates can be set in advance. Second, a reconciliation or true-up between forecast and actual costs will occur such that a utility only recovers its actual costs in the long-term and does not make a profit. Variation in the treatment of gas supply pass-through costs is more apparent than real; in practice there are few substantive differences.

The timeframes for estimation and reconciliation can vary regardless of regulatory approach applied, for example, estimation of gas supply costs and/or UFG may be on a monthly or quarterly basis, while reconciliation usually occurs annually. These differences are also not substantive in the context of the impact of customers as they will eventually only pay for the actual costs of the gas supply and the utility will also recover its costs where undercharging has occurred. The only issue for the utility is the duration over which it must fund under-recovery of gas costs if this occurs.

7.1.2 Practice in other jurisdictions

Among the case study utilities examined by LEI (see Figure 14) and the survey utilities (see Appendix B), all the gas distribution businesses except one (Bangor Gas, Maine), were allowed to recover UFG. Bangor Gas was not permitted to recover UFG, however, this reflects circumstances specific to Bangor Gas as a start-up company and therefore is not relevant to Union. The regulator, Maine PUC, did not consider it necessary for Bangor Gas to recover UFG costs as Bangor Gas' return on equity ("ROE") was set to manage any risks associated with this cost.

Alberta has a slightly different mechanism in that the process involves first establishing the amount of UFG which is allocated to a customer and then applying charges (credits) only to under (over) supply imbalances within the gas distribution network. However, the underlying principle remains the same, i.e., cost recovery.

Figure 14. Examples of approaches to UFG cost recovery

Alberta	*Separate Rider to establish (on annual basis) amount of UFG based on three year average. Gas supply (including UFG share) imbalance variation then settled on monthly basis against Canadian Gas Price Reporter Rate 5A*
British Columbia	*UFG part of overall gas commodity costs and are passed through to customers at cost. Variations between forecast and actual gas costs are managed through a deferral account*
California (SDG&E)	*Recovered through fixed cost balancing accounts*
Maine (Bangor Gas Co.)	*No deferral accounts as the Maine PUC viewed the company as earning a return high enough to not warrant the use of deferral accounts*
Massachusetts	*Standard Cost of Gas Adjustment Clause (regulatory code) – semi-annual adjustment of gas sales to recover costs of firm send-out gas, including UFG.*

7.1.3 Why Union's proposal is appropriate

Union is proposing a deferral account, where costs are reconciled between actual and forecast costs on an annual basis.[37] LEI finds that this approach is consistent with standard regulatory practice, that is, it supports cost recovery and meets OEB objectives.

Union's proposal for implementing a deferral account for UFG is consistent with the framework in other jurisdictions in that: it is clearly defined; it is subject to a high level of scrutiny and transparency as it is managed through a separate deferral account which is monitored by the OEB; it is non-discretionary in that gas must be purchased and managed on behalf of consumers; and the existence of UFG is known in the sense that Union knows it will incur these costs over the period of the ratemaking plan. However, the amounts cannot be quantified with a high degree of accuracy due to uncertainty regarding actual customer consumption.

With regards to the OEB's objectives, providing for pass-through of UFG costs, either separately or as part of overall gas supply costs, is consistent with OEB objectives of maintaining a financially-viable gas distribution industry and protecting consumers with respect to price.

Union is only seeking to recover UFG expenses at cost, that is, the pass-through of these costs to consumers is cost-reflective. Furthermore, the reconciliation mechanism ensures that customers do not over/under pay for gas costs thereby protecting consumers.

7.2 Treatment of capital projects

7.2.1 Theoretical underpinnings

A principal issue in IR is whether and how IR regulation can support continued investment in infrastructure. IR in theory should allow for "normal" capital investment based on steady state historical investment patterns. There are two sources of funds for utilities to finance capital projects under IR: the depreciation expense that is embedded in the base rate and the cash flow generated through productivity gains. Theory assumes a steady state environment, where generally, depreciation expense should be sufficient to cover normal going forward capital expenditure. However, there are a number of practical realities that put into question the sustainability of capital expenditure under a price cap regime where the X-factor is based on a TFP approach.

One issue is related to accounting and time. In an inflationary environment, the portion of rates related to depreciation expense is based on historical costs, and these would be insufficient to fund replacement at current costs. Moreover, cash flow generated through productivity gains may be insufficient to bridge the gap. But even if it was sufficient to bridge the gap,

[37] Union's proposal mentioned consistency with Enbridge IR plan. Enbridge's 2008-2012 IR plan calculated the difference between the forecast and actual gas costs, with the variance calculated at the end of the calendar year and an adjustment made in the subsequent year. Source: 2007-08-02 EB-2007-0615 Exhibit B Tab 5 Schedule 1 Page 12 of 20

reinvestment may result in below normal returns once the added risk for the IR regime is accounted for.

Another issue is that future capital investment patterns may not reflect historical patterns and therefore, the I-X annual adjustment mechanism may not be sufficient to cover new, large scale capital projects. For the utilities industry this is a particular challenge - as capital investment can be lumpy - reflecting the need for large, one-off projects to meet the needs of both current and future customers. Such investment, due to the capital intensive nature of the utility industry, cannot be incremental and may be non-discretionary. Often the two may be related as non-discretionary capital projects may also reflect future rather than historical investment needs. However, regulatory frameworks may not always require both or may take different approaches depending on the circumstances. This is discussed in more detail in Section 7.2.3.

To address these issues, IR frameworks often include rate adjustment mechanisms outside the I-X framework. These mechanisms have a range of criteria so as balance the need to protect consumers against inappropriate cost pass-throughs against the need for a utility to be able to invest prudently and recover its return on investment including in circumstances where it has no discretion regarding the investment.

7.2.2 Practice in other jurisdictions

The case study analysis (Figure 15) showed that in the majority of cases costs for certain capital projects may be treated outside the I-X annual adjustment framework recognizing that this framework cannot cater for large and outside the norm capital expenditures and/or situations where the utility has no discretion. However, to maintain the integrity of the IR framework these projects are generally subject to a range of criteria so as to constrain the extent to which capital expenditures can occur outside the ratemaking framework.

Figure 15. Approaches to treatment of known capital projects

Alberta	*Capital (K) Factor: outside normal course of operations; ordinarily replacement of existing capital assets or undertaking project required by an external party; material effect on the company's finances*
British Columbia	*Limited rebasing of capital if annual capex +10% outside I-X adjustment; projects requiring Certificate of Public Convenience and Necessity (CPCN) placed in rate base once in service and subject to minimum $5million threshold*
California (SDG&E)	*No specific measures*
Maine (Bangor Gas Co.)	*Not applicable*
Massachusetts	*Targeted infrastructure recovery factor ("TIRF") which adjusts the Company's rates annually to recover its capital investments on the replacement of leak-prone mains, services and associated facilities*

In Alberta, when establishing capital trackers or K-factors as they are called in Alberta, the AUC acknowledged that *".., there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for some necessary capital expenditures."*[38] However, so as to maintain a strong IR framework, the AUC has applied strict criteria (presented in Figure 15).

The two case study exceptions to projects being treated separately to the IR framework – SDG&E and Bangor Gas – are not applicable to Union. As a startup, Bangor Gas recently built most of its infrastructure, while SDG&E can file a new rate application if required. Although in SDG&E's case this is more related to unknown capital expenditures, it does provide room for SDG&E to request a rate adjustment for capital expenditures if costs are outside its control.

An additional example found in the survey companies (Columbia Gas of Ohio) followed practices that can illustrate how criteria, similar to that proposed by Union, can be used to effectively limit the use of Y-factors and protect ratepayers. The Ohio Public Utilities Commission approved an Infrastructure Replacement Program rider for Columbia Gas of Ohio[39] with parameters similar to Union, notably: in place for lesser of five years or until new rates become effective; and recovery of return on and of plant investment, inclusive of capitalized interest or post-in-service carrying cost charges, and depreciation expense and property taxes. This illustrates that regulators recognize the need to provide for capital projects that may not be included in the rate base at the start of the period. However, this should only be for contained periods to manage costs during a rate period.

7.2.3 Experience in Ontario

In Ontario, there is no standard framework that applies to gas utility rate regulation on how to treat capital costs outside the 'norm' and/or non–discretionary capital costs. Enbridge and Union's settlement agreements for the 2008 to 2012 ratemaking period treated Y-factors differently. Union's agreement listed four costs, two of which had been determined through separate OEB processes, and supported the continuation of three broad categories of deferral costs related to gas costs, storage and transportation and other matters. Enbridge's settlement agreement contained agreement that annual capital expenditures related to the attachments of natural gas-fired power generation projects, that are approved through 'leave to construct' applications and are placed into service, are to be treated as Y-factors including the system reinforcement necessitated by these projects.

The approach to capital expenditure in electricity rate regulation has been standardized and has evolved over the course of IR plan development moving from no specific treatment under first generation ratemaking to allowing electricity utilities to develop Customized IR plans in fourth

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[38] AUC (2012) AUC Decision 2012-237 http://www.auc.ab.ca/applications/decisions/Decisions /2012/2012-091.pdf paragraph 529

[39] For details see Westlaw (2008) WL 5158185 (Ohio P.U.C.), Pur Slip Copy, Re Columbia Gas of Ohio, Inc. Case No. 08-72-GA-AIR, Case Nos. 08-73-GA-ALT, 08-74-GA-AAM, Case No. 08-75-GA-AAM, Ohio Public Utilities Commission, December 3, 2008

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generation ratemaking. Customized IR plans for multi-year periods provide for distributor-specific rate trends for the plan term with deferral and variance accounts to track capital spending against the plan as needed. The OEB provides some guidance that a Customized IR plan "may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures"[40,] The OEB adds that it "will be most appropriate [where expenditure]… exceed[s] historical levels."[41]

Under fourth generation ratemaking, for utilities not choosing the customized approach the Incremental Capital Module ("ICM") developed for third generation ratemaking is still available for "non-discretionary" expenditure.[42] The ICM framework sets thresholds below which a utility must absorb the costs of a capital project and is applied for an annual basis. There is more detail on how this is applied through the OEB's decision on Toronto Hydro's application for rates for 2012 to 2014 which sets out the following:[43]

- preferable approach is to use in-service approach for recovery of capital expenditure;
- ICM criteria require that the work must be undertaken and that the existing capital in the rebasing year is insufficient to do so;
- purpose of the ICM deadband is to reduce the amount of funding available by a further 20%; and
- acceptance of Toronto Hydro's criteria for determining essential and non-discretionary projects including: existing or imminent reliability degradations; existing or imminent capacity shortages; and a material increase in cost (beyond the time value of money), if the project is necessary but undertaken at a later time.

These mechanisms recognize that the basic rate cap formula cannot warrant that capital investment needs will be met completely, because it makes implicit assumptions about the pattern of capital investment: namely that capital investment has been smooth and consistent with the pace of depreciation (also referred to commonly as amortization), such that the rate base (net book value) remains stable over time. It is also recognizes that capital investment is lumpy and cyclical. In fact there have been periods of heavy investment in the industry, as well as periods of low investment as reflected by the limited requests for capital pass-through by Union and Enbridge in their previous ratemaking plans.

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40 OEB (2012) *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, p.14

41 OEB (2012) *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, p.19

42 OEB (2012) *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, p.18

43 OEB (2013) EB-2012-0064 Partial Decision and Order, April 2, 2013

What does all this mean for the development of a ratemaking plan in the gas utility sector? Some form of treatment is required for certain capital projects (i.e. non-discretionary) which cannot be accommodated within the rate cap framework. As can be seen from the case study analysis and the above discussion on Ontario, the exact nature of these frameworks varies but they generally have built in incentive mechanisms such that a utility must absorb some of the project costs and criteria limiting what can be included in the mechanism.

7.2.4 Why Union's proposal is appropriate

Union is proposing to treat the costs of three clearly defined and specific projects (Parkway West, Parkway Growth and Burlington-Oakville) outside the I-X annual adjustment mechanism. Union is also proposing a more general mechanism that capital additions which meet certain criteria including minimum cost thresholds and are subject to full regulatory review are treated as pass-through items. This is much like the ICM mechanism in electricity. Overall the approach reflects common industry practice and takes into account the need for controls to protect ratepayers. This approach is also within the traditional range of options for Ontario. It is also consistent with the Customized IR approach for Ontario electricity distribution utilities where specific capital projects can be tracked through deferral and variance accounts.

LEI's case study and survey analysis shows that gas distribution utilities face the challenge of managing costs of multi-year capital projects over the course of the ratemaking period. The approaches in dealing with this challenge vary, but a set of common principles is applied so that ratepayers are protected and utilities can earn a fair return.

With regards to the three large capital projects, LEI finds that Union's proposal is consistent with this common set of principles, notably:

- the leave to construct process, which each of the above projects is going through or about to go through, will provide for transparent review of the projects and their costs and an opportunity for stakeholders to comment on the need and cost for the projects. This need for regulatory approval of projects as one criteria for eligibility for pass-through is also applied in BC;

- through the leave to construct process, Union will be required to demonstrate 'need' for the projects.[44] Union has outlined what alternatives were considered and why the proposed projects are the optimal approach;

- the projects are non-discretionary in that they are required to meet the structural changes occurring in the gas industry, increased gas fired generation in Ontario and customer demands to import low cost gas from northeast US; and

[44] That is, through the regulatory approval process the projects will be deemed necessary (non-discretionary).

- costs will only be passed through once the projects are in service. This approach is consistent with the requirement set out by the OEB in the Toronto Hydro decision.[45]

In this context, LEI finds that the proposed approach, which is only for the term of the current plan and to deal with costs which arise over the life of the plan, protects consumers and allows Union the opportunity to earn a fair return.

The mechanism for passing through costs for capital projects outside the IR framework is similar in nature to the ICM applied by the OEB in electricity as well as other frameworks examined by LEI, in particular:

- it applies a threshold below which Union must absorb the costs of capital projects (similar to OEB's ICM and the materiality requirement applied in Alberta);

- a project must be to meet customer needs and/or system safety, reliability and or integrity; that is, Union will be required to demonstrate project need such as occurs under ICM and was required by Illinois Commerce Commission in approving rate riders for Northern Illinois Gas Company; and

- open to full regulatory review as with an ICM application.

Given the lack of a standardized framework for dealing with non-discretionary capital expenses in the gas utility sector, Union's approach, which reflects principles applied in electricity as well as gas utilities, is reasonable and provides safeguards for ratepayers particularly through the application of a threshold and the full regulatory review process. It also balances Union's needs to maintain a financially-viable business.

[45] OEB (2013) EB-2012-0064 Partial Decision and Order, April 2, 2013 p.12

8 Approach to unforeseen costs (Z-factors)

8.1 Theoretical underpinnings

Under any ratemaking framework, where the ratemaking period extends over more than one year, the treatment of unknown or unforeseeable costs should be considered. Under such circumstances, there is a greater likelihood that an unknown event may trigger costs for a utility as it has to deal with the consequences. The longer the regulatory period the greater the likelihood of an unknown event occurring.

The treatment of unknown costs requires balancing of competing objectives. A utility requires certainty that it can recover any unknown costs so that it can continue to have an opportunity to earn a return on its investment. However, customers may not wish to provide a utility with a 'blank check' to recover these costs, especially if they are within management control. Providing some incentives for management to control costs within its revenue allowance encourages efficiency and assessment by management on how to prudently manage unknown costs within a utility's overall cost structure. If a utility is to have the opportunity to recover unknown costs, particularly where these are outside the control of management, the customers may want an independent review of the costs to assess if they are efficient. Furthermore, to encourage efficient expenditure and minimize regulatory burden, some threshold may be applied before a utility can apply to pass-through unknown costs. From a customer point of view, limiting a utility's ability to recover unknown costs is most important for limiting price increases.

So as to balance the objectives of price stability and supporting a financially-viable gas distribution industry, there tend to be some common elements to the recovery of unknown costs in ratemaking plans. A summary of the types of elements which can be included are listed below, however, not all elements need to be included. The items are:

- assessed as separate component of the ratemaking plan. There are a variety of terms which can be used but unknown costs can be called Z-factors, riders or exogenous costs;

- defined as costs that are outside of management's control (and cannot be well defined). The idea is that management cannot make decisions about how to efficiently manage these costs and absorb them within operations and therefore additional revenue is required;

- defined as specific events; and

- application of a threshold and/or requiring a utility to file a specific application for recovering unknown costs.

8.2 Practice in other jurisdictions

The case study analysis shows that unknown costs are treated as a separate component of the ratemaking plan and will contain one or more of the last three elements discussed above. The survey analysis (see Appendix B) also identified three jurisdictions providing for a process for gas utilities to recover unknown costs. As summarized in Figure 16, both Alberta and British Columbia pass on costs associated with events outside the control of management (such as regulatory changes, changes in accounting practices etc.). Berkshire Gas in Massachusetts has a threshold limit of $65,000, while the threshold for ATCO Gas is $0.5 million and approximately $0.2 million for AltaGas.

Figure 16. Examples of treatment for unforeseen costs

Alberta	*Z factor accounts for material exogenous events that are outside the control of the company with tresholds*
British Columbia	*List of factors for which actual costs could be passed on to customers such as regulatory changes and catastrophic events*
California (SDG&E)	*Costs outside the control of SDG&E where costs will result in an increase in customer costs then an application shall be filed*
Maine (Bangor Gas Co.)	*No explicit provision, instead the plan provides an opportunity to earn enough revenue for Bangor Gas to cover its investment requirements*
Massachusetts	*Berkshire Gas Co.: Annual PBR filing requires documentation of the exogenous factors and capital cost changes. Costs are limited only to those greater than $65,000; New England Gas Co.: no specific provisions but can submit a new rate application at anytime*

8.3 Why Union's proposal is appropriate

Union is proposing to maintain the existing Z-factor criteria, along with requesting an adjustment to 2015 rates and other parameters for any changes resulting from the OEB Cost of Capital review in 2014, which will be outside of Union's control. Recovery of unknown costs outside of management control is a common feature of IR formulas, albeit with some constraints to encourage utility efficiency and protect consumers with regards to price impacts.

The design of Union's proposed Z-factor is consistent with OEB principles and IR frameworks elsewhere in that Union has agreed to absorb some of the costs arising due to unknown factors up to a threshold of $1.5 million. Where costs are above this threshold, Union is proposing a pass-through of these costs to customers in order to maintain its financial viability. By absorbing some of the costs, Union will need to look for efficiency gains in other areas of its business if it is to earn its allowed return.

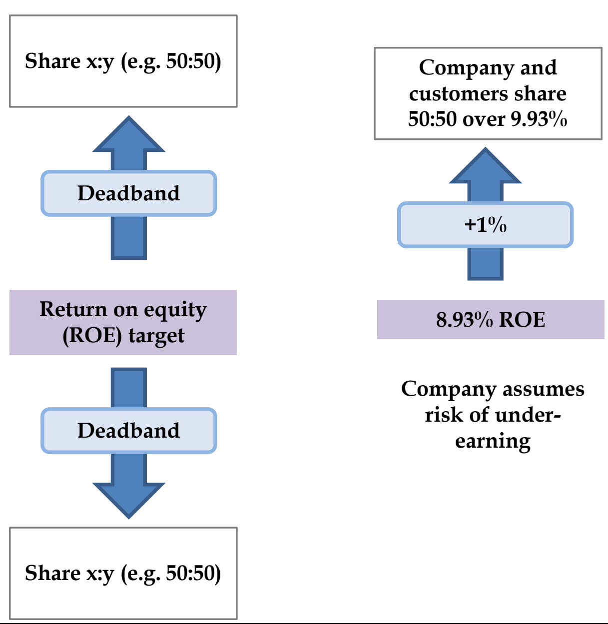
9 ESM approaches

9.1 Theoretical underpinnings

An ESM represents a trade-off between high powered efficiency incentives, whereby regulated companies take on more risk yet have the potential for higher profits if they significantly improve efficiency or performance, and a view that the company and ratepayers should be partners in ongoing operational and financial gains. The issues surrounding design of an ESM are less a question for economists – who will largely agree that higher incentives can potentially spur companies to greater efficiency – than for social scientists, who can assess a society's definition of what constitutes a "fair" return.

ESMs generally consist of three elements: a target ROE, a deadband around that ROE in which no sharing takes place, and sharing of gains or losses that are outside of the deadband. These elements are shown graphically in Figure 17. The approach presented on the right hand side mirrors that proposed by Union based on the 2013 ROE of 8.93%. In the example, if the company's ROE is above 9.93 percent (100 basis points over approved ROE), the company and customers will share the profits or losses 50:50. Pass-through or sharing of profits and losses with customers often occurs through an annual true-up mechanism, which may be in the form of a deferral account or customer bill credits and surcharges.

Figure 17. Description of approach and example of symmetrical ROE-based ESM



Deadbands, and sharing percentages outside of them, can be symmetrical, with customers sharing both upside or downside risk, or asymmetrical, with either customers or the regulated company taking on a disproportionate portion of risk. Note that Union is proposing an asymmetric ESM in the favor of ratepayers, i.e., ratepayers do not share in losses in case of under-earnings.

Furthermore, sharing percentages may be gradated, with customers or companies achieving a greater proportion of savings, or bearing a greater proportion of costs as profits increase or decrease. Decisions regarding whether to gradate sharing are based on whether the added complexity in the formula is outweighed by the incentive or fairness properties gained thereby. As efficiencies become harder and harder to achieve, companies may need to be allowed to keep a greater proportion of the resulting savings; however higher levels of savings can result in the appearance of supernormal returns for the companies if not disproportionately shared with customers.

ESMs can be applied under both I-X frameworks and under more traditional cost of service ratemaking approaches where some 'softer' efficiency incentive mechanisms (e.g. ESM and regulatory lag) are still built into the ratemaking framework to provide efficiency incentives.

In relation to the OEB's objectives, an ESM does not overly diminish efficiency incentives, but allows for some sharing of the benefit between customers and shareholders. An ESM also reduces incentives for a utility to delay its capital investment program, as a utility that tries to boost its ROE by not investing must return a share of profits to customers. This facilitates investment in required distribution infrastructure thereby supporting system reliability and safety.

9.2 Practice in other jurisdictions

From the case study analysis of I-X regimes, ESMs are applied in two jurisdictions (see Figure 18) and they are applied in three of the eleven survey jurisdictions (Appendix B). Within the same jurisdiction, a regulator may apply an ESM on a case by case basis, for example, the Alberta regulator decided not to apply ESMs for gas distribution utilities but did so for ENMAX electricity distribution when ENMAX first proposed IR, noting that PBR was relatively a relatively new development in Alberta.

Figure 18. Examples of ESMs

Alberta	*AUC did not approve ESM for the gas distribution PBR plans (although was approved for ENMAX electricity distribution); issue of ESM blunting efficiency incentives*
British Columbia	*50/50 sharing of profits (losses) for any variations above (below) approved ROE*
California (SDG&E)	*Not adopted although proposed by SDG&E*
Maine (Bangor Gas Co.)	*Initially, asymetrical with earnings above 15% to be shared on 50/50 basis with the ratepayers; the three year extension modified the ESM with a new ROE trigger of 30%*
Massachusetts	*No ESM*

ESMs have a trigger point beyond which earnings sharing is applied. As in the case of Union's proposal and Bangor Gas Company (Maine), the trigger point can be asymmetrical, i.e., providing for benefit sharing only on the upside (similar to that proposed by Union). This means that customers are protected from having to contribute towards a utility's costs when its

ROE is below a certain threshold. In this situation, utilities also face the risk that if they under-earn, for instance due to overspending, they will not be able to recover their lost earnings from customers. This type of ESM can benefit customers by providing downside risk protection but can undermine utility financial viability.

ESMs are also applied across the electricity distribution sector in a variety of ways. Examples of ESMs include: symmetrical without a deadband (Central Maine Power Company); asymmetrical with a deadband (New York State Electricity and Gas Corporation); and symmetrical with a deadband (NSTAR, MA). As with gas, the particular details of an ESM are customized to each utility and are often the outcomes of negotiations with stakeholders.

9.3 Why Union's proposal is appropriate

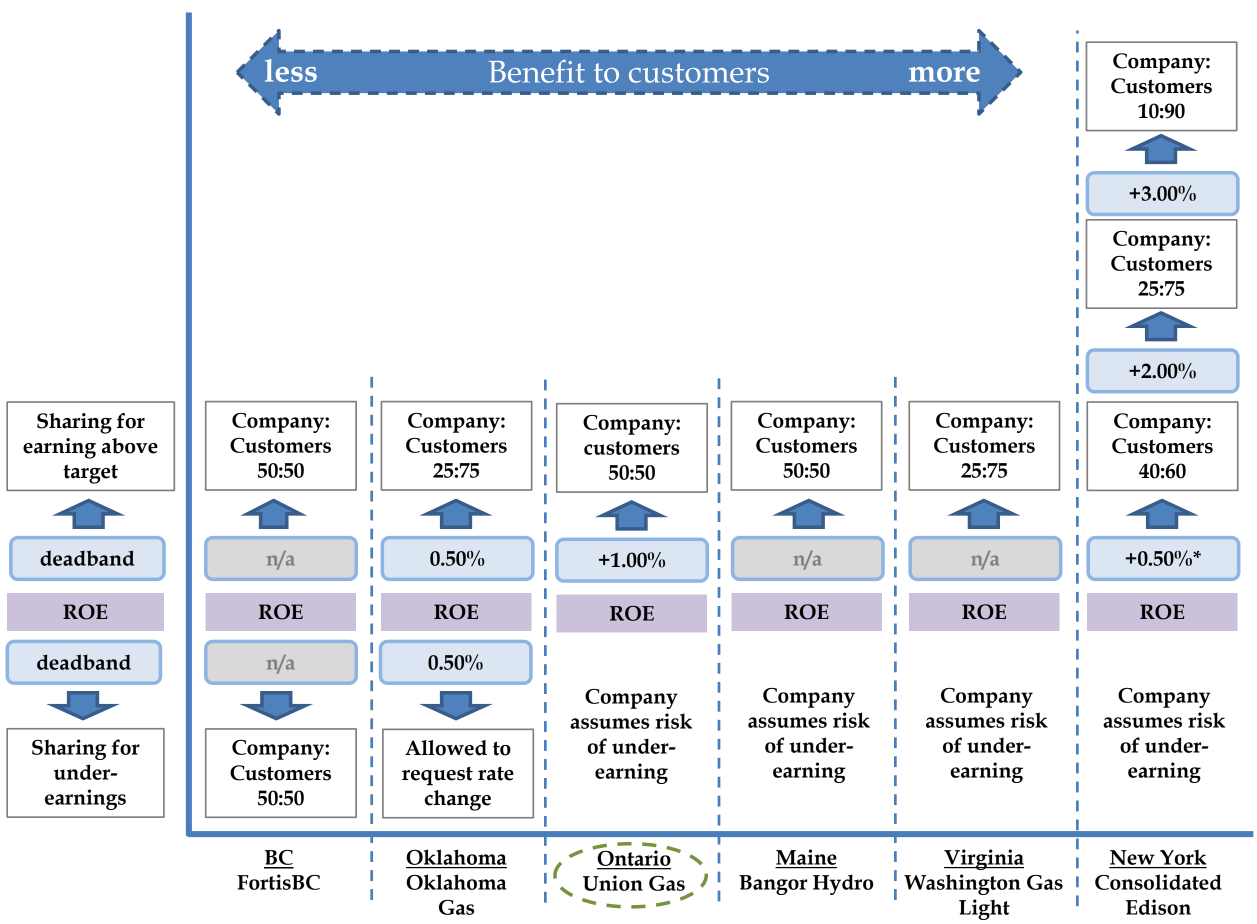
Union's proposal to reduce the ESM deadband from 200bp (in the 2008-2012 IR plan) to 100bp in the 2014-2018 IR plan allows ratepayers to share in the benefits of improved earnings more quickly. The reduction in deadband offsets the reduced X-factor impact for customers and aligns productivity incentives for Union. The asymmetrical nature of the proposed arrangement provides additional efficiency incentives for Union to improve its performance as it must absorb any cost pressures in order to maintain its ROE.

LEI found that ESMs are widely applied in utility ratemaking plans, with examples found in both gas and electricity sectors. Union's proposed approach is comparable with many of the ESMs in that it contains a deadband in which no earnings sharing will occur. This can be seen as providing further incentives for Union to improve its performance if it wishes to earn a higher ROE.

The 50/50 sharing arrangement is within the range of ESMs examined by LEI and the same as that proposed by FortisBC and applied by Bangor Gas. However, FortisBC has a symmetrical arrangement which means that ratepayers face downside risks as well as benefitting from any over performance. The Bangor Gas proposal has a higher ROE before earnings sharing applies. Therefore, Union's proposed approach is in some ways more generous to customers than either of these two case studies.

By way of comparison, the most generous proposal (Consolidated Edison Co. of New York) to ratepayers involves a 40:60 (utility: ratepayer) earnings sharing split, which increases to a 90/10 sharing split for a 300 basis point increase above the allowed ROE. Other proposals, such as Oklahoma Natural Gas and Washington Gas Light Company, involve a 25:75 (utility: ratepayer) earnings sharing split and commence at 50 basis points above the allowed ROE and for any increases above the allowed ROE respectively.

Figure 19. Union's proposal relative to select jurisdictions



* For the first year, this deadband is 0.75% (instead of 0.5%) for Consolidated Edison Co. (NY)

Union's proposal is within the range of examples for ESMs in other jurisdictions, and balances shareholder and consumer interests. Union's proposal also meets OEB criteria for establishing incentives for sustainable efficiency improvements to benefit customers and shareholders. It still encourages efficiency gains by allowing Union to retain some gains in ROE but ensures that shareholders also share in the benefits of improved performance.

10 Approach to applying and measuring service quality indicators

10.1 Theoretical underpinnings

Implementation of IR results in incentives to reduce costs; however, the IR arrangement also assumes that such cost cutting is accomplished within a framework of constrained optimization. In other words, it is presumed that the regulated company is required to provide service in a manner at least equal to the level of service quality in place before IR was implemented.

Service quality indicators and performance standards are often used concurrently with efficiency incentives, to ensure that any cost reductions implemented by the utility do not lead to deteriorating service quality.

There are several important guidelines that must be taken into consideration as performance standards are set. When designed, they should ideally meet a variety of different objectives:

- protect consumers from hidden cost increases and degraded service quality;
- align incentives, such that the utility's service level improvement is maintained;
- be objectively measurable (rather than subjective), requiring relevant and accurate data for monitoring performance;
- be realistic for utilities to meet specified levels of performance within the allocated levels of capital expenditure; and
- performance standards chosen should be relevant to attributes of service quality that ratepayers value

10.2 Practice in other jurisdictions

Figure 20 presents broad SQI categories that are implemented in case study and survey jurisdictions studied. Six of eleven survey utilities (as presented in Appendix B) were generally subject to SQIs (as specifically mentioned in their respective decisions) with similar performance measures applied as the case study utilities.

SQIs themselves are mainly based on industry-specific benchmarks, related to operations and reliability, customer service, and safety. The common requirements observed across case studies fall under categories such as meter reading standards, customer service and billing (including customer appointments), complaint tracking, monitoring of calls, customer appointments, customer satisfaction surveys, telephone service responses and emergency response service standards.

Figure 20. Examples of SQI categories

Company	Meter reading	Customer service	Pipeline safety and integrity	Financial reporting
AmerenCIPS (IL)	√	√	√	
ATCO Gas and AltaGas (AB)	√	√	√	
Bangor Hydro (ME)	√	√		
Bekshire Gas, New England Gas (MA)	√	√	√	√
Columbia Gas (OH)	√	√		
ConEd (NY)	√	√	√	√
FortisBC (BC)	√	√	√	√
Nicor Gas (IL)	√	√	√	
PSC of Colorado (CO)	√	√		
PSE (NJ)	√	√	√	√
SDGE (CA)	√	√	√	√
Union Gas Limited (ON)	√	√		√

Note: Pipeline safety is not currently an explicit part of OEB service quality indicators.

10.3 Why Union's proposal is appropriate

Union is proposing to maintain existing OEB-approved service quality measures. As the above graphic demonstrates, Union's proposal is consistent with North American practice. These include telephone answering performance, billing performance, meter reading performance, service appointment response times, gas emergency responses, customer complaint responses and disconnections/reconnections.[46] As discussed earlier, various service quality benchmarks specific to the gas utility industry are used in case study jurisdictions, which are similar to OEB approved measures. Examples include monthly meter readings, consumer division cases, telephone service responses, service appointments met, number of billing adjustments, lost time accident rates, responses to odor calls, changes in staffing levels, restricted work-day rates, property damage claims, unaccounted-for gas, summary of capital spending, consumer survey data, customer service guarantees etc.

These service quality indicators provide a framework for monitoring the reliability and quality of the gas service provided by Union as well as the safe operation of the industry, thereby meeting OEB criteria.

[46] OEB (2012) *Gas Distribution Access Rule*: September 6th, 2012, page 17

11 Evaluating Union's 2014 to 2018 plan

LEI finds that Union's proposed 2014 to 2018 plan is consistent with the OEB's objectives and follows practices applied in other jurisdictions. It also applies the same overarching framework, with only differences in the details, as the 2008 to 2012 plan, which meets OEB criteria as set out by the National Gas Forum and outlined in Section 2.2 and has been accepted by the OEB. The OEB did not comment on each of the individual elements of the 2008 to 2012 Settlement Agreement and it is therefore assumed that OEB had no objections to the proposed framework. Indeed, the OEB said in relation to overall Settlement Agreement for the 2008 to 2012 plan that it "… meets these criteria [National Gas Forum] and is in the public interest."[47]

The approach to applying a 0% X-factor reflects a general trend downwards in the achievable level of productivity growth of well-run gas distribution companies and more generally of the Ontario electricity and gas utilities sectors. Furthermore, Union's productivity growth during its 2008 to 2012 plan may limit its ability to make further substantial improvements in efficiency at reasonable cost. Figure 21 summarizes how the elements of Union's 2014 to 2018 plan meet key OEB objectives.

There is a natural tension between some of the OEB objectives. For instance, striving for continuous efficiency improvements (particularly within well-run utilities) may not always allow easy facilitation of maintaining a financially-viable business. The design and selection of ratemaking parameters effectively often comes down to a need to balance the protection of consumer interests with the need to maintain a financially-viable gas industry.

Figure 21. Comparison of elements of Union's 2014 to 2018 plan against objectives

Union plan element	OEB Criteria Sustainable efficiency improvements	OEB Criteria Environment conducive to investment	OEB Criteria Quality of service	Consistency with practices in other jurisdictions
I factor (GDP IPI FDD)	✓	✓		✓
X factor (0%)	✓	✓	✓	✓
Y-factor (UFG)	✓			✓
Y-factor (capital projects)		✓	✓	✓
Z-factor (unforeseen costs)		✓		✓
ESM	✓	✓		✓
SQIs			✓	✓

47 EB-2007-0606 Union Gas Settlement Agreement for 2008-2012 ratemaking, January 17, 2008, p.3

To summarize, each of the elements Union's 2014 to 2018 plan meets the OEB's objectives as follows:

- ***I-factor based on GDP IPI FDD***, supports investment under a steady state environment and encourages sustainable efficiency improvements by limiting price increases thereby encouraging firms to look for efficiency improvements so they can keep costs below revenue. This index has been widely applied in Ontario in the past and as OEB staff have previously recognized is relevant to the gas industry (capital, labour, materials);[48]

- ***X-factor of 0%*** means Union must still operate under cost constraints and must face efficiency incentives as its prices are capped under the I-X formula. By setting an X-factor of 0%, it ensures that Union has the opportunity to earn a fair return and recognizes that Union, as with many utilities, is operating in an environmental where productivity growth is slowing or flat. It is also conducive to supporting investment and service quality as Union is facing a productivity growth factor that is consistent with the performance it can achieve and indeed that of the utilities industry;

- ***Y-factor (UFG)*** is consistent with supporting sustainable efficiency improvements and also with maintaining a financially-viable gas distribution industry and protecting consumers with respect to price. Union is only seeking to recover UFG expenses at cost, that is, the pass-through of these costs to consumers is cost-reflective. Furthermore, the reconciliation mechanism ensures that customers do not over/under pay for gas costs thereby protecting consumers. It also reflects past practice in Ontario and other jurisdictions;

- ***Y-factor (capital projects)*** supports an environment conducive to investment, as it recognizes non-steady state investment requirements and therefore also supports improved quality of service, as Union can invest in its network to better meet the demands of its customers. It provides safeguards for ratepayers particularly through the application of a threshold and the full regulatory review process of proposed projects, which is similar to the requirements for electricity distributors under the Custom IR model. As with electricity, it is an important element of rates and "hence will be subjected to thorough reviews by parties to the proceeding."[49] There is no guarantee that the regulatory process will allow Union to pass through these costs and therefore Union must clearly demonstrate that its capital projects meet the requirements;

- ***Z-factor*** supports an environment conducive to investment as Union can recover unforeseen costs where they meet the criteria and therefore make any necessary investments without impacting other areas of its business. The proposed criteria are consistent with the OEB's recognition that z-factors are required but application of z-

[48] OEB (2007) EB-2006-0209 Staff Discussion Paper on an Incentive Regulation Framework for Natural Gas Utilities, January 5, 2007 p.10

[49] OEB (2012) Renewed Regulatory Framework for Electricity Distributors, October 18, 2012, p.20

factors should be in "limited, well-defined and well-justified cases only."[50] Union must absorb costs up to a threshold ($1.5 million), and can only recover costs above the threshold in specific circumstances. This protects consumers interests and balances Union's needs to earn a fair return and run a financially-viable utility;

- ***ESM*** still encourages efficiency gains and provides an environment conducive to investment by allowing Union to retain some ROE gains but ensures that shareholders also share in the benefits of improved performance. Whilst the OEB did not intend for ESM to form part of a gas utility's rate plan,[51] this practice has not been followed in the previous rate plan Settlement Agreements for Union and Enbridge, and there is a dead band under which Union can still retain earnings within its IR plan to achieve sustainable efficiencies as seen by the OEB as a strong incentive;[52] and

- ***SQIs*** provide a framework for monitoring Union's performance ensuring that services continue to be provided to a reasonable standard thereby protecting the interests of consumers.

[50] OEB (2005) *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* Report on the Ontario Energy Board Natural Gas Forum, p.31

[51] OEB (2005) *Natural Gas Regulation in Ontario: A Renewed Policy Framework,* Report on the Ontario Energy Board Natural Gas Forum, p.28

[52] Ibid.

12 Addendum – Comments on Union Draft Settlement Agreement

After reviewing the original Union 2014 to 2018 IR plan proposal, LEI was subsequently asked for additional comment on a Draft Settlement Agreement[53] ("Agreement") prepared for the consideration of the OEB. This Agreement is the result of negotiations between Union and stakeholders to date,[54] and provides a proposed framework for settlement of the 2014-2018 IR plan elements.

Although key elements of the Agreement are discussed separately below, LEI believes that overall the Agreement from the point of view of stakeholders strengthens the original plan particularly with regards to the proposed I-X formula and the ESM. The Agreement largely benefits the consumers given changes (such as more generous ESM, higher Z-factor threshold etc.) summarized in the text box.

Key changes in Agreement compared to Union's initial proposal

- X-factor = 60% of I-factor (vs. 0%)
- ESM: 90:10 (consumers/utility) sharing in earnings over 200 basis points over approved ROE (vs. 50:50 sharing)
- Major capital additions in Y-factor: minimum increase of $5 million per project in net delivery revenue requirement (vs. $25 million capital costs) and capital cost must exceed $50 million
- Z-factor threshold increased to $4 million (vs. $1.5 million)
- No off-ramp (vs. trigger if earnings 300ps above ROE for two consecutive years)

12.1 Multi-year incentive ratemaking framework and X-factor

Similar to the original proposal, the Agreement applies a multi-year price cap index which is a function of: an inflation factor (I); productivity factor (X); certain non-routine adjustments (Z-factors); certain predetermined pass-throughs (Y-factors); and an adjustment for normalized average consumption ("NAC").

Compared to the initial proposal, a key change is the treatment of the X-factor. Instead of a 0% X-factor (proposed initially), the Agreement proposes an inflation coefficient mechanism, similar to that previously used by Enbridge, whereby the X-factor is a fixed percentage (60% in this case) of the I-factor, i.e., the I-X formula effectively becomes "I*X". Because X<I, this ensures that customers' rates increase by only a proportion of the I-factor. Per the Agreement, I-X = I – (0.6*I) = "0.4*I", i.e., ratepayers will face an annual net inflationary increase of 40% of I or (GDP

[53] Source: DRAFT EB-2013-0202 Union Gas Limited Settlement Agreement, June 21, 2013

[54] The following parties participated in the negotiations arriving at this Agreement: Association of Power Producers of Ontario ("APPRO"), Building Owners and Managers Association of Greater Toronto Area ("BOMA"), Canadian Manufacturers and Exporters ("CME"), Consumers Council of Canada ("CCC"), Energy probe Research Foundation ("Energy Probe"), Federation of Rental-housing Properties of Ontario ("FRPO"), Industrial Gas Users Association ("IGUA"), City of Kitchener ("Kitchener"), London property Management Association ("LPMA"), Ontario Association of Physical Plant Administrators ("OAPPA"), Six Nations Natural Gas ("Six Nations"), School Energy Coalition ("SEC"), TransCanada Pipelines Limited ("TCPL"), Union and Vulnerable Energy Consumers Coalition ("VECC").

IPPI FDD). Thus, in real terms, customers will be facing decreasing rates (before accounting for necessary capital expenditure and pass-through elements).

Given observed declining trends in utility productivity growth (as discussed in Section 6.2) and the previous history of Union's challenging productivity measure (1.82% in the 2008-2012 IR plan), this settlement provides meaningful benefits for ratepayers. We observed in Section 6 that with Union's initial proposal of a 0% X-factor, the all-encompassing I-X framework continued to incentivize Union to improve efficiency, as Union will still need to operate within the constraints of a price cap and manage unknown costs by finding efficiency improvements.

In comparison, the Agreement obligates Union to further improve productivity, and provides a more than reasonable balance between the interests of the consumers and industry viability. Given the declining marginal returns of productivity investments, it may be an uphill task for Union to maintain such efficiency improvements in future IR plans. The agreed upon coefficient mechanism will also avoid circumstances where the X-factor is greater than the I-factor, which could undermine Union's financial viability due to the possibility of decreasing rates in nominal terms (before accounting for other adjustments).[55]

Furthermore, outside of the price cap adjustment formula, the Agreement provides for an upfront productivity commitment of $4.5 million. Base rates will be reduced by this amount at the outset, and will be allocated to rate classes in proportion to the allocation of administrative and general operating and maintenance costs in the 2013 Board-approved rates. The concept is similar to the P_0 adjustments found at the beginning of the regulatory periods in the UK. This will allow customers to further share in gains already achieved, and further incentivize Union to achieve efficiency gains.

12.2 I-factor

The I-factor in the Agreement is the same as proposed by Union initially, discussed earlier in Section 5.

12.3 Y-factor – UFG and major capital additions

The Y-factor represents certain pre-determined pass-throughs with the Agreement clarifying the capital projects as 'non-deferrable' major capital pass-throughs and limiting the inclusion of any operating and maintenance expenses. The two specific issues that LEI was asked to examine, UFG and major capital additions, are discussed in more detail below.

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[55] This remains a theoretical possibility in the proposed formula under a deflationary environment, whereby the I-factor is negative, and thus (I*X) is also negative, and rates decrease in nominal terms (not accounting for other adjustments). Although StatsCan's GDP IPI FDD has not been negative, estimating year-over-year changes using quarterly indices, it reached as low as 0.29% in Q3 2009. Using the same methodology, Canada's CPI estimate in the same quarter was negative (-0.86%), US CPI in the first three quarters of 2009 was negative, and Japan has experienced deflation over numerous quarters recently.

12.3.1 UFG

UFG costs include: (i) a percentage of throughput volume that determines the UFG volume, and (ii) the Board-approved weighted average cost of gas ("WACOG"). Union's Quarterly Rate Adjustment Mechanism ("QRAM") captures any changes to WACOG, also part of Union's 2008-2012 IR plan.

In the 2013 base rates, the Board approved UFG costs of $14.7 million. The Agreement envisions a new UFG volume deferral account that will account for differences between actual UFG volumes and what has been included in rates, calculated using the most recent approved WACOG.

The Agreement also states that this amount will be subject to a symmetrical deadband of $5 million, i.e., the deferral treatment will only account for variances greater than $5 million (below $9.7 million and above $19.7 million). We understand that the introduction of the deadband is an extension of Union's initial proposal, which only referred to a UFG volume deferral account.

The proposal meets the OEB objective of maintaining a financially-viable gas distribution industry and protecting consumers with respect to price. Union will be able to recover costs if they are unusually large and ratepayers will receive a credit where UFG costs are lower than expected. Also, as discussed in the report above, all ratemaking plans studied (with the exception of one) provide for some sort of mechanism to recover costs for UFG. Not all mechanisms involve deferral accounts, however the underlying principle for utilities to recover such costs and only pass-through actual costs to customers remains constant.

12.3.2 Major capital additions

With regards to major capital additions, the key changes relate to thresholds, additional criteria for major capital additions and the removal of the Burlington-Oakville project from the specified list of Y-factor capital additions. A Rate Impact Threshold ("RIT") has been set, which is equal to a minimum increase of $5 million in net delivery revenue requirement[56] per new project. The original Union proposal set a similar threshold of $25 million or more capital cost per project (instead of increase in net delivery revenue requirement). This $25 million capital cost threshold translates into a less than $2.5 million increase in net delivery revenue requirement.[57] Thus, the $5 million minimum increase in the Agreement is more stringent and favorable for consumers.

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[56] In the Agreement, net delivery revenue requirement associated with a capital project includes costs associated with incremental operating and maintenance expenses, depreciation expense, municipal property tax expense, incremental long-term debt costs, and required return and income taxes.

[57] A capital project worth $25 million is likely to result in about $2.4 million increase in the revenue requirement. This is estimated based on following assumptions derived from examples provided in Appendix E of the Agreement: O&M costs are about 0.04% of the capital costs, annual depreciation expense at the rate of 1.96%, property tax of 0.78%, required return on equity portion (64%) of the capital investment at 8.93%, required return on debt portion (36%) at the rate of 4%, income tax at the rate of 26.5% of the required equity return.

Additional criteria to the $5 million net revenue requirement include the following: (i) the capital cost of the project must exceed $50 million (ii) project is outside the base rates of the IR framework; (iii) project must be needed to serve customers and/or maintain safety, reliability or integrity, and cannot reasonably be delayed; (iv) project to be identified to stakeholders and the Board as soon as possible including in that year's stakeholder review session if practical; (v) project will be subject to full regulatory review prior to inclusion in rates; (vi) allocate net revenue requirement using 2013 cost allocation methodologies (unless directed otherwise from the Board); and (vii) project will include a deferral account request to capture any differences between the forecast and actual net delivery revenue requirement in each year of the 2014-2018 IR plan for which the project is included in rates. LEI considers this proposal is reasonable as already discussed in Section 7.2.

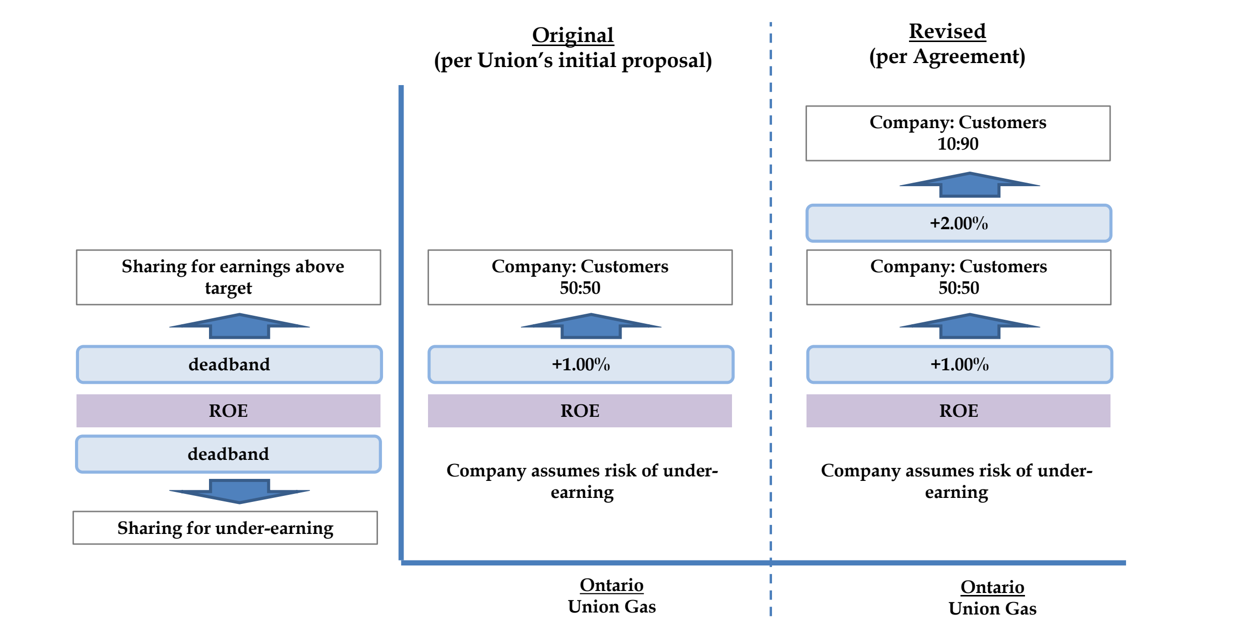
12.4 Z-factor

The Z-factor arrangement in the Agreement has two changes: including eligible cost increases/decreases (prospective and historical) to qualify for pass through, and an increase in the materiality threshold to $4 million from $1.5 million, otherwise it maintains the same criteria as the original proposal to stakeholders. Increase in the materiality threshold provides important benefits to ratepayers as it increases the amount of costs that Union must absorb before it can pass through costs under the Z-factor arrangement. This complements the increase in the X-factor and the increase in the major capital additions threshold that are incorporated in the Agreement compared with the original proposal.

12.5 ESMs

The ESM arrangement in the Agreement is more generous towards ratepayers, as compared to the initial proposal described in the report (and presented in Figure 22).

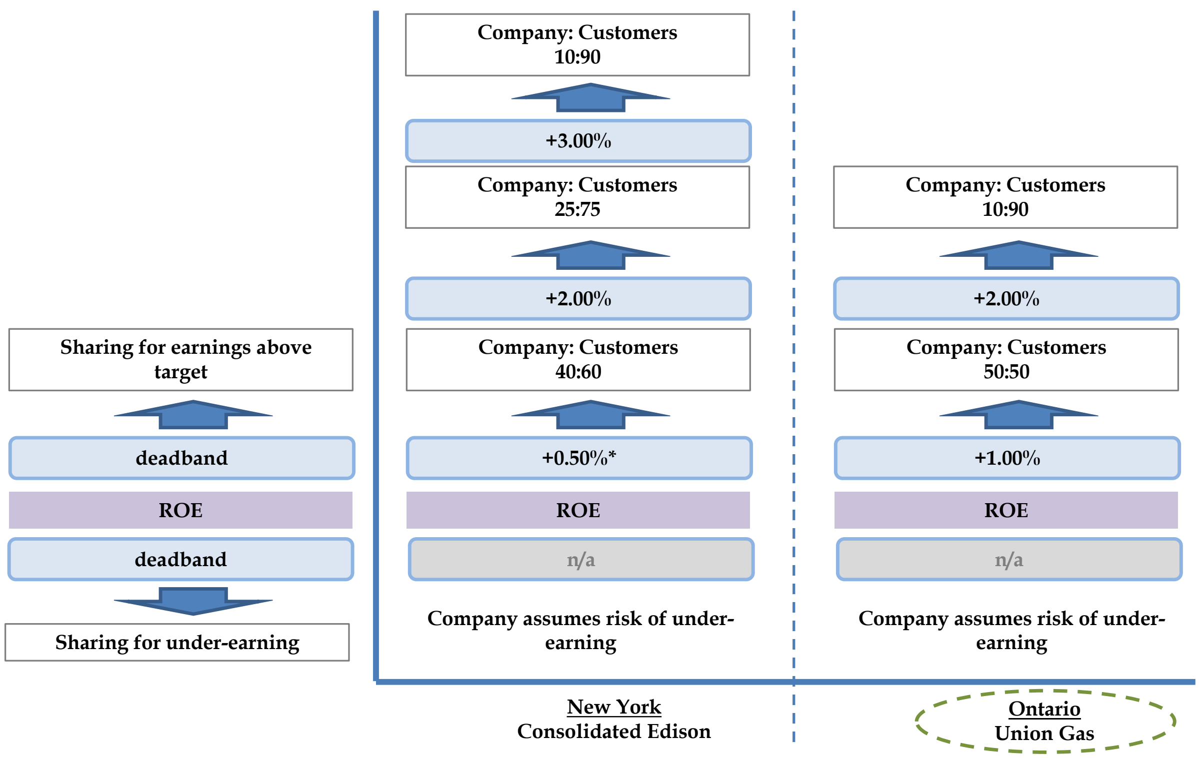
Figure 22. Union's revised ESM mechanism (compared to its initial proposal)



The revised arrangement suggests that if Union's ROE is above 9.93 percent (100 basis points over approved ROE) but below 10.93 percent (200 basis points over approved ROE), Union and ratepayers will share the profits 50:50. However, if Union's ROE is above 10.93 percent, Union and ratepayers will share the profits 10:90 in the favor of ratepayers. The ESM mechanism remains asymmetric, i.e., ratepayers do not share in losses in case of under-earnings.

This revision in ESM is of considerable benefit to ratepayers, given its asymmetric nature and 90% sharing of benefits. Across the case study and survey review, the revenue sharing arrangement, where customers end up receiving 90% of the benefits is equivalent to the most generous that LEI observed (Consolidated Edison Co of New York). Indeed, overall it is more generous than the Consolidated Edison proposal, as the 90% sharing applies for every year of the ratemaking period and becomes effective earlier at 200 basis points above the ROE compared with 300 basis points for Consolidated Edison (see Figure 23).

Figure 23. Union's revised ESM mechanism (compared to that of Consolidated Edison Co. of New York)



* For the first year, this deadband is 0.75% (instead of 0.5%) for Consolidated Edison Co. (NY)

12.6 Off-ramps

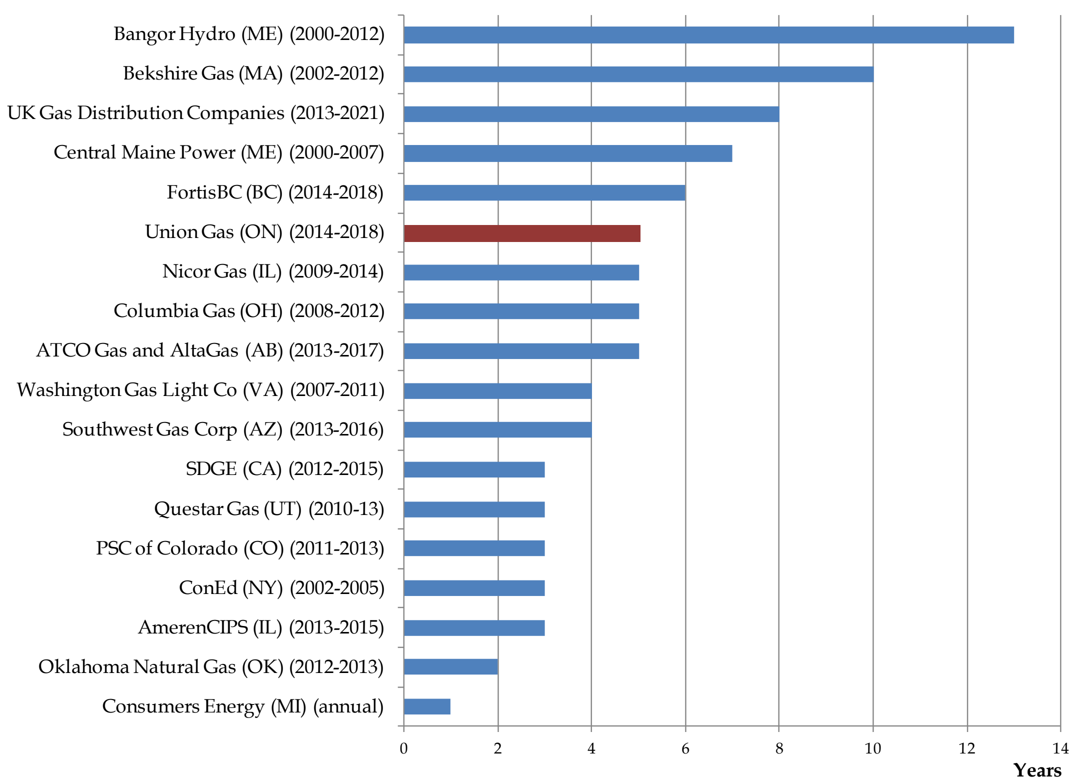
The Agreement sets out no off-ramps for the 2014-2018 IR plan. This is a change from the Union initial proposal, whereby an off-ramp was proposed to be triggered if earnings exceeded allowed ROE by 300 basis points for two consecutive years. Given that the envisioned ESM mechanism protects consumers such that they receive 90% of earnings over allowed ROE plus 200 basis points, LEI believes the off-ramp proposed initially becomes unnecessary. The ESM mechanism addresses any misalignment of productivity incentives/over-earnings, which was the initial purpose for the off-ramp.

12.7 Term of the plan

A five year term has been proposed, similar to the previous IR plan and Union's initial proposal. The length of the regulatory period needs to balance competing pressures. A longer regulatory period has benefits in that it may provide utilities with a longer-term planning horizon, allows longer period to benefit from efficiency incentives, and increasing companies' confidence about regulatory treatment on their investment decisions. This is particularly important in a capital-intensive business that relies upon long-lived assets.

Longer periods between resets also reduce regulatory burden, but potentially increase the risk for regulators and utilities, due to an inability to act on changing circumstances in a timely fashion. However, frequent resets while minimizing risks for utilities, may negatively affect utilities' investment planning and not provide sufficient efficiency incentives.

Figure 24. Regulatory periods for gas utilities



LEI's case study analysis finds that regulatory periods usually range from one to over ten years, and that Union's proposed five year plan term provides a reasonable balance between managing risks, particularly through the inclusion of Y- and Z-factors and providing efficiency incentives. This allows the balancing of OEB objectives by creating an environment conducive to encouraging efficiency for the benefit of ratepayers while providing Union with the opportunity to maintain a financially-viable business.

Internationally, the UK electricity distribution has applied 5-year regulatory terms since the early 1990s, with reopeners on occasion. This includes rate re-basing and the IR terms. Gas distribution has only been regulated separately since 2002 with gas transmission and distribution largely run by the same the entity prior to this date. In 2002, TransCo's (National Grid) gas distribution business was restructured into eight units from twelve. Four of the units were then sold. Gas distribution since 2002 has also applied 5-year terms with one plan extended for a year. All electricity and gas utilities are moving to 8 year reviews (also includes rate rebasing as part of this process) and with 4 mid-year term review.[58]

12.8 Reporting requirements

The Agreement states that Union agrees to make its RRR filings with the Board available to intervenors. In addition, relevant utility information[59] will be prepared by Union on an annual basis for the most recent historical year. In addition, Union will hold annual stakeholder meetings after the public release of year-end financial results but prior to its annual filing on non-commodity deferral accounts disposition application. Overall, such reporting requirements mean stakeholders have access to information similar to cost of service regimes. Stakeholders can monitor the company's performance and gain confidence in the operation of the IR regime.

We understand that Union's Agreement is essentially unchanged from its initial proposal in this regard.

12.9 Concluding observations

Overall, the Agreement provides a more beneficial arrangement (relative to what was already a fair proposal) to ratepayers particularly through the following:

- enhanced performance incentives through the revised I-X formula;
- generous ESM arrangement;
- stronger criteria around the Y-factor (capital additions); and
- increased Z-factor threshold above which Union can pass through costs.

These enhancements protect the interests of consumers with respect to price, consistent with the OEB objectives. They still provide Union with the opportunity to earn a fair return albeit after it has met higher incentive hurdles where it will need to identify additional efficiency opportunities before it can pass costs through to consumers.

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[58] Ofgem (2009) "*Regulating Energy Networks for the Future: RPI-X@20 History of Energy Network Regulation*"

[59] As included in Section 10.1 (pages 19-20) of the Agreement

13 Appendix A: Case Study Analysis (I-X ratemaking framework)

This Appendix contains the details of the case study analysis undertaken by LEI on gas utilities where an I-X framework has been applied. These are:

1. Alberta – AltaGas and ATCO Gas
2. British Columbia ("BC") – Fortis BC Energy Inc. ("FEI")
3. California – SDG&E
4. Maine – Bangor Gas Company
5. Massachusetts – Berkshire Gas Company
6. Massachusetts – New England Gas Company

13.1 Alberta – AltaGas and ATCO Gas[60]

13.1.1 Brief overview

AltaGas and ATCO Gas have customers across Alberta, with 72,000 and one million customers respectively.

13.1.2 Form of rate cap and regulatory period

For gas utilities, a revenue per customer cap is being applied with an annual I-X adjustment plus capital adjustment (K-factor); Y accounts for material foreseen costs outside of the management's control; and a Z-factor accounts for material unforeseen costs outside of the management's control.

The base year is 2012 and the term of the ratemaking plan is 2013 to 2017. This is the first time that this framework has been applied in Alberta.

13.1.3 Productivity and X-factor trends

The TFP analysis for the AUC was based on a population of 72 US electric and electric-gas utilities from 1972 to 2009. The AUC justified using this study rather than a gas specific study which was submitted by the Consumers Coalition of Alberta due to the broad based (electricity and gas) nature and transparency of the analysis.[61] The observed productivity was 0.96% which was applied as the starting point for the X-factor. A stretch factor of 0.2% was then added to arrive at the X-factor of 1.16%. This is the same as was applied to electricity distribution companies.

13.1.4 I-factor

The I-factor is based on a composite measure combine from 55% of the Alberta average weekly

[60] Based on AUC Decision 2012-237 (http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-091.pdf)

[61] Ibid. p.86

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earnings index and 45% of the Alberta CPI.

13.1.5 Treatment of unknown costs

Z-factor accounts for material unforeseen costs outside of management control. The materiality threshold for the Z-factor events was set at the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement. Such dollar amount is subject to escalation using the I-X formula. The threshold for ATCO Gas is $0.5 million and approximately $0.2 million for AltaGas. The companies are directed to file the Z- factor rate adjustment applications as part of the annual PBR rate adjustment filing.

Such events will qualify for Z-factor treatment if they meet all of the following conditions:

- the impact must be attributable to some event outside management's control;
- the impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business;
- the impact of the event should not have a significant influence on the inflation factor in the PBR formulas;
- all costs claimed as an exogenous adjustment must be prudently incurred; and
- the impact of the event must be unforeseen.

The AUC identified a list of items (presented below) that may be considered for Z-factor adjustment, and the final decisions shall be made when such items are presented as part of annual PBR filings:

- self-insurance/reserve for injuries and damages;
- depreciation rate changes;
- accounting changes / changes to International Financial Reporting Standards ("IFRS");
- acquisitions (only when such costs are outside of the management's control);
- defined benefit pension plans (only material changes to the special payment obligations may qualify, current service pension costs will be included in the PBR); and
- insurance proceedings.

13.1.6 ESM

The AUC did not approve the ESM proposed by gas utilities. The main argument against ESM was focused on weakening the link between efficiency gains and returns thereby blunting performance incentives, and the variability of earnings that may result in either a utility not being able to recover its costs (high earnings trigger ESM in year one, and low earnings in year two may be not be sufficient to trigger ESM) or customers paying more than necessary (low earnings trigger ESM in year one and high earnings in year two not high enough for ESM trigger).

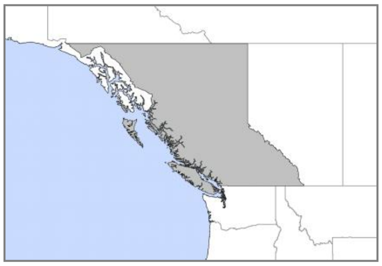
Although an ESM was not applied to the gas utilities, the AUC has previously approved an ESM for ENMAX, an electricity utility. The AUC granted approval despite concerns about an ESM blunting efficiency incentives, as it recognized that performance-based regulation was relatively new in Alberta and that an ESM would provide a safeguard in the early stages.

13.1.7 Mechanisms for treatment of UFG

Gas utilities can recover the costs of UFG through a separate rate rider. It is established on an annual basis to determine the amount of UFG that can be recovered from customers. This is based on a three year average. Gas supply (including UFG share) imbalance variations are then settled on monthly basis against Canadian Gas Price Reporter Rate 5A.

13.1.8 Service quality indicators

SQIs cover requirements for meter reading standards, customer appointments service standards, emergency response service standards, and call answering service standards. The AUC will initiate proceedings to revise the rule related to SQIs (Rule 002) in 2013. There will be no performance bonuses introduced with regard to SQI requirements.



13.2 BC –FEI

13.2.1 Brief overview

FEI supplies 835,000 customers in four service areas across Southern British Columbia and through the inland mountain areas from the Okanagan to Northern British Columbia.

13.2.2 Form of rate cap and regulatory period

A revenue cap with I-X adjustment was approved for the 2004 to 2009 ratemaking period and is proposed for the 2014 to 2018 ratemaking period. The periods between the two ratemaking periods was covered by two separate cost of service reviews. The 2014 to 2018 ratemaking framework is largely the same as the previous period:

- the I-X adjustment applies to both O&M and capital expenditure for controllable expenses; and
- separate processes for passing through exogenous costs (e.g. administrative changes, legislative changes and major seismic incidents) and non-controllable expenses (e.g. property taxes, pension costs, deprecation rate changes).

13.2.3 Productivity and X-factor trends

A fixed X-factor of 0.5% is proposed for the 2014 to 2018 ratemaking period. This has been informed by a TFP study conducted for FEI which recommended a 0% X factor (see Section 6.2.2 for further discussion). The TFP study measured TFP in a range of -0.0313% to -0.0493% and covered a period of five years so it does not provide an indication of longer historical trends. FEI acknowledges the results of the study but has proposed a more challenging X-factor as part of the overall package of proposed measures in the 2014 to 2018 period "that ensures the continuation of a productivity improvement culture."[62]

13.2.4 I-factor

FEI is proposing a change in calculation of the I-factor to a composite formula based on weighted average of the BC-CPI and average weekly earnings compared with a single measures (BC-CPI) in the previous ratemaking period. FEI notes that this follows trends in Alberta and Ontario, and better reflects cost drivers.

13.2.5 Treatment of unknown costs

FEI proposes a list of factors for which actual costs could be passed on to customers. These were part of the previous 2004 to 2009 plan and include:

- judicial, legislative or administrative changes, orders or directions;

[62] Fortis BC Energy Inc. (2013) *Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018*, June 10, 2013, p.53

- catastrophic events;
- major seismic incidents;
- acts of war, terrorism or violence;
- changes in generally accepted accounting principles ("GAAP"), standards or policies; and
- changes in revenue requirements due to British Columbia Utilities Commission ("BCUC") decisions (examples include changes to depreciation rates and cost of capital changes).

13.2.6 ESM

FEI is proposing that the ESM be symmetric for earning above and below the allowed ROE, which is established each year by the BCUC. The sharing of benefits/costs will be on a 50:50 basis between customers and shareholders. This is the same mechanism used in the previous plan.

13.2.7 Mechanisms for treatment of unaccounted-for gas

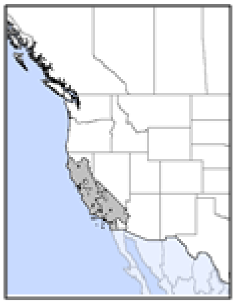
UFG costs are considered part of overall gas commodity costs. Under the current and proposed ratemaking plans, these are passed through to customers at cost and reported on a quarterly basis. Any variations between forecast and actual gas costs are managed through a deferral account.

13.2.8 Service quality indicators

FEI is proposing annual reporting on a range of SQIs focused on:

- customer service (e.g. telephone service, customer satisfaction, appointments met for meter exchanges and billing performance); and
- safety (e.g. emergency response and injuries).

FEI has also submitted a balanced scorecard and at the direction of the BCUC has benchmarked this against peer group companies and jurisdictions. The balanced scorecard covers financial, safety, customer, employees, and governance performance measures.



13.3 California –SDG&E[63]

13.3.1 Brief overview

SDG&E has 860,000 gas customers in the San Diego and southern Orange county areas of California.

13.3.2 Form of rate cap and regulatory period

For the 2012 to 2015 ratemaking period (where the base or test year is 2012) a revenue cap mechanism is being applied with an annual adjustment mechanism based on CPI (Urban) plus 75 basis points. This differs from the previous period where a fixed revenue requirement was set for each year of the ratemaking period.

13.3.3 Productivity and X-factor trends

No specific X-factor is applied. The X-factor could implicitly be interpreted as being set at -0.75% that is the adjustment to the I-factor applied by the CPUC. The CPUC acknowledges that the framework "*aligns the increases in 2013-2015 closer to what consumers are experiencing in terms of inflation, rather than the higher costs that the utilities may face [for example through a utility cost index]. This also creates a strong incentive for the utilities to manage costs through improvements in efficiency and productivity*."[64]

13.3.4 I-factor

The I-factor is based on the CPI Urban (US Bureau of Labor Statistics).

13.3.5 Treatment of unknown costs

A Z-factor mechanism for costs outside the control of SDG&E is applied. An application needs to be filed for review of such costs.

13.3.6 ESM

SDG&E proposed an ESM but the CPUC did not accept the proposed measures. The CPUC accepted an alternative package of mechanisms which gives SDG&E a reasonable opportunity to earn their authorized rate or return.

13.3.7 Mechanisms for treatment of unaccounted-for gas

UFG costs are recovered through fixed cost balancing accounts.

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[63] Based on CPUC (2013) *Decision on General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company*, Decision 13-05-010 May 9, 2013

[64] CPUC Press Release (2013) *CPUC sets revenue requirements for SDG&E and SoCalGas*, May 9, 2013

13.3.8 Service quality indicators

Customer service quality measures focus on customer satisfaction and reputation, including complaint tracking, monitoring of calls, customer satisfaction surveys and time it takes to complete telephone calls. Introduced in most recent decision, semi-annual gas distribution safety reports include:

- description of approach to determine and rank:
    - distribution safety, integrity and reliability projects;
    - O&M activities; and
    - inspections of pipelines
- funds budgeted and actual expenditure, and explanation for any differences

13.4 Maine – Bangor Gas Company[65]

13.4.1 Brief overview

The company serves approximately 3,000 customers around the town of Bangor in Maine.

13.4.2 Form of rate cap and regulatory period

The framework consists of a price cap with I-X annual adjustment. Rate adjustments are not to result in cross subsidization or an individual rate element (i.e. fixed or volumetric rates) increasing by more than 10%. The initial term was set at ten years (2000 to 2009) and extended for three years following the acquisition of the company (2010 to 2012). Bangor Gas submitted an annual price cap adjustment for 2013 consistent with the price cap index methodology applied under the previous rate plan.

13.4.3 Productivity and X-factor trends

Approved 0.5% to be applied after the initial five years with no discussion on the merits of the X-factor or how it was derived.

13.4.4 I-factor

US Department of Commerce's Gross Domestic Product Price Index (GDP PI) is applied as the inflation factor.

13.4.5 Treatment of unknown costs

No explicit provisions for recovery of unknown costs. Bangor Gas has an opportunity to earn revenue to cover costs through plan length (revenue stability) and its return on equity (i.e. ESM trigger ROE of 15%).

13.4.6 ESM

Earnings above ROE of 15% are shared on 50/50 basis with the ratepayers. There is no sharing requirement in the event of under-earning. ROE was approved with the rationale that Bangor Gas as a start-up should be allowed a higher rate than established businesses. The three year

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[65] Sources: State Of Maine Public Utilities Commission (1998) *Order Approving Rate Plan (Bangor Gas Company, LLC, Docket No. 97-795 - Petition For Approval To Provide Gas Service In The Greater Bangor Area).* June 26, 1998

(2007) *Order Approving Reorganization With Conditions (Bangor Gas Company, LLC, DOCKET NO. 2007-151, Request For Approval Of Reorganization With Sale Of Penobscot Natural Gas, Inc. And Petition For Approval Of Affiliated Transaction Agreement Between Bangor Gas And Energy West, Inc.).* November 21, 2007

(2013) *Order Denying Rate Plan Extension (Bangor Gas Company, LLC, Docket No. 2012-00604 - Request For Approval Of Price Cap Adjustment; Bangor Gas Company, LLC, Docket No. 2012-00598 - Petition To Renew Multi-Year Rate Plan).* May 10, 2013 extension granted in 2007 modified the ESM with a new ROE trigger of 30%. The Commission was cognizant of the high ROE but argued that Bangor risk profile is that of an unregulated firm. The Commission's experience was such firms typically require that investments have a payback period of two to three years which equates to a return of equity of 30% to 50%.

13.4.7 Mechanisms for treatment of unaccounted-for gas

The Maine PUC viewed that the company is earning a return high enough to make the use of deferral accounts unnecessary.

13.4.8 Service quality indicators

There were no SQI requirements specific to the rate plan.

13.5 Massachusetts - Berkshire Gas Company[66]

13.5.1 Brief overview

Berkshire Gas Company provides natural gas to more than 36,000 customers in western Massachusetts.

13.5.2 Form of rate cap and regulatory period

The regulatory period is ten years, approved in 2002, with a price cap mechanism, which provides for annual price adjustments for a range of costs (including an inflation adjustment for certain O&M costs). Base rates were frozen for the first 31 months. To date, no new rate case application has been filed with the Massachusetts Department of Public Utilities.

13.5.3 Productivity and X-factor trends

The mechanism provides a guaranteed "annual consumer dividend", in the form of an annual 1% reduction to the GDP inflator.

13.5.4 I-factor

GDP-PI index is the inflation factor.

13.5.5 Treatment of unknown costs

Unknown costs are defined as exogenous costs outside of company's control and not reflected in the GDP-PI index (with a minimum threshold of $65,000). This threshold was based on a percentage (0.1253%) of operating revenues. Berkshire must file details of exogenous costs in annual compliance filing.

13.5.6 ESM

Not applied.

13.5.7 Mechanisms for treatment of unaccounted-for gas

Provided for under Massachusetts Department of Public Utilities Regulations Standard Cost of Gas Adjustment Clause. This provides for semi-annual adjustment of gas sales to recover costs of firm send-out gas, including UFG.[67]

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[66] Sources: DPU (2002) DTE 01-56 *Order on the motions of Berkshire Gas Company and the Attorney General for reconsideration, clarification and recalculation*, August 5, 2002; Avery, James (2007) *Mid-period report on performance of price cap mechanism plan* April 1, 2007; DPU 10-114. (2011) ORDER. March 31, 2011; Berkshire Gas Company (2013) *The Berkshire Gas Company's 2012 Service Quality Report. DPU 13-SQ-02*. Jan, 3 2013

[67] See DPU Regulations 220CMR 6.00: Standard Cost of Gas Adjustment Clause

13.5.8 Service quality indicators

A range of standard service quality indicators exist, including:

- customer service - telephone service response; service appointments met; billing adjustments; response to odor calls; and property damage claims; consumer survey data; and customer service guarantees;
- safety - lost time accident rate and accidents ; and
- performance (including tracking of UFG).

13.6 Massachusetts - New England Gas Company[68]

13.6.1 Brief overview

New England Gas Company is a division of Southern Union Company which serves over 50,000 residential and commercial customers in Massachusetts.

13.6.2 Form of rate cap and regulatory period

Revenue-per-customer plus a cap on the total amount of revenue that may be added to rates in any season, with the cap set at three percent of total revenues from firm sales and firm transportation throughput for the most recent corresponding peak or off-peak periods. The regulatory period applies from April 2011 until the next review, which has no set date. There is no specific trigger mentioned for the review with a utility able to request a rate review as required. The previous ratemaking period was from 2009 to 2011.

13.6.3 Productivity and X-factor trends

No productivity factor but in order to receive the inflation adjustment, the utility must demonstrate efforts to reduce O&M costs in its rate application.

13.6.4 I-factor

No specific I-factor but inflation allowance based on GDP IPD (GDP implicit price deflator) for certain O&M expenses.

13.6.5 Treatment of unknown costs

There is no specific mention in the Department of Public Utilities ("DPU)" order. However, a utility may file a rate application as required.

13.6.6 ESM

Not applied

13.6.7 Mechanisms for treatment of unaccounted-for gas

The Massachusetts Department of Public Utilities Regulations Standard Cost of Gas Adjustment Clause provides for semi-annual adjustment of gas sales to recover costs of firm send-out gas,

[68] Sources: DPU (2011) *ORDER. By Chair Berwick and Commissioner Westbrook. DPU 10-114*. March 31, 2011

New England Gas Company (2013) *New England Gas Company's 2012 Annual Service Quality Report. DPU 13-SQ-08.* March 1, 2013 including UFG.[69]

13.6.8 Service quality indicators

A range of standard indicators exist, including:

- customer service - telephone service response; service appointments met; billing adjustments; response to odor calls; property damage claims; consumer survey data; and customer service guarantees;
- safety - lost time accident rate and accidents; and
- performance (including tracking of UFG).

[69] See DPU Regulations 220CMR 6.00: Standard Cost of Gas Adjustment Clause

14 Appendix B: Summary of survey of gas utilities with similar customer size to Union[70]

Company & number of customers	Framework and gas customers	Regulatory period	Productivity and X factor trends	Inflation factor	Treatment of unforeseen costs	Deferral accounts / other mechanisms for unaccounted for gas	ESM	Service quality indicators
Ameren CIPS (IL) 810,049	Price cap with number of riders to adjust prices + regulatory lag	2012 onwards; no end date	N/A	No adjustment during rate period	Can file new application at any time	Purchased gas adjustment charge - adjusted monthly and reconciled annually	N/A	Minimum Standards of Service. Records must be kept for: customer complaints, interruptibility. Must also maintain minimum pressures and gas purity
Columbia Gas of Ohio Inc (OH) 843,175	Straight fixed variable - Price cap with number of riders to adjust prices + regulatory lag - Moving to 100% fixed rates by end of period - Infrastructure rider must file annually and costs capped with excess costs deffered and accruing at long-term cost of debt	5 yrs (2008 to 2012)	N/A	No adjustment during rate period	Can file application in accordance with Ohio Administrative Code	Adjusted annually	N/A	Minimum Service Standards: customer service levels for service connection and upgrades, telephone response, scheduled appointments; complaint handling
Consolidated Edison Co of New York Inc (current framework) 882,650	Fixed revenue requirement (revenue cap with RDM, Revenue Decoupling Mechanism) with built in productivity incentives plus adjustments	3 yr rate plan	Final approved revenues adjusted for austerity and productivity ($6m in Yr 1, $4m in Yr 2 and $2m in Yr 3)	N/A	N/A	Cost of gas adjustment mechanism assumes 1.315% loss factor	Yr 1: ROE between 9.6% and 10.35% - no sharing; above 10.35% and up to 11.59% - 60% to ratepayers; above 11.60% and up to 12.59% - 75% to ratepayers; above 12.6% - 90% to ratepayers; Yrs 2 and 3: ROE between 9.6% and 10.1% - no sharing; above 10.1% and up to 11.59% - 60% to ratepayers; other increments same as in Yr 1	Safety and response time indicators, customer service performance mechanism; customers could be credited up to $3.3m ($550,000 for each 0.1% drop in customer satisfaction rating)
Consolidated Edison Co of New York Inc (1995 to 1996) 882,650	PBR - revenue cap: increases are limited to the lesser of (i) latest forecast of the GDP deflator plus 1% + gas incentives or (ii) 4.8%	3 yr rate plan: rebase year and 2 yrs of revenue cap increases	May range from -0.1% to -1.85% (depending on attainment of SQIs), subject to total cap of 4.8%	GDP Price Deflator (forecast)	Costs not recovered through capped revenue increase are deferred for later recovery	Costs not recovered through the capped revenue increase are deferred for later recovery	ESM: 50/50 sharing on ROE above 75 bp of approved ROE (10.9%), i.e. ROE above 11.65%; no sharing on shortfall	Gas incentives: reward or penlaty of up to 60 bp for meeting leak reduction targets, reward of up to 25 bp or penalty of 30 bp for customer satisfaction (to be determined through independent polling agency)
Consumers Energy Co (MI) 1,710,335	Cost of service regulation	Applications filed annually	N/A	N/A	N/A	N/A	N/A	N/A
Nicor Gas (Northern Illinois Gas Company) (IL) 1,932,591	Price cap with number of riders to adjust prices + regulatory lag	Test year: 2009; Rate period: 2010-2013	N/A	No adjustment during rate period	Can file new application at any time	Gas Supply Rider - costs calculated on monthly basis and revenues/costs reconciled annually Storage Service Cost Recovery - costs calculated on annual basis and revenues/costs reconciled annually	N/A	Minimum Standards of Service. Records must be kept for: customer complaints, interruptibility. Must maintain: minimum pressures, gas purity; In process of adding penalty programs

[70] Note: Survey included eleven companies. The table lists twelve, as there are two separate rows for Consolidated Edison Co. of New York (current and older framework).

Company & number of customers	Framework and gas customers	Regulatory period	Productivity and X factor trends	Inflation factor	Treatment of unforeseen costs	Deferral accounts / other mechanisms for unaccounted for gas	ESM	Service quality indicators
Oklahoma Natural Gas Co (OK) 844,105	Performance Based Rate Change Plan with text year revenue requirement set in 2010 and annual adjustments for certain; specified operating expenses	2 yr rate plan	N/A	N/A	N/A	N/A	Allowed ROE of 10.5%; deadband between 10.0% and 11.0%, earnings above 11% shared 75% to ratepayers, if the amount is greater than $200,000; Company may request rate change if ROE below 10.0%	N/A
Public Service Co of Colorado (CO) 1,305,352	Revenue requirement test year 2010	Last base rate adjustment was in 2011 and must file next gas rate case no later than Dec 2013	N/A	N/A	N/A	N/A	N/A	Establishing meter-measurement standards, determining customer deposit requirements, establishing guidelines for non-discriminatory reservation of pipeline capacity by gas transportation customers
Public Service Electric & Gas Co (NJ) 1,681,058	Test year 2009 with tracker for weather normalization (withdrew trackers for pension and expanded infrastructure program)	Last base rate adjustment in 2010	N/A	N/A	N/A	N/A	N/A	Emergency response, customer service and reliability, commitment to cost control, corporate culture of transparency and local decision making, technical expertise and proven environmental track record
Questar Gas Co (UT) 913,270	Revenue per customer with test year 2010 and adjustments including infrastructure tracker and low-income assistance	3 years (New application filed July 2013)	N/A	N/A	N/A	Pass through at cost	N/A	N/A
Southwest Gas Corp (AZ) 983,803	Revenue per customer	Gas rates filed with Arizona Corporation Commission. Last base rate adjustment was in 2012, the next one expected in 2016.	N/A	N/A	N/A	Purchased Gas Cost Adjustment Provision allows to track the difference between purchased gas and billed gas	N/A	N/A
Washington Gas Light Co (VA) 928,069	PBR - total revenue requirement, frozen for 4 years	4 year term - rates set in Yr 1; frozen over term	Productivity targets are implicitly equal to inflation rates; frozen rates	N/A	N/A	N/A	Any earnings above ROE of 10.5% are shared 75% to customers, no sharing of shortfall	N/A

15 Appendix C: Works Consulted

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16 Appendix D: Relevant LEI experience

16.1 About LEI

London Economics International LLC is a global economic, financial, and strategic advisory professional services firm specializing in energy, water, and infrastructure. The firm combines detailed understanding of specific network and commodity industries, such as natural gas distribution, with sophisticated analysis and a suite of proprietary quantitative models to produce reliable and comprehensible results.

The firm also has in-depth expertise in economic and financial issues related to the electricity, gas, and water sectors, such as asset valuation, procurement, regulatory economics, and market design and analysis. LEI has worked extensively in North America, Europe, Asia, Latin America, Africa, and the Middle East, and has a comprehensive understanding of the issues faced by the utilities and regulators alike.

The following attributes make LEI unique:

- *clear, readable deliverables* grounded in substantial topical and quantitative evidence;
- *internally developed proprietary models* for electricity price forecasting incorporating game theory, real options valuation, Monte Carlo simulation, and sophisticated statistical techniques;
- *balance of private sector and governmental clients* enables LEI to effectively advise both regarding the impact of regulatory initiatives on private investment and the extent of possible regulatory responses to individual firm actions;
- *ability to estimate relative efficiency levels* and efficiency frontiers provides expertise to advise on network tariffs and design rates under performance-based ratemaking; and
- *worldwide experience* backed by multilingual and multicultural staff.

16.2 Relevant PBR and regulatory experience in Ontario

LEI has been involved in the regulatory proceedings at the Ontario Energy Board since PBR inception. LEI has advised and provided testimony of behalf of multiple stakeholders in all of the major PBR proceedings at the OEB, including on behalf of the OEB itself on second generation PBR design, cost of capital for regulated generation assets, conservation and demand management under PBR framework, etc. LEI has also advised the Coalition of Large Distributors (third generation of electricity IRM) and Ontario Power Generation (applicability of PBR to generation assets) on PBR in Ontario.

16.3 PBR experience worldwide

LEI has been involved with precedent-setting PBR proceedings in Alberta (consulted ENMAX on its first formula-based ratemaking application for distribution and transmission services and FortisAlberta on its first PBR application), the Middle East (development of regulatory framework for electricity, water and wastewater businesses that are not currently regulated by the national regulator in Saudi Arabia; advisory services on optimal capital structure and cost of capital for a Jordanian regulator; advisory services to distribution companies in Jordan on PBR incentives for operating costs), Europe (review of regulatory regimes in multiple jurisdictions in Europe), the Caribbean and Latin America (advised a power utility on PBR implications, advised Argentine regulator on tariff review), and Asia (advised Hong Kong regulator on regulatory regime best practices).

LEI has also been involved with a number of stakeholders (industry association, investors and operating companies) in reviewing PBR practices worldwide and their implications for the clients' operations and profitability (assisting investor to develop consensus approaches by a Romanian regulator to PBR applications, review of lease transactions involving utilities in Belgium and potential impact of PBR framework, review of PBR practices for the Canadian Electricity Association, valuation of potential acquisition targets in the US).

16.4 Gas experience

LEI has worked on a number of engagements related to the gas industry across North America and Europe. These include work in the following areas:

- ***gas transmission and distribution***: investigating the status of natural gas deregulation in the US; reviewing barriers to entry for foreign investment in the US; netback analysis of proposed new pipelines; contract review for gas transport network in the Netherlands; and analysis of swap contracts involving gas transport assets in Austria;
- ***storage***: analyzed the growing natural gas storage business in the US in the context of greater pricing flexibility, changes in storage methods and shorter-term market fluctuations; and
- ***ratemaking and policy***: review of treatment of allowed returns and capital investment requirements across the US; advised on building blocks application (similar to regulation in Australia and the UK) in North America; studied impact of tax credits for non-conventional fuels production on natural gas drilling and innovation.

APPENDIX B

uniongas
A Spectra Energy Company

Union Gas

2013 Pricing Parameters Study

Prepared by:

enrg RESEARCH GROUP

NRG Research Group

Andrew Enns

204-989-8986

July 10, 2013

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Executive Summary

NRG Research Group (NRG) was contracted by Union Gas to conduct a study with its residential customers' regarding attitudes toward price stability and predictability in natural gas delivery charges. NRG completed 1200 surveys via Computer Assisted Telephone Interviewing from May 23rd to June 4th, 2013. The key study findings are provided below.

Awareness of Rates

The majority of respondents (82%) are aware that their bill contains charges for procuring gas to Union's system, its storage, and transportation to customers.

Concept of Stability

Almost half of all respondents (49%) indicate that if Union is working to provide stable delivery charges, they expect that Union is working to provide charges that *could change but not by a large degree*. Just over a quarter of individuals (28%) expect that stable delivery charges would be charges that *do not change over time.*

Opinion on Stabilizing Delivery Charges

When asked which statement best describes their opinion on stabilizing deliver charges, 42% indicate that *Union Gas working to stabilize delivery charges is better than doing nothing at all,* while 38% indicate they *prefer stable rates for all charges on my bill/do not see any benefit in stabilizing only delivery charges*. Just under one-fifth of respondents (18%) indicate that *it makes no difference to me whether you try to stabilize delivery charges or not.*

Acceptable Increase in Delivery Charges

When asked what percentage increase in delivery charges would be acceptable, 30% believe there should be *No increase;* 18% consider an increase of no more than 1% acceptable; 15% consider an increase between 1.01% and 2% acceptable; 16% find an increase of 2.01% or more to be acceptable and; 5% say an increase should be equal to the inflation rate.

Acceptability of Delivery Charge Increases Equal to Inflation

When asked specifically of their willingness to accept a *delivery charge rate increase at the rate of inflation annually over the next 5* years, over six out of ten respondents (62%) feel that this is acceptable.

Value – Stability and Predictability

Sixty-eight percent (68%) of respondents agree that stable delivery charges will help them budget more effectively for their household, while just over two-thirds of respondents (67%) feel that knowing the delivery rate for the year in advance would be beneficial.

Background, Objectives and Methodology

Background

Union Gas Limited (Union) is a major Canadian natural gas utility, providing energy delivery and related services to approximately 1.4 million residential, commercial and industrial customers in over 400 communities in Northern, Southwestern and Eastern Ontario.

Union is preparing for the 3rd generation incentive regulation framework. It is contemplated that this framework would provide for annual rate increases in the delivery charge equivalent to the annual inflation rate over the 5 year time frame. The company believes that this proposal provides benefits to the customer in terms of stability and predictability in rates.

NRG Research Group (NRG) was contracted by Union to conduct research with Union's residential customers to determine whether the company's hypothesis aligns with customer perception of rate stability and predictability, and specifically the level of customer acceptance of annual inflationary increases in delivery rates over the next 5 years.

Objectives

The overall objective of the research is to explore the relative importance of concerns and preferences in the pricing of natural gas delivery services with respect to price stability and predictability. The key components of the inquiry included:

1. To test a common understanding of the words *stability* and *predictability* with reference to this study.
2. This enquiry will include an exploration of the perceived benefits of rate stability and predictability and gauge their relative importance in the minds of customers.
3. To determine customer acceptance of annual delivery rate increases equivalent to the general inflation rate over a 5 year period, particularly the extent to which such increases align with delivering stable and predictable rates.

Methodology

Using a random sample of residential customers provided by Union, NRG conducted a total of 1200 interviews across the Union Gas Franchise Area via Computer-Assisted Telephone Interviewing (CATI). Telephone interviews were conducted between May 27th and June 4th, 2013 with all calling taking place out of NRG's Winnipeg call centre. The average length of the survey was 7 minutes.

Individuals qualified for the study if they personally viewed the bill from Union Gas and were the person in the household who usually pays the monthly natural gas utility bill.

The survey was pre-tested and monitored by Union Gas and NRG staff on the 23rd of May. Based on the pre-test findings, several edits were made to the questionnaire to improve respondent comprehension. The script was pre-tested again on the 24th of May. This pre-test confirmed to Union Gas and NRG that it was in a satisfactory form to move forward with full fielding.

Sample records were called up to 5 times before being dispositioned as non-responsive. Please refer to Appendix B for the study's Call Record Summary for this study.

This study included surveys with customers from the seven Union Gas districts in Ontario: Eastern, Waterloo/Brantford, London/Sarnia, Northeast, Northwest, Windsor/Chatham, and Hamilton/Halton. The table below displays the number of surveys completed within each district and overall. The margin of error is provided at the 95% confidence interval.

Customer District	Sample N (un-weighted)	Sample N (Weighted)	Margin of error % (95% Confidence)
Eastern	86	84	+/-10.7
Hamilton/Halton	288	297	+/-5.7
London/Sarnia	231	230	+/-6.5
Northeast	118	116	+/-9.1
Northwest	82	81	+/-10.9
Waterloo/Brantford	239	237	+/-6.4
Windsor/Chatham	156	155	+/-7.9
Total	**1200**	**1200**	**+/-2.8**

During the data collection, NRG established hard quotas to ensure the final sample resembled the actual customer distribution on two dimensions:

1. The percentage of customers subscribing and not subscribing to Union's Equal Billing Plan reflected the actual distribution (41% on EBP); and
2. The district distribution of customers across Union's service area.

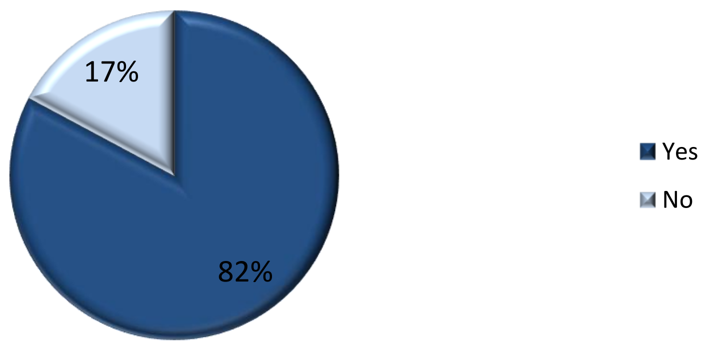
The final data set was examined and weighted to actual proportions from Union's billing system to ensure the findings were representative of Union's customer base. The table above indicates the extent of the regional weighting required.

Survey Results

Listed below are the notable findings for the 2013 Union Gas Pricing Parameters Study. The questionnaire used in the research is provided in Appendix A, and the demographic profile of respondents is provided in Appendix C.

Awareness of Rates

1. *Your bill contains charges for the natural gas that you use as well as for getting gas to Union's system as well as storing and transporting that gas to your home. Prior to today, were you aware of this?*



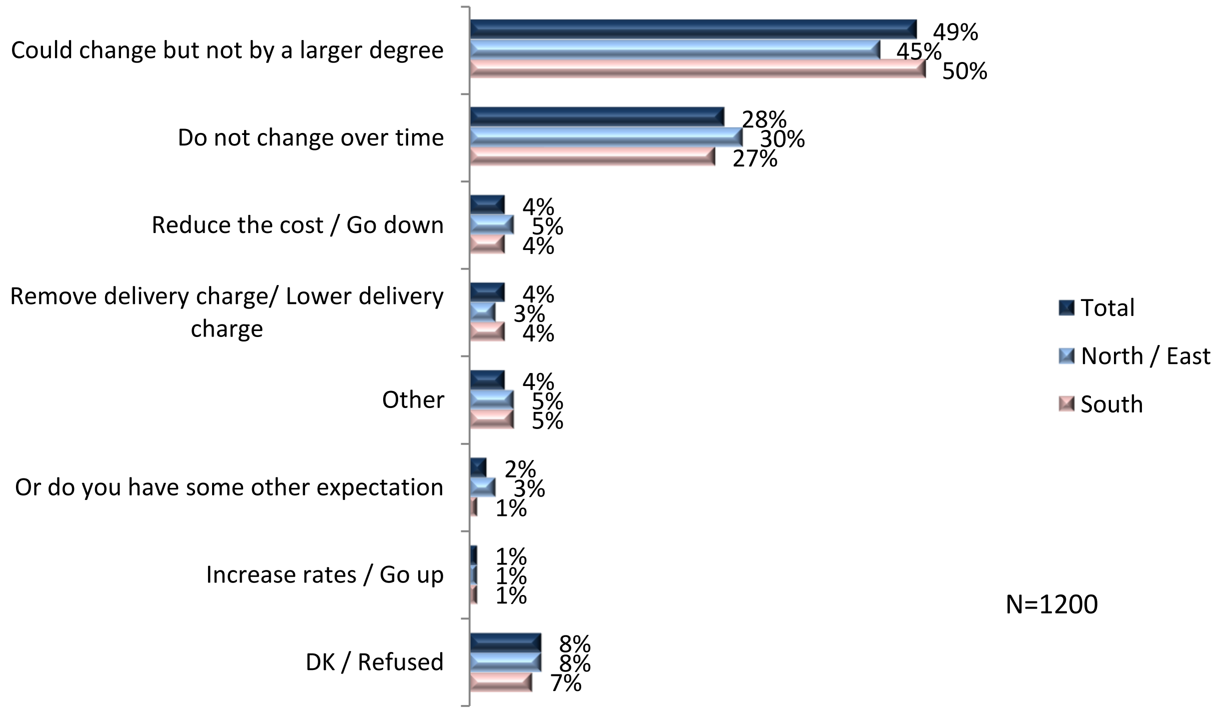
N=1200

The majority of respondents (82%) were aware that their bill contains charges for natural gas use, its storage, and transportation. Awareness was highest in the London/Sarnia and Northeast districts (85%) and lowest in the Northwest (76%).

Respondents 50 years of age and older (84%) and those who had some post secondary education or some university (88%) were significantly more likely to be aware of the contents of their Union bill.

Concept of Stability

2. *Now I'd like to hear your expectations about stable delivery charges. When you hear that Union Gas is working to provide you with stable delivery charges, is your expectation that they are working to provide charges that...*



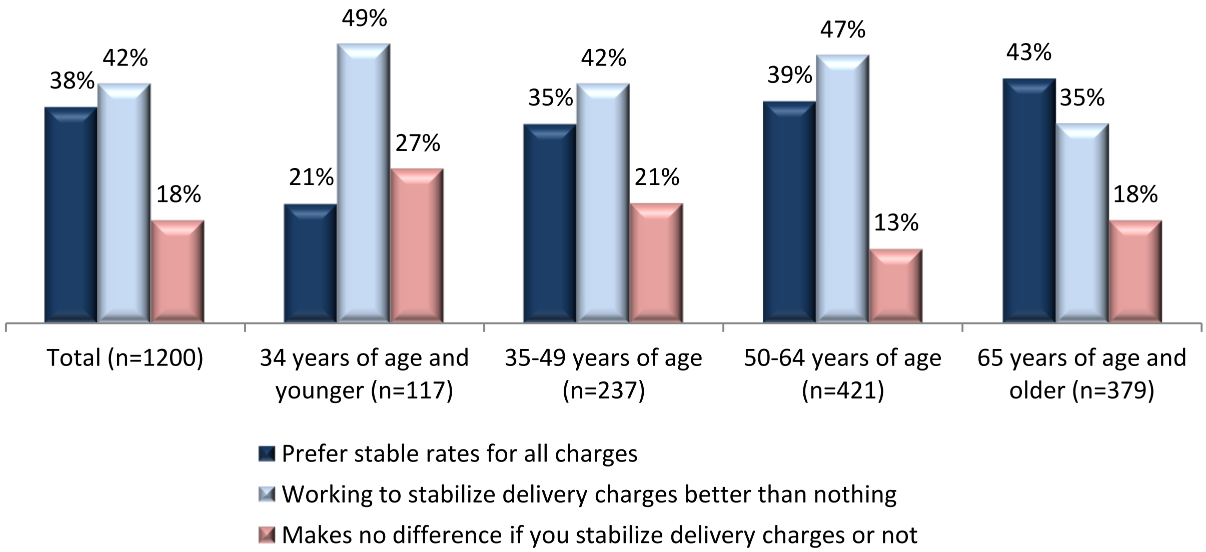
Nearly half of respondents (49%) surveyed indicated their expectation that Union working to provide stable delivery charges would mean that charges *could change but not by a large degree*. The second most frequent response was *do not change over time,* as 28% customers selected this statement.

Respondents from the London/Sarnia district (55%) and those who had a household income of $100K or more (55%) were significantly more inclined to indicate *could change but not by a large degree*.

A higher percentage of respondents below the age of 65 (31%) indicated that working towards stable rates meant charges that *do not change over time* relative to those 65 and over (23%).

Opinion on Stabilizing Delivery Charges

3. *Union Gas is working to provide customers with stable charges, but they cannot stabilize all of the charges. They can, however, influence the delivery charge portion that we have been speaking about. Which statement best describes your opinion about stabilizing delivery charges?.*

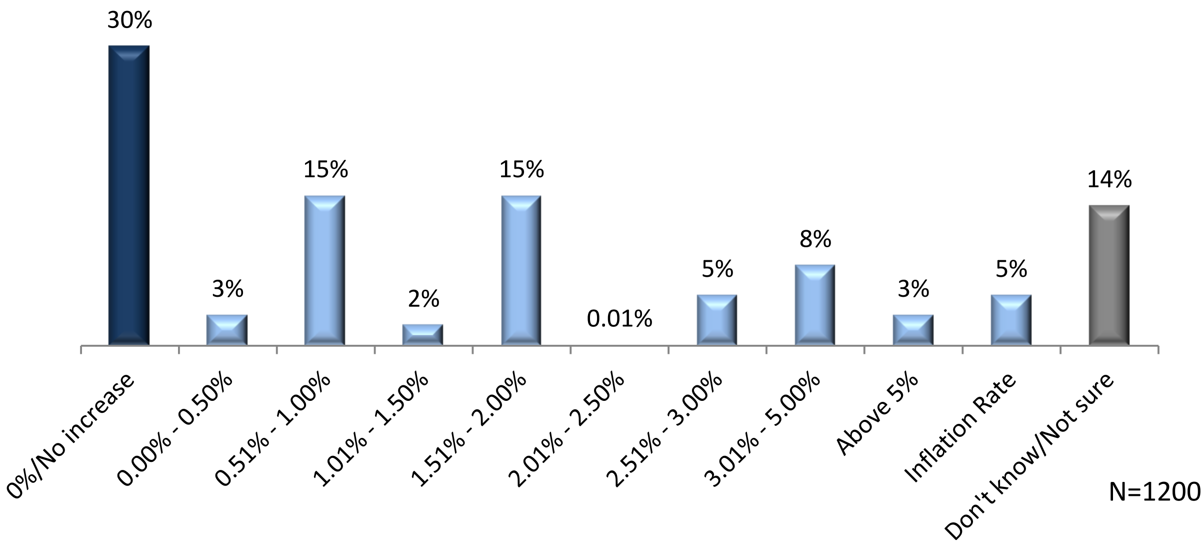


Working to stabilize delivery charges is better than doing nothing at all was the opinion most agreed upon by Union customers (42%). There were no statistically significant differences across the districts. A higher percentage of customers under the age of 65 (46%) are relatively more likely to share this opinion over those 65 and over (35%). Customers that had a household income of at least $40K were significantly more likely than those earning less than $40K to share this opinion (45% vs. 35%).

Nearly four in ten (38%) respondents indicated they *would prefer stable rates for all charges on my bill and I do not see any benefit in stabilizing only delivery charges*. Respondents aged 65 and older (43%) were most likely to share this opinion. Those who indicated that they subscribed to equal billing were also significantly more likely to opt for stable rates for all charges when compared to those indicating they were not on equal billing (42% vs. 35%).

Acceptable Increase in Delivery Charges

4A. Now, I would like to talk with you about your total charges for delivery. Based on an average annual charge of [$350 South, $460 North and Eastern], what would you consider to be an acceptable amount of increase in these charges from one year to the next in percentage terms?

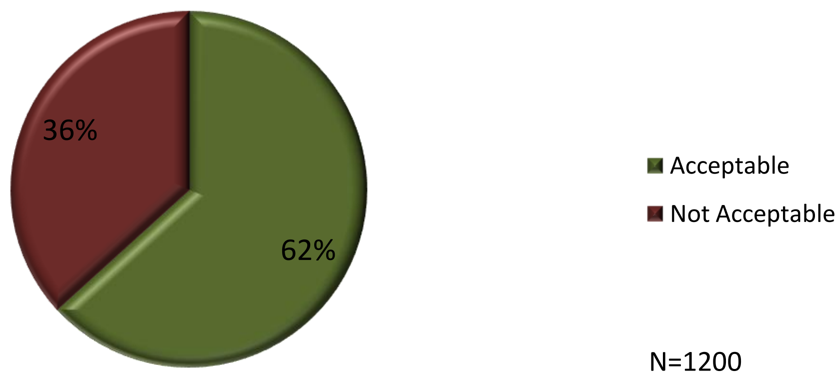


Three in ten respondents believed that there should be *No increase/0%* in the average annual charges from one year to the next. Customers from the Northeast district were particularly in favour of no increase (37%). Individuals with a household income of less than $40K (35%), 50 plus (32%), and/or with a high school education or less (35%) were significantly more likely to indicate a preference for no increase.

The percentage increases of *0.51% to 1%* and *1.51% to 2%* were tied for the second most commonly mentioned responses at 15%. Sixteen percent (16%) of Union customers would consider an increase of *2.01% or more* acceptable, while 5% viewed an increase equal to the inflation rate to be an acceptable increase. Fourteen percent (14%) of respondents were unsure what the percentage increase should be.

Acceptability of Delivery Charge Increases Equal to Inflation

4B. In the last 5 years, the general inflation rate for the Canadian economy has been 1.8%. Going forward, the inflation rate may be higher or lower than this rate. Suppose Union Gas was allowed to increase delivery charges each year by no more than the general inflation rate over a 5 year period. Please tell me if this would be acceptable to you?

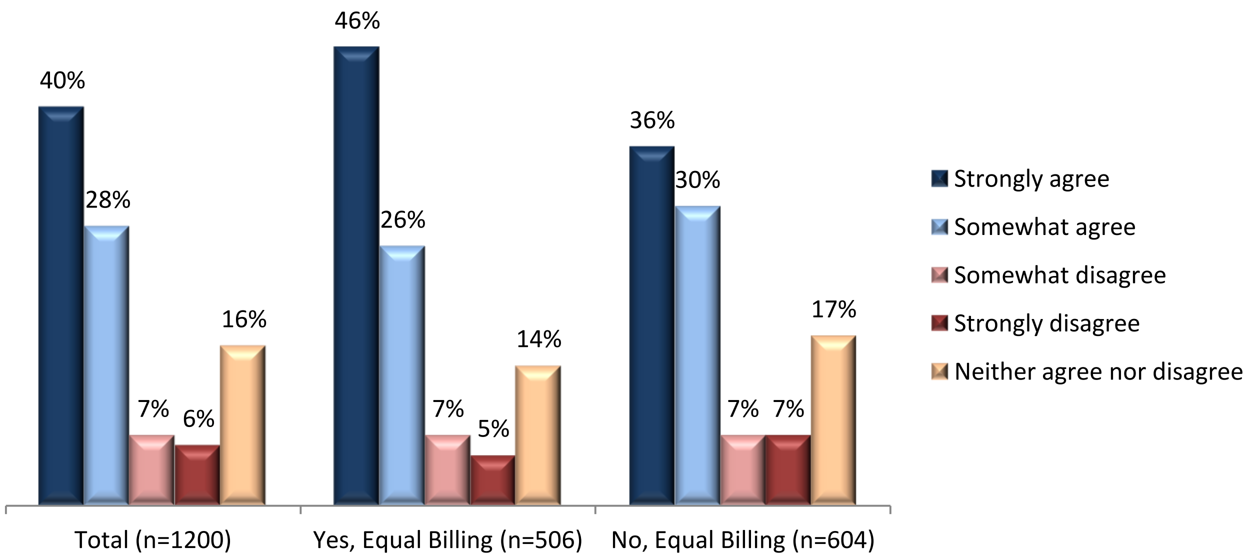


Just over six out of ten (62%) respondents felt that an increase in delivery charges each year by no more than the general inflation rate over a 5 year period was *Acceptable*. Acceptance was strongest in the Eastern district (67%) and Hamilton/Halton (66%) and weakest in Windsor/Chatham (57%).

There were no significant differences in acceptance across age groups or education levels. However, those with incomes over $100K indicated higher acceptability of increases tied to inflation relative to those earning less than $40K (69% vs. 59%).

Value – Stability and Predictability

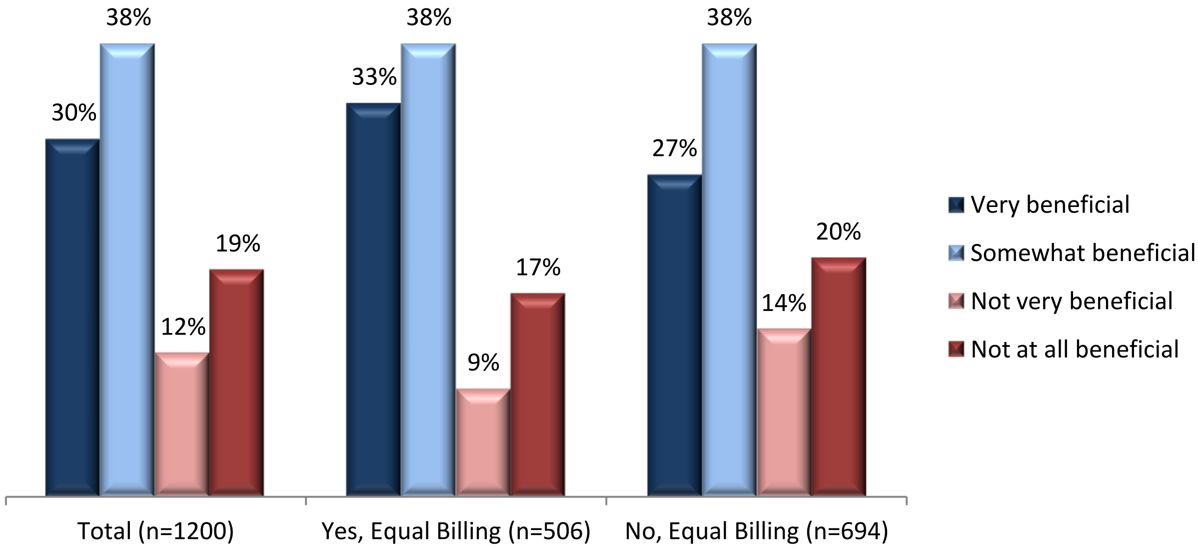
5. *Please tell me if you agree, disagree or neither agree nor disagree that having stable delivery charges will help you budget more effectively for your household.*



Just over two-thirds (68%) of Union customers *Strongly or somewhat agree* that having stable delivery charges will help you budget more effectively for your household. The total disagreement to this question was 13% while 16% *neither agreed nor disagreed*.

Overall agreement was highest in the Northeast and Northwest districts (74% and 73% respectively). Agreement was particularly strong amongst the following groups: those 50 to 64 years of age (75%); those in the $40K to less than $80K age bracket (73%); those with some high school education or less (72%) and; those who were aware of subscribing to equal billing (72%).

6. *Would knowing what this rate will be for the year in advance be very beneficial, somewhat beneficial, not very beneficial or not at all beneficial to you?*



In total, 67% of respondents felt that knowing this rate a year in advance would be either *Very or Somewhat beneficial*. The strongest perception of benefit came from the Northwest (79%) and Northeast (72%) districts. Perceived benefit was lowest in the Eastern district, with only 56% indicating that knowing in advance would be *Very or Somewhat beneficial*.

Among those that indicated awareness to subscribing to equal billing, 71% felt knowing in advance would be beneficial. In addition, those under the age of 65 were significantly more likely to view as beneficial (73%) relative to those 65 and over (57%).

Appendix A: Questionnaire

Union Gas 2013 Pricing Parameters Study Questionnaire

INTRODUCTION

A. Good (morning / afternoon), my name is ___________________ and I'm calling from NRG Research, a national market research firm. I am calling on behalf of Union Gas. May I please speak with (NAME FROM SAMPLE FILE) OR the person in your household who usually pays the monthly natural gas utility bills? Would that be you?

Yes, speaking **(CONTINUE)**
Yes, I'll get them **(REINTRODUCE)**
No, not available **(SCHEDULE CALLBACK, THANK & TERMINATE)**

B. This survey focuses on what you are charged for the delivery of natural gas to your home. The survey lasts approximately 7 minutes and your participation is completely confidential. Is this a convenient time to speak with you?

Yes **(CONTINUE)**
No **(SCHEDULE APPOINTMENT, THANK & TERMINATE)**
Refused **(THANK & TERMINATE)**

S1. Do you or does anyone living in your household currently work for any of the following types of companies? **[READ LIST]**

A market research company
The media
An advertising company
A public utility or energy retailer

Yes
No
DK/NS
[IF YES OR DK/NS TO ANY OF THE ABOVE THANK AND TERMINATE, ELSE CONTINUE]

S2. Do you personally see the bill from Union Gas?

Yes
No
DK/NS
[ASK FOR SOMEONE WHO DOES, IF NOT AVAILABLE SCHEDULE APPOINTMENT]

S3. You may know that Union Gas currently offers an Equal Billing Plan or Budget Billing Plan. This plan estimates your total gas consumption and related charges for the year and divides that amount into equal monthly payments. To the best of your knowledge, do you subscribe to the Equal Billing Plan? [ADD INTERVIEWER NOTE DEFINING EQUAL BILLING]

Yes
No
DK/NS
[SOFT QUOTA 37% EQUAL BILLING OVERALL – IF DK/NS THANK AND TERMINATE]

Understanding of Rates

1. I'd like to begin by asking you about some of the components of the bill you receive from Union Gas.

Your bill contains charges for the natural gas that you use as well as for getting gas to Union's system as well as storing and transporting that gas to your home. The costs for gas, transportation, and for delivery are all based on different rates. So the amount you owe Union Gas every month is actually calculated based on a variety of rates. Prior to today, were you aware of this?

Yes
No
DK/NS

Concept of Stability
2. I would like to talk with you specifically about the delivery charges that appear on your bill from Union Gas.

UNION SOUTH (from sample file)
These are the charges for operating and maintaining the pipes used to get gas to your home, as well as for the storage required to meet your needs. For the average customer, delivery charges amount to about $350 for the entire year.

UNION NORTH & Eastern(from sample file)
I would like to talk with you specifically about the delivery charges that appear on your bill from Union Gas. These are the charge for operating and maintaining the pipes used to get gas to your home. For the average customer, delivery charges amount to about $460 for the entire year.

Now I'd like to hear your expectations about stable delivery charges. When you hear that Union Gas is working to provide you with stable delivery charges, is your expectation that they are working to provide charges that **[READ LIST AND ROTATE A and B]**

A. Do not change over time
B. Could change but not by a large degree
C. Or do you have some other expectation? **[SPECIFY. ALWAYS READ LAST]**

[INTERVIEWER INSTRUCTION: If respondents questions whether asking about entire natural gas bill, clarify only asking about the 'delivery charges' portion of the bill. In South, this includes the monthly charge, storage charge and the delivery charge. In North, this includes the monthly charge and the delivery charge]

3. Union Gas is working to provide customers with stable charges, but they cannot stabilize ***all*** of the charges on your bill. They *can*, however, influence the delivery charges portion that we have been speaking about. I am referring specifically to the charges you pay for the delivery of gas to your home.

I am going to read you three statements and I would like you to tell me which one best describes your opinion about stabilizing delivery charges. Would it be? **[READ AND RANDOMIZE]**.

A. I would prefer stable rates for all charges on my bill and I do not see any benefit in stabilizing only delivery charges
B. Working to stabilize delivery charges is better than doing nothing at all
C. It makes no difference to me whether you try to stabilize delivery charges or not

4a. Now, I would like to talk with you about your total charges for delivery. I'd like to hear about what you think is an acceptable amount of increase for this portion of your bill. Based on an average annual charge of [$350 South, $460 North and Eastern], what would you consider to be an acceptable amount of increase in these charges from one year to the next in dollars?

NOTE TO INTERVIEWER: WE ARE LOOKING FOR AN INCREASE OF DOLLARS AND NOT WHAT THE TOTAL AMOUNT SHOULD BE. ALSO, WE ARE LOOKING FOR WHAT IS ACCEPTABLE.

[RECORD AMOUNT IN DOLLARS]
(RECORD EXACT AMOUNT IF OFFERED. $0/NO INCREASE IS A VALID RESPONSE)
[IF INFLATION RATE ANSWERED CLARIFY WITH... "That would mean about a $6/$8 increase annually based on the annual inflation rate of the past years. Is that your answer?
DK/NS

4b. In the last 5 years, the general inflation rate for the Canadian economy has been 1.8%. Going forward, the inflation rate may be higher or lower than this rate. Suppose Union Gas was allowed to increase delivery charges each year by no more than the general inflation rate over a 5 year period. Please tell me if this would be acceptable to you?

Acceptable
Not Acceptable
DK/NS

Value – Stability and Predictability

5. I'd like to hear how stabilizing the delivery charges portion of your monthly natural gas bill might impact you and your family. Once again, I am referring specifically to the charges you pay for the delivery of gas to your home. Please tell me if you agree, disagree or neither agree nor disagree that having stable delivery charges will help you budget more effectively for your household. Is that strongly or somewhat agree/disagree?

Strongly Agree
Somewhat Agree
Somewhat Disagree
Strongly Disagree
Neither Agree nor Disagree
DK / NS

6. Now, I would like to know how beneficial it would be for Union Gas to tell you in advance what the delivery charge portion of your bill would be. Would knowing what this rate will be for the year in advance be very beneficial, somewhat beneficial, not very beneficial or not at all beneficial to you?

Very Beneficial
Somewhat Beneficial
Not Very Beneficial
Not At All Beneficial
DK / NS

DEMOGRAPHICS

Now I have some quick questions for statistical purposes.

D1. RECORD GENDER **[DO NOT ASK]**

D2. In what year were you born? **[RECORD NUMERICALLY]**

19___
DK/NS

D3. And which of the following best describes the total annual income of your household - that is of everyone living in your house, before taxes, please stop me when I reach your category?

Under $20,000
$20,000 to just under $40,000
$40,000 to just under $60,000
$60,000 to just under $80,000
$80,000 to just under $100,000
$100,000 to just under $120,000
$120,000 to just under $140,000
$140,000 and above
DK/REFUSED

D4. Finally, what is the highest level of education that you have completed? **(READ LIST – ACCEPT RESPONSE BEFORE FINISHING LIST)**

Grade school or some high school
Completed high school
Post secondary technical school
Some university or college
Completed college diploma
Completed university degree
Post-grad degree (masters or PhD)

That completes our survey. On behalf of Union Gas and NRG Research Group thank you very much for your time.

SPECIAL [PRE-TEST ONLY]

S1. Finally, I would like to hear whether or not you think the survey you just completed was clear and easy to understand. Would you say that you agree, disagree or neither agree nor disagree that the survey you just completed was clear and easy to understand? Is that strongly or somewhat agree/ disagree?

Strongly Agree
Somewhat Agree
Somewhat Disagree
Strongly Disagree
Neither Agree nor Disagree
DK/NS

IF DISAGREE PROBE for what was problematic or unclear about the survey OPEN END

Appendix B: Call Record Summary

Call Record for Union Study – June 2013			
A	Total records	19861	100%
1.	Not in service	2801	14%
2.	Fax /Modem	95	1%
3.	Business/Wrong number	836	4%
Remaining		**16129**	**81%**
B	Total eligible numbers	16129	100%
4.	Busy	147	1%
5.	Answering machines	1931	12%
6.	No answer	7286	45%
7/8.	Language/ illness /incapability	258	2%
9.	Selected/eligible respondent not available/ Callbacks	887	6%
Remaining		**5620**	**35%**
C	Total asked	5620	100%
10.	Household refusal	1788	32%
11.	Respondent refusal	2205	39%
12.	Qualified respondent break off	161	3%
Remaining		**1466**	**26%**
D	Co-operative contacts	1466	100%
13.	Disqualified / Quota Full	266	18%
14.	Completed interviews	1200	82%
Refusal rate = (10+11+12)/C		**4154**	**74%**
Response rate (D/B)		**1466**	**9%**

The incidence rate was 82%.

Appendix C: Demographics

The table below provides the demographic characteristics of respondents participating in the study.

Categories	% (n=1200)
Gender	
Male	51
Female	49
Age	
16 to 34	10
35 to 49	21
50 to 64	36
65 and older	33
Income	
Under $40K	19
$40K to just under $80K	32
$80K to just under $100K	12
$100K and over	19
Education	
High school or less	31
Post secondary/Some university	19
Completed college/university or post-grad degree	46
Region	
North/East	23
South	77
Region	
Eastern	7
Hamilton/Halton	25
London/Sarnia	19
Northeast	10
Northwest	7
Waterloo/Brantford	20
Windsor/Chatham	13

TAB 2

EB-2013-0202

UNION GAS LIMITED

SETTLEMENT AGREEMENT

July 31, 2013

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Appendix A – April 29, 2013 IR parameter presentation to stakeholders

Appendix B – Responses to information requests during settlement discussions

Appendix C – Estimated 2014 – 2018 rate impacts

Appendix D – Deferred tax adjustment calculation

Appendix E – Allocation of base rate adjustments

Appendix F – New accounting orders

Appendix G – Revenue Requirement Calculations for (i) Parkway West Project, and (ii) Brantford-Kirkwall Pipeline and Parkway D Compressor Station Projects

Appendix H – Existing accounting orders

Appendix I – Illustrative 2014 Rate Working Papers

EB-2013-0202

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2013-0202, of the 2014-2018 rate-setting methodology for Union Gas Limited ("Union").

On April 29, 2013, Union convened a meeting with stakeholders to present its 2014-2018 Incentive Rate Mechanism ("IRM") proposals. Those invited were intervenors that participated in Union's 2013 Rebasing Proceeding (EB-2011-0210), and representatives of Board Staff. The purpose of the meeting was to inform stakeholders of Union's proposals and provide an opportunity for stakeholders to ask questions to better understand those proposals. A copy of the slides used at that meeting are included at Appendix A. Those slides describe the original Union proposals for 2014-2018 rates. At the end of the April 29, 2013 meeting, it was determined that further meetings would be held, which occurred on May 23, June 10, June 11, June 17 and July 15, 2013. It was agreed that Union would provide written responses to the information requests stakeholders had with respect to Union's proposals contained in Appendix A. All of the written responses Union provided to such information requests are included in Appendix B. The initial stakeholder meeting and all subsequent discussions, except the July 15 meeting, were facilitated by Mr. Ken Rosenberg, who was retained by Union to perform this function.

At the May 23, 2013 meeting, Union responded to further information requests from stakeholders. It was also determined in the May 23rd meeting that the further discussions in June and July would take the form of a Settlement Conference with a view to agreeing on some or all of Union's IRM proposals. Parties agreed that all discussions would be subject to the Board's Settlement Conference Guidelines, interpreted as if this Agreement were the result of a Board-ordered settlement conference.

Settlement negotiations between Union and stakeholders took place on June 10, June 11, June 17 and July 15, 2013. The product of those negotiations is the comprehensive settlement of the IRM by which Union would set rates over the 2014-2018 period, subject to the determination of certain issues remaining to be determined, as set forth in Section 13.3 of this Agreement.

At the time that the April through July of 2013 discussions between the parties took place, Union's application in EB-2013-0202 (the "Application") had not been filed. Union has prepared its Application for Approval of a 2014-2018 Incentive Rate Making Framework based on this Agreement, and the documents considered by the parties hereto which are included in appendices to this Agreement. Additional evidence filed in support of the Application has been reviewed by the parties to the Agreement prior to filing. The parties agree that they regard the Application materials and this Agreement to constitute a sufficient evidentiary record to support the resolution of each of the issues as set forth in this Agreement.

The parties to the Agreement acknowledge and agree that none of the completely settled provisions of this Agreement are severable. If the Board does not accept the completely settled provisions of the Agreement in their entirety, there is no Agreement (unless the parties agree that any portion of the Agreement the Board does accept may continue as a valid Agreement).

The Other Issues set forth in Section 13.3 were deferred to other processes and, unless settled through those processes, remain to be determined by the Board in EB-2013-0202 or Union's 2014 rates application. Each of those issues has to be resolved in order to establish 2014 rates, except as otherwise expressly set out in Section 13.3.

It is further acknowledged and agreed that parties will not withdraw from this Agreement under any circumstances except as provided under Rule 32.05 of the Board's Rules of Practice and Procedure, interpreted as if this Agreement were the result of a Board-ordered settlement conference.

The parties agree that all communications between parties during the Settlement Conference, and all documents exchanged during the conference which were prepared to facilitate settlement discussions are, unless subsequently placed on the record by agreement between the parties, strictly confidential, without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Agreement. The parties intend that the confidentiality of these negotiations be determined in accordance with the Board's Settlement Conference Guidelines, interpreted as if this Agreement were the result of a Board-ordered settlement conference.

The role adopted by Board Staff in Settlement Conferences is set out on page 5 of the Board's Settlement Conference Guidelines. Although Board Staff is not a party to this Agreement, as noted in the Guidelines, "Board Staff who participate in the settlement conference are bound by the same confidentiality standards that apply to parties to the proceeding". Board Staff attended these discussions on that basis.

The following parties participated in the Settlement Conference:

Association of Power Producers of Ontario (“APPrO”)

Building Owners and Managers Association of the Greater Toronto Area (“BOMA”)

Canadian Manufacturers & Exporters (“CME”)

Consumers Council of Canada (“CCC”)

Energy Probe Research Foundation (“Energy Probe”)

Federation of Rental-housing Properties of Ontario (“FRPO”)

Industrial Gas Users Association (“IGUA”)

City of Kitchener (“Kitchener”)

London Property Management Association (“LPMA”)

Ontario Association of Physical Plant Administrators (“OAPPA”)

School Energy Coalition (“SEC”)

Six Nations Natural Gas (“Six Nations”)

TransCanada PipeLines Limited (“TCPL”)

Union Gas Limited (“Union”)

Vulnerable Energy Consumers Coalition (“VECC”)

Except for those parties who are noted under specific issues as having taken no position, all parties agreed with and supported the resolution of each settled issue. No party opposes the resolution of any of the issues set forth in this Agreement.

OVERVIEW

The Board stated in the Natural Gas Forum ("NGF") Report that incentive rate regulation should meet three objectives:

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.

The parties have entered into this Agreement with the intent of achieving those objectives. Therefore, the parties agree that these objectives are met by the proposed resolution of the various issues discussed as part of arriving at the 5-year IRM proposed to the Board in this Agreement.

Further, the parties to the Agreement represent the major stakeholders and constituencies with an interest in Union's rates. These parties represent a wide range of sometimes competing interests who hold a wide range of sometimes competing objectives. These parties also are experienced in understanding IRM, not only as it relates to Union, but also as it relates more broadly to other utilities regulated by the Board.

The evidence in EB-2013-0202, including the Application, this Agreement and the Appendices to this Agreement, indicates that the IRM parameters agreed to by the parties herein will result in rates that are consistent with the Board's rate making objectives and principles. These factors, when combined with the experience gained by Union and stakeholders over the term of Union's last IRM (2008-2012), lead the parties to this settlement to encourage the Board to accept this Agreement, in its entirety, as the basis for setting Union's rates from 2014 to 2018.

In this Agreement, the term "net delivery revenue requirement impacts" is used in a number of places. As used in this Agreement, that term means the annual costs of a project or initiative, including operating costs, depreciation, cost of incremental debt, return, and related taxes, net of any incremental delivery revenues arising from, associated with, or enabled by the project or initiative.

RESULTING RATES AND BILL IMPACTS

Union has attached at Appendix C the estimated delivery rate and total bill impacts flowing from this Agreement.

Union has also attached at Appendix I a calculation of 2014 illustrative rates flowing from this Agreement.

Union will file an application for actual 2014 rates in September 2013.

1 MULTI-YEAR INCENTIVE RATEMAKING FRAMEWORK

The parties agree that Union's regulated rates over the IRM term will be set by applying the Incentive Regulation Mechanism described below to Base Rates being Union's 2013 Board-approved rates adjusted in the manner hereinafter described.

1.1 Incentive Regulation Mechanism

(Complete Settlement)

The parties agree that a multi-year Price Cap Index ("PCI") mechanism will be used to set regulated distribution, transmission and storage rates over the IRM term which are a function of:

- An inflation factor (I);
- A productivity factor (X);
- Certain non-routine adjustments (Z factors);
- Certain predetermined pass-throughs (Y factors); and,
- An adjustment for normalized average consumption (NAC),

all as further set out in this Agreement.

The parties further agree that rates each year will be adjusted as described below and as set out in Appendix I to this Agreement which illustrates how 2014 rates will be determined.

1. The base year adjustments to 2013 Board-approved revenue set forth in Section 1.2 below will be allocated to rate classes, and within each rate class to the rate components, as set out in Appendix E attached. Subject to any changes ordered by the Board as a result of the resolution of the issues set forth in Section 13.3 of this Agreement, the adjusted 2013 Board-approved revenues would be the base revenues to which the PCI mechanism adjustments will apply for 2014.

2. Prior year Y factor amounts that are embedded in base rates will be deducted from those rates on a class by class basis and within each rate class from the revenues applicable to rate components, to get base revenue net of Y factor amounts. For example, the Demand Side Management ("DSM") budget, upstream transportation costs and capital pass-through costs (if any) included in 2013 rates will be deducted from the approved revenue to be collected from each class, and within each class from each component of rates, prior to the application of inflation net of productivity.

3. The net revenue described above will be multiplied by the inflation factor (I) net of productivity (X). I is the inflation factor referred to in Section 2 below, and X is the productivity factor described in Section 3 below, equal to 60% of I. Thus, the PCI percentage will in all years be 40% of I. This application of the index will result in the indexed revenues.

4. The new Y factor amounts, and any Z factors approved by the Board, will be added to the indexed revenues on a class by class basis and within each class, to arrive at total proposed revenue.

5. Board approved billing determinants for rates M1, M2, 01 and 10 will be adjusted to reflect changes in NAC as set forth below. Board approved billing determinants for other rate classes will be adjusted to reflect LRAM.

6. For all classes, these adjusted Board approved billing determinants will be applied to total proposed revenues from #4 above to calculate final rates.

Rates for each of 2015 through 2018 will be established on the same basis as above, based on the rates for the previous year, but without Step 1 above.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

1.2 Base Rates

(Complete Settlement)

The parties agree that the PCI mechanism will apply to Union's 2013 Board-approved regulated distribution, transmission and storage revenue ("2013 Board-approved revenue") (EB-2011-0210) subject to the following adjustments for January 1, 2014:

1.2.1 Deferred Tax Drawdown

The parties agree to a $3.152 million increase to Union's 2013 Board-approved revenue relating to deferred taxes over the IRM term. The amount, calculated in detail in Appendix D, is the levelized difference between the credit to ratepayers for deferred taxes included in 2013 rates, and the lower credits that will be owing to ratepayers in each of the years 2014 through 2018. That levelized difference is grossed-up to a pre-tax amount, because it is taxable.

This is a continuation of a series of known and accepted rate adjustments that have taken place for many years. In 1997, Union changed its accounting for income taxes for utility operations from the tax allocation (or accrual) method to flow through (or cash-basis) tax accounting. The change to flow through tax accounting was adopted for rate-making purposes on a prospective basis in EBRO 493/494 (Union's 1997 rate case). The tax allocation method of tax accounting used for rate-making purposes prior to EBRO 493/494 resulted in an accumulated deferred tax balance. In the EBRO 499 (Union's 1999 rate case) settlement agreement, parties agreed that the accumulated deferred tax balance would be used to reduce Union's cost of service in future years.

As was the case in EB-2007-0606, the parties agree to adjust the 2013 Board-approved revenue to reflect the difference in the deferred tax credit in 2013 Board-approved revenue and the average of the deferred tax drawdown over the 2014-2018 IRM term. Without adjusting the deferred tax credit in rates during the IRM period, Union would over-refund the accumulated deferred tax balance which would then have to be collected from customers upon rebasing. Accordingly, an adjustment should be made to avoid this circumstance.

Union's 2013 rates contain a deferred tax credit of $15.169 million, which absent any adjustment, would be credited to ratepayers annually over the IRM term, a total of $75.845 million. The remaining accumulated deferred tax balance to be credited to customers after 2013 is $64.094 million, which is $11.751 million less than the amount that would otherwise be refunded through the amount embedded in rates. The levelized amount would be $12.819 million (i.e. $64.094 million accumulated balance / 5 years), requiring a base rate increase of $2.350 million (i.e. $15.169 million in rates less $12.821 million levelized credit) which when grossed-up equals $3.154 million pre-tax. The effect of this adjustment is to keep both Union and the ratepayers whole over the 2014-2018 period.

The detailed calculation of the deferred tax adjustment is provided at Appendix D. The allocation of the deferred tax adjustment is provided in Appendix E.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

1.2.2 Upfront Productivity Commitment

Union agrees to reduce the 2013 Board-approved revenue by an upfront productivity commitment of $4.5 million. That is, Union agrees that in addition to the productivity factor included in the PCI mechanism, Union will be incented to seek further productivity savings of $4.5 million in each of the five years of the IRM term. The parties further agree that the reductions in the 2013 Board-approved revenue represented by the upfront productivity commitment will be allocated to rate classes in proportion to the allocation of Administrative and

General Operating and Maintenance costs included in 2013 Board-approved rates. The allocation of the $4.5 million adjustment is included in Appendix E.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

1.2.3 Winter Warmth Program/Low Income Energy Assistance Program (LEAP) Funding

(Complete Settlement)

The parties agree that there will be no adjustments to rates over the term of the IRM to recover the costs associated with Winter Warmth Program/LEAP. Currently, Union's Winter Warmth Program/LEAP is managed by the United Way of Chatham-Kent and funded from the Late Payment Penalty settlement. If the Late Payment Penalty settlement funds are depleted over the term of the IRM, Union will pay but not seek to adjust rates to reflect the Board's Winter Warmth Program/LEAP funding requirements until the end of the IRM term. Union's Winter Warmth Program/LEAP funding requirement is approximately $0.835 million annually.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

2 <u>INFLATION FACTOR</u>

(Complete Settlement)

The parties agree that the inflation factor to be used in Union's PCI mechanism is the actual year over year percentage change in the annualized average of 4 quarters (using Q2 to Q2) of Statistics

Canada's Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP IPI FDD). The inflation factor will be adjusted annually on this basis with no restatement for adjustments by Statistics Canada. By way of example, the inflation factor for 2014 rates will be based on the actual change in the GDP IPI FDD from 2012 Q2 to 2013 Q2 which will be available in August 2013. The price inflator and calculation method are the same as those used during Union's 2008-2012 IRM. For the purposes of calculating the rate impacts contained in Appendix C, Union has used the 2011 Q4 to 2012 Q4 change in GDP IPI FDD of 1.63%.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

3 **PRODUCTIVITY FACTOR**

(Complete Settlement)

The annual productivity factor ("X factor") in this Agreement is expressed as a percentage of inflation. The parties agree that Union will commit to pursuing productivity of 60% of GDP IPPI FDD, inclusive of a stretch factor, for each year of the IRM term. This results in an annual rate escalation factor, before the impact of Y and Z factors and earnings sharing, of 40% of GDP IPI FDD, i.e. subject to other adjustments base rates will increase annually by 40% of GDP IPI FDD. Together, the Upfront Productivity Commitment described in Section 1.2.2 and the X factor are inclusive of a stretch factor.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

4 **WEATHER NORMALIZATION**

(Complete Settlement)

The parties agree that for the duration of the IRM term, Union will use the normalization methodology approved by the Board in Union's 2013 rates case (EB-2011-0210). Specifically, the Board approved Union using a 50:50 blend of the 30-year average and the 20-year declining trend.

The following parties agree with the settlement of this issue: BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: APPrO, Six Nations, TCPL

5 **NORMALIZED AVERAGE CONSUMPTION ADJUSTMENT**

(Complete Settlement)

The parties agree that it is appropriate during the IRM term to adjust rates to reflect the impact of changes in normalized average consumption ("NAC") for the general service rate classes (rate classes M1, M2, R01 and R10). Further, the parties agree that the way to accomplish this is to update the NAC in rates based on the last known actual NAC, weather normalized using the Board-approved 50:50 weighting of the 30-year average and the 20-year declining trend. For example, for setting 2014 rates, Union will use the 2012 actual NAC. This adjustment captures all volumetric consumption changes related to efficiency gains and Demand Side Management initiatives. As a result, any lost general service volumes as a result of DSM activities will be captured through the NAC adjustment and not through the Lost Revenue Adjustment Mechanism

("LRAM"). The LRAM deferral account will continue to be used to capture lost volumes for the contract rate classes, but will no longer apply to M1, M2, R01 or R10.

Further, parties agree to establish a Normalized Average Consumption deferral account to capture the variance between forecast NAC in rates and what is observed on an actual basis for the same year. This deferral account will be disposed of annually through the non-commodity deferral accounts and earnings sharing proceeding. The draft NAC accounting order can be found at Appendix F.

The following parties agree with the settlement of this issue: BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: APPrO, Six Nations, TCPL

6 Y FACTORS

(Complete Settlement)

The parties agree that the costs associated with identified Y factors will not be adjusted by the PCI but will be passed through directly to rates. Each of the Y factors is subject to deferral account treatment. The Y factor deferral accounts capture the variances between the costs/revenues included in rates compared to the actual costs/revenues. The principle is that neither Union nor its ratepayers should gain or lose with respect to variances recovered from ratepayers on account of Y factor items. This principle will be determinative in any conflict between the application of the principle and the wording of any particular deferral account.

Items that will be treated as Y factors are:

- Upstream gas costs
- Upstream transportation costs
- Incremental DSM costs (as determined in EB-2011-0327 and in any subsequent DSM proceeding)
- LRAM for the contract rate classes
- Unaccounted for gas ("UFG") volume variances
- Major Capital Additions (as defined below)

These Y factors are each described in more detail below.

6.1 Upstream Gas Costs

The parties agree that changes in upstream gas costs, as approved through the QRAM process, or as otherwise determined by the Board, will be passed through to ratepayers through the gas commodity deferral accounts cleared during the QRAM process, through rates during the annual rate setting or through the earnings sharing and deferral accounts clearing processes. That is, the pass-through of upstream gas costs will be unchanged in both substance and procedure from the 2013 Board-approved pass-through mechanisms.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

6.2 Upstream Transportation Costs

The parties agree that changes in upstream transportation costs that underpin Union's gas supply plan will be passed through to ratepayers through the gas supply deferral accounts or as otherwise determined by the Board, and through rates during the annual rate setting or the earnings sharing and deferral accounts clearing processes. The upstream transportation costs include the 2013 Board-approved treatment of upstream transportation optimization revenues. Thus, the pass-through of upstream transportation costs will be unchanged in both substance and procedure from the 2013 Board-approved pass-through mechanisms.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

6.3 Incremental DSM Costs

The parties agree the DSM costs in rates will be adjusted annually per the Board's EB-2011-0327 Decision or any subsequent DSM Decision.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

6.4 LRAM Volume Reductions

The parties agree that contract rates will be adjusted annually to take into account volume reductions due to DSM activity (LRAM) per the Board's EB-2011-0327 Decision or any subsequent Decision.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

6.5 Unaccounted for Gas Volume Variances

The total cost of UFG is comprised of two elements: a percentage of throughput volume that determines the UFG volume, and the Board-approved weighted average cost of gas (“WACOG”). Changes to WACOG and the corresponding impact on the total cost of UFG using the Board-approved UFG volume are captured in Union’s Quarterly Rate Adjustment Mechanism (“QRAM”).

The Board has approved a total cost of $14.7 million for UFG in 2013 base rates (EB-2011-0210) calculated by multiplying the Board-approved total UFG volume of 70,253 10^3m^3 by the gas cost of $210.506/ 10^3m^3 (the cost of gas used in Union’s January 1, 2013 QRAM). The parties agree that total UFG cost changes resulting from a difference between the UFG volume included in rates and the actual UFG volume will be recorded in a new UFG Volume Deferral Account. The amount to be recorded in the UFG Volume Deferral Account will be calculated using the most recent Board-approved WACOG. The amount of the UFG Volume Deferral Account to be cleared to customers will be subject to a symmetrical dead-band of $5 million, with amounts within such dead-band being to Union’s account only. This means that for 2014 UFG, a volume variance less than $9.7 million and greater than $19.7 million will be subject to deferral. To illustrate, if the volume variance is $25.7 million, $6 million would be deferred and recovered from ratepayers.

The parties agree that Union will include the amounts in the UFG Volume Deferral account in its annual application to the Board to dispose of the balances in the non-commodity deferral accounts in accordance with the provision above.

The draft UFG accounting order can be found at Appendix F.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

6.6 Major Capital Additions

The parties agree to Y factor treatment for major capital projects that meet the criteria in sections (i) through (viii) below. If the two major facility expansion projects set out below meet the criteria and are approved by the Board in their respective leave to construct applications and, provided they continue to meet the requisite criteria, the net delivery revenue requirement impacts of those projects will be treated as Y-factors in each year of the IRM term beginning with the first year that each project comes into service:

1. The facilities included in the Parkway West Project as that term is used in EB-2012-0433. The current forecast of the net delivery revenue requirement impacts are shown in Appendix G. Rate recovery would, assuming the current forecast of 2015 as the in-service year, commence with rates effective January 1, 2015;
2. The facilities included in the Brantford-Kirkwall Pipeline and Parkway D Compressor Station Projects as those terms are used in EB-2013-0074. The current forecast of the net delivery revenue requirement impacts is shown in Appendix G. Rate recovery would, assuming the current forecast of 2016 as the in-service year, commence with rates effective January 1, 2016.

Y-factor treatment also applies to additional capital projects that result in net delivery revenue requirement impacts over the IRM term which meet the requisite criteria specified below.

The criteria that must be met for any capital project to quality for Y factor treatment are as follows:

i) A minimum increase, or a minimum decrease, of $5 million in net delivery revenue requirement for a single new project (the "Rate Impact Threshold"). For the purposes of making this determination, capital costs are those costs relating to that capital project as defined under the applicable accounting rules. For the purpose of determining whether the Rate Impact Threshold is met, the net delivery revenue requirement associated with the capital project for each of the years from the in-service year until 2018 shall be calculated; should the net delivery revenue requirement exceed the Rate Impact Threshold in any year, the project would meet the Rate Impact Threshold criterion. The rate adjustment for each year will be based on the forecast net delivery revenue requirement impacts for each specific year, subject to true-up to actual as discussed in subparagraph (viii) below.

   In determining net delivery revenue requirement for any year, the following parameters will be applied:

   - Depreciation expense will be calculated using 2013 Board-approved depreciation rates;
   - Required return assumes a capital structure of 64% long-term debt and 36% common equity;

- The incremental long-term debt cost will be calculated based on expected financing costs for the incremental borrowing required by the project, at market rates in effect at the time the project is approved;
- The return will be calculated using the 2013 Board-approved return on equity of 8.93%;
- Income and other taxes related to the equity component of the return will be calculated using the 2013 Board-approved tax rate of 25.5%;
- Incremental delivery revenues associated with the project will be calculated as an offset to the delivery revenue requirement;
- For the in-service year, all components of the calculation except taxes (but including, without limitation, depreciation, cost of debt, and return) will be calculated only for the period from the month of in-service to the end of the year; and,
- Union agrees to make no changes to these parameters during the IRM term.

ii) The capital cost of the project, using the same capitalization policies as were in place for the purposes of the approved EB-2011-0210 revenue requirement, must exceed $50 million. Provided, however, that in the event that Union is required to change its accounting standard from USGAAP to any other standard (including IFRS), and as a result its capitalization policies must change, the capitalization policies under the new accounting standard shall apply;

iii) The project is outside the base rates on which this incentive regulation framework is set;

iv) The project must be needed to serve customers and/or to maintain system safety, reliability or integrity, and cannot reasonably be delayed, and is demonstrated to be the most cost effective manner of achieving the project's objective relative to the reasonably available alternatives;

v) The project will be identified to stakeholders and the Board as soon as possible, including in that year's stakeholder review session where practical (see Section 12.2);

vi) The project will be subject to a full regulatory review equivalent to a leave to construct proceeding, in which the applicant must demonstrate need, safety or reliability purposes, and economic viability prior to inclusion in rates. For any project that requires leave-to-construct approval of the Board, the full regulatory review will be conducted in that proceeding. For any project that does not require leave-to-construct approval of the Board, Union commits to filing its annual rate adjustment application with the Board by July 1 of the year prior to rate impacts of the project going into effect, to allow sufficient time for a full regulatory review of the project in its rates application;

vii) Subject to direction otherwise from the Board, Union will allocate the net revenue requirement using 2013 Board-approved cost allocation methodologies. Any party, including Union, may take any position with respect to the proposed allocation for any particular capital project during review of the project, or its rate impacts, by the Board; and,

viii) The project will include a deferral account request to capture any differences between the forecast annual net delivery revenue requirement and the actual net delivery revenue requirement for each year of the IRM term for which the project is included in rates. The true-up will occur annually during the period the project is subject to Y factor treatment. If, at the end of the 2018 year, the actual net delivery revenue requirement has not exceeded the $5 million minimum for every year the project has been in service, then the project will be deemed not to have qualified, and all amounts collected thereon shall be refunded/debited to ratepayers through an end of IRM term true-up deferral account mechanism.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

7 **DEFERRAL AND VARIANCE ACCOUNTS**

(Complete Settlement)

The parties agree that the Deferral and Variance Accounts described and listed in Appendix H will continue during the term of the IRM. It is understood and agreed that Union will make no changes in the manner in which it administers and clears the Deferral and Variance Accounts during the course of the IRM without first fully disclosing the proposed changes to the parties, and then obtaining prior Board approval for such proposals. Moreover, it is understood and agreed that Union will administer the pass through items of expenses and savings in a manner that is compatible with the principle that neither Union nor its ratepayers should gain or lose on such pass through items.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

8 **Z FACTORS**

(Complete Settlement)

The parties agree that for prospective or historical cost increases/decreases to qualify for pass through as a "Z factors", the cost increases/decreases must:

1. causally relate to an external event that is beyond the control of utility's management;
2. result from, or relate to, a type of risk;
    a. for which a prudent utility would not be expected to take risk mitigation steps; and,
    b. which is out of the realm of the basic undertaking of the utility (per EB-2011-0277 Decision, page 13);
3. not otherwise be reflected in the price cap index;
4. be prudently incurred; and,
5. meet the materiality threshold of $4.0 million of annual net delivery revenue requirement impact per Z factor event. Net delivery revenue requirement will be defined in the same manner as set forth in Section 6.6 above.

The parties agree that changes in the amounts of taxes payable by Union through the 2014-2018 IRM term resulting from changes to Federal and/or Provincal legislation and/or regulations thereunder are Z factors and will be shared 50:50, as applied to the tax level reflected in rates. Treating 50% of tax changes as a Z factor is consistent with the Board's findings in its EB-2007-0606/EB-2007-0615 Decision (dated July 31, 2008).

As during the 2008-2012 IRM term, Union will continue to calculate the variance between current year tax rates and calculation methods/rules to those used in current Board-approved rates. This variance will be allocated to rate classes using 2013 Board-approved rate base as the allocation factor. Any variance between taxes using the actual rates and calculation methods/rules and the approved rates and calculation methods/rules in Union's rates will be captured in a new deferral account. The draft Tax accounting order can be found at Appendix F.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

9 **TERM OF THE PLAN**

(Complete Settlement)

The parties agree that the term of the IRM plan shall be 5 years, being the calendar years 2014 to 2018 inclusive.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

10 **OFF-RAMPS**

(Complete Settlement)

The parties agree that in light of the settlement on earnings sharing set out in Section 11 below and the other IRM parameters there should be no off ramps for this IRM plan. Union and each of the other parties hereto agrees not to apply for rates applicable to Union for any of the years 2014-2018 except rates that are in all respects consistent with this Agreement.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

11 EARNINGS SHARING MECHANISM (ESM)

11.1 Earnings Sharing

(Complete Settlement)

The parties agree that there will be an earnings sharing mechanism, based on actual utility earnings. If in any calendar year Union's actual utility return on equity is more than 100 basis points over the 2013 Board-approved ROE of 8.93%, then excess earnings between 100 basis points and 200 basis points will be shared 50/50 between Union and its customers. If in any calendar year Union's actual utility return on equity is more than 200 basis points over the 2013 Board-approved ROE of 8.93%, then such earnings in excess of 200 basis points will be shared 90/10 between customers and Union (i.e., customers will be credited 90% and Union will be credited 10%). For the purposes of the earnings sharing mechanism, Union shall calculate its earnings using the regulatory rules prescribed by the Board from time to time, and shall not make any material changes in accounting practices that have the effect of either reducing or increasing utility earnings. All revenues that would be included in revenues in a cost of service application shall be included in the earnings calculation and only those expenses (whether operating or capital) that would be allowable as deductions from earnings in a cost of service application shall be included in the earnings calculation.

Parties acknowledge that the DSM related Shared Savings Mechanism ("SSM") and Lost Revenue Adjustment Mechanism ("LRAM") and storage related deferral accounts are outside of the earnings sharing mechanism identified above.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

11.2 ROE in rates and for earnings sharing

(Complete Settlement)

The parties agree that the return on equity ("ROE") included in rates shall be fixed at the 2013 Board-approved level of 8.93% for the term of the IRM. The parties also agree that the 2013 Board-approved ROE of 8.93% will be the benchmark ROE for the purposes of calculating earnings sharing for the term of the IRM.

If a proceeding is instituted before the Board, before the term of this IRM expires, in which changes to the methodology for determining ROE are requested or changes in capital structure are proposed, then all parties including Union will be free to take such positions as they consider appropriate with respect to that proceeding. Notwithstanding any such positions, however, the parties agree that if the Board determines that a change in ROE methodology or capital structure is appropriate, such changes will only be implemented in respect of Union's rates after the conclusion of the IRM term.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

12 REPORTING REQUIREMENTS

12.1 Information filed with the Board and intervenors

(Complete Settlement)

Union agrees to continue to make its RRR filings with the Board available to intervenors. Union also agrees to prepare, and distribute to all parties to this Agreement and all intervenors in any of Union's subsequent rate proceedings, the following utility information annually for the most recent historical year:

1. Calculation of revenue deficiency / (sufficiency);
2. Statement of utility income;
3. Statement of earnings before interest and taxes;
4. Summary of cost of capital;
5. Total weather normalized throughput volume by service type and rate class;
6. Total actual (non-weather normalized) throughput volumes by service type and rate class;
7. Total weather normalized gas sales revenue by service type and rate class;
8. Total actual (non-weather normalized) gas sales revenue by service type and rate class;
9. Delivery revenue by service type and rate class and service class;
10. Total customers by service type and rate class;
11. Summary revenue from regulated storage and transportation;
12. Other revenue;
13. Operating and maintenance expense by cost type – actuals only;
14. Calculation of utility income taxes;
15. Calculation of capital cost allowance;
16. Provision for depreciation, amortization and depletion;
17. Capital budget analysis by function;

18. Statement of utility rate base – actuals only;

19. Unregulated Continuity of Property, Plant and Equipment, & Unregulated Continuity of Accumulated Depreciation;

20. Service Quality Indicators per the RRR; and

21. Audited financial statements for utility operations.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

12.2 Annual stakeholder meeting

(Complete Settlement)

The parties agree that Union will hold an annual, funded stakeholder meeting (including funding for reasonable preparation for the meeting and follow up comments from the meeting), after the public release of year-end financial results but prior to Union filing its annual non-commodity deferral accounts disposition application (March/April timeframe). At the stakeholder meeting Union will:

1. Review previous year's financial results (i.e. earnings, capital spending) and other key operating parameters (i.e. SQI performance) for the most recently completed year;
2. Present and explain market conditions and expected changes/trends, and the impact these may have on the regulated operations;
3. Present and review the gas supply plan for the coming year;
4. Present new capital projects that meet the capital pass-through criteria as defined in Section 6.6; and,
5. Present results of any customer surveys undertaken during the year.

Union will file all information resulting from this annual meeting with the Board and ensure it is available to any party not able to attend.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

13 <u>RATE-SETTING PROCESS</u>

13.1 Annual Adjustment

(Complete Settlement)

The parties agree that annual rate adjustments will be made in accordance with the following process:

1. Union will file an application for approval of any Z factor adjustments, the pricing of any new regulated services, and/or for any other adjustments for which advance approval from the Board is required, in a time frame that will enable these issues to be resolved in sufficient time to be reflected prospectively in the next year's rates.
   Union will file a draft rate order with supporting documentation by September 30 which reflects the impact of the PCI, Y factors, approved Z factors and NAC. The documentation shall be in sufficient detail to allow the Board to issue a procedural order such that a final rate order could be issued by December 15 for implementation by January 1; and,
2. As soon as reasonably possible following the public release of Union's annual audited financial statements, Union will make application (as it does now) for disposition of actual year end non-commodity deferral account balances. (This would coincide with the filing of an annual earnings sharing calculation as described in section 11.1). Union

will use its best efforts to file its application and pursue the regulatory process such that, after the Board's decision, Union will be able to implement all rate adjustments associated with deferral account disposition at the time of its July 1 QRAM. Union will continue to adjust gas supply commodity and upstream transportation through the QRAM mechanism as approved in EB-2008-0106.

The parties agree that stakeholders, including all parties to this proceeding, should have a reasonable opportunity to review the application and calculations, including the ability to make reasonable requests for additional information with respect thereto from Union, and to make submissions or comments thereon.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

13.2 New Energy Services

(Complete Settlement)

Union agrees that all new regulated energy services will require prior Board approval. Accordingly, Union will make an application, on notice with supporting material, for all new regulated energy services.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

13.3 Other Issues

(Complete Settlement)

The parties agree that the following issues have not been settled in this Agreement, and remain to be determined by the Board in EB-2013-0202 or in Union's 2014 rates application and agree that rates will be adjusted in accordance with any such determination. This Agreement is without prejudice to the positions that the parties may take with respect to these issues.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

13.3.1 M1/M2 and R01/R10 Volume Breakpoint

In its EB-2011-0210 Decision, the Board found that, while Union's proposal to reduce the volume breakpoint between the Rate 01/Rate 10 and Rate M1/Rate M2 rate classes and harmonize the blocking structures had merit, the methodology used by Union to allocate costs between the rate classes was flawed. Accordingly, the Board did not approve Union's proposals. The Board directed Union to undertake a comprehensive cost allocation study which includes the volume breakpoint reduction proposal as part of its 2014 rates filing.

In response to the Board's directive, Union has formed a working group with intervenors to determine the appropriate allocation of costs for Union's Rate M1/Rate M2 and Rate 01/Rate 10 volume breakpoint reduction proposal. Should Union and intervenors reach a consensus on an appropriate cost allocation methodology, Union will file with the Board a Settlement Agreement, together with supporting evidence, seeking approval of the agreed methodology in the EB-2013-

0202 proceeding or Union’s 2014 rates proceeding. In the event that the parties cannot reach a consensus in a timely manner, Union will file sufficient evidence on cost allocation with respect to these rate classes to allow the Board to adjudicate the issue in the EB-2013-0202 proceeding or in the 2014 rates proceeding.

13.3.2 Parkway Obligation Working Group

In the EB-2011-0210 Settlement Agreement, the parties agreed to establish a Working Group to review Union’s Parkway delivery obligation and determine whether or not any changes should be made in whole or in part to that obligation after 2013. Union was directed to report to the Board during its 2014 rate proceedings, on the outcome of the Working Group process and Union’s proposal, if any, in respect to the delivery obligation arising from the Working Group process.

In response to the Board’s directive, Union has formed a Working Group with intervenors to review the Parkway delivery obligation and whether or not any changes should be made to that obligation. Should Union and intervenors reach a consensus on an appropriate response to this review, Union will file with the Board a Settlement Agreement, together with supporting evidence, seeking approval of the agreed response in the 2014 rates proceeding. In the event that the parties cannot reach a consensus, Union will file sufficient evidence on the issue and its position on whether or not any changes should be made to allow the Board to adjudicate the issue in the 2014 rates proceeding.

13.3.3 Gas Supply Plan Studies

In its EB-2011-0210 Decision, the Board directed Union to hire a consultant to review its gas supply plan and the cost allocation of the gas supply costs. Union contracted Sussex Economic

Advisors ("Sussex") and Concentric Energy Advisors ("Concentric") to review and provide reports on Union's gas supply plan and the allocation of costs associated with the gas supply plan. Union filed the Sussex and Concentric reports in its 2012 Deferrals and Earnings Sharing Disposition proceeding (EB-2013-0109). Subject to Sections 6.1 and 6.2 above, any changes required following the review of the gas supply plan reports in EB-2013-0109 will be implemented per the Board's Decision in that proceeding.

13.3.4 M5 and T3 Rates

The parties agree that as part of EB-2013-0202 or Union's 2014 rates proceeding parties will have an opportunity to review and, if appropriate, to lead evidence on the M5 and T3 cost allocation and rate design as approved by the Board in EB-2011-0210. Parties, including Union, are free to take such positions as they see appropriate with respect to the appropriateness of the current methodologies and resulting rates. If, as part of EB-2013-0202 or Union's 2014 rates proceeding, the Board finds that changes to the current methodologies and resulting M5 and T3 rates are appropriate, in no event shall the changes result in any change to overall revenue to which the incentive regulation formula will apply for the term of the IRM.

13.4 NON-ENERGY SERVICES

(Complete Settlement)

Parties agree that miscellaneous non-energy service charges shall be outside of the price cap formula. If Union requires any changes to its miscellaneous non-energy service charges during the IR term, Union will provide the Board with evidence that supports the change. The parties agree to the principle that non-energy service charges should not generate incremental revenue in excess of any related incremental costs.

Union agrees that all new regulated non-energy services will require prior Board approval. Accordingly, Union will make application on notice with supporting material, for all new regulated non-energy services.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

14 **REBASING**

(Complete Settlement)

Union agrees (subject to any subsequent agreement of all parties to extend the IRM term) to prepare a full cost of service filing at the time of rebasing, regardless of whether Union applies to set rates for 2019 on a cost of service basis or not.

At the time of rebasing, Union will provide 2013-2017 actual, 2018 bridge and 2019 forecast information. In addition, Union will provide historical plant continuity information for 2012, 2013, 2014, 2015 and 2016 similar to the information provided in the EB-2011-0210 proceeding at B6/T1 & T2/S 1 – 5.

The following parties agree with the settlement of this issue: APPrO, BOMA, CCC, CME, Energy Probe, FRPO, IGUA, Kitchener, LPMA, OAPPA, SEC, Union, VECC

The following parties take no position: Six Nations, TCPL

APPENDIX A

A Spectra Energy Company

Incentive Regulation

Stakeholder Consultation
April 29, 2013

Purpose

- **To review and discuss the proposed parameters for a multi-year incentive regulation framework effective January 1, 2014 for Union Gas.**

What We Learned (2008-2012)

A simple pricing formula works.

There is a misalignment on the appropriate level of productivity incentive and reward.

Additional OEB and stakeholder engagement and information during the incentive regulation term will assist the re-basing process.

Objectives

- Provide an incentive for Union to continue to be more productive on a sustainable basis
- Create an environment that is conducive to investment
- Develop a similar construct to the past price cap mechanism, as familiarity will facilitate the regulatory approval process
- Provide for modest, predictable annual rate increases
- Address alignment of appropriate level of productivity incentive and reward
- Address certain items that cannot be managed within a price cap framework
- Meet or exceed all customer service measures
- Meet investor expectations

Proposed Parameters

- **Price cap framework (uses 2013 approved rates as base rates)**
- **Annual inflationary increase – continue to use GDP IPI FDD, with no X-factor**
    - Addresses most future cost increases, and changes to S&T exchange revenues
    - e.g. 1.6% GDP (Q4, 2012) = $13.5 million
- **Earnings sharing with smaller dead-band**
    - Addresses misalignment of productivity incentive/reward
    - Reduce to 100 bps dead-band, with 50/50 sharing beyond that (previous framework was 200 bps) – value of 100 bps is $18 million

Proposed Parameters (cont'd)

- **5-year term (2014-2018)**
  - Tied to other parameters
- **Average use adjustment and deferral account**
  - Protects against continued declines in small volume use
  - Component of past framework, and supported for 2013
  - Incorporate LRAM for simplicity
- **Capital cost pass-through mechanism for specific projects (Parkway West, Parkway Growth, Burlington-Oakville)**
  - Approx. $450 million capital
  - Delivery rate impacts in 2015-2018, including tax effects

Proposed Parameters (cont'd)

- **Capital cost pass-through criteria:**
  - $ 25 million or more capital for a single new project
  - Outside of base on which price cap is set
  - Profitability index < 1.0 (delivery rate impacts)
  - Identification in that year's stakeholder review session (where possible)
  - Full regulatory review prior to inclusion in rates

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Proposed Parameters (cont'd)

- **Pass-through mechanism for annual adjustment to ROE per formula**
  - Matches ROE in rates to that used for earnings sharing
- **Pass-through mechanism for change to weather normalization methodology**
  - Include evidence with incentive regulation application
  - Response to OEB re-basing decision (EB-2011-0210)
  - Implement in 2014

Proposed Parameters (cont'd)

- **Unaccounted-for gas ratio variance deferral account**
  - Uncontrollable item
  - Significant contributor to earnings during last IRM term
  - Consistency with Enbridge

- **Other pass-through items**
  - Maintain existing pass-through mechanisms for upstream gas costs, upstream transportation, DSM parameters and the disposition of deferral accounts. Also includes application for LEAP/winter warmth funding (0.12% of net distribution revenue).

Proposed Parameters

- **Changes to level, treatment and sharing of net exchange revenues**
  - Includes impacts of NEB Mainline tolls decision (RH-003-2011)
  - Treatment as revenue
  - Change to sharing of variances to 50/50

Net Exchange Revenues

NEB Mainline tolls decision (RH-003-2011) eliminated FT-RAM service attribute effective June 30, 2013; increase rates by $5.2 million

Exchange transactions should be classified as revenue, based on services sold and historical OEB treatment

2014 estimated exchange revenues and sharing at different risk levels:

Risk level	Base rates (rev.)	Revenue	Diff	Sharing	Ratepayer (Cost)
1	$9.1	$3.1	($6.0)	90/10	($5.4) million
2	$9.1	$6.0	($3.1)	75/25	($2.3) million
3	$9.1	$12.0	$2.9	50/50	$1.5 million

Proposed Parameters (cont'd)

- **Z-factors**
  - Maintain existing criteria
  - Add an adjustment to 2015 rates and other parameters for any changes resulting from the OEB Cost Of Capital review in 2014

- **Off-ramp (triggers OEB review of parameters)**
  - Addresses misalignment of productivity incentive/reward
  - Regulated utility earnings exceed the allowed ROE by 300 bps for 2 consecutive years

Proposed Parameters (cont'd)

- **Service quality indicators**
  - Maintain existing OEB-approved service quality measures
- **Treatment of changes in taxes**
  - Maintain existing 50/50 sharing of tax changes
- **Rate redesign**
  - Maintain existing flexibility

Proposed Parameters (cont'd)

- **Reporting requirements**
  - Maintain 18-schedule annual reporting package and RRR availability
- **Annual, funded stakeholder meetings**
  - Annual stakeholder meetings to explain financial results, sources of earnings, any new activities, and changes in market conditions. Documented and filed with OEB.
  - Include review of gas supply plan
  - Timing: after year-end but prior to annual application to dispose of non-commodity deferral account balances
- **Rebasing**
  - Prepare a full cost-of-service filing at end of term

Timeline

- April - May: individual and group stakeholder meetings, and evidence preparation
- June: complete evidence and application, and file
- Fall: settlement discussions and hearing

Summary of Changes

Changes from previous IRM framework

- No X-factor in pricing formula
- Smaller dead-band for earnings sharing (*)
- Capital cost pass-through for defined projects
- ROE synchronization (*)
- UFG volume deferral account (*)
- Exchange revenue sharing (*)
- Z-factor for Cost Of Capital Review (*)
- Off-ramp (*)
- Annual stakeholder information sessions (*)

(*) – additional ratepayer protection/benefit measures

Discussion

Parameters

Next meeting date

Appendix

GDP IPI FDD 2008-2012 (Q3)

Used to set rates for:

2008	2.04%
2009	1.54%
2010	2.73%
2011	0.72%
2012	1.72%

2-year average	1.22%
5-year average	1.75%
Q4 2012	1.63%

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Rate Class Impacts From Proposed Parameters

Rate class	Avg. annual delivery rate change	Avg. annual total bill change	Avg. annual amount (total bill)
M1	1.5%	0.98%	$6.30
M2 (small)	1.6%	0.54%	$64.60
M2 (large)	1.6%	0.54%	$253.60
M4 (large)	1.6%	0.54%	$4,320

Rate Class Impacts From Proposed Parameters

Rate class	Avg. annual delivery rate change	Avg. annual total bill change	Avg. annual amount (total bill)
T1 (avg)	1.5%	0.18%	$3,010
T2 (avg)	1.5%	0.06%	$17,105
T3	2.0%	0.18%	$66,630

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Rate Class Impacts From Proposed Parameters

Rate class	Avg. annual delivery rate change	Avg. annual total bill change	Avg. annual amount (total bill)
R01	1.1%	1.06%	$10.31
R10 (large)	0.8%	0.32%	$190.20
R20 (large)	1.2%	0.1%	$3,402
R100 (large)	1.5%	0.06%	$30,756

Rate Class Impacts From Proposed Parameters

Rate class	Avg. annual demand charge change		
M12	4.6%		
C1	5.2%		

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Additional Reference Material

3rd Generation IRM for Electricity Utilities

Pricing formula parameters:

- **GDP IPI FDD as inflator (Q4)**
- **Fixed productivity factor of 0.72%**
- **Stretch factor added to productivity factor, based on placement against benchmark for O&M unit comparison:**
    - Group I: 0.2%
    - Group II: 0.4%
    - Group III: 0.6%
- **Note: no earnings sharing mechanism**
- **Note: symmetrical off-ramp +/- 300 bps**

APPENDIX B

LIST OF ASSUMPTIONS
For 2014-2018 Incentive Regulation (IR) Forecast
Calculation of Estimated Rate and Bill Impacts

- 5 year Incentive Regulation term (2014-2018) with rebasing in 2019
- Inflation factor ('I' factor) of 1.6%
- No Productivity factor ('X' factor)

Y-Factors
- Escalate DSM ('Y' factor) each year by the same inflation factor of 1.6%
- Inclusion of Capital pass-throughs each year related to Brantford to Kirkwall and Parkway D Compressor, Parkway West and Burlington to Oakville Projects
  - i.e. not subject to PCI escalation
- Burlington to Oakville treated as an Other Transmission asset for cost allocation purposes

Billing Unit Adjustments
- No LRAM or Average Use volume-related adjustments
- Weather-related volume adjustment for 20-year declining trend weather methodology
  - 20% volume phase-in for each year of the IR term
- M12 Demands for Dawn to Parkway – increase of 363,000 GJ/day for Brantford to Kirkwall and Parkway D Compressor Project
  - 2 months of demand included in 2015, full amount in each year thereafter
- No other billing unit or demand adjustments (including Dawn to Kirkwall turnback)

Others
- Gas Supply Optimization margin of $13.426 million related to FT-RAM ($5.220 million) and Base Exchanges ($8.206 million) removed from gas supply transportation rates.
- Base Exchange margin of $8.206 million included in delivery rates beginning in 2014.
  - Of the $8.206 million, $2.992 million is allocated to Union North and $5.214 million is allocated to Union South
  - Exchange margin subject to PCI consistent with other S&T transactional margin
- No change for ROE, UFG or S&T transactional margin
- No Z-factors
- No changes for taxes
- Based on 2013 Board-approved Gas Supply Plan
  - No cost of gas adjustments related to Intra-period WACOG or Upstream Transportation costs (e.g. TCPL toll changes)
  - Does not include changes associated with the Long-term contracting proposal filed in the Brantford to Kirkwall and Parkway D Compressor Project application
- No 2014 General Service rate design proposals included
- General Service customer charges – maintain 2013 approved levels ($21.00/month for Rate 01 & Rate M1 and $70.00/month for Rate 10 & Rate M2)
  - Revenue neutral adjustment to delivery commodity rates

Note:
- April 2013 QRAM (EB-2013-0033) used as base rates

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast

Line No.	Particulars	Current Approved Revenue ($000's) (a)	2014 Proposed Revenue ($000's) (b)	Δ in Revenue ($000's) (c) = (b - a)	2015 Proposed Revenue ($000's) (d)	Δ in Revenue ($000's) (e) = (d - b)	2016 Proposed Revenue ($000's) (f)	Δ in Revenue ($000's) (g) = (f - d)	2017 Proposed Revenue ($000's) (h)	Δ in Revenue ($000's) (i) = (h - f)	2018 Proposed Revenue ($000's) (j)	Δ in Revenue ($000's) (k) = (j - h)	Total Δ in Revenue ($000's) (l) = (j - a)	Total Δ in Revenue (%) (m) = (l / a)	Average Δ per Year (%) (n) = (m / 5)
	North Delivery														
1	Rate 01	161,158	161,198	41	162,204	1,005	164,379	2,176	167,322	2,943	170,271	2,949	9,113	5.7%	1.1%
2	Rate 10	19,951	19,637	(314)	19,747	110	20,025	279	20,383	358	20,742	359	791	4.0%	0.8%
3	Rate 20	13,487	13,518	31	13,567	48	13,755	188	14,011	256	14,267	256	780	5.8%	1.2%
4	Rate 25	4,473	4,537	65	4,559	22	4,622	63	4,707	85	4,793	85	320	7.2%	1.4%
5	Rate 100	15,481	15,699	217	15,808	110	16,037	229	16,325	288	16,614	288	1,132	7.3%	1.5%
6	Total North Delivery	214,550	214,589	40	215,884	1,295	218,818	2,934	222,749	3,931	226,687	3,937	12,137	5.7%	1.1%
	South Delivery & Storage														
7	Rate M1	388,998	392,483	3,486	395,324	2,840	403,602	8,278	410,809	7,208	418,020	7,210	29,022	7.5%	1.5%
8	Rate M2	50,183	50,174	(9)	50,572	398	52,299	1,727	53,229	930	54,155	926	3,972	7.9%	1.6%
9	Rate M4	12,282	12,223	(60)	12,324	101	12,801	477	13,028	226	13,252	225	970	7.9%	1.6%
10	Rate M5A	13,265	13,457	191	13,549	92	13,741	192	13,988	247	14,236	248	970	7.3%	1.5%
11	Rate M7	4,120	4,094	(26)	4,128	34	4,312	183	4,388	76	4,463	75	343	8.3%	1.7%
12	Rate M9	724	707	(17)	715	8	768	53	781	13	793	13	70	9.6%	1.9%
13	Rate M10	10	9	(1)	9	(0)	10	1	10	0	10	0	1	6.9%	1.4%
14	Rate T1	10,637	10,591	(46)	10,693	102	11,054	361	11,242	188	11,428	186	791	7.4%	1.5%
15	Rate T2	42,154	41,269	(885)	41,768	498	43,862	2,094	44,591	729	45,306	715	3,152	7.5%	1.5%
16	Rate T3	4,400	4,273	(126)	4,325	51	4,684	360	4,762	78	4,839	76	439	10.0%	2.0%
17	Total South Delivery & Storage	526,773	529,280	2,507	533,406	4,126	547,133	13,726	556,828	9,696	566,503	9,674	39,729	7.5%	1.5%
18	Total In-Franchise Delivery	741,323	743,870	2,547	749,291	5,421	765,951	16,660	779,578	13,627	793,189	13,612	51,866	7.0%	1.4%

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast

Line No.	Particulars	Current Approved Revenue ($000's)	2014 Proposed Revenue ($000's)	Δ in Revenue ($000's)	2015 Proposed Revenue ($000's)	Δ in Revenue ($000's)	2016 Proposed Revenue ($000's)	Δ in Revenue ($000's)	2017 Proposed Revenue ($000's)	Δ in Revenue ($000's)	2018 Proposed Revenue ($000's)	Δ in Revenue ($000's)	Total Δ in Revenue ($000's)	Total Δ in Revenue (%)	Average Δ per Year (%)
		(a)	(b)	(c) = (b - a)	(d)	(e) = (d - b)	(f)	(g) = (f - d)	(h)	(i) = (h - f)	(j)	(k) = (j - h)	(l) = (j - a)	(m) = (l / a)	(n) = (m / 5)
	North Transportation & Storage														
19	Rate 01	98,362	98,615	253	99,676	1,061	100,460	784	100,092	(368)	99,701	(392)	1,339	1.4%	0.3%
20	Rate 10	31,679	31,745	66	32,061	315	32,312	251	32,263	(49)	32,209	(54)	530	1.7%	0.3%
21	Rate 20	10,532	10,551	19	10,668	117	10,768	100	10,791	23	10,813	22	281	2.7%	0.5%
22	Rate 25	2,127	2,127	0	2,127	(1)	2,126	(1)	2,126	0	2,126	0	(0)	0.0%	0.0%
23	Rate 100	166	168	2	176	8	183	7	184	2	186	2	20	12.2%	2.4%
24	Total North Transportatiion & Storage	142,866	143,206	340	144,707	1,500	145,848	1,142	145,457	(391)	145,035	(421)	2,169	1.5%	0.3%
25	Total In-Franchise	884,190	887,076	2,886	893,997	6,921	911,799	17,802	925,035	13,235	938,225	13,190	54,035	6.1%	1.2%
	Ex-Franchise														
26	Rate M12	160,467	163,694	3,227	175,836	12,142	201,078	25,242	204,005	2,927	206,734	2,729	46,267	28.8%	5.8%
27	Rate M13	417	423	7	430	7	437	7	444	7	451	7	34	8.3%	1.7%
28	Rate M16	755	768	12	780	12	792	12	805	13	818	13	62	8.3%	1.7%
29	Rate C1	45,096	45,218	123	45,561	343	45,924	363	46,053	129	46,180	127	1,085	2.4%	0.5%
30	Total Ex-Franchise	206,735	210,103	3,369	222,607	12,504	248,231	25,624	251,307	3,076	254,183	2,876	47,449	23.0%	4.6%
31	Total Company	1,090,924	1,097,179	6,255	1,116,605	19,425	1,160,030	43,426	1,176,342	16,312	1,192,408	16,066	101,484	9.3%	1.9%

M12/C1 Demand Charge Impacts 2014-2018

Line No.	Services	EB-2011-0210 Rate Order ($/GJ/day) (1)	2014 Forecast ($/GJ/day)	2015 Forecast ($/GJ/day)	2016 Forecast ($/GJ/day)	2017 Forecast ($/GJ/day)	2018 Forecast ($/GJ/day)	Δ in Rates ($/GJ/day)	% Δ in Rates
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-a)	(h) = (g/a)
1	M12/C1 Dawn to Kirkwall	0.0661	0.0675	0.0723	0.0790	0.0801	0.0811	0.0150	23%
2	M12/C1 Dawn to Parkway	0.0783	0.0799	0.0868	0.0940	0.0953	0.0966	0.0182	23%
3	M12/C1 Kirkwall to Parkway	0.0122	0.0125	0.0135	0.0150	0.0152	0.0154	0.0032	26%
4	C1 Parkway to Kirkwall	0.0190	0.0194	0.0213	0.0234	0.0237	0.0240	0.0050	26%
5	C1 Kirkwall to Dawn	0.0336	0.0343	0.0371	0.0413	0.0419	0.0424	0.0088	26%
6	C1 Parkway to Dawn	0.0190	0.0194	0.0213	0.0234	0.0237	0.0240	0.0050	26%
7	M12-X	0.0974	0.0994	0.1081	0.1174	0.1191	0.1206	0.0232	24%

Notes:
(1) EB-2011-0210, Appendix A, Pages 14-16, column (c), effective January 1, 2013.

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union North

Line No.	Particulars	EB-2013-0033 April 2013 QRAM (1) Bill ($)	Unit Rate (cents/m^3)	2018 Forecast Bill ($)	Unit Rate (cents/m^3)	Impact Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate 10							
4	Delivery Charges	4,781	7.9675	5,049	8.4155	0.4480	269	5.6%
5	Gas Supply Charges	10,215	17.0256	10,680	17.8005			
6	Total Bill	14,996	24.9931	15,730	26.2160	0.4480	269	1.8%
	Large Rate 10							
7	Delivery Charges	15,548	6.2193	16,499	6.5997	0.3804	951	6.1%
8	Gas Supply Charges	42,564	17.0256	44,501	17.8005			
9	Total Bill	58,112	23.2449	61,001	24.4002	0.3804	951	1.6%
	Small Rate 20							
10	Delivery Charges	74,816	2.4939	79,237	2.6412	0.1474	4,422	5.9%
11	Gas Supply Charges	617,378	20.5793	636,124	21.2041			
12	Total Bill	692,194	23.0731	715,361	23.8454	0.1474	4,422	0.6%
	Large Rate 20							
13	Delivery Charges	285,803	1.9054	302,814	2.0188	0.1134	17,011	6.0%
14	Gas Supply Charges	2,881,670	19.2111	2,962,010	19.7467			
15	Total Bill	3,167,473	21.1165	3,264,824	21.7655	0.1134	17,011	0.5%
	Average Rate 25							
16	Delivery Charges	63,659	2.7982	68,215	2.9985	0.2002	4,556	7.2%
17	Gas Supply Charges	344,604	15.1475	350,769	15.4184			
18	Total Bill	408,264	17.9457	418,984	18.4169	0.2002	4,556	1.1%
	Small Rate 100							
19	Delivery Charges	259,798	0.9622	278,597	1.0318	0.0696	18,800	7.2%
20	Gas Supply Charges	5,760,139	21.3338	5,760,139	21.3338			
21	Total Bill	6,019,937	22.2961	6,038,737	22.3657	0.0696	18,800	0.3%
	Large Rate 100							
22	Delivery Charges	2,095,718	0.8732	2,249,498	0.9373	0.0641	153,780	7.3%
23	Gas Supply Charges	50,116,431	20.8818	50,116,431	20.8818			
24	Total Bill	52,212,149	21.7551	52,365,929	21.8191	0.0641	153,780	0.3%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South

Line No.	Particulars	EB-2013-0033 April 2013 QRAM (1) Bill ($)	Unit Rate (cents/m^3)	2018 Forecast Bill ($)	Unit Rate (cents/m^3)	Impact Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M2							
4	Delivery Charges	4,190	6.9832	4,512	7.5208	0.5376	323	7.7%
5	Gas Supply Charges	7,785	12.9744	7,954	13.2568			
6	Total Bill	11,975	19.9575	12,467	20.7775	0.5376	323	2.7%
	Large Rate M2							
7	Delivery Charges	14,250	5.7001	15,519	6.2075	0.5074	1,268	8.9%
8	Gas Supply Charges	32,436	12.9744	33,142	13.2568			
9	Total Bill	46,686	18.6745	48,661	19.4643	0.5074	1,268	2.7%
	Small Rate M4							
10	Delivery Charges	35,237	4.0271	38,279	4.3748	0.3476	3,042	8.6%
11	Gas Supply Charges	113,526	12.9744	115,997	13.2568			
12	Total Bill	148,763	17.0015	154,276	17.6315	0.3476	3,042	2.0%
	Large Rate M4							
13	Delivery Charges	270,978	2.2581	292,576	2.4381	0.1800	21,598	8.0%
14	Gas Supply Charges	1,556,923	12.9744	1,590,811	13.2568			
15	Total Bill	1,827,901	15.2325	1,883,388	15.6949	0.1800	21,598	1.2%
	Small Rate M5							
16	Delivery Charges	29,255	3.5461	31,252	3.7881	0.2420	1,997	6.8%
17	Gas Supply Charges	107,038	12.9744	109,368	13.2568			
18	Total Bill	136,294	16.5204	140,620	17.0449	0.2420	1,997	1.5%
	Large Rate M5							
19	Delivery Charges	155,313	2.3894	167,414	2.5756	0.1862	12,102	7.8%
20	Gas Supply Charges	843,333	12.9744	861,689	13.2568			
21	Total Bill	998,646	15.3638	1,029,104	15.8324	0.1862	12,102	1.2%
	Small Rate M7							
22	Delivery Charges	616,645	1.7129	666,936	1.8526	0.1397	50,290	8.2%
23	Gas Supply Charges	4,670,770	12.9744	4,772,434	13.2568			
24	Total Bill	5,287,415	14.6873	5,439,369	15.1094	0.1397	50,290	1.0%
	Large Rate M7							
25	Delivery Charges	2,358,392	4.5354	2,558,316	4.9198	0.3845	199,924	8.5%
26	Gas Supply Charges	6,746,667	12.9744	6,893,515	13.2568			
27	Total Bill	9,105,059	17.5097	9,451,831	18.1766	0.3845	199,924	2.2%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South

Line No.	Particulars	EB-2013-0033 April 2013 QRAM (1) Bill ($)	Unit Rate (cents/m^3)	2018 Forecast Bill ($)	Unit Rate (cents/m^3)	Impact Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M9							
1	Delivery Charges	116,256	1.6727	127,801	1.8389	0.1661	11,545	9.9%
2	Gas Supply Charges	901,718	12.9744	921,345	13.2568			
3	Total Bill	1,017,974	14.6471	1,049,145	15.0956	0.1661	11,545	1.1%
	Large Rate M9							
4	Delivery Charges	345,244	1.7110	379,591	1.8812	0.1702	34,347	9.9%
5	Gas Supply Charges	2,617,966	12.9744	2,674,949	13.2568			
6	Total Bill	2,963,210	14.6854	3,054,540	15.1380	0.1702	34,347	1.2%
	Small Rate T1							
7	Delivery Charges	127,339	1.6895	137,556	1.8251	0.1356	10,217	8.0%
8	Gas Supply Charges	977,878	12.9744	999,162	13.2568			
9	Total Bill	1,105,217	14.6639	1,136,718	15.0818	0.1356	10,217	0.9%
	Average Rate T1							
10	Delivery Charges	193,986	1.6772	209,037	1.8073	0.1301	15,051	7.8%
11	Gas Supply Charges	1,500,606	12.9744	1,533,269	13.2568			
12	Total Bill	1,694,592	14.6516	1,742,306	15.0641	0.1301	15,051	0.9%
	Large Rate T1							
13	Delivery Charges	427,194	1.6672	458,782	1.7904	0.1233	31,587	7.4%
14	Gas Supply Charges	3,324,560	12.9744	3,396,923	13.2568			
15	Total Bill	3,751,754	14.6415	3,855,704	15.0472	0.1233	31,587	0.8%
	Small Rate T2							
16	Delivery Charges	480,912	0.8116	524,582	0.8853	0.0737	43,670	9.1%
17	Gas Supply Charges	7,688,087	12.9744	7,855,426	13.2568			
18	Total Bill	8,168,998	13.7859	8,380,008	14.1420	0.0737	43,670	0.5%
	Average Rate T2							
19	Delivery Charges	1,105,628	0.5590	1,191,154	0.6022	0.0432	85,526	7.7%
20	Gas Supply Charges	25,661,967	12.9744	26,220,525	13.2568			
21	Total Bill	26,767,595	13.5334	27,411,680	13.8590	0.0432	85,526	0.3%
	Large Rate T2							
22	Delivery Charges	1,799,626	0.4863	1,931,569	0.5219	0.0357	131,943	7.3%
23	Gas Supply Charges	48,016,679	12.9744	49,061,810	13.2568			
24	Total Bill	49,816,305	13.4606	50,993,379	13.7787	0.0357	131,943	0.3%
	Large Rate T3							
25	Delivery Charges	2,912,694	1.0680	3,245,844	1.1902	0.1222	333,150	11.4%
26	Gas Supply Charges	35,382,636	12.9744	36,152,775	13.2568			
27	Total Bill	38,295,330	14.0424	39,398,619	14.4470	0.1222	333,150	0.9%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED
Summary of Average Residential Bill Impacts for Rate 01 and Rate M1
2014-2018 Incentive Regulation Forecast

	2013 Current Approved (a)	2014 Forecast (b)	2015 Forecast (c)	2016 Forecast (d)	2017 Forecast (e)	2018 Forecast (f)	Cumulative Bill Impact (g) = (f - a)	Percent Bill Impact (h) = (g / a)
Rate M1 Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	89.54	92.47	95.09	101.76	107.54	113.38	23.83	26.6%
Storage Services	16.21	16.49	16.55	16.85	17.27	17.68	1.47	9.1%
Total Delivery Charge	357.75	360.97	363.63	370.62	376.81	383.06	25.31	**7.1%**
Supply Charges								
Transportation to Union	92.13	98.34	98.34	98.34	98.34	98.34	6.21	-
Commodity & Fuel	193.31	193.31	193.31	193.31	193.31	193.31	-	-
Total Supply Charge	285.44	291.65	291.65	291.65	291.65	291.65	6.21	2.2%
Total Bill	643.19	652.61	655.28	662.27	668.46	674.71	31.52	**4.9%**
Year-over-year Impact - Delivery Bill ($)		3.21	2.67	6.99	6.19	6.25	25.31	
Year-over-year Impact - Delivery Bill (%)		**0.9%**	**0.7%**	**1.9%**	**1.7%**	**1.7%**	7.1%	
Year-over-year Impact - Total Bill ($)		9.43	2.67	6.99	6.19	6.25	31.52	
Year-over-year Impact - Total Bill (%)		1.5%	0.4%	1.1%	0.9%	0.9%	4.9%	
Rate 01 (EZ) Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	206.93	208.52	212.43	219.46	228.63	237.90	30.97	15.0%
Total Delivery Charge	458.93	460.52	464.43	471.46	480.63	489.90	30.97	**6.7%**
Supply Charges								
Transportation to Union	197.65	207.40	207.45	207.39	207.32	207.21	9.56	4.8%
Storage Services	78.75	79.45	84.13	88.19	88.97	89.76	11.01	14.0%
Commodity & Fuel	231.45	231.45	231.45	231.45	231.45	231.45	-	0.0%
Total Supply Charge	507.85	518.30	523.03	527.03	527.74	528.42	20.57	4.1%
Total Bill	966.78	978.82	987.46	998.49	1,008.37	1,018.32	51.54	**5.3%**
Year-over-year Impact - Delivery Bill ($)		1.59	3.91	7.03	9.17	9.27	30.97	
Year-over-year Impact - Delivery Bill (%)		**0.3%**	**0.8%**	**1.5%**	**1.9%**	**1.9%**	6.7%	
Year-over-year Impact - Total Bill ($)		12.04	8.64	11.03	9.88	9.95	51.54	
Year-over-year Impact - Total Bill (%)		1.2%	0.9%	1.1%	1.0%	1.0%	5.3%	

LPMA QUESTIONS

1. In the EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors dated September 17, 2008, the Board set out a formula for the materiality threshold for an incremental capital module. This formula is shown in page V, with an illustration on page VI of Appendix B: Amended Filing Guidelines.

a) Based on the Board approved figures for the 2013 rates application, please provide the values for Union for each of the parameters used in the formula. For the price cap index (PCI), please assume that it is equal to the inflation index, with the productivity factor and stretch factor both equal to zero.

Rate Base (RB) = $3,712,759,000 2013 Board-approved

Depreciation (d) = $196,091,000 2013 Board-approved

Regulated Revenue Growth (g) = -2.87% Normalized 2012 actuals vs. 2013 Board-approved

PCI = 1.63%

b) Based on the parameters noted above, please calculate the materiality threshold.

The materiality threshold is $188 million using the parameters above in the Board's Incremental Capital Module formula for Electricity Distributors (Chapter 3 of the Filing Requirements for Transmission and Distribution Applications, June 22, 2011)

c) Based on the above calculations, what would be the amount that would qualify for incremental capital module treatment for the three projects noted in Slide 6 of the April 29, 2013 Stakeholder Consultation.

Based on the materiality threshold in the response to b) above, all of the capital required for the Parkway West, Parkway Growth and Burlington Oakville capital projects would qualify for incremental capital module treatment.

2.

	Normalized	Benchmark	Required		
Year	ROE	ROE	X-Factor (1)	Proceeding	Reference
2008	12.11%	8.81%	8.72%	EB-2009-0101	Ex. B, Tab 5, Sch. 4
2009	11.01%	8.47%	7.26%	EB-2010-0039	Ex. B7.07
2010	11.59%	8.54%	8.34%	EB-2011-0038	Ex. B5.5
2011	11.77%	8.10%	9.46%	EB-2012-0087	Ex. B9.6
(1) X-Factor required to set normalized ROE to Benchmark ROE					

a) **Please confirm the above figures for 2008 through 2011 are correct. If not, please provide a corrected table.**

Please see an updated schedule in c) below. The years 2008 and 2011 have been updated to reflect the Board decision from the respective proceedings. The years 2009 and 2010 are correct.

b) **If available, please provide the figures for 2012 for the normalized ROE, Benchmark ROE and required X-factor.**

Figures for 2012 are provided below.

	Normalized	Benchmark	Required		
Year	ROE	ROE	X-Factor (1)	Proceeding	Reference
2008	12.97%	8.81%	10.53%	EB-2009-0101	
2009	11.01%	8.47%	7.26%	EB-2010-0039	Ex. B7.07
2010	11.59%	8.54%	8.34%	EB-2011-0038	Ex. B5.5
2011	10.58%	8.10%	6.98%	EB-2012-0087	
2012	12.38%	7.67%	11.97%	EB-2013-0109	
(1) X-Factor required to set normalized ROE to Benchmark ROE					

c) **In Slide 9 of the April 29, 2013 Stakeholder Consultation, Union is proposing a UFG gas ratio variance account and has indicated that it was a significant contributor to earnings during the last IRM term. Please re-calculate the normalized ROE and Required X-factors in the above table assuming that the UFG volume variances were included in a deferral account and did not impact on the utility earnings used for earnings sharing purposes. Please also include the figures for 2012 if they have been provided in the response to part (b).**

The schedule below shows results for normalized weather and UFG.

Year	Normalized ROE	Benchmark ROE	Required X-Factor (1)
2008	12.90%	8.81%	10.38%
2009	12.06%	8.47%	9.51%
2010	10.06%	8.54%	3.88%
2011	8.37%	8.10%	2.38%
2012	10.86%	7.67%	8.70%
(1) X-Factor required to set normalized ROE to Benchmark ROE			

d) Please do the same calculations as requested in part (c) above, reflecting the removal of any other significant driver of the earnings over the IRM period that Union believes will no longer exist in the next IRM period. Please provide an explanation for any such drivers.

The schedule below shows results for normalized weather, UFG, and FT RAM.

Year	Normalized ROE	Benchmark ROE	Required X-Factor (1)
2008	12.62%	8.81%	9.80%
2009	11.31%	8.47%	7.91%
2010	9.44%	8.54%	2.54%
2011	8.37%	8.10%	2.38%
2012	8.84%	7.67%	4.34%
(1) X-Factor required to set normalized ROE to Benchmark ROE			

3.

a) Is the earnings sharing proposed in Slide 5 of the April 29, 2013 Stakeholder Consultation asymmetric, in that there would be no sharing if Union's ROE was lower than the benchmark ROE?

The proposed earnings sharing mechanism is asymmetric. If Union's actual ROE was lower than the benchmark ROE, Union would not recover the variance from ratepayers.

b) Is the earnings sharing proposed based on actual results or normalized actual results? Is this the same as the sharing that was in place for 2008 through 2012?

The proposed earnings sharing is based on actual results. This is consistent with the earnings sharing that was in place for the 2008-2012 IR term.

4. What impact on the LRAM calculation, if any, would the incorporation of the LRAM for simplicity in the average use adjustment have, as proposed in Slide 6 of the April 29, 2013 Stakeholder Consultation?

Union is proposing to update the normalized annual consumption ("NAC") in rates based on the last known year of actuals. Union proposes to update the NAC in rates rather than update average use ("AU") and the Lost Revenue Adjustment Mechanism ("LRAM").

Updating for NAC captures all volume related adjustments including AU and LRAM.

Union proposes to amend the AU deferral accounting order to be for NAC. Any variances from the actual NAC to the NAC in rates would be captured in the NAC deferral account.

Union proposes to eliminate the LRAM deferral account following the implementation of 2015 rates.

5. As shown in Slide 5 of the April 29, 2013 Stakeholder Consultation, Union is proposing to continue to use the GDP IPI FDD as the measure of inflation for the price cap. Did Union consider using a weighted price index for labour, non-labour O&M costs and capital costs such as that used by Pacific Economics Group Research in the May 2013 Report to the Ontario Energy Board titled Empirical Research in Support of Incentive Rate Setting in Ontario? If not, why not? If yes, please provide the results of Union's analysis.

No. Union did not consider using a weighted price index for labour, non-labour O&M costs and capital costs as that used by PEG in their Report to the OEB. To calculate a weighted price index, several comparator utilities are required and the utility to which the index will apply should not influence the index. Given that Union is 1 of 2 major gas utilities in Ontario, Union would influence the weighted price index.

As was the case in Union's 2008-2012 IR term, Union is proposing to use the GDP IPI FDD as an inflation factor. The key benefits of the GDP IPI FDD include:

- Coverage - applies to a broad coverage of goods and services relevant to the gas industry (capital, labour, materials);
- Simplicity - facilitates the calculation of input price and productivity differentials used in X factor calibration;
- Availability - published annually for Canada and Ontario and quarterly for Canada

- Stability - less volatile due to the exclusion of petroleum products, gas exports and other price-volatile exports

6. With respect to the capital cost pass-through mechanism and criteria shown in Slides 6 and 7 of the April 29, 2013 Stakeholder Consultation:

a) Please confirm that the capital cost pass through would be based on $25 million or more capital for a single new project <u>closed to rate base</u> in the year.

Confirmed.

b) Please explain how the profitability index criterion would be applied to non-distribution projects, such as IT expenditures or transmission projects.

As shown on Slide #7, “PI<1.0 (delivery rate impacts)” is one of the criteria for the proposed Capital pass-through mechanism. A qualifying project must have a profitability index (“PI”) of less than 1 which means the project has insufficient revenue compared to its costs over the life of the project. As implied in the question, projects that qualify for Capital pass-through treatment must be outside the Board’s EBO 188 parameters for distribution facilities (i.e. transmission, information technology, reliability).

c) How would the costs to be passed through be allocated to rate classes?

Union will use 2013 Board-approved cost allocation methodologies to allocate these project-specific costs to rate classes.

7. In Slide 8 of the April 29, 2013 Stakeholder Consultation, Union indicates that it is proposing a pass through mechanism for annual adjustments to ROE per formula.

a) Does this pass through mechanism include any change related to capital structure that may result from a Board review?

Yes.

b) Why is there no pass through mechanism for the annual change in the cost of debt?

Union is not proposing to track changes in interest rates. Interest costs, like most of Union’s operating costs, were re-based for 2013. Those costs will be managed within the price cap framework during the IRM term, and will be re-set during the next cost-of-service application.

The need for synchronization of the ROE arises because of the existence of the earnings sharing mechanism (“ESM”). Two of the primary measures of the utility’s productivity are the rate levels over the IRM term, and the earnings shared over the IRM term. Both rates and the ESM threshold incorporate an allowed ROE. Union believes that it is appropriate to have a single ROE for both of these calculations, and therefore a single ROE against which its productivity may be ultimately assessed.

Accordingly, Union is indifferent as to which ROE is used for both rates and ESM purposes, provided that they are consistent and arise from an OEB-approved approach. That is, the ROE used to determine the ESM threshold could be fixed at the 2013 Board-approved amount of 8.93% for the length of the IRM term, or both rates and the ESM threshold could be adjusted annually by using the OEB-approved ROE formula. The key principle is that the ROE be the same for both rates and earnings sharing purposes.

c) How would Union adjust the inflation index, which includes an impact on costs related to the change in interest rates (cost of money) to avoid the double counting of changes in interest rates?

Union is not adjusting the inflation index. Please see the response to b) above.

d) Union indicates that this proposal matches the ROE in rates to that used for earnings sharing. An example was provided at the stakeholder consultation. Please provide this example, and a full explanation of the impact of the ROE built into rates and that used for earnings sharing being different.

Union is proposing that the ROE used for the earnings sharing calculation be the same ROE used in rates for the year in question.

At the stakeholder consultation, Union discussed a high level example showing that the disconnect between the ROE in rates and the ROE calculated by the Board's formula ("benchmark") resulted in Union earning revenues in excess of the Board's ROE formula without increasing productivity gains.

For example:

	Actual ROE	ROE in Rates	Benchmark ROE	Deadband	Earnings Sharing Mechanism	Shared ROE 50/50
	(a)	(b)	(c)	(d)	(c + d=e)	(a – e = f)
Current	11	8.5	8.0	2.0	10.0	1.0
Proposed	10.5	8.0	8.0	2.0	10.0	0.5

In the "current" example, the higher actual ROE was not achieved through productivity gains, but through the difference between the ROE in rates and the benchmark ROE.

In the "proposed" example, the ROE in rates is synchronized with the benchmark ROE which results in a lower actual ROE for Union. The ROE shared with ratepayers (column f) is lower than the “current” example but delivery rates overall would be lower because of the decrease in ROE from 8.5 to 8.0. Said another way, ratepayers would benefit from 100% of the ROE change in rates in the “proposed” example but only receive 50% of the shared ROE in the “current” example.

e) Instead of change the ROE in rates through a pass through mechanism, so that the ROE built into rates and that used for earnings sharing are the same, why not keep the ROE used for earnings sharing equal to that built into the original rates?

The synchronization of the ROE built into rates with that used for earnings sharing purposes is the primary focus of Union’s proposal. In doing so, this ensures that a single ROE is incorporated into the two primary measures of productivity. In this respect, Union would also support the use of the same 8.93% ROE approved for rate-making purposes in Union’s 2013 Rebasing proceeding (EB-2011-0210) for earnings sharing for the 2014 to 2018 IR term.

f) With respect to the proposal for a pass-through mechanism for change to the weather normalization methodology, is this a one-time change to the weather normalization methodology, or would it be an annual review of the methodology during the IRM term, or would the methodology be set for 2014 and then only updated for actual figures during the subsequent years of the IRM term (i.e. no change in methodology, but updated for more recent actual data)?

Union is proposing to implement the recommended methodology phased-in over the five-year IR period. The methodology would not be updated on an annual basis.

8.

a) Does the proposal to treat LEAP/winter warmth funding as a pass through item (Slide 9 of the April 29, 2013 Stakeholder Consultation) include the use of a variance/deferral account for this expenditure, similar to other pass through costs? If not, why not?

The proposal to treat LEAP/Winter Warmth funding as a pass through item does not include the use of a deferral/variance account. Union will build the funds required for LEAP/Winter Warmth into rates. All funds collected from customers will be paid to and managed by the Trustee, the United Way of Chatham-Kent. Accordingly, there will be no variances, and therefore no need for a deferral account.

b) Is Union proposing any materiality thresholds applicable to pass through items?

No.

9.

a) Please explain the link between the proposed IRM plan and the proposal to change the sharing of variances to 50/50 as noted in Slide 10 of the April 29, 2013 Stakeholder Consultation. Is this change solely related to Union taking greater risks if the shareholder share of the proceeds is greater?

Yes.

b) Please explain why Union proposes to treat the ratepayer portion of the proceeds as revenue rather than gas cost offsets. Would the proceeds of these transactions be credited to all distribution customers, rather than only to system gas customers? Would transmission customers also be allocated a share of the proceeds?

Union proposes to treat net transportation exchange revenue as revenue rather than gas costs because:

1. 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 exchanges is consistent with how Union generates transportation exchange revenue. In its EB-2013-0109 evidence (Exhibit B, Tab 2) Union describes the criteria Union uses to determine whether net transportation exchange revenue should be treated as utility earnings or as a gas cost offset.

2. Notwithstanding the Board's EB-2010-0210 and EB-2012-0087 Decisions, treating net transportation exchange revenue as a gas cost offset is inconsistent with the historical treatment of upstream transportation exchange revenue and the way in which the revenue is generated.

3. 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.

4. Union's proposed treatment of net transportation exchange revenue will ensure that a robust and active secondary market for transportation services will continue to exist and provide ongoing benefits to Ontario.

Under the mechanism approved in EB-2011-0210, exchange revenues are treated as gas costs and are allocated to Union North sales service and bundled direct purchase customers and Union South sales service customers only. Under Union's proposal the net transportation exchange revenue would be shared with all in-franchise customers. Transmission customers would not be allocated any share of the revenues.

c) **Has Union considered contracting out the optimization of exchange revenues to a third party and locking in the ratepayer and shareholder benefits and transferring the risk/reward to the third party? If not, why not?**

Union has contracted out the optimization of exchange revenues to third parties through the use of Asset Management Agreements but on a limited basis on paths that Union is unable to extract much value. Generally, Union is in the best position to understand the optimization opportunities on the upstream contracts used to serve its gas supply plan. Further, any incentive paid to a third party to optimize the system would result in less revenue being shared between ratepayers and Union.

10.

a) **With respect to the proposal in Slide 12 of the April 29, 2013 Stakeholder Consultation related to the off-ramp, please confirm that the proposed off-ramp is asymmetric in that there is no off-ramp if Union under earns by more than 300 basis points for 2 consecutive years.**

Confirmed. The proposed off-ramp is asymmetrical in that there will be no off-ramp if Union under-earns by more than 300 basis points for 2 consecutive years.

b) **Would Union be open to an off-ramp is the regulated utility earnings exceed the allowed ROE by 300 basis points on average over 2 consecutive years?**

The reason for an off-ramp is to review the continued appropriateness of the IRM parameters. A single year with earnings of 300 bps beyond the allowed ROE could cause the 2-year average to also exceed 300 bps. In Union's view, a single year's performance should not give rise to a review of the IRM parameters. However, Union remains open to further discussion on this ratepayer-protection matter.

11. Would Union be open to the potential for the extension of the IRM term beyond 5 years, perhaps on a year-to-year basis, if parties agreed to do so, rather than be locked into a full cost of service rebasing application as indicated in Slide 14 of the April 29, 2013 Stakeholder Consultation?

Yes. Union would be receptive to an extension of the IR term. At the end of the IR term, Union could still prepare the necessary evidence for a cost of service rebasing proceeding. That way, a cost-of-service application could proceed if an extension could not be negotiated, or if such an extension was not approved by the Board.

12. Please provide a table similar to that shown in Slide 19 of the April 29, 2013 Stakeholder Consultation that shows a 3 year average for each of 2008 through 2012. Please comment on the variability of the 3 year average as compared to the single year that has been used and is proposed to be used in the future IRM.

2008	2.04%
2009	1.54%
2010	2.73%
2011	0.72%
2012	1.72%

- 2-year average 1.22%
- 3-year average 2008-2010 2.10%
2009-2011 1.66%
2010-2012 1.72%
- 5-year average 1.75%
- Q4 2012 1.63%

The 3-year averages are more stable than the year-over-year inflation factor. However, GDP IPI FDD is already a lagging proxy for increases to Union's future costs; using a 3-year average would further dilute the relationship between the inflation factor and Union's cost increases.

CME QUESTIONS

RELEVANT TO A CONSIDERATION OF UNION'S 5 YR IRM PROPOSAL 2014-2018

1. Possible Adjustments to 2013 Rates

Please provide the following information reflecting Union's 2013 results to date to assist in considering whether any adjustments to Base Rates are necessary before using them as the point of departure for a further 5 year IRM Plan:

a) Provide schedules, in the traditional format, which will compare the various elements of the 2013 Board-approved amounts for Rate Base, Revenues, Cost of Service, Utility Income and Return on Equity to actual amounts for the three (3)

months ending March 31, 2013, and estimated amounts for the nine (9) months between April 1, 2013, and December 31, 2013;

Please see Attachment CME 1 for the 2013 Board Approved vs. the 2013 3+9 outlook schedules.

b) **In the information to be provided in response to (a), please identify the factors giving rise to any variances between the Board-approved amounts and three (3) month actuals and nine (9) months estimated amounts;**

Please see Attachment CME 1 for the 2013 Board Approved vs. the 2013 3+9 outlook schedules.

c) **Provide total Board-approved through-put estimates for each rate class for 2013 and compare those amounts to the three (3) month actual and nine (9) months estimated amounts for the 2013 Base Year. Please provide explanations for any variances;**

Please see Attachment CME 2 for the Board approved through put estimates for each rate class for 2013 vs. the 3+9 outlook.

d) **Please provide the allocation factor being used in 2013 to separate regulated and unregulated storage assets, along with the information that was used to calculate that allocation factor.**

Please refer to Attachment CME 3 for the allocation factor being used in 2013 to separate regulated and unregulated assets by storage pool, and by asset class.

2. <u>Union's Utility Expectations Over the Period 2014 to 2018</u>

a) **Please provide, in confidence, Union's 5 year Business Plan covering the period 2014 to 2018.**

Union does not have information for the business plan for years 2016-2018. Union's 3 year business plan (Attachment CME 4) will be provided on a confidential basis at the May 23, 2013 stakeholder consultation.

b) **Please provide Union's 5 year Capital Expenditures Budget for the years 2014 to 2018 inclusive in sufficient detail to disclose the significant capital projects which Union expects to undertake in that time frame.**

Please see Attachment CME 5 for Union's Capital plan for the period of 2013-2015. Union does not currently have a capital plan prepared beyond 2015.

c) What is the approximate amount Union expects to spend, year-by-year, over the period 2014 to 2018 inclusive on unregulated storage projects and what impact are such expenditures likely to have on the allocation factor used to separate, between regulated and unregulated storage services, the costs and expenses associated with the provision of such services?

Union expects to spend approximately $25 million in total on unregulated storage projects over the 2013-2015 period, depending on market demand and pricing. There is no capital plan beyond 2015. Those expenditures are expected to have a minimal impact on the allocation factors for unregulated and regulated activities.

3. Escalation Formula

a) Please provide details of the productivity gains made by Union year-over-year for the period 2008 to 2012 inclusive, and advise what the X-factor would be if that data was used to set the X-factor for the period 2014 to 2018.

Union has hired a consultant to review the productivity factor for the 2008-2012 period and to estimate the factor for 2014-2018. Union does not have the information at this time.

b) In providing the response to the previous question, please identify each of the significant factors which produced the productivity gains realized by Union in each year over the period 2008 to 2012 inclusive.

Please see the response to 3a) above.

4. Pass- Throughs

Please describe the capital expenditure pass-through criteria which would apply if those criteria were specified to be the same criteria which apply to the currently approved Incremental Capital Module ("ICM") for electricity distributors.

The criteria Union has proposed for its Capital pass-through mechanism include:

- $25 million or more threshold for a single new project;
- expenditure must be outside the base on which price cap is set;
- expenditure must have delivery rate impacts (i.e. insufficient revenue) but may be offset by gas cost savings for some customers (to be determined in QRAM process;
- expenditures will be identified in that year's annual stakeholder information session (where possible); and,

- full regulatory review prior to inclusion in rates (committed to this even when a leave-to-construct application is not required).

The intent of the ICM as described in Chapter 3 of the Filing Requirements for Transmission and Distribution Applications (dated June 22, 2011) is to address the treatment of new capital investment needs in the electricity sector that arise during the IRM plan term. The eligibility criteria of the ICM are:

- Materiality – amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor, otherwise they should be dealt with at rebasing; For Union, $25 million in capital is a material amount, as it represents more than 10% of our historical capital budget, and results in a revenue requirement that approximates the materiality level used by Union's external auditors.
- Need – amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived; Union agrees with this, and,
- Prudence – amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers. Union agrees with this.

Union's proposed criteria for the Capital pass-through mechanism applies to those of the ICM. Each has a materiality threshold while the ICM's need and prudence criteria are covered off by Union's commitment to initiate a full regulatory review prior to inclusion in rates.

5. <u>Union's Acquisition of Transmission Services from Others</u>

a) To what degree is Union's reliance upon Upstream Transportation on the TCPL system likely to decline over the period 2014 to 2018?

Given the uncertainty surrounding the recent NEB decision and the TCPL Review and Variance filing, Union does not know specifically how the reliance on the TCPL system may change over the period 2014 to 2018.

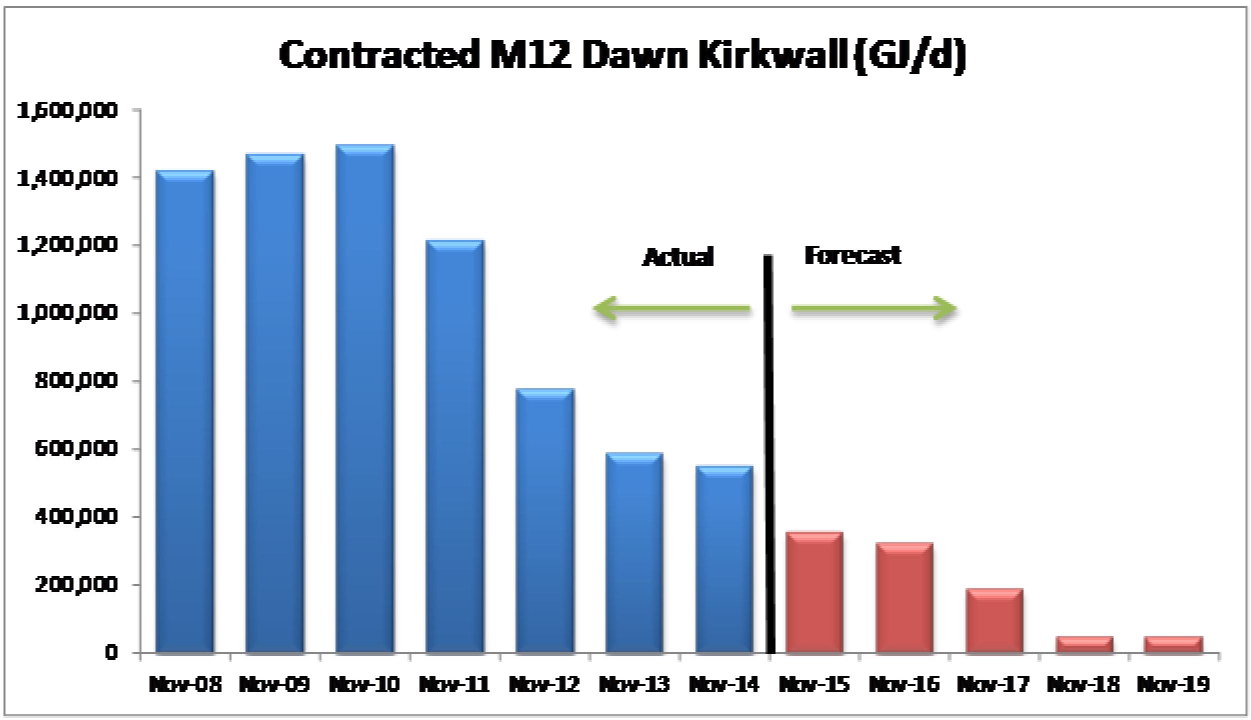
b) What transmission systems of others is Union likely to use year-over-year between 2014 and 2018 inclusive to bring gas to its system to meet the needs of its system gas customers and its bundled direct purchasers in the north?

Union will continue to evaluate all upstream transportation options to ensure the gas supply principles are adhered to. This would include all the current transportation paths Union has contracted on the various pipelines from the multiple supply basins to its system as well as any new transportation options from the emerging basins (ie Marcellus/Utica) that may arise over this time period. Union will follow the prescribed processes and perform a landed costs analysis on the available options in accordance with its previous practice and the Sussex Economic Advisors recommendations.

6. <u>Union's Provision of Transmission Services to Others</u>

To what extent does Union expect its provision of transmission services to others will increase year-over-year for each of the years 2014 to 2018 inclusive?

Since 2008, Union has received notice of termination for 978,809 GJ/d of Dawn to Kirkwall transportation capacity at contract term expiry, including notice received as recently as October 2012 to terminate approximately 37,000 GJ/d of Dawn to Kirkwall capacity starting November 1, 2014. A summary of the firm Dawn to Kirkwall transportation contracts terminated since 2008 is provided below. Further notices of contract termination for Dawn to Kirkwall capacity are expected in the future. A summary of the remaining firm Dawn to Kirkwall transportation contracts is also provided below.



Due to increasing Marcellus and Utica supply, Union sees no future market opportunity to sell or resell Dawn to Kirkwall capacity for natural gas exports to the United States

Demand for transportation on the Dawn-Parkway System continues to grow. Customers interested in contracting on the Dawn-Parkway System are generally driven by:

1. increased access to the liquid market, diverse natural gas supplies and premium storage facilities at the Dawn Hub;

2. the continuing trend from long haul transportation to short haul transportation; and

3. growing demand in central, eastern and northern Ontario as well as Québec and the U.S. Northeast.

The growth of 70,157 GJ/d of in-franchise demand, combined with the additional 440, 252 GJ/d of net ex-franchise demand creates a net overall Dawn-Parkway System demand increase of 510,409 GJ/d. For further details see Attachment CME 6.

7. Unaccounted For Gas ("UFG")

a) What is the UFG experience to date in 2013 compared to the Board-approved UFG allowance? Is 2013 UFG tracking higher or lower than the Board-approved 2013 forecast?

As of Q1 2013 Union has experienced $0.4 million favourable UFG volumes compared to 2013 Board-approved.

8. Expected Reductions in Cost of Debt Refinancings 2014 to 2018

a) What is the embedded cost of debt for 2013? Please provide, in the usual rate case format, a list of all of the outstanding debt issuances in 2013 and from that list, identify each financing which will be renewed in each of the years 2014 to 2018 inclusive.

The embedded cost of debt for 2013 is 6.53% for long-term debt and 1.31% for unfunded short-term debt. Please see Attachment CME 7 for the list of outstanding debt issuances in 2013 with maturity dates. Union does not have a financing forecast extending beyond 2015. Therefore, Union does not have sufficient information to determine whether maturing issuances will be renewed for years beyond 2015. The current 3-year forecast assumes that the debt issuances maturing in 2014 and 2015 will be renewed.

b) At what rates of interest does Union expect to re-finance debt maturing in each of the years 2014 to 2018 inclusive?

Please see Attachment CME 8 which provides both the short and long-term debt rate assumptions for the period May, 2013 through 2018.

c) By how much are annual debt costs related to financings which will mature in the 2014 to 2018 time frame likely to reduce in each of the years 2014 to 2018 inclusive?

Please see the response to a) above.

9. **Possible Change to Weather Normalization Methodology**

Please explain how Union is proposing to implement in rates any change in weather normalization methodology which the Board might approve.

Union is in the process of determining the impact of the recommended weather changes. Subject to the results, Union proposes to implement the weather normalization change phased-in over the five- year IR term.

10. **Net Exchange Revenues**

Apart from the National Energy Board ("NEB") Mainline Tolls Decision terminating the FT-RAM service attribute, what material changes in circumstances have occurred since the Board rendered its Decision pertaining to Union's 2013 rates which justify Union's proposal to have the Board re-classify exchange revenues as Transactional Services revenues rather than Upstream Transportation cost reductions?

For the reasons outlined in Union's EB-2013-0109 evidence (filed on May 8, 2013) Union believes that net transportation exchange revenues should be treated as revenue and not upstream transportation cost reductions. Please see the response to LMPA 9 b).

11. **Rate Redesign Flexibility**

a) **What are the 2013 revenue to cost ratios for each of the Board-approved rate classes?**

Please see Attachment CME 9 for the Rate Order, Working Papers, Schedule 13, column (h) for the 2013 Board-approved revenue to cost ratios for each of Union's rate classes.

b) **Please describe the information that could be provided on an annual basis to enable the Board and other stakeholders to monitor, year-over-year, any shifts in the revenue to cost ratios embedded in 2013 rates.**

Union is unable to provide such information in the absence of a full cost-of-service study.

c) **Could rates be re-balanced in any year during the 5 year IRM Plan if the revenue to cost ratios embedded in Base Rates varied by an amount greater than a specified materiality factor such as 10%?**

No. Please see the response to b) above.

FRPO QUESTIONS ON UNION'S IR PROPOSAL

1. Slide 2: Can Union correlate SQI performance to customer satisfaction surveys?

a) If so, please provide.

No, Union cannot correlate SQI performance with customer satisfaction levels.

b) If not, would Union be willing to do this going forward?

Union completes research on a monthly as well as annual basis to measure customer satisfaction with respect to matters such as call handling and "first call" resolution, gas emergency response, appointment times, etc. Union's Operations and Customer Care organizations track this performance detail and applies the results to a balanced scorecard. Throughout the 2008-2012 IR term, Union's performance relative to SQIs was at a consistently high level. Union plans to maintain the same SQIs as applied during its 2008-2012 IR term and maintain its monthly and annual customer satisfaction research. Union could provide information on the monthly and annual customer satisfaction research at the annual stakeholder meeting if desired.

2. Slide 7: Please clarify the point on PI<1.0 i.e., if PI>1.0, Union will not request Capital inclusion?

Please see the response at LPMA 6 b).

3. Slide 9: In addition to LPMA's Question 2, please provide the actual dollar value difference (rates vs. actual) for each year that flowed from keeping UFG constant.

Please see Attachment FRPO 1.

4. Slide 10: Please provide the annual value of deferral account 179-69 for the five years prior to its elimination.

Please see Attachment FRPO 2, which is Exhibit C1.19 filed in EB-2007-0606 for the 179-69 deferral balance for years 1999 to 2006.

The data provided for 2007 in the interrogatory attached was an estimate. The actual 2007 deferral balance (in $000's) was:

Deferral Account 179-69 2007 Balance	$6,118 (credit)
75% Ratepayers	$4,589

25% Shareholder	$1,530

5. **Slide 11: In discussing Union's view on risk, one component was the risk that TCPL starts providing exchange services.**

a) **To Union's knowledge, does TCPL have an undertaking or right conferred to it by the NEB to engage in this practice?**

To Union’s knowledge, TCPL does not specifically rely on an undertaking or right conferred to it by the NEB to engage in the sale of exchange services, rather it sells transportation services. However, TCPL’s use of Transportation by Others (TBO) where it contracts for services on other pipelines to affect the sale of transportation services results in an exchange-type of transaction for its shippers.

The recent NEB Decision (RH-003-2011) also provides TCPL with considerable flexibility in setting tolls for interruptible and short-term firm transportation services. Union understands that the NEB has given TCPL a strong financial incentive to maximize its discretionary revenues to earn its approved rate of return. This ability for TCPL to discount or increase those tolls will increase TCPL’s ability to sell transportation services that compete against Union’s exchange services. Further, as TCPL uses its increased flexibility to increase the sale of the interruptible and short-term firm services, less capacity will be available to other shippers such as Union who require that capacity to provide the exchange services.

TCPL has also applied to the NEB for Review and Variance of the Decision (RH-003-2011). In this application TCPL proposes to eliminate downstream diversions and alternative receipt points. This change will further limit Union’s ability to provide exchange services.

6. **Slide 16: If Union were to establish a consensus with the Parkway obligation working group, would Union propose to include the impacts in the 2014 rates?**

Yes, depending on the consensus Union would propose to include impacts in 2014 rates, or in rates following the year consensus is reached.

a) **Had Union been ordered to implement a Revenue Cap IRM model similar to EGD, what would the results have been?**

Union has not modelled a revenue cap and is therefore not able to respond to this question.

ENERGY PROBE COMMENTS/QUESTIONS

1. **Mid-term Review? Minimum Stakeholder Conference and response to questions? extension?**

   Union proposes to hold an annual stakeholder information session. Potential topics for discussion include, but are not limited to, review of Union's financial results and other key operating parameters specific to the IR framework; market conditions (changes/trends) and the impact this could have on Union's regulated operations; and, a review of the Company's Gas Supply Plan.

   With respect to an extension please see the response at LPMA 11.

2. **GPPI adjusted annually per old IRM? ROE Adjustment? Other Capital?**

   Yes. Union proposes to adjust the GDP IPI annually.

   For ROE, please see the response at LPMA 6 d) and e).

3. **Justify based on TFP over 2007-2012**

4. **Discuss other options for Off-Ramp**

   Earnings Sharing:

5. **Please confirm asymmetric, normalized and relation to X factor.**

   Please see the response at LPMA 3 a). Union's proposed earnings sharing mechanism is asymmetric and is based on actual earnings. Union's proposal to eliminate the X factor is directly related to Union's proposal to reduce the earnings sharing deadband from 200 bps to 100 bps.

   Y Factor:

6. **Unless Board approves different budget.**

7. **Subject to ICM threshold like Electricity Distributors**

   Please see the response at LPMA 1.

8. **The Burlington to Oakville Project is treated as an Other Transmission asset for cost allocation purposes. Please provide details of the allocation.**

The annual revenue requirement associated with the Burlington to Oakville Project ranges from approximately ($0.04 million) in 2015 to $4.25 million in 2018. The revenue requirements represent the costs associated with the Project facilities deemed to be in service in each year from 2015 to 2018. The calculation of the annual revenue requirement from 2015 to 2018 and the underpinning assumptions is provided at Schedule 1.

The Burlington to Oakville Project facilities will be classified as Other Transmission assets in the plant accounting records. In accordance with the treatment of Other Transmission assets in Union's Board-approved cost allocation study, costs associated with the Burlington to Oakville Project are allocated to all Union South in-franchise rate classes in proportion to Union South in-franchise design day demands.

To determine the rate impacts by rate class, Union added the Project revenue requirements to its 2013 Board-approved cost allocation study. Using the allocation of Other Transmission Demand costs per the 2013 Board-approved cost allocation study results in a rate increase to Union South in-franchise rate classes and a rate decrease to Union North in-franchise and ex-franchise rate classes.

The decrease to Union North in-franchise and ex-franchise rate classes is caused by a shift in indirect costs. Adding the rate base and operating costs associated with the Project as Other Transmission Demand costs to the 2013 Board-approved cost allocation study results in the re-allocation of cost components that are functionalized based on rate base and O&M. As a result of the additional Project costs, indirect costs (general plant, administrative and general expenses, and general operations and engineering costs), and taxes (income taxes, deferred taxes and property taxes) are re-allocated from Union North and ex-franchise rate classes to Union South in-franchise rate classes. The cost allocation impact of the Burlington to Oakville project by rate class is provided at Schedule 2.

For the purposes of preparing 2014-2018 IR rates impacts for the April 29, 2013 stakeholder consultation, Union added the annual revenue requirements associated with the Burlington to Oakville, Parkway West and Brantford to Kirkwall and Parkway D Compressor Projects to its 2013 Board-approved cost allocation study. The annual rate adjustments resulting from the addition of these three projects to the 2013 Board-approved cost allocation study represent the annual capital pass through adjustments included in the 2014-2018 IR rate impacts provided in the April 29, 2013 presentation.

9. **Continue AUTVA for low volume rates. Please provide details on LRAM.**

Please see the response at LPMA 4.

10. **Subject to results of Board requirements regarding weather/volume forecast**

11. Please provide more information on Dawn-Parkway volumes and turn-back for 2014-2015. See LTC applications

Please see the response at CME 6.

12. Of the $8.206 million, $2.992 million is allocated to Union North and $5.214 million is allocated to Union South – Provide details at next meeting.

In Union's EB-2011-0210 Rate Order (2013 Rates), the Board approved an allocation of the ratepayer portion of net exchange revenue ($8.206 million) between Union North and Union South based on the upstream transportation contracts designed to serve each delivery area. Net exchange 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) was allocated to Union North. Net exchange revenues generated using upstream transportation long-haul contracts designed to serve Union South (the CDA delivery point) was allocated to Union South. Accordingly, $2.992 million in net exchange revenue was allocated to Union North and $5.214 million to Union South.

For the purposes of preparing a 2014-2018 Incentive Regulation rate impacts for the April 29, 2013 stakeholder consultation, the Union North portion of net exchange revenue was allocated to rate classes in proportion to the 2013 Board-approved excess of peak day demand over average day demand (XSPK&AVG allocator). The Union South portion of net exchange revenue was allocated to rate classes in proportion to EB-2011-0210 design (peak) day demand. This approach is consistent with the allocation of 2013 transportation-related S&T transactional margin to Union North and Union South rate classes.

Please see Attachment Energy Probe 1 for the allocation of the ratepayer and shareholder portions of net exchange revenues.

Please see Attachment Energy Probe 2 for the allocation of net exchange revenues to Union North and Union South.

Please see Attachment Energy Probe 3 for the allocation of net exchange revenues to rate classes.

13. Please confirm treatment of UFG Variance Accounts.

Union proposes to implement a deferral account to capture the difference between the Board approved Unaccounted for Gas ("UFG") ratio and the actual UFG ratio experienced. This account will be symmetrical to ensure that neither the ratepayer nor Union will be harmed or benefit from variances in actual UFG to forecast.

14. How will any changes be addressed during IRM?

Union is proposing to update rates on an annual basis to reflect changes to the Gas Supply

Plan. Rates will be updated to reflect changes to gas supply plan including tolls, volumes and changing transportation paths or services. This will allow Union to take advantage of new transportation paths and services available that will benefit the ratepayer during IR term. Union is also proposing that the North Tolls, Fuel and Balancing deferral account (No. 179-100) be amended to capture all gas supply plan cost differences.

UNION GAS LIMITED
Statement of Utility Income
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000s)	Board Approved	3+9 Outlook	Variance
		(a)	(b)	(c)
	Operating revenues:			
1	Gas sales	1,448,762	1,509,892	61,130 (1)
2	Transportation	155,505	151,300	(4,205) (2)
3	Other	20,198	15,800	(4,398) (3)
4		1,624,465	1,676,992	52,527
	Operating expenses:			
5	Cost of gas	699,910	746,175	46,265 (1)
6	Operating and maintenance expenses	379,322	378,535	(787)
7	Depreciation	196,091	194,206	(1,885) (4)
8	Other financing	1,179	824	(355)
9	Property & Capital taxes	63,272	62,755	(517)
10		1,339,774	1,382,495	42,720
11	Earnings before interest & taxes	284,691	294,497	9,807
12	Interest expense	149,464	147,440	(2,024)
13	Income taxes	15,441	18,067	2,626
14	Net utility income	119,786	128,990	9,204
15	Preferred dividend requirements	3,117	3,114	(3)
16	Utility income applicable to common equity (before storage adj)	116,669	125,876	9,208
17	Storage premium subsidy (after tax)	3,390	3,344	(46)
18	Total utility income applicable to common equity	120,059	129,221	9,162
19	Common equity	1,344,432	1,358,475	14,043
20	Return on equity (line 18/line 19)	8.93%	9.51%	0.58%

Notes:

(1) Distribution margin variance is driven primarily by lower compressor fuel costs due to lower Dawn sendout, higher customer supplied fuel due to increased volumes and higher contract revenues from chemical, greenhouse and large commercial/industrial markets.

(2) Transportation variance is driven primarily by decreased Dawn to Parkway short-term revenue due to lower volumes.

(3) Other Revenue variance is driven primarily by a loss related to the over-refund of 2010 deferrals in 2011 which was recognized in 2013 and decreased connection charges as a result of changes to customer service rules.

(4) Variance in depreciation is primarily driven by lower than expected regulated IT expenditures capitalized in 2012.

UNION GAS LIMITED
Summary of Cost of Capital
Calendar Year Ending December 31, 2013

Line No.	Particulars	Board-Approved Utility Capital Structure ($000s)	Board-Approved Utility Capital Structure (%)	Board-Approved Cost Rate %	Board-Approved Return ($000s)	3+9 Outlook Utility Capital Structure ($000s)	3+9 Outlook Utility Capital Structure (%)	3+9 Outlook Cost Rate %	3+9 Outlook Return ($000s)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Board Approved								
1	Long-term debt	2,289,139	61.30	6.53%	149,481	2,240,741	59.38	6.55%	146,689
2	Unfunded short-term debt	(1,287)	(0.03)	1.31%	(17)	71,528	1.90	1.05%	751
3	Total debt	2,287,852	61.26		149,464	2,312,269	61.28		147,440
4	Preference shares	102,248	2.74	3.05%	3,117	102,798	2.72	3.03%	3,114
5	Common equity	1,344,432	36.00	8.93%	120,058	1,358,475	36.00	8.93%	121,312
6	Total rate base	3,734,532	100.00		272,639	3,773,542	100.00		271,866

UNION GAS LIMITED
Calculation of Utility Income Taxes
Calendar Year Ending December 31, 2013

Line No.	Particulars ($000s)	Board Approved (a)	3+9 Outlook (b)
	Determination of Taxable Income		
1	Utility income before interest and income taxes	284,691	294,497
	Adjustments required to arrive at taxable utility income:		
2	Interest expense	(149,464)	(147,440)
3	Utility permanent differences	4,693	4,686
4		139,920	151,744
	Utility timing differences		
5	Capital Cost Allowance	(185,314)	(187,413)
6	Depreciation	196,091	194,206
7	Depreciation through clearing	2,265	2,265
8	Other	(32,921)	(35,382)
9	Gas Cost Deferral and Other (current)	-	-
10		(19,879)	(26,324)
11	Taxable income	120,041	125,419
	Calculation of Utility Income Taxes		
12	Income taxes (line 11 * line 18)	30,610	33,236
13	Deferred tax on Gas Cost Deferrals	-	-
14	Deferred tax drawdown	(15,169)	(15,169)
15	Total taxes	15,441	18,067
	Tax Rates		
16	Federal tax	15.00%	15.00%
17	Provincial tax	10.50%	11.50%
18	Total tax rate	25.50%	26.50%

UNION GAS LIMITED
Statement of Utility Rate Base
Calendar Year Ending December 31

Line No.	Particulars ($000's)	Board Approved (a)	3+9 Outlook (b)	Variance (c)
	Gas Utility Plant			
1	Gross plant at cost	6,361,532	6,414,273	52,741
2	Less: accumulated depreciation	2,754,071	2,775,192	21,121
3	Net utility plant	3,607,462	3,639,081	31,620
	Working Capital and Other Components			
4	Cash working capital	20,007	20,144	137
5	Gas in storage and line pack gas	163,109	146,891	(16,218)
6	Balancing gas	72,963	74,444	1,481
7	ABC receivable (gas in storage)	(44,901)	(27,018)	17,883
8	Inventory of stores, spare equipment	29,618	30,259	641
9	Prepaid and deferred expenses	4,955	5,236	281
10	Customer deposits	(48,231)	(46,038)	2,193
11	Customer interest	(764)	(458)	306
12	Total working capital and other components	196,756	203,460	6,704
13	Total rate base before deduction of accumulated deferred income taxes	3,804,218	3,842,541	38,323
14	Accumulated deferred income taxes	69,686	68,999	(687)
15	Total rate base	3,734,532	3,773,542	39,010

UNION GAS LIMITED
Total Weather Normal Throughput Volume by Service Type and Rate Class (1)
Year Ended December 31

Line No.	Particulars (10^6m^3)	Board Approved 2013 (a)	3 + 9 (b)	Variance (c) = (b) - (a)	% Variance (d) = (c) / (a)	Variance Explanations (e)
	General Service					
1	Rate M1 Firm	2,940	2,951	12	0%	
2	Rate M2 Firm	976	972	(4)	0%	
3	Rate 01 Firm	884	898	14	2%	
4	Rate 10 Firm	323	325	2	1%	
5	Total General Service	5,122	5,147	24	0%	Weather
	Wholesale - Utility (2)					
6	Rate M9 Firm	61	62	1	2%	
7	Rate M10 Firm	0	0	0		
8	Rate 77 Firm	-	-	-		
9	Total Wholesale - Utility	61	62	1	2%	
	Contract (2)					
10	Rate M4	405	432	28	7%	Greenhouse (acreage) and LCI (# of accts)
11	Rate M7	147	168	21	14%	Power
12	Rate 20 Storage	-	-	-		
13	Rate 20 Transportation	630	641	11	2%	Power
14	Rate 100 Storage	-	-	-		
15	Rate 100 Transportation	1,895	1,896	1	0%	Power
16	Rate T-1 Storage	-	-	-		
17	Rate T-1 Transportation	5,429	5,594	164	3%	Power & Steel
18	Rate T-3 Storage	-	-	-		
19	Rate T-3 Transportation	273	267	(6)	-2%	
20	Rate M5	535	547	12	2%	Greenhouse (acreage) and LCI (# of accts)
21	Rate 25	160	177	18	11%	Power
22	Rate 30	-	-	-		
23	Total Contract	9,474	9,722	249	3%	
24	Total	14,657	14,931	274	2%	

Note:
(1) The impact of weather normalization for rates M1, M2, 01, and 10 is calculated based on the weather normalization methodology in place for each respective year.
(2) Union's contract and wholesale classes are not weather normalized.

Regulated vs Unregulated Storage Assets Allocation

as at December 31, 2012
To be used for 2013 Maintenance Capital Projects

Storage Pools

		Oil City	Mandaumin	Mandaumin (Sarnia Airport)	Bluewater	HTLP Custody Transfer	Dow Moore	Waubuno	Payne	Bickford
Asset Class		X139	X140	X140	X145	X148	X151	X152	X153	X154
Land	Reg	80.14%	62.34%	N/A	N/A	N/A	N/A	62.34%	62.34%	62.34%
	Nreg	19.86%	37.66%	N/A	N/A	N/A	N/A	37.66%	37.66%	37.66%
Land Rights	Reg	62.34%	62.34%	N/A	62.34%	N/A	62.34%	62.34%	62.34%	N/A
	Nreg	37.66%	37.66%	N/A	37.66%	N/A	37.66%	37.66%	37.66%	N/A
Structures & Improvements	Reg	N/A	62.34%	0.00%	N/A	N/A	N/A	62.34%	62.34%	62.34%
	Nreg	N/A	37.66%	100.00%	N/A	N/A	N/A	37.66%	37.66%	37.66%
Storage Wells	Reg	50.93%	62.34%	N/A	51.06%	N/A	N/A	62.34%	43.24%	62.34%
	Nreg	49.07%	37.66%	N/A	48.94%	N/A	N/A	37.66%	56.76%	37.66%
Field Lines	Reg	62.34%	62.34%	N/A	62.34%	N/A	N/A	62.34%	62.34%	62.34%
	Nreg	37.66%	37.66%	N/A	37.66%	N/A	N/A	37.66%	37.66%	37.66%
Compressor Equipment	Reg	N/A	N/A	0.00%	N/A	N/A	N/A	62.34%	34.10%	62.34%
	Nreg	N/A	N/A	100.00%	N/A	N/A	N/A	37.66%	65.90%	37.66%
Measuring & Regulating Equipment	Reg	90.06%	62.34%	100.00%	62.34%	0.00%	N/A	62.34%	62.34%	62.34%
	Nreg	9.94%	37.66%	0.00%	37.66%	100.00%	N/A	37.66%	37.66%	37.66%
Base Pressure Gas	Reg	62.34%	62.34%	N/A	62.34%	N/A	62.34%	62.34%	62.34%	62.34%
	Nreg	37.66%	37.66%	N/A	37.66%	N/A	37.66%	37.66%	37.66%	37.66%

	Oil City	Mandaumin	Mandaumin (Sarnia Airport)	Bluewater	HTLP Custody Transfer	Dow Moore	Waubuno	Payne	Bickford
Total Regulated - %age	64%	62%	92%	58%	0%	62%	63%	52%	63%
Total Unregulated - %age	36%	38%	8%	42%	100%	38%	37%	48%	37%
Total Regulated - Asset Values	6,493,660.41	18,212,960.52	816,730.70	3,008,039.00	-	8,081,371.77	4,582,990.04	8,238,693.09	14,897,392.02
Total Unregulated - Asset Values	3,619,381.97	11,003,294.32	72,749.04	2,172,217.71	231,000.20	4,882,376.00	2,746,219.89	7,487,770.72	8,918,852.93

Regulated vs Unregulated Storage Assets Allocation

as at December 31, 2012
To be used for 2013 Maintenance Capital Projects

Storage Pools

Asset Class		Sombra	Enniskillen	Bentpath	Terminus	Rosedale	Dawn 167	Oil Springs East	Dawn 47 & 49	Dawn 59 & 85
		X155	X156	X157	X158	X159	X160	X162	X163	X164
Land	Reg	62.34%	62.34%	62.34%	N/A	N/A	80.14%	80.14%	62.34%	62.34%
	Nreg	37.66%	37.66%	37.66%	N/A	N/A	19.86%	19.86%	37.66%	37.66%
Land Rights	Reg	62.34%	62.34%	62.34%	N/A	62.34%	N/A	62.34%	N/A	62.34%
	Nreg	37.66%	37.66%	37.66%	N/A	37.66%	N/A	37.66%	N/A	37.66%
Structures & Improvements	Reg	62.34%	62.34%	62.34%	62.34%	N/A	80.14%	80.14%	62.34%	62.34%
	Nreg	37.66%	37.66%	37.66%	37.66%	N/A	19.86%	19.86%	37.66%	37.66%
Storage Wells	Reg	62.34%	50.60%	62.34%	62.34%	62.34%	62.34%	45.54%	62.34%	22.54%
	Nreg	37.66%	49.40%	37.66%	37.66%	37.66%	37.66%	54.46%	37.66%	77.46%
Field Lines	Reg	62.34%	62.34%	62.34%	62.34%	62.34%	62.34%	62.34%	62.34%	40.89%
	Nreg	37.66%	37.66%	37.66%	37.66%	37.66%	37.66%	37.66%	37.66%	59.11%
Compressor Equipment	Reg	62.34%	62.34%	62.34%	N/A	N/A	80.14%	80.14%	N/A	N/A
	Nreg	37.66%	37.66%	37.66%	N/A	N/A	19.86%	19.86%	N/A	N/A
Measuring & Regulating Equipment	Reg	62.34%	62.34%	62.34%	62.34%	N/A	90.06%	90.06%	62.34%	35.21%
	Nreg	37.66%	37.66%	37.66%	37.66%	N/A	9.94%	9.94%	37.66%	64.79%
Base Pressure Gas	Reg	62.34%	62.34%	62.34%	62.34%	62.34%	62.34%	62.34%	62.34%	62.34%
	Nreg	37.66%	37.66%	37.66%	37.66%	37.66%	37.66%	37.66%	37.66%	37.66%

	Sombra	Enniskillen	Bentpath	Terminus	Rosedale	Dawn 167	Oil Springs East	Dawn 47 & 49	Dawn 59 & 85
Total Regulated - %age	62%	59%	62%	62%	62%	69%	70%	62%	35%
Total Unregulated - %age	38%	41%	38%	38%	38%	31%	30%	38%	65%
Total Regulated - Asset Values	15,588,505.58	7,874,904.95	14,763,900.83	4,665,789.45	5,765,096.20	12,348,824.54	16,360,139.51	6,549,205.52	6,007,921.96
Total Unregulated - Asset Values	9,624,848.13	5,500,560.39	8,899,106.51	2,805,270.50	3,468,075.95	5,586,131.33	7,036,428.90	3,938,265.54	11,179,689.38

100% Un-reg
Wells:
D273
D274
D275
D276
D277

Regulated vs Unregulated Storage Assets Allocation

as at December 31, 2012
To be used for 2013 Maintenance Capital Projects

Storage Pools

Asset Class		Dawn 156 X165	Edys Mills X167	Booth Creek X168	Bentpath East X169	Dow A Plant X170	Black Creek X171	Heritage Pool X173	Jacob Pool X174	Head Office X050
Land	Reg	62.34%	80.14%	N/A	62.34%	80.14%	N/A	0.00%	0.00%	N/A
	Nreg	37.66%	19.86%	N/A	37.66%	19.86%	N/A	100.00%	100.00%	N/A
Land Rights	Reg	43.46%	62.34%	62.34%	62.34%	62.34%	62.34%	0.00%	0.00%	62.34%
	Nreg	56.54%	37.66%	37.66%	37.66%	37.66%	37.66%	100.00%	100.00%	37.66%
Structures & Improvements	Reg	62.34%	80.14%	62.34%	62.34%	80.14%	N/A	0.00%	0.00%	N/A
	Nreg	37.66%	19.86%	37.66%	37.66%	19.86%	N/A	100.00%	100.00%	N/A
Storage Wells	Reg	30.69%	52.11%	62.34%	54.41%	50.79%	N/A	0.00%	0.00%	N/A
	Nreg	69.31%	47.89%	37.66%	45.59%	49.21%	N/A	100.00%	100.00%	N/A
Field Lines	Reg	14.90%	62.34%	62.34%	62.34%	62.34%	N/A	0.00%	0.00%	62.34%
	Nreg	85.10%	37.66%	37.66%	37.66%	37.66%	N/A	100.00%	100.00%	37.66%
Compressor Equipment	Reg	35.75%	80.14%	N/A	N/A	75.11%	N/A	0.00%	0.00%	N/A
	Nreg	64.25%	19.86%	N/A	N/A	24.89%	N/A	100.00%	100.00%	N/A
Measuring & Regulating Equipment	Reg	26.31%	90.06%	62.34%	62.34%	90.06%	N/A	0.00%	0.00%	62.34%
	Nreg	73.69%	9.94%	37.66%	37.66%	9.94%	N/A	100.00%	100.00%	37.66%
Base Pressure Gas	Reg	62.34%	62.34%	62.34%	62.34%	62.34%	N/A	0.00%	0.00%	N/A
	Nreg	37.66%	37.66%	37.66%	37.66%	37.66%	N/A	100.00%	100.00%	N/A

Total Regulated - %age	32%	71%	62%	61%	68%	62%	0%		62%
Total Unregulated - %age	68%	29%	38%	39%	32%	38%	100%		38%
Total Regulated - Asset Values	19,476,385.63	11,368,108.33	2,199,568.90	9,694,742.28	20,197,689.73	1,005,670.95	-	-	9,799,320.58
Total Unregulated - Asset Values	41,973,451.67	4,668,873.52	1,326,234.13	6,221,982.39	9,574,315.54	607,577.00	13,329,709.52	-	5,919,637.00

100% Un-reg
Wells:
D280
D281
D282
D283
D284
D285

Regulated vs Unregulated Storage Assets Allocation

as at December 31, 2012
To be used for 2013 Maintenance Capital Projects

Dawn Plant

		Dawn Plant Trans Non Mainline	Dawn Yard	Dawn J	Dawn Dehy Plant	Dawn Plant Trans Mainline	Dawn A Compressor	Dawn B Compressor	Dawn C Compressor	Dawn D Compressor
Asset Class		X184	X186	X187	X188	X189	X190	X191	X192	X193
Land	Reg	100.00%	80.14%	N/A	N/A	100.00%	80.14%	N/A	N/A	80.14%
	Nreg	N/A	19.86%	N/A	N/A	N/A	19.86%	N/A	N/A	19.86%
Structures & Improvements	Reg	100.00%	80.14%	57.55%	66.35%	100.00%	80.14%	80.14%	80.14%	80.14%
	Nreg	N/A	19.86%	42.45%	33.65%	N/A	19.86%	19.86%	19.86%	19.86%
Compressor Equipment	Reg	100.00%	80.14%	57.55%	45.38%	100.00%	80.14%	80.14%	80.14%	80.14%
	Nreg	N/A	19.86%	42.45%	54.62%	N/A	19.86%	19.86%	19.86%	19.86%
Measuring & Regulating Equipment	Reg	100.00%	90.06%	57.55%	N/A	100.00%	90.06%	N/A	N/A	N/A
	Nreg	N/A	9.94%	42.45%	N/A	N/A	9.94%	N/A	N/A	N/A
		*See note below				*See note below				
Total Regulated - %age		100%	84%	58%	47%	100%	82%	79%	80%	81%
Total Unregulated - %age		0%	16%	42%	53%	0%	18%	21%	20%	19%
Total Regulated - Asset Values		20,187,124.95	2,050,533.29	22,983,364.05	6,923,728.43	8,369,410.43	13,946,572.27	22,835,784.23	20,352,428.12	63,885,982.65
Total Unregulated - Asset Values		-	393,566.17	16,320,200.35	7,696,964.88	-	3,012,701.54	6,047,085.75	4,955,347.97	15,452,755.74

Dawn Plant Trans Non-Mainline - Plant Code X 184
Includes the following assets:
TCPL Measurement
Great Lakes Header
Tecumseh Measurement
Tecumseh (16" Sombra Line Tie-in)

Dawn Plant Trans Mainline - Plant Code X 189
Includes the following assets:
Dawn to Enniskillen 48" Tie-In
Dawn 26", 34", 42" Meter Run
Total Measurement

Regulated vs Unregulated Storage Assets Allocation

as at December 31, 2012
To be used for 2013 Maintenance Capital Projects

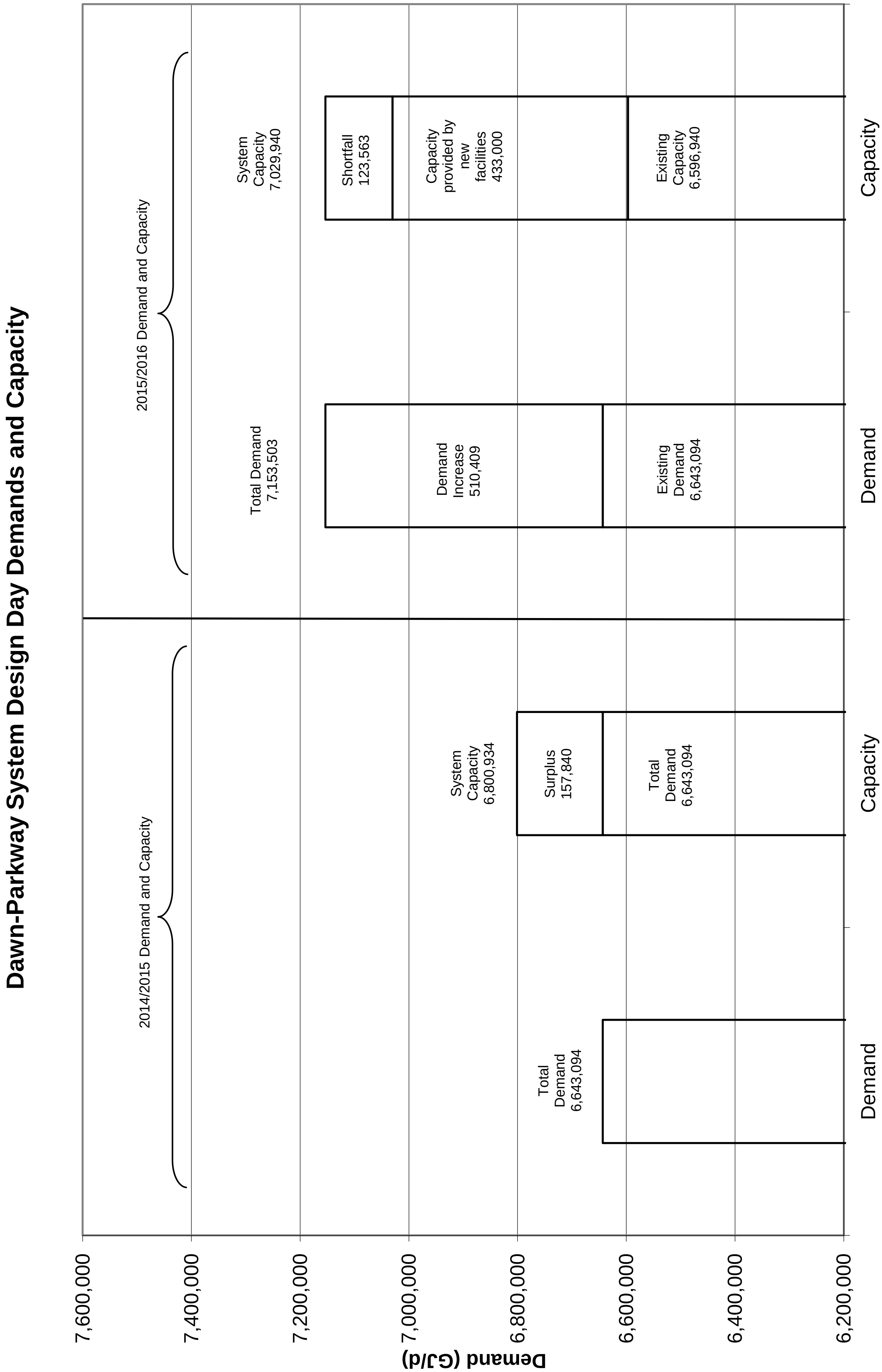
Dawn Plant

		Dawn E Compressor	Dawn F Compressor	Dawn G Compressor	Dawn I Compressor	Vector Interconnect @ Dawn
Asset Class		X194	X195	X196	X198	X225
Land	Reg	N/A	N/A	N/A	N/A	N/A
	Nreg	N/A	N/A	N/A	N/A	N/A
Structures & Improvements	Reg	100.00%	80.14%	80.14%	N/A	100.00%
	Nreg	N/A	19.86%	19.86%	100.00%	N/A
Compressor Equipment	Reg	100.00%	80.14%	77.23%	N/A	100.00%
	Nreg	N/A	19.86%	22.77%	100.00%	N/A
Measuring & Regulating Equipment	Reg	N/A	N/A	N/A	N/A	100.00%
	Nreg	N/A	N/A	N/A	N/A	N/A

Total Regulated - %age	100%	80%	77%	0%	100%
Total Unregulated - %age	0%	20%	23%	100%	0%
Total Regulated - Asset Values	29,880,875.35	44,676,048.42	31,279,059.67	-	43,243.20
Total Unregulated - Asset Values	-	10,983,128.24	9,097,794.83	65,584,146.97	-

Distribution
Capital Expenditures
CDN$Millions

Particulars	In Service Date	2013 Forecast	2014 Forecast	2015 Forecast
Expansion				
Nanticoke Prespend	tbd	-	-	-
Jacob (Freedom) Storage Development	tbd	-	-	8.3
Eastern Power Lambton	Nov-14	0.9	9.7	0.1
Project Pre-spend		2.0	2.0	2.0
Overheads		1.0	0.5	1.0
Parkway West	Nov-15	30.9	52.9	131.8
Kirkwall Flow Reverseal	Nov-12	0.1	-	-
Dow-Moore Storage Enhancements	Aug-16	-	-	1.0
Storage Enhancements Phase I (PMOP)	Sep-13	11.4	-	-
Storage Enhancements Phase II (PMOP)	Jul-15	-	0.2	4.1
Parkway D Compressor	Nov-15	2.8	33.0	38.5
Parkway GTA Measurement & Control	Nov-15	0.1	0.4	16.0
Burlington - Oakville Pipeline	Nov-14	3.8	31.3	2.0
TFEP Brantford to Kirkwall	Nov-15	0.6	2.5	75.8
Total Expansion		**53.6**	**132.5**	**280.6**
Maintenance				
Distribution New Business		68.5	66.5	61.6
Distribution Other		96.4	71.1	69.1
Total Distribution		164.9	137.6	130.7
Transmission		36.9	33.7	38.5
Storage		14.0	11.2	12.1
General		12.4	18.8	23.7
Overheads		53.8	57.7	58.4
Total Maintenance		**282.0**	**259.0**	**263.4**
IT		28.3	32.5	32.5
Total Maintenance and IT		**310.3**	**291.5**	**295.9**
Total Union Gas Capex		**$ 363.9**	**$ 424.0**	**$ 576.5**


Dawn-Parkway System Design Day Demands and Capacity
2014/2015 Demand and Capacity
2015/2016 Demand and Capacity
Total Demand 6,643,094
System Capacity 6,800,934
Surplus 157,840
Total Demand 6,643,094
Total Demand 7,153,503
Demand Increase 510,409
Existing Demand 6,643,094
System Capacity 7,029,940
Shortfall 123,563
Capacity provided by new facilities 433,000
Existing Capacity 6,596,940
Demand
Capacity
Demand
Capacity
Demand (GJ/d)
7,600,000
7,400,000
7,200,000
7,000,000
6,800,000
6,600,000
6,400,000
6,200,000

UNION GAS LIMITED
Cost of Long-Term Debt Capital
Year Ending December 31, 2013

Line No.	Offering Date (a)	Coupon Rate (b)	Maturity Date (c)	Principal Amount Offered ($000's) (d)	Premium Discount and Expenses ($000's) (e)	Net Capital Employed: Total Amount ($000's) (f)	Net Capital Employed: Per $100 Principal Amount (in Dollars) (g)	Effective Cost Rate (1) (h)	Total Amount Outstanding at 12/31/12 ($000's) (i)	Total Amount Outstanding at 12/31/13 ($000's) (j)	Avg. Monthly Averages ($000's) (k)	Carrying Cost ($000's) (l)	Projected Average Embedded Cost Rates (m)
1	08/28/90	11.50	08/28/15	150,000	1,620	148,380	98.92	11.63	150,000	150,000	150,000	17,445	
2	11/06/92	9.70	11/06/17	125,000	1,500	123,500	98.80	9.83	125,000	125,000	125,000	12,288	
3	08/05/93	8.75	08/03/18	125,000	1,275	123,725	98.98	8.90	125,000	125,000	125,000	11,125	
4	10/19/93	8.65	10/19/18	75,000	908	74,092	98.79	8.79	75,000	75,000	75,000	6,593	
5	02/24/93	7.90	02/24/14	150,000	1,869	148,131	98.75	8.04	150,000	150,000	150,000	12,060	
6	11/10/95	8.65	11/10/25	125,000	1,612	123,388	98.71	8.79	125,000	125,000	125,000	10,988	
7	09/21/05	4.64	06/30/16	200,000	1,100	198,900	99.45	4.70	200,000	200,000	200,000	9,400	
8	09/11/06	5.46	09/11/36	165,000	898	164,102	99.46	5.51	165,000	165,000	165,000	9,092	
9	11/23/06	4.85	04/25/22	125,000	854	124,146	99.32	4.91	125,000	125,000	125,000	6,138	
10	04/28/08	5.35	04/27/18	200,000	1,060	198,940	99.47	5.42	200,000	200,000	200,000	10,840	
11	09/02/08	6.05	09/02/38	300,000	2,076	297,924	99.31	6.10	300,000	300,000	300,000	18,300	
12	07/23/10	5.20	07/23/40	250,000	2,455	247,545	99.02	5.27	250,000	250,000	250,000	13,175	
13	06/21/11	4.88	06/21/41	300,000	2,171	297,829	99.28	4.93	300,000	300,000	300,000	14,790	
14	08/01/13	4.06	08/01/43	250,000	1,250	248,750	99.50	4.10	-	250,000 (2)	93,750	3,844	
15									2,290,000	2,540,000	2,383,750	156,078	6.55%

Notes:

(1) Computation of effective cost rate takes into account sinking fund requirements and the amortization of any premium/discount and issue expenses, on the average life of each issue.

(2) Debt issue is included in 3+9 Outlook. Timing of issue, rates of interest, financing costs and principle are dependent on conditions in effect at the actual time of issue.

UNION GAS LIMITED
Future long-term interest rate assumptions
as of March 5, 2013

	2013	2014	2015	2016	2017	2018
10-Year rates	3.200%	3.350%	3.550%	3.700%	3.900%	4.050%
30-Year rates	4.100%	4.150%	4.250%	4.300%	4.350%	4.400%

Filed: 2012-12-13
EB-2011-0210
Rate Order
Working Papers
Schedule 13
Page 1 of 2

UNION GAS LIMITED
Revenue Deficiency Recovery
Effective January 1, 2013

		Before Recovery				After Recovery					
Line No.	Particulars	Current Approved Revenue (1) ($000's)	Current Approved Rates (2) (cents/m^3)	Revenue (Deficiency) / Sufficiency ($000's)	Approved Revenue Requirement (3) ($000's)	Revenue (Deficiency) / Sufficiency ($000's)	Approved Revenue (4) ($000's)	Approved Rates (5) (cents/m^3)	Revenue to Cost Ratios	Rate Change (%)	EB-2005-0520 Approved Revenue to Cost Ratios
		(a)	(b)	(c) = (a -d)	(d)	(e) = (f - d)	(f)	(g)	(h) = (f / d)	(i) = (g - b) / (b)	(j)
	North Delivery										
1	R01	139,945	15.8233	(20,698)	160,643	(176)	160,467	18.1438	0.999	14.7%	0.976
2	R10	16,954	5.2508	(2,789)	19,743	-	19,743	6.1146	1.000	16.5%	1.058
3	R20	9,726	1.5443	(7,073)	16,799	(3,382)	13,417	2.1304	0.799	38.0%	0.597
4	R25	3,197	2.0039	(2,125)	5,323	(850)	4,473	2.8033	0.840	39.9%	0.467
5	R100	12,658	0.6678	(2,853)	15,511	(32)	15,478	0.8166	0.998	22.3%	0.895
6	Total North Delivery	182,480		(35,538)	218,019	(4,440)	213,579		0.980	17.0%	0.939
7	Total Recovery of North Delivery Deficiency (col. f - a)						31,099				
	South Delivery & Storage										
8	M1	382,233	13.0323	(6,191)	388,424	(708)	387,717	13.1897	0.998	1.2%	0.972
9	M2	44,791	4.5962	(6,387)	51,178	(1,426)	49,752	5.0998	0.972	11.0%	0.972
10	M4	11,558	2.8561	(3,968)	15,526	(3,377)	12,149	3.0022	0.783	5.1%	0.783
11	M5A	8,916	1.6662	(6,970)	15,886	(2,791)	13,096	2.4472	0.824	46.9%	0.824
12	M7	3,951	2.6852	(1,182)	5,133	(1,062)	4,071	2.7667	0.793	3.0%	0.697
13	M9	819	1.3486	77	743	(40)	702	1.1562	0.946	-14.3%	0.946
14	M10	5	2.5245	(69)	74	(64)	10	5.1152	0.131	102.6%	0.131
15	T1	58,963	1.0860	6,267	52,696	-	52,696	0.9706	1.000	-10.6%	0.973
16	T3	4,571	1.6762	(92)	4,663	(264)	4,400	1.6133	0.943	-3.8%	0.943
17	Total South Delivery & Storage	515,808		(18,515)	534,324	(9,732)	524,592		0.982	1.7%	0.958
18	Total Recovery of South Delivery & Storage Deficiency (col. f - a)						8,783				
19	Total In-Franchise Delivery (line 6 + line 17)	698,289		(54,054)	752,342	(14,172)	738,171		0.981	5.7%	0.953

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (b).
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (c).
(3) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (e).
(4) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (g).
(5) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (h).

UNION GAS LIMITED
Revenue Deficiency Recovery
Effective January 1, 2013

Line No.	Particulars	Before Recovery: Current Approved Revenue (1) ($000's) (a)	Before Recovery: Current Approved Rates (2) (cents/m^3) (b)	Before Recovery: Revenue (Deficiency) / Sufficiency ($000's) (c) = (a -d)	Approved Revenue Requirement (3) ($000's) (d)	After Recovery: Revenue (Deficiency) / Sufficiency ($000's) (e) = (f - d)	After Recovery: Approved Revenue (4) ($000's) (f)	After Recovery: Approved Rates (5) (cents/m^3) (g)	After Recovery: Revenue to Cost Ratios (h) = (f / d)	After Recovery: Rate Change (%) (i) = (g - b) / (b)	EB-2005-0520 Approved Revenue to Cost Ratios (j)
	North Transportation & Storage										
1	R01	70,790	8.0041	(27,572)	98,362	(3,920)	94,442	10.6784	0.960	33.4%	1.000
2	R10	23,140	7.1667	(8,539)	31,679	(1,342)	30,338	9.3957	0.958	31.1%	1.000
3	R20	8,815	7.2291	(1,717)	10,532	(477)	10,055	8.2463	0.955	14.1%	1.000
4	R25	1,685	3.9269	(442)	2,127	(117)	2,010	4.6844	0.945	19.3%	1.000
5	R100	197	-	48	150	16	166	-	1.109		0.701
6	Total North Transportation & Storage	104,628		(38,222)	142,850	(5,839)	137,011		0.959	31.0%	0.991
7	Total Recovery of North Transport & Storage Deficiency (col. f -a)						32,383				
8	Total In-Franchise (page 1, line 19 + line 6)	802,916		(92,276)	895,192	(20,011)	875,181		0.978	9.0%	0.956
9	Total Recovery of In-Franchise Deficiency (col. f - a)						72,265				
	Ex-Franchise										
10	M12	161,163		1,123	160,040	(2,507)	157,532		0.984	-2.3%	0.984
11	M13	373		162	211	200	411		1.952	10.2%	1.470
12	M16	748		297	451	286	736		1.634	-1.5%	1.356
13	C1	45,392		31,622	13,770	31,245	45,015		3.269	-0.8%	2.610
14	Total Ex-Franchise	207,676		33,205	174,471	29,224	203,695		1.167	-1.9%	1.177
15	Total Recovery of Ex-Franchise Deficiency (col. f - a)						(3,981)				
16	Total Delivery, Transportation & Storage (line 8 + line 14)	1,010,592		(59,071)	1,069,663	9,213 (6)	1,078,876		1.009	6.8%	1.004
17	Total In-Franchise Commodity / Admin	625,443		48,673	576,769	44,414	621,183		1.077	-0.7%	-
18	Total Recovery of Commodity / Admin Sufficiency (col. f - a)						(4,260)				
19	Total Union Gas (line 16 + line 17)	1,636,035		(10,398)	1,646,432	53,626	1,700,059		1.033	3.9%	1.002

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (b).
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (c).
(3) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (e).
(4) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (g).
(5) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (h).
(6) Includes Phase I sharing of short-term storage margin of $0.661 million and Phase II update of a $0.155 million decrease; Phase I sharing of optimization margin of $1.492 million; Heritage Pool sufficiency of $0.056 million; exclusion of $0.300 million of System Integrity costs related to Union's non-utility storage space per Board Decision; and Union South Gas Supply Transportation Optimization of $7.570 million.

Energy Probe 1
Attachment

UNION GAS LIMITED
Summary of 2013 Gas Supply Optimization Margin

Line No.	Particulars ($ 000's)	Total Revenue (1) (a)	Allocated Cost (b)	Total Margin (c) = (a - b)	Shareholder Portion of Margin (d) = (c) * 10%	Margin Included in Rates (e) = (c - d)
	Exchanges (2)					
1	Base Exchanges	9,118	-	9,118	912	8,206
2	FT-RAM Related Exchanges	-	-	-	-	-
3	Total Exchanges Revenue	9,118	-	9,118	912	8,206

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, Page 11, Line 18, column (g).
(2) EB-2011-0210, Board Decision, page 40.

Energy Probe 2
Attachment

UNION GAS LIMITED
Allocation of Net Exchange Revenue to Union North and Union South

Line No.	Particulars ($000s)	Union South CDA (a)	Union North NCDA (b)	SSMDA (c)	EDA (d)	NDA (e)	Other (1) (f)	Union North (g) = (b + c + d + e + f)	Total North & South (h) = (a + g)
1	Base exchanges	$ 5,794	$ -	$ 320	$ 2,558	$ -	$ 446	$ 3,324	$ 9,118
2	FT-RAM related exchanges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Total Exchanges	$ 5,794	$ -	$ 320	$ 2,558	$ -	$ 446	$ 3,324	$ 9,118
4	90% Rate Payer Portion	$ 5,214	$ -	$ 288	$ 2,302	$ -	$ 402	$ 2,992	$ 8,206
5	10% Union Incentive Payment	$ 579	$ -	$ 32	$ 256	$ -	$ 45	$ 332	$ 912

Notes:

(1) Represents northern component of contract for Dawn-Parkway transportation on TCPL. The southern component of this same contract has been included in column (a) Union South.

Energy Probe 3
Attachment

UNION GAS LIMITED
Allocation of 2013 Net Exchange Revenue In-franchise Rate Classes

Line No.	Rate Class	Union North Allocation Units (10^3m^3/day) (1)	Union North Margin ($000's)	Union South Allocation Units (10^3m^3/day) (2)	Union South Margin ($000's)	Total Margin ($000's)
		(a)	(b)	(c)	(d)	(e) = (b + d)
1	Rate 01	6,498	(2,238)			(2,238)
2	Rate 10	1,701	(586)			(586)
3	Rate 20	455	(157)			(157)
4	Rate 100	32	(11)			(11)
5	Rate 25	-	-			-
6	Total Union North	8,685	(2,992)			(2,992)
7	Rate M1			28,724	(2,211)	(2,211)
8	Rate M2			9,650	(743)	(743)
9	Rate M4			3,113	(240)	(240)
10	Rate M5			51	(4)	(4)
11	Rate M7			1,128	(87)	(87)
12	Rate M9			362	(28)	(28)
13	Rate M10			11	(1)	(1)
14	Rate T1			2,654	(204)	(204)
15	Rate T2			19,541	(1,504)	(1,504)
16	Rate T3			2,511	(193)	(193)
17	Total Union South			67,745	(5,214)	(5,214)
18	Total Net Exchange Revenue					(8,206)

Notes:
(1) EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, page 21, XSPK&AVG allocation factor, updated for EB-2011-0210 Board Decision.
(2) EB-2011-0210, Exhibit G3, Tab 5, Schedule 21, pages 10-11, OTHERTRANS allocation factor, updated for EB-2011-0210 Board Decision.

UFG

	Board Approved	Actuals						Budget
	2007	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Volume (PJs)	5.6	7.7	5.4	7.6	2.5	1.3	2.6	2.6
Expense ($ millions)	52.4	70.4	56.2	56.0	13.7	8.0	12.9	14.7
Avg Price ($ / GJ)	$9.44	$9.20	$10.39	$7.35	$5.39	$5.97	$4.97	$5.57
% of throughput	0.455%	0.609%	0.411%	0.637%	0.192%	0.105%	0.210%	0.219%

Variance from Board Approved						
Volume Variance (Volume Variance * BA price)	-19.8	1.3	-19.5	28.5	39.7	27.9
Price Variance (Price Variance * Actual Volume)	1.8	-5.1	15.9	10.3	4.7	11.6
Total Variance	-18.0	-3.8	-3.6	38.7	44.4	39.5

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Reference: Union Ex. B, Tab 1, page 12 of 48

Issue 14.1 - Are there adjustments that should be made to base year revenue requirements?

Question:

Union states in evidence that it is requesting the elimination of the following three deferral accounts (179-69 -Transportation Exchange Services Account, 179-73 -Other S&T Services Account and 179-74 -Other Direct Purchase Services Account) beginning January 1, 2008.

a) *Please provide historical year end balances for each year from 2003 to 2006 and estimate for 2007 for each of the three accounts that Union has requested to eliminate. Please use the following headings for the table:*

Year	*Account No.*	*Balance for disposition credit/(debit)*
2003		
2004		
2005		
2006		
2007 (est)		

b) *In Union's view, should the Transportation and Storage Revenue in 2007 base rates be also adjusted if the three deferral accounts are eliminated?*

Response:

a) The attached schedule includes the balances in the three transportation related deferral accounts from 1999 to 2007. The balance for disposition (ratepayer portion) appears in column c.

b) As part of eliminating the Transportation Exchange Services Account (179-69), Other S&T Services Deferral Account (179-73) and Other Direct Purchase Services

Deferral Account (174-74) beginning January 1, 2008, Union will adjust the base rates applicable to infranchise customers to include 100% of the 2007 forecast approved by the Board in the EB-2005-0520 proceeding.

This treatment is consistent with how the forecast of any other source of revenues is treated. Please see Union's evidence on this issue in the EB-2005-0520 rates proceeding (attached).

Union Gas Limited
Summary of Deferral Accounts
For the Years Ending December 31
($000's)

Line No.	Year	Deferral Account Number	75% Ratepayers [1.]	25% Shareholder	Total Margin Subject to Sharing [2.]
	(a)	(b)	(c)	(d)	(e) = (c) + (d)
1	1999	179-69	1,509	503	2,012
2	2000	179-69	1,709	570	2,278
3	2001	179-69	823	274	1,097
4	2002	179-69	3,713	1,238	4,951
5	2003	179-69	309	103	412
6	2004	179-69	7,449	2,483	9,933
7	2005	179-69	3,404	1,135	4,539
8	2006	179-69	4,004	1,335	5,339
9	2007 (Est)	179-69	3,323	1,108	4,430
10	1999	179-73	(495)	(165)	(660)
11	2000	179-73	(109)	(36)	(146)
12	2001	179-73	(423)	(141)	(564)
13	2002	179-73	197	66	262
14	2003	179-73	(3,707)	(1,236)	(4,942)
15	2004	179-73	405	135	539
16	2005	179-73	427	142	569
17	2006	179-73	390	130	520
18	2007 (Est)	179-73	65	22	87
19	1999	179-74	1,187	396	1,583
20	2000	179-74	744	248	992
21	2001	179-74	817	272	1,089
22	2002	179-74	375	125	500
23	2003	179-74	434	145	579
24	2004	179-74	869	290	1,159
25	2005	179-74	749	250	999
26	2006	179-74	373	124	497
27	2007 (Est)	179-74	(750)	(250)	(1,000)

Notes:
1. Positive number represents a payable to customers.
2. Actual margin less the current Board approved level.

Question: August 20, 2007
Answer: September 4, 2007
Docket: EB-2007-0606 / EB-2007-0615

uniongas
A Spectra Energy Company

Union Gas Limited
Earnings Before Interest and Taxes

CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Operating Revenue				
Distribution Margin	$ 711.7	$ 751.0	$ 757.0	$ 766.3
S&T	268.6	252.0	238.7	235.5
Other Revenue	28.7	24.5	24.7	24.9
Earnings Sharing	15.0	-	-	-
Stretch	-	12.2	56.0	88.4
Total Operating Revenue	**1,024.0**	**1,039.7**	**1,076.4**	**1,115.1**
Operating Expenses				
Operating & Maintenance Expense	380.1	397.0	413.0	426.4
Depreciation and Amortization	211.8	204.9	213.6	226.9
Taxes Other than Income Taxes	62.8	64.3	65.9	68.0
Total Operating Expenses	**654.7**	**666.2**	**692.5**	**721.3**
HTLP Income / (Loss)	(1.0)	(1.3)	(1.3)	(1.3)
Other Income / (Loss)	(1.6)	-	-	-
Earnings Before Interest, Taxes (CDN Reporting)	**$ 366.7**	**$ 372.2**	**$ 382.6**	**$ 392.5**
US Reporting Adjustment	5.4	2.5	2.5	2.5
Union Gas EBIT (US Reporting)	**$ 372.1**	**$ 374.7**	**$ 385.1**	**$ 395.0**
Market Hub (including Sarnia Airport Pool)	1.1	0.1	(0.2)	(0.2)
St Clair Pipelines LP	0.2	0.2	0.1	0.2
Gas Distribution EBIT (US Reporting)	**$ 373.4**	**$ 375.0**	**$ 385.0**	**$ 395.0**

Incentive Measure (US Reporting)	**2012 EBIT**	**2013 EBIT**
Minimum	$ 390	$ 362
Target	$ 402	$ 375
Maximum	$ 426	$ 401

Union Gas Limited
Gas Distribution Margin

CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Delivery Revenue *				
General Service	$ 565.6	$ 620.3	$ 625.1	$ 630.3
Contract (excluding CSF)	112.5	118.6	121.8	124.6
Customer Supplied Fuel	7.3	3.1	3.3	3.4
Stretch - Contract	-	-	-	-
Rate Variance (1)	-	3.1	1.7	1.7
LRAM Recovery	2.6	1.1	1.1	1.2
	688.0	746.2	753.0	761.2
Cost of Gas - "below the line items"				
UFG	12.9	14.7	14.1	14.1
Compressor fuel	22.9	34.2	32.7	32.7
Customer Supplied Fuel	(34.4)	(30.0)	(26.8)	(26.8)
Winter peaking costs	-	-	-	-
Other	1.0	1.0	1.0	1.0
	2.4	19.9	21.0	21.0
Gas supply revenue less COG ("above the line")	26.1	24.7	25.0	26.1
Gas Distribution Margin	**$ 711.7**	**$ 751.0**	**$ 757.0**	**$ 766.3**
Heating Degree Days	3,547	3,981	3,981	3,981
(1) Rate Change Detail:				
Estimate vs. Approved rates	-	3.1	1.7	1.7
	$ -	$ 3.1	$ 1.7	$ 1.7

* Budget and forecast reflect approved 2013 rates (EB-2011-0210).

Union Gas Limited
S&T Revenue
CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Transportation (Regulated)				
Long Term Transportation				
M12 Long Term Transportation	$ 133.7	$ 120.7	$ 115.1	$ 116.4
M12X Long Term Transportation	5.9	13.5	13.5	13.5
Other Long Term Transportation	8.0	6.4	6.1	6.1
Total Long Term Transportation	**147.6**	**140.5**	**134.6**	**135.9**
Short Term Transportation				
C1 Short Term Firm Transportation	7.7	9.4	9.2	9.4
C1 Short Term Interruptible Transportation	2.4	1.1	1.1	1.1
Exchanges/Third Party Revenue	52.2	14.9	14.9	14.9
Deferral - Exchanges & Optimization	(53.6)	(13.4)	(13.4)	(13.4)
Total Short Term Transportation	**8.7**	**12.0**	**11.8**	**12.1**
Other S&T Services	**1.0**	**1.1**	**1.1**	**1.1**
Total Transportation (Regulated)	**157.3**	**153.6**	**147.5**	**149.0**
Storage (Unregulated)				
Long Term Storage				
Long Term Storage	83.1	69.4	63.4	59.5
High Deliverability Storage	13.4	13.6	12.0	11.3
Other Long Term Storage	3.9	3.7	4.0	4.0
Total Long Term Storage	**100.4**	**86.6**	**79.4**	**74.7**
Short Term Storage & Balancing				
Peak Short Term Storage	10.6	10.3	10.9	10.9
Off Peak Short Term Storage	1.4	0.5	0.5	0.5
Balancing	1.7	2.0	2.0	2.0
Loans	-	-	-	-
Total Short Term Storage & Balancing	**13.7**	**12.8**	**13.4**	**13.4**
Total Storage (Unregulated)	**114.1**	**99.4**	**92.8**	**88.1**
Deferral Accounts				
Deferral - Long Term Storage	-	-	-	-
Deferral - Short Term Storage & Balancing	(2.8)	(1.1)	(1.6)	(1.6)
Total Deferral Accounts	**(2.8)**	**(1.1)**	**(1.6)**	**(1.6)**
Total Unregulated Storage Net of Deferrals	**111.3**	**98.4**	**91.2**	**86.5**
Total Net S&T	**$ 268.6**	**$ 252.0**	**$ 238.7**	**$ 235.5**

Union Gas Limited
Other Revenue

CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Delayed payment charges	$ 6.1	$ 6.5	$ 6.8	$ 6.8
Connection charges	6.2	7.0	7.0	7.0
Billing revenue / ABC revenue	4.7	3.5	3.5	3.5
Mid market revenue	1.4	2.0	2.0	2.0
Shared savings mechanism	8.8	4.3	4.4	4.6
Market transformation	-	-	-	-
Conservation and demand management	-	-	-	-
Service revenue	0.7	0.7	0.7	0.7
Miscellaneous	0.8	0.5	0.3	0.3
Total other revenue	**$ 28.7**	**$ 24.5**	**$ 24.7**	**$ 24.9**

Union Gas Limited
O&M Expense By Cost Type

CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Direct				
Salaries/Wages	$ 183.4	$ 195.1	$ 199.8	$ 207.0
Employee Benefits (non-pension)	33.9	33.8	35.8	37.0
Employee Expenses & Training	12.0	14.5	14.8	14.8
Contract Services	65.0	64.1	70.1	74.3
Consulting	7.8	9.7	9.0	9.0
Materials	8.2	10.0	10.5	10.9
General & Other	25.0	21.0	23.7	24.0
Transportation	7.0	9.5	7.8	7.8
Fuel	2.0	2.4	2.5	2.5
Utility Costs	4.1	4.6	4.8	4.8
Computers	5.3	5.7	6.9	7.3
Communications	5.8	6.2	6.5	6.5
Advertising	2.3	2.5	2.4	2.4
Lease	4.5	4.0	5.8	6.1
Insurance	8.1	8.3	9.3	9.5
Financial	1.4	1.8	1.9	1.9
OEB Cost Assessment / Intervenor Costs	4.5	4.3	3.4	3.4
Recovery Cost	(8.0)	(2.7)	(2.6)	(2.6)
Total Direct	**372.3**	**394.8**	**412.4**	**426.6**
Indirect				
Pension Benefits	50.0	47.4	47.4	47.4
Bad Debt	5.0	5.1	5.1	5.1
DSM Program Costs	24.0	24.0	25.0	25.5
Total Indirect	**79.0**	**76.5**	**77.5**	**78.0**
Allocations				
Affiliate Expenses	10.0	11.1	11.3	11.6
Affiliate Revenue	(13.8)	(13.2)	(14.0)	(14.4)
Total Allocations	**(3.8)**	**(2.1)**	**(2.7)**	**(2.9)**
Total Gross O&M	**447.5**	**469.2**	**487.2**	**501.7**
Loadings	(15.0)	(21.8)	(19.9)	(19.9)
Capitalization	(52.4)	(50.5)	(54.2)	(55.4)
Total Net O&M	**$ 380.1**	**$ 397.0**	**$ 413.0**	**$ 426.4**

Union Gas Limited
O&M By Responsibility Area

CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Executive				
Salaries & Wages	$ 2.2	$ 2.2	$ 2.4	$ 2.5
Employee Expenses & Training	0.1	0.2	0.2	0.2
Other	0.8	0.7	0.8	0.8
Executive Gross	**3.1**	**3.1**	**3.4**	**3.5**
Indirect Capitalization	(0.4)	(0.3)	(0.4)	(0.4)
Executive Net	**2.7**	**2.8**	**3.0**	**3.1**
Engineering, Construction & Storage Transmission				
ECS Direct				
Salaries & Wages	26.3	27.5	26.3	27.2
Employee Expenses & Training	2.3	2.3	2.5	2.5
Contract Services	8.6	10.9	13.2	13.5
Materials & General	4.1	4.3	4.5	4.6
Own Use Gas & Utilities	2.0	2.2	2.3	2.3
Other	0.9	2.9	2.4	2.5
ECS Direct Gross	**44.1**	**50.1**	**51.2**	**52.6**
Indirect Capitalization	(8.7)	(9.0)	(7.2)	(7.4)
ECS Direct Net	**35.5**	**41.1**	**44.0**	**45.3**
ECS Indirect				
Environment, Health & Governance	0.7	0.9	1.0	1.0
Global & Fleet Services	0.6	0.7	0.9	0.9
Procurement	1.2	1.3	1.2	1.2
Project Systems & Control	0.1	0.1	0.2	0.2
ECS Indirect Gross	**2.6**	**3.0**	**3.3**	**3.3**
Indirect Capitalization	(0.8)	(0.6)	(1.1)	(1.1)
ECS Indirect Net	**1.8**	**2.4**	**2.2**	**2.2**
Engineering, Construction & Storage Transmission Net	**37.3**	**43.5**	**46.2**	**47.5**
Distribution Operations				
Salaries & Wages	64.9	66.5	68.6	71.0
Employee Expenses & Training	5.2	5.7	5.4	5.4
Contract Services	21.4	19.7	23.2	25.4
Materials & General	6.2	7.1	7.5	7.6
Transportation	7.0	7.2	7.8	7.8
Own Use Gas & Utilities	2.1	2.5	2.6	2.6
Other	(1.8)	(0.4)	(0.5)	(0.5)
Distribution Operations Gross	**105.0**	**108.2**	**114.5**	**119.3**
Direct Capitalization	(7.4)	(9.9)	(10.1)	(10.1)
Indirect Capitalization	(18.1)	(16.2)	(18.2)	(18.6)
Total Capitalization	(25.4)	(26.0)	(28.3)	(28.7)
Distribution Operations Net	**79.5**	**82.2**	**86.2**	**90.6**

Union Gas Limited
O&M By Responsibility Area

CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Business Development, Storage & Transmission				
BDS&T Direct				
Salaries & Wages	11.9	12.8	13.1	13.5
Employee Expenses & Training	0.5	0.8	0.9	0.9
Consulting	1.1	0.5	0.2	0.2
Other	2.4	3.0	3.3	3.3
BDS&T Direct Gross	**15.9**	**17.2**	**17.5**	**17.9**
Indirect Capitalization	(0.4)	(0.3)	(0.5)	(0.5)
BDS&T Direct Net	**15.5**	**16.9**	**17.0**	**17.4**
Infranchise Sales and Marketing, and Customer Care				
Sales, Marketing & Customer Care				
Salaries & Wages	21.6	21.6	23.3	24.2
Employee Expenses & Training	1.0	1.2	1.3	1.3
Contract Services	20.5	20.6	21.1	22.4
Materials & General	9.4	9.6	10.3	10.5
Other	2.7	3.4	3.7	3.8
Sales & Marketing Net	**55.2**	**56.4**	**59.7**	**62.2**
Energy Conservation				
Salaries & Wages	6.0	6.4	6.6	7.1
Employee Expenses & Training	0.7	0.9	0.9	0.9
DSM Program Costs	24.0	24.0	25.0	25.5
Other	0.2	0.3	0.3	0.3
Energy Conservation Net	**31.0**	**31.6**	**32.8**	**33.8**
Infranchise Sales, Marketing & Customer Care Net	**86.1**	**88.0**	**92.5**	**95.9**
Government, Aboriginal and Public Affairs				
Salaries & Wages	2.2	2.3	2.2	2.3
Employee Expenses & Training	0.3	0.5	0.5	0.5
Contract Services	0.3	0.2	0.2	0.2
Materials & General	1.1	1.1	0.5	0.5
Other	0.9	0.9	0.5	0.6
Government, Aboriginal and Public Affairs Net	**4.8**	**5.0**	**4.0**	**4.1**
Regulatory Affairs and Lands				
Salaries & Wages	3.3	3.3	3.0	3.1
Employee Expenses & Training	0.3	0.3	0.3	0.3
OEB Cost Assessment	4.5	4.3	3.4	3.4
Lease	4.0	3.8	4.7	4.7
Other	1.2	1.8	1.9	2.0
Regulatory Affairs and Lands Gross	**13.3**	**13.5**	**13.4**	**13.5**
Indirect Capitalization	(0.6)	(0.8)	(0.4)	(0.4)
Regulatory Affairs and Lands Net	**12.7**	**12.7**	**12.9**	**13.1**

Union Gas Limited
O&M By Responsibility Area

CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Finance				
Finance Direct				
Salaries & Wages	8.9	8.6	8.8	9.1
Employee Expenses & Training	0.3	0.4	0.4	0.4
Financial	1.7	1.7	1.7	1.7
Bad Debt	5.0	5.1	5.1	5.1
Other	0.2	0.2	0.4	0.4
Finance Direct Gross	**16.2**	**16.0**	**16.4**	**16.7**
Indirect Capitalization	(0.8)	(1.3)	(0.5)	(0.5)
Finance Direct Net	**15.4**	**14.6**	**16.0**	**16.3**
Finance Indirect				
Information Technology				
Information Systems (IS)				
Salaries & Wages	7.7	7.6	8.3	8.6
Employee Expenses & Training	0.2	0.3	0.3	0.3
Computers	2.5	2.8	3.2	3.6
Other	1.4	1.6	1.6	1.6
IS Gross	**11.8**	**12.3**	**13.4**	**14.1**
Indirect Capitalization	(1.8)	(1.5)	(2.0)	(2.1)
IS Net	**10.0**	**10.8**	**11.4**	**12.0**
Information Technology Infrastructure (ITI)				
Salaries & Wages	2.0	2.3	2.3	2.3
Employee Expenses & Training	0.1	0.1	0.2	0.2
Communication	4.0	4.2	4.3	4.3
Other	4.9	5.6	5.7	5.8
ITI Gross	**11.0**	**12.2**	**12.5**	**12.7**
Capitalization	(1.7)	(1.2)	(1.9)	(1.9)
ITI Net	**9.4**	**11.0**	**10.6**	**10.8**
SCADA Tech Support				
SCADA Gross	**0.8**	**0.9**	**1.0**	**1.0**
Indirect Capitalization	-	-	-	-
SCADA Net	**0.8**	**0.8**	**0.9**	**0.9**
IT Security				
IT Security Gross	**1.1**	**1.3**	**1.5**	**1.5**
Indirect Capitalization	(0.1)	(0.1)	(0.2)	(0.2)
IT Security Net	**1.0**	**1.2**	**1.2**	**1.3**
BIS/SAP Gross				
BIS/SAP Gross	1.4	1.7	1.5	1.6
Indirect Capitalization	-	(0.1)	-	-
BIS/SAP Net	1.4	1.6	1.5	1.6
Technology Enterprise (ITE) Net	0.3	-	0.4	0.4
Information Technology Net	**22.8**	**25.5**	**26.1**	**26.9**
Insurance				
Insurance	8.1	8.3	9.3	9.3
Other	0.3	0.4	0.4	0.7
Insurance Net	**8.4**	**8.7**	**9.7**	**9.9**
Tax	1.1	1.2	1.2	1.3
Audit Services	0.3	0.5	0.5	0.5
Finance Indirect Net	**32.7**	**35.8**	**37.5**	**38.7**
Finance Net	**48.1**	**50.5**	**53.5**	**54.9**

Union Gas Limited
O&M By Responsibility Area
CDN$Millions

Particulars	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Employee & Labour Relations				
Salaries & Wages	17.1	23.9	24.4	25.2
Employee Expenses & Training	0.6	1.0	1.0	1.0
Pension Benefits	47.4	47.4	47.4	47.4
Employee Benefits (non-pension)	33.7	33.5	35.5	36.7
Contract Services	2.4	1.5	1.5	1.5
Other	(0.4)	1.0	1.2	1.2
Employee & Labour Relations Gross	**100.7**	**108.3**	**111.0**	**113.0**
Direct Capitalization	(4.6)	(7.4)	(7.5)	(7.5)
Indirect Capitalization	(14.9)	(20.0)	(16.6)	(16.9)
Total Capitalization	**(19.5)**	**(27.4)**	**(24.1)**	**(24.4)**
Employee & Labour Relations Net	**81.2**	**80.8**	**86.9**	**88.7**
Corporate Services				
Salaries & Wages	1.8	1.9	2.0	2.0
Employee Expenses & Training	0.1	0.2	0.1	0.1
Contract Services	5.6	5.0	5.4	5.5
Other	9.7	11.5	11.2	11.4
Corporate Services Gross	**17.3**	**18.6**	**18.7**	**19.1**
Indirect Capitalization	(2.5)	(2.8)	(3.0)	(3.0)
Corporate Services Net	**14.8**	**15.8**	**15.7**	**16.1**
Affiliates				
Affiliate Expenses	10.0	11.1	11.3	11.6
Affiliate Revenues	(13.8)	(13.2)	(14.0)	(14.4)
Affiliates Gross	**(3.8)**	**(2.1)**	**(2.7)**	**(2.9)**
Indirect Capitalization	(1.6)	(1.5)	(1.7)	(1.7)
Affiliates Net	**(5.4)**	**(3.6)**	**(4.4)**	**(4.6)**
Other				
Legal	1.1	1.3	1.4	1.5
Government Relations	0.5	0.5	0.6	0.6
Corporate Adjustments	4.5	(0.3)	0.5	0.5
Other Gross	**6.1**	**1.5**	**2.5**	**2.5**
Direct Capitalization	(3.0)	(4.5)	(2.4)	(2.4)
Indirect Capitalization	(0.2)	5.2	(0.5)	(0.5)
Total Capitalization	**(3.2)**	**0.7**	**(2.9)**	**(2.9)**
Other Net	**2.9**	**2.3**	**(0.4)**	**(0.4)**
Total Gross O&M	**447.5**	**469.1**	**487.2**	**501.7**
Direct Capitalization	(15.0)	(21.8)	(19.9)	(19.9)
Indirect Capitalization	(52.4)	(50.5)	(54.2)	(55.4)
Total Capitalization	(67.4)	(72.2)	(74.2)	(75.3)
Total Net O&M	**$ 380.1**	**$ 397.0**	**$ 413.0**	**$ 426.4**

Union Gas Limited
Capital Expenditures

CDN$Millions

Particulars	In Service Date	2012 Actual	2013 Budget	2014 Forecast	2015 Forecast
Expansion					
Dawn to Dawn TCPL Export	Dec-10	0.5	-	-	-
Marcellus-Kirkwall	Nov-12	4.1	0.1	-	-
Jacob Storage Development	TBD	0.1	-	-	8.3
Storage Enhancements Phase I (PMOP)	Sep-13	0.1	11.4	-	-
Eastern Power Lambton	Nov-14		0.9	9.7	0.1
Burlington-Oakville Pipeline	Nov-14	-	3.8	31.3	2.0
Storage Enhancements Phase II (PMOP	Jul-15	-	-	0.2	4.1
TFEP Brantford to Kirkwall	Nov-15	0.1	0.6	2.5	75.8
Parkway West - Land	Nov-15	3.1	30.9	-	-
Parkway West	Nov-15	-	-	52.9	131.8
Parkway Compression D	Nov-15	-	2.8	33.0	38.5
Parkway GTA Measurement Upgrade	Nov-15	-	0.1	0.4	16.0
Dow-Moore Storage Enhancements	Aug-16	-	-	-	1.0
Nanticoke Power Plant	TBD	0.3	-	-	-
Project Pre-spend	N/A		2.0	2.0	2.0
Overheads		0.1	1.0	0.5	1.0
Total Expansion		**8.4**	**53.6**	**132.5**	**280.6**
Maintenance					
Distribution New Business		65.4	68.5	66.5	61.6
Distribution Other		75.1	96.4	71.1	69.1
Total Distribution		140.5	164.9	137.6	130.7
Transmission		19.5	36.9	33.7	38.5
Storage		14.4	14.0	11.2	12.1
General		12.7	12.4	18.8	23.7
Overheads		51.5	53.8	57.7	58.4
Total Maintenance		**238.6**	**282.0**	**259.0**	**263.4**
IT		23.3	28.3	32.5	32.5
Total Maintenance, IT and OH		**261.9**	**310.3**	**291.5**	**295.9**
Total Union Gas Capex		**$ 270.3**	**$ 363.9**	**$ 424.0**	**$ 576.5**
Huron Tipperary LP - Expansion	Jun-08	-	-	-	-
Huron Tipperary LP - Maintenance		0.6	0.2	-	-
Total Consolidated Union Gas Capex		**$ 270.9**	**$ 364.1**	**$ 424.0**	**$ 576.5**
MHP - St. Clair Pool (Maintenance)	N/A	-	0.4	-	-
Bluewater Crossing	Jul-12	2.6	0.1	-	-
Bluewater Crossing Station	Jul-12	1.7	-	-	-
SD1 Storage Development (Grayling)	Jul-14	-	-	2.1	2.1
SD2 Storage Development (Nottingham)	Jul-15	-	-	-	-
Diamond Storage Development	Jul-16	-	-	-	-
SD3 Storage Development (Generic)	Jul-16	-	-	-	-
Total Gas Distribution Capex		**$ 275.2**	**$ 364.6**	**$ 426.1**	**$ 578.6**

1. **Please confirm that the debt savings of the expiring debt, assuming all expiring debt is renewed an interest rate of 4%, is $75 million.**

   Based on the assumptions above, the total cumulative utility savings over the 2014-2018 IR term would be $79.4 million.

2. **For deferral account 179-69, what amount is included in rates from 1999 – 2007?**

Line No.	Year	Deferral Account #179-69 Reference Amount Included In Approved Rates ($000's)
1	1999	906
2	2000	906
3	2001	906
4	2002	906
5	2003	906
6	2004	619
7	2005	619
8	2006	619
9	2007	2325

3. **What were the revenues over the 2008-2012 IR term associated with the services in the former 179-69 deferral account?**

   Please see the response to J.6.2 from EB-2011-0210 for the years 2010 to 2013 (attached).

4. **For Attachment CME 2, please provide the actual volumes for January to March.**

   The volumes provided in Attachment CME 2 for January to March are actual.

5. **Please provide the actual heating degree days for January – March.**

Actual HDD Year 2013

	January	February	March
Union South	645.0	632.8	572.1
Union North	840.7	768.4	674.9

6. **What are the well identification numbers on Attachment CME 3? Are these wells included in the asset allocation allocators?**

   The unregulated wells on the bottom of the Attachment CME 3 "Regulated vs. Unregulated Storage Assets Allocation" are the well numbers that are classified as 100% unregulated. These are new storage wells that have been added since the NGEIR Decision. The new wells increase capacity/deliverability and therefore are classified as 100% unregulated. These wells are reflected in the allocation factor percentages in the table and result in an increase to the unregulated percentages under the storage wells asset class.

7. **On Attachment CME 5, under what heading would the Leamington Expansion project be included?**

   The Leamington Reinforcement Project is part of the Transmission category under maintenance capital.

8. **What is the path of the proposed Burlington – Oakville transmission line?**

   The path has not been finalized at this time. Union anticipates that the Burlington – Oakville transmission line will run between the Dawn – Trafalgar transmission system and the Burlington-Oakville pipeline. The distance is 12 to 14 km.

9. **Please provide Union's YTD exchange revenue.**

   Transportation Exchange Revenue (Jan – Mar 2013)

   $ 4 million is FT-RAM Exchanges
   <u>$ 8 million is Base Exchanges</u>
   $12 million total

10. **Can Union split exchange revenues based on the assets (upstream vs. Union owned) underpinning the exchange? Is it predicable/ stable?**

    Union does not have an historical split of net transportation exchange revenue attributable to upstream transportation capacity vs. Union transmission capacity. In Union's 2012 Deferral Account and Earnings Sharing proceeding (EB-2013-0109), Union estimated the Dawn to Parkway transportation component of the net transportation exchange revenue to be $1.0 million of the $51.6 million total net revenue. Union does not have a split for 2013 and beyond. Not enough data is available to determine whether this split would be predictable/stable.

11. What is the deferred tax base rate adjustment?

A deferred tax base rate adjustment is required so that Union does not over-refund to ratepayers the remaining balance of deferred taxes during the 2014-2018 IR term. The credit in 2013 rates is $15.2 million, and the remaining balance to be credited to customers is $64.1 million. Two options are:

1. Adjust rates annually for the change in the deferred tax credit. The annual changes would be:
    a. 2014: $1.704 million increase ($2.287 million pre-tax)
    b. 2015: $0.090 million decrease ($0.121 million pre-tax)
    c. 2016: $0.454 million increase ($0.609 million pre-tax)
    d. 2017: $0.040 million decrease ($0.054 million pre-tax)
    e. 2018: $2.3 million increase ($3.1 million pre-tax)
2. Similar to the 2008-2012 IR term, levelize the amount for each year of the IR term. The levelized amount would be $12.8 million, requiring a base rate adjustment of $2.4 million ($3.2 million pre-tax).

12. Please provide the rate impacts of Union's IRM proposal without the weather normalization adjustment.

Union's 2014 – 2018 incentive regulation assumptions and the rate impacts sent to intervenors on May 9, 2013 contained a mathematical error for North R01 and R10 Transportation and Storage only. Please see the attachment "2014-2018 – Rate assumptions & impacts – corrected.pdf".

For the rate impacts without the weather normalization adjustment, please see the attachment "2014-2018 IR schedules excluding weather.pdf".

UNION GAS LIMITED

Undertaking of Ms. Elliott
To Mr. Aiken

Please add to Attachment 1 the same type of information that would have been in accounts 179-73 and 179-74 for the 2010 through 2013 period.

Please see the Attachment.

Union Gas Limited
Summary of Transmission-Related Transactional Services
For the Years Ending December 31
($000's)

Line No.	Particulars		Actual 2010 (a)	Actual 2011 (b)	Forecast 2012 (c)	Forecast 2013 (d)
	Transportation and Exchange Services Previously Account #179-69					
1	Net Revenue	(1)	33,100	44,245	32,186	20,186
2	Less: Costs		12,557	9,965	9,040	6,448
3	Gross Margin		20,543	34,280	23,146	13,738
4	Less: Board Approved Margin in Rates		6,883	6,883	6,883	13,738
5	Hypothetical Deferred Margin	(2)	13,660	27,397	16,263	-
	Other S&T Services Previously Account #179-73					
6	Revenue		1,072	1,092	1,067	1,067
7	Less: Costs		75	76	75	75
8	Gross Margin		997	1,016	992	992
9	Less: Board Approved Margin in Rates		853	853	853	992
10	Hypothetical Deferred Margin	(2)	144	163	139	-
	Other Direct Purchase Services Deferral Account Previously Account #179-74					
11	Revenue		1,928	1,063	2,000	2,000
12	Less: Costs		1,311	782	1,360	1,360
13	Gross Margin	(3)	617	281	640	640
14	Less: Board Approved Margin in Rates		2,000	2,000	2,000	640
15	Hypothetical Deferred Margin	(2)	(1,383)	(1,719)	(1,360)	-

Notes:
(1) Revenue less direct costs to provide exchange services.
(2) Margin would have been subject to earnings sharing.
(3) Reduction in Other Direct Purchase Services due to return to system.

Corrected

LIST OF ASSUMPTIONS
For 2014-2018 Incentive Regulation (IR) Forecast
Calculation of Estimated Rate and Bill Impacts

- 5 year Incentive Regulation term (2014-2018) with rebasing in 2019
- Inflation factor ('I' factor) of 1.6%
- No Productivity factor ('X' factor)

Y-Factors

- Escalate DSM ('Y' factor) each year by the same inflation factor of 1.6%
- Inclusion of Capital pass-throughs each year related to Brantford to Kirkwall and Parkway D Compressor, Parkway West and Burlington to Oakville Projects
  - i.e. not subject to PCI escalation
- Burlington to Oakville treated as an Other Transmission asset for cost allocation purposes

Billing Unit Adjustments

- No LRAM or Average Use volume-related adjustments
- Weather-related volume adjustment for 20-year declining trend weather methodology
  - 20% volume phase-in for each year of the IR term
- M12 Demands for Dawn to Parkway – increase of 363,000 GJ/day for Brantford to Kirkwall and Parkway D Compressor Project
  - 2 months of demand included in 2015, full amount in each year thereafter
- No other billing unit or demand adjustments (including Dawn to Kirkwall turnback)

Others

- Gas Supply Optimization margin of $13.426 million related to FT-RAM ($5.220 million) and Base Exchanges ($8.206 million) removed from gas supply transportation rates.
- Base Exchange margin of $8.206 million included in delivery rates beginning in 2014.
  - Of the $8.206 million, $2.992 million is allocated to Union North and $5.214 million is allocated to Union South
  - Exchange margin subject to PCI consistent with other S&T transactional margin
- No change for ROE, UFG or S&T transactional margin
- No Z-factors
- No changes for taxes
- Based on 2013 Board-approved Gas Supply Plan
  - No cost of gas adjustments related to Intra-period WACOG or Upstream Transportation costs (e.g. TCPL toll changes)
  - Does not include changes associated with the Long-term contracting proposal filed in the Brantford to Kirkwall and Parkway D Compressor Project application
- No 2014 General Service rate design proposals included
- General Service customer charges – maintain 2013 approved levels ($21.00/month for Rate 01 & Rate M1 and $70.00/month for Rate 10 & Rate M2)
  - Revenue neutral adjustment to delivery commodity rates

Note:

- April 2013 QRAM (EB-2013-0033) used as the base for current approved revenue

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast

Line No.	Particulars	Current Approved Revenue ($000's) (a)	2014 Proposed Revenue ($000's) (b)	Δ in Revenue ($000's) (c) = (b - a)	2015 Proposed Revenue ($000's) (d)	Δ in Revenue ($000's) (e) = (d - b)	2016 Proposed Revenue ($000's) (f)	Δ in Revenue ($000's) (g) = (f - d)	2017 Proposed Revenue ($000's) (h)	Δ in Revenue ($000's) (i) = (h - f)	2018 Proposed Revenue ($000's) (j)	Δ in Revenue ($000's) (k) = (j - h)	Total Δ in Revenue ($000's) (l) = (j - a)	Total Δ in Revenue (%) (m) = (l / a)	Average Δ per Year (%) (n) = (m / 5)
	North Delivery														
1	Rate 01	161,158	161,198	41	162,204	1,005	164,379	2,176	167,322	2,943	170,271	2,949	9,113	5.7%	1.1%
2	Rate 10	19,951	19,637	(314)	19,747	110	20,025	279	20,383	358	20,742	359	791	4.0%	0.8%
3	Rate 20	13,487	13,518	31	13,567	48	13,755	188	14,011	256	14,267	256	780	5.8%	1.2%
4	Rate 25	4,473	4,537	65	4,559	22	4,622	63	4,707	85	4,793	85	320	7.2%	1.4%
5	Rate 100	15,481	15,699	217	15,808	110	16,037	229	16,325	288	16,614	288	1,132	7.3%	1.5%
6	Total North Delivery	214,550	214,589	40	215,884	1,295	218,818	2,934	222,749	3,931	226,687	3,937	12,137	5.7%	1.1%
	South Delivery & Storage														
7	Rate M1	388,998	392,483	3,486	395,324	2,840	403,602	8,278	410,809	7,208	418,020	7,210	29,022	7.5%	1.5%
8	Rate M2	50,183	50,174	(9)	50,572	398	52,299	1,727	53,229	930	54,155	926	3,972	7.9%	1.6%
9	Rate M4	12,282	12,223	(60)	12,324	101	12,801	477	13,028	226	13,252	225	970	7.9%	1.6%
10	Rate M5A	13,265	13,457	191	13,549	92	13,741	192	13,988	247	14,236	248	970	7.3%	1.5%
11	Rate M7	4,120	4,094	(26)	4,128	34	4,312	183	4,388	76	4,463	75	343	8.3%	1.7%
12	Rate M9	724	707	(17)	715	8	768	53	781	13	793	13	70	9.6%	1.9%
13	Rate M10	10	9	(1)	9	(0)	10	1	10	0	10	0	1	6.9%	1.4%
14	Rate T1	10,637	10,591	(46)	10,693	102	11,054	361	11,242	188	11,428	186	791	7.4%	1.5%
15	Rate T2	42,154	41,269	(885)	41,768	498	43,862	2,094	44,591	729	45,306	715	3,152	7.5%	1.5%
16	Rate T3	4,400	4,273	(126)	4,325	51	4,684	360	4,762	78	4,839	76	439	10.0%	2.0%
17	Total South Delivery & Storage	526,773	529,280	2,507	533,406	4,126	547,133	13,726	556,828	9,696	566,503	9,674	39,729	7.5%	1.5%
18	Total In-Franchise Delivery	741,323	743,870	2,547	749,291	5,421	765,951	16,660	779,578	13,627	793,189	13,612	51,866	7.0%	1.4%

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast

Line No.	Particulars	Current Approved Revenue ($000's) (a)	2014 Proposed Revenue ($000's) (b)	Δ in Revenue ($000's) (c) = (b - a)	2015 Proposed Revenue ($000's) (d)	Δ in Revenue ($000's) (e) = (d - b)	2016 Proposed Revenue ($000's) (f)	Δ in Revenue ($000's) (g) = (f - d)	2017 Proposed Revenue ($000's) (h)	Δ in Revenue ($000's) (i) = (h - f)	2018 Proposed Revenue ($000's) (j)	Δ in Revenue ($000's) (k) = (j - h)	Total Δ in Revenue ($000's) (l) = (j - a)	Total Δ in Revenue (%) (m) = (l / a)	Average Δ per Year (%) (n) = (m / 5)
	North Transportation & Storage														
19	Rate 01	98,362	98,615	253	100,295	1,680	101,718	1,424	102,009	291	102,288	279	3,926	4.0%	0.8%
20	Rate 10	31,679	31,745	66	32,181	436	32,556	375	32,635	79	32,710	76	1,031	3.3%	0.7%
21	Rate 20	10,532	10,551	19	10,668	117	10,768	100	10,791	23	10,813	22	281	2.7%	0.5%
22	Rate 25	2,127	2,127	0	2,127	(1)	2,126	(1)	2,126	0	2,126	0	(0)	0.0%	0.0%
23	Rate 100	166	168	2	176	8	183	7	184	2	186	2	20	12.2%	2.4%
24	Total North Transportatiion & Storage	142,866	143,206	340	145,446	2,240	147,350	1,905	147,745	394	148,123	379	5,257	3.7%	0.7%
25	Total In-Franchise	884,190	887,076	2,886	894,736	7,660	913,301	18,565	927,322	14,021	941,313	13,990	57,123	6.5%	1.3%
	Ex-Franchise														
26	Rate M12	160,467	163,694	3,227	175,836	12,142	201,078	25,242	204,005	2,927	206,734	2,729	46,267	28.8%	5.8%
27	Rate M13	417	423	7	430	7	437	7	444	7	451	7	34	8.3%	1.7%
28	Rate M16	755	768	12	780	12	792	12	805	13	818	13	62	8.3%	1.7%
29	Rate C1	45,096	45,218	123	45,561	343	45,924	363	46,053	129	46,180	127	1,085	2.4%	0.5%
30	Total Ex-Franchise	206,735	210,103	3,369	222,607	12,504	248,231	25,624	251,307	3,076	254,183	2,876	47,449	23.0%	4.6%
31	Total Company	1,090,924	1,097,179	6,255	1,117,344	20,165	1,161,533	44,189	1,178,630	17,097	1,195,496	16,866	104,572	9.6%	1.9%

M12/C1 Demand Charge Impacts 2014-2018

Line No.	Services	EB-2011-0210 Rate Order ($/GJ/day) (1)	2014 Forecast ($/GJ/day)	2015 Forecast ($/GJ/day)	2016 Forecast ($/GJ/day)	2017 Forecast ($/GJ/day)	2018 Forecast ($/GJ/day)	Δ in Rates ($/GJ/day)	% Δ in Rates
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-a)	(h) = (g/a)
1	M12/C1 Dawn to Kirkwall	0.0661	0.0675	0.0723	0.0790	0.0801	0.0811	0.0150	23%
2	M12/C1 Dawn to Parkway	0.0783	0.0799	0.0868	0.0940	0.0953	0.0966	0.0182	23%
3	M12/C1 Kirkwall to Parkway	0.0122	0.0125	0.0135	0.0150	0.0152	0.0154	0.0032	26%
4	C1 Parkway to Kirkwall	0.0190	0.0194	0.0213	0.0234	0.0237	0.0240	0.0050	26%
5	C1 Kirkwall to Dawn	0.0336	0.0343	0.0371	0.0413	0.0419	0.0424	0.0088	26%
6	C1 Parkway to Dawn	0.0190	0.0194	0.0213	0.0234	0.0237	0.0240	0.0050	26%
7	M12-X	0.0974	0.0994	0.1081	0.1174	0.1191	0.1206	0.0232	24%

Notes:
(1) EB-2011-0210, Appendix A, Pages 14-16, column (c), effective January 1, 2013.

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union North

		EB-2013-0033 April 2013 QRAM (1)		2018 Forecast		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate 10							
1	Delivery Charges	4,781	7.9675	5,049	8.4155	0.4480	269	5.6%
2	Gas Supply Charges	10,215	17.0256	10,683	17.8051			
3	Total Bill	14,996	24.9931	15,732	26.2206	0.4480	269	1.8%
	Large Rate 10							
4	Delivery Charges	15,548	6.2193	16,499	6.5997	0.3804	951	6.1%
5	Gas Supply Charges	42,564	17.0256	44,513	17.8051			
6	Total Bill	58,112	23.2449	61,012	24.4048	0.3804	951	1.6%
	Small Rate 20							
7	Delivery Charges	74,816	2.4939	79,237	2.6412	0.1474	4,422	5.9%
8	Gas Supply Charges	617,378	20.5793	636,124	21.2041			
9	Total Bill	692,194	23.0731	715,361	23.8454	0.1474	4,422	0.6%
	Large Rate 20							
10	Delivery Charges	285,803	1.9054	302,814	2.0188	0.1134	17,011	6.0%
11	Gas Supply Charges	2,881,670	19.2111	2,962,010	19.7467			
12	Total Bill	3,167,473	21.1165	3,264,824	21.7655	0.1134	17,011	0.5%
	Average Rate 25							
13	Delivery Charges	63,659	2.7982	68,215	2.9985	0.2002	4,556	7.2%
14	Gas Supply Charges	344,604	15.1475	350,769	15.4184			
15	Total Bill	408,264	17.9457	418,984	18.4169	0.2002	4,556	1.1%
	Small Rate 100							
16	Delivery Charges	259,798	0.9622	278,597	1.0318	0.0696	18,800	7.2%
17	Gas Supply Charges	5,760,139	21.3338	5,760,139	21.3338			
18	Total Bill	6,019,937	22.2961	6,038,737	22.3657	0.0696	18,800	0.3%
	Large Rate 100							
19	Delivery Charges	2,095,718	0.8732	2,249,498	0.9373	0.0641	153,780	7.3%
20	Gas Supply Charges	50,116,431	20.8818	50,116,431	20.8818			
21	Total Bill	52,212,149	21.7551	52,365,929	21.8191	0.0641	153,780	0.3%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South

Line No.	Particulars	EB-2013-0033 April 2013 QRAM (1) Bill ($)	Unit Rate (cents/m^3)	2018 Forecast Bill ($)	Unit Rate (cents/m^3)	Impact Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M2							
1	Delivery Charges	4,190	6.9832	4,512	7.5208	0.5376	323	7.7%
2	Gas Supply Charges	7,785	12.9744	7,954	13.2568			
3	Total Bill	11,975	19.9575	12,467	20.7775	0.5376	323	2.7%
	Large Rate M2							
4	Delivery Charges	14,250	5.7001	15,519	6.2075	0.5074	1,268	8.9%
5	Gas Supply Charges	32,436	12.9744	33,142	13.2568			
6	Total Bill	46,686	18.6745	48,661	19.4643	0.5074	1,268	2.7%
	Small Rate M4							
7	Delivery Charges	35,237	4.0271	38,279	4.3748	0.3476	3,042	8.6%
8	Gas Supply Charges	113,526	12.9744	115,997	13.2568			
9	Total Bill	148,763	17.0015	154,276	17.6315	0.3476	3,042	2.0%
	Large Rate M4							
10	Delivery Charges	270,978	2.2581	292,576	2.4381	0.1800	21,598	8.0%
11	Gas Supply Charges	1,556,923	12.9744	1,590,811	13.2568			
12	Total Bill	1,827,901	15.2325	1,883,388	15.6949	0.1800	21,598	1.2%
	Small Rate M5							
13	Delivery Charges	29,255	3.5461	31,252	3.7881	0.2420	1,997	6.8%
14	Gas Supply Charges	107,038	12.9744	109,368	13.2568			
15	Total Bill	136,294	16.5204	140,620	17.0449	0.2420	1,997	1.5%
	Large Rate M5							
16	Delivery Charges	155,313	2.3894	167,414	2.5756	0.1862	12,102	7.8%
17	Gas Supply Charges	843,333	12.9744	861,689	13.2568			
18	Total Bill	998,646	15.3638	1,029,104	15.8324	0.1862	12,102	1.2%
	Small Rate M7							
19	Delivery Charges	616,645	1.7129	666,936	1.8526	0.1397	50,290	8.2%
20	Gas Supply Charges	4,670,770	12.9744	4,772,434	13.2568			
21	Total Bill	5,287,415	14.6873	5,439,369	15.1094	0.1397	50,290	1.0%
	Large Rate M7							
22	Delivery Charges	2,358,392	4.5354	2,558,316	4.9198	0.3845	199,924	8.5%
23	Gas Supply Charges	6,746,667	12.9744	6,893,515	13.2568			
24	Total Bill	9,105,059	17.5097	9,451,831	18.1766	0.3845	199,924	2.2%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South

Line No.	Particulars	EB-2013-0033 April 2013 QRAM (1) Bill ($) (a)	Unit Rate (cents/m^3) (b)	2018 Forecast Bill ($) (c)	Unit Rate (cents/m^3) (d)	Impact Unit Rate (cents/m^3) (e) = (d-b)	Delivery Rate Change ($) (f) = (c-a)	Bill (%) (g) = (f/a)
	Small Rate M9							
1	Delivery Charges	116,256	1.6727	127,801	1.8389	0.1661	11,545	9.9%
2	Gas Supply Charges	901,718	12.9744	921,345	13.2568			
3	Total Bill	1,017,974	14.6471	1,049,145	15.0956	0.1661	11,545	1.1%
	Large Rate M9							
4	Delivery Charges	345,244	1.7110	379,591	1.8812	0.1702	34,347	9.9%
5	Gas Supply Charges	2,617,966	12.9744	2,674,949	13.2568			
6	Total Bill	2,963,210	14.6854	3,054,540	15.1380	0.1702	34,347	1.2%
	Small Rate T1							
7	Delivery Charges	127,339	1.6895	137,556	1.8251	0.1356	10,217	8.0%
8	Gas Supply Charges	977,878	12.9744	999,162	13.2568			
9	Total Bill	1,105,217	14.6639	1,136,718	15.0818	0.1356	10,217	0.9%
	Average Rate T1							
10	Delivery Charges	193,986	1.6772	209,037	1.8073	0.1301	15,051	7.8%
11	Gas Supply Charges	1,500,606	12.9744	1,533,269	13.2568			
12	Total Bill	1,694,592	14.6516	1,742,306	15.0641	0.1301	15,051	0.9%
	Large Rate T1							
13	Delivery Charges	427,194	1.6672	458,782	1.7904	0.1233	31,587	7.4%
14	Gas Supply Charges	3,324,560	12.9744	3,396,923	13.2568			
15	Total Bill	3,751,754	14.6415	3,855,704	15.0472	0.1233	31,587	0.8%
	Small Rate T2							
16	Delivery Charges	480,912	0.8116	524,582	0.8853	0.0737	43,670	9.1%
17	Gas Supply Charges	7,688,087	12.9744	7,855,426	13.2568			
18	Total Bill	8,168,998	13.7859	8,380,008	14.1420	0.0737	43,670	0.5%
	Average Rate T2							
19	Delivery Charges	1,105,628	0.5590	1,191,154	0.6022	0.0432	85,526	7.7%
20	Gas Supply Charges	25,661,967	12.9744	26,220,525	13.2568			
21	Total Bill	26,767,595	13.5334	27,411,680	13.8590	0.0432	85,526	0.3%
	Large Rate T2							
22	Delivery Charges	1,799,626	0.4863	1,931,569	0.5219	0.0357	131,943	7.3%
23	Gas Supply Charges	48,016,679	12.9744	49,061,810	13.2568			
24	Total Bill	49,816,305	13.4606	50,993,379	13.7787	0.0357	131,943	0.3%
	Large Rate T3							
25	Delivery Charges	2,912,694	1.0680	3,245,844	1.1902	0.1222	333,150	11.4%
26	Gas Supply Charges	35,382,636	12.9744	36,152,775	13.2568			
27	Total Bill	38,295,330	14.0424	39,398,619	14.4470	0.1222	333,150	0.9%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED
Summary of Average Residential Bill Impacts for Rate 01 and Rate M1
2014-2018 Incentive Regulation Forecast

	2013 Current Approved (a)	2014 Forecast (b)	2015 Forecast (c)	2016 Forecast (d)	2017 Forecast (e)	2018 Forecast (f)	Cumulative Bill Impact (g) = (f - a)	Percent Bill Impact (h) = (g / a)
Rate M1 Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	89.54	92.47	95.09	101.76	107.54	113.38	23.83	26.6%
Storage Services	16.21	16.49	16.55	16.85	17.27	17.68	1.47	9.1%
Total Delivery Charge	357.75	360.97	363.63	370.62	376.81	383.06	25.31	**7.1%**
Supply Charges								
Transportation to Union	92.13	98.34	98.34	98.34	98.34	98.34	6.21	-
Commodity & Fuel	193.31	193.31	193.31	193.31	193.31	193.31	-	-
Total Supply Charge	285.44	291.65	291.65	291.65	291.65	291.65	6.21	2.2%
Total Bill	643.19	652.61	655.28	662.27	668.46	674.71	31.52	**4.9%**
Year-over-year Impact - Delivery Bill ($)		3.21	2.67	6.99	6.19	6.25	25.31	
Year-over-year Impact - Delivery Bill (%)		**0.9%**	**0.7%**	**1.9%**	**1.7%**	**1.7%**	7.1%	
Year-over-year Impact - Total Bill ($)		9.43	2.67	6.99	6.19	6.25	31.52	
Year-over-year Impact - Total Bill (%)		1.5%	0.4%	1.1%	0.9%	0.9%	4.9%	
Rate 01 (EZ) Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	206.93	208.52	212.43	219.46	228.63	237.90	30.97	15.0%
Total Delivery Charge	458.93	460.52	464.43	471.46	480.63	489.90	30.97	**6.7%**
Supply Charges								
Transportation to Union	197.65	207.40	207.46	207.45	207.44	207.41	9.76	4.9%
Storage Services	78.75	79.45	84.11	88.11	88.91	89.73	10.98	13.9%
Commodity & Fuel	231.45	231.45	231.45	231.45	231.45	231.45	-	0.0%
Total Supply Charge	507.85	518.30	523.02	527.01	527.80	528.59	20.74	4.1%
Total Bill	966.78	978.82	987.45	998.47	1,008.43	1,018.49	51.71	**5.3%**
Year-over-year Impact - Delivery Bill ($)		1.59	3.91	7.03	9.17	9.27	30.97	
Year-over-year Impact - Delivery Bill (%)		**0.3%**	**0.8%**	**1.5%**	**1.9%**	**1.9%**	6.7%	
Year-over-year Impact - Total Bill ($)		12.04	8.63	11.02	9.96	10.06	51.71	
Year-over-year Impact - Total Bill (%)		1.2%	0.9%	1.1%	1.0%	1.0%	5.3%	

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast
Excludes Weather-related Volume Adjustments for 20-year Declining Trend

Line No.	Particulars	Current Approved Revenue ($000's) (a)	2014 Proposed Revenue ($000's) (b)	Δ in Revenue ($000's) (c) = (b - a)	2015 Proposed Revenue ($000's) (d)	Δ in Revenue ($000's) (e) = (d - b)	2016 Proposed Revenue ($000's) (f)	Δ in Revenue ($000's) (g) = (f - d)	2017 Proposed Revenue ($000's) (h)	Δ in Revenue ($000's) (i) = (h - f)	2018 Proposed Revenue ($000's) (j)	Δ in Revenue ($000's) (k) = (j - h)	Total Δ in Revenue ($000's) (l) = (j - a)	Total Δ in Revenue (%) (m) = (l / a)	Average Δ per Year (%) (n) = (m / 5)
	North Delivery														
1	Rate 01	161,158	161,198	41	162,204	1,005	164,379	2,175	167,322	2,942	170,271	2,949	9,113	5.7%	1.1%
2	Rate 10	19,951	19,637	(314)	19,747	110	20,025	279	20,383	358	20,742	359	791	4.0%	0.8%
3	Rate 20	13,487	13,518	31	13,566	48	13,755	188	14,011	256	14,267	256	780	5.8%	1.2%
4	Rate 25	4,473	4,537	65	4,559	22	4,622	63	4,707	85	4,793	85	320	7.2%	1.4%
5	Rate 100	15,481	15,699	217	15,808	110	16,037	229	16,325	288	16,614	288	1,132	7.3%	1.5%
6	Total North Delivery	214,550	214,589	40	215,884	1,295	218,818	2,934	222,749	3,931	226,686	3,937	12,136	5.7%	1.1%
	South Delivery & Storage														
7	Rate M1	388,998	392,483	3,486	395,324	2,841	403,602	8,278	410,810	7,208	418,017	7,207	29,020	7.5%	1.5%
8	Rate M2	50,183	50,174	(9)	50,572	398	52,299	1,727	53,230	931	54,155	926	3,972	7.9%	1.6%
9	Rate M4	12,282	12,223	(60)	12,324	101	12,802	477	13,028	226	13,253	225	970	7.9%	1.6%
10	Rate M5A	13,265	13,457	191	13,549	92	13,741	192	13,988	247	14,235	247	970	7.3%	1.5%
11	Rate M7	4,120	4,094	(26)	4,128	34	4,312	183	4,388	76	4,463	75	343	8.3%	1.7%
12	Rate M9	724	707	(17)	715	8	768	53	781	13	793	13	70	9.6%	1.9%
13	Rate M10	10	9	(1)	9	(0)	10	1	10	0	10	0	1	6.9%	1.4%
14	Rate T1	10,637	10,591	(46)	10,693	102	11,054	361	11,242	188	11,428	186	791	7.4%	1.5%
15	Rate T2	42,154	41,269	(885)	41,768	498	43,862	2,094	44,591	729	45,306	715	3,152	7.5%	1.5%
16	Rate T3	4,400	4,273	(126)	4,325	51	4,684	360	4,762	78	4,839	76	439	10.0%	2.0%
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18	Total In-Franchise Delivery	741,323	743,870	2,547	749,291	5,421	765,951	16,660	779,579	13,628	793,187	13,608	51,864	7.0%	1.4%

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast
Excludes Weather-related Volume Adjustments for 20-year Declining Trend

Line No.	Particulars	Current Approved Revenue ($000's) (a)	2014 Proposed Revenue ($000's) (b)	∆ in Revenue ($000's) (c) = (b - a)	2015 Proposed Revenue ($000's) (d)	∆ in Revenue ($000's) (e) = (d - b)	2016 Proposed Revenue ($000's) (f)	∆ in Revenue ($000's) (g) = (f - d)	2017 Proposed Revenue ($000's) (h)	∆ in Revenue ($000's) (i) = (h - f)	2018 Proposed Revenue ($000's) (j)	∆ in Revenue ($000's) (k) = (j - h)	Total ∆ in Revenue ($000's) (l) = (j - a)	Total ∆ in Revenue (%) (m) = (l / a)	Average ∆ per Year (%) (n) = (m / 5)
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21	Rate 20	10,532	10,551	19	10,668	117	10,768	100	10,791	23	10,813	22	281	2.7%	0.5%
22	Rate 25	2,127	2,127	0	2,127	(1)	2,126	(1)	2,126	0	2,126	0	(0)	0.0%	0.0%
23	Rate 100	166	168	2	176	8	183	7	184	2	186	2	20	12.2%	2.4%
24	Total North Transportatiion & Storage	142,866	143,206	340	145,446	2,240	147,350	1,905	147,745	394	148,123	379	5,257	3.7%	0.7%
25	Total In-Franchise	884,190	887,076	2,886	894,736	7,660	913,301	18,565	927,323	14,022	941,310	13,987	57,121	6.5%	1.3%
	Ex-Franchise														
26	Rate M12	160,467	163,694	3,227	175,836	12,142	201,078	25,242	204,005	2,927	206,734	2,729	46,267	28.8%	5.8%
27	Rate M13	417	423	7	430	7	437	7	444	7	451	7	34	8.3%	1.7%
28	Rate M16	755	768	12	780	12	792	12	805	13	818	13	62	8.3%	1.7%
29	Rate C1	45,096	45,218	123	45,561	343	45,924	363	46,053	129	46,180	127	1,085	2.4%	0.5%
30	Total Ex-Franchise	206,735	210,103	3,369	222,607	12,504	248,231	25,624	251,307	3,076	254,183	2,876	47,449	23.0%	4.6%
31	Total Company	1,090,924	1,097,179	6,255	1,117,344	20,164	1,161,533	44,189	1,178,631	17,098	1,195,494	16,863	104,570	9.6%	1.9%

UNION GAS LIMITED
Summary of Average Residential Bill Impacts for Rate 01 and Rate M1
2014-2018 Incentive Regulation Forecast
Excludes Weather-related Volume Adjustments for 20-year Declining Trend

	2013 Current Approved (a)	2014 Forecast (b)	2015 Forecast (c)	2016 Forecast (d)	2017 Forecast (e)	2018 Forecast (f)	Cumulative Bill Impact (g) = (f - a)	Percent Bill Impact (h) = (g / a)
Rate M1 Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	89.54	92.12	94.36	100.59	105.88	111.18	21.63	24.2%
Storage Services	16.21	16.42	16.41	16.64	16.97	17.30	1.09	6.7%
Total Delivery Charge	357.75	360.55	362.77	369.23	374.85	380.48	22.73	**6.4%**
Supply Charges								
Transportation to Union	92.13	98.34	98.34	98.34	98.34	98.34	6.21	-
Commodity & Fuel	193.31	193.31	193.31	193.31	193.31	193.31	-	-
Total Supply Charge	285.44	291.65	291.65	291.65	291.65	291.65	6.21	2.2%
Total Bill	643.19	652.19	654.42	660.88	666.50	672.13	28.94	**4.5%**
Year-over-year Impact - Delivery Bill ($)		2.79	2.22	6.46	5.62	5.62	22.73	
Year-over-year Impact - Delivery Bill (%)		**0.8%**	**0.6%**	**1.8%**	**1.5%**	**1.5%**	6.4%	
Year-over-year Impact - Total Bill ($)		9.01	2.22	6.46	5.62	5.62	28.94	
Year-over-year Impact - Total Bill (%)		1.4%	0.3%	1.0%	0.9%	0.8%	4.5%	
Rate 01 (EZ) Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	206.93	207.22	209.82	215.41	222.96	230.55	23.62	11.4%
Total Delivery Charge	458.93	459.22	461.82	467.41	474.96	482.55	23.62	**5.1%**
Supply Charges								
Transportation to Union	197.65	207.40	207.46	207.45	207.44	207.41	9.76	4.9%
Storage Services	78.75	79.45	84.11	88.11	88.91	89.73	10.98	13.9%
Commodity & Fuel	231.45	231.45	231.45	231.45	231.45	231.45	-	0.0%
Total Supply Charge	507.85	518.30	523.02	527.01	527.80	528.59	20.74	4.1%
Total Bill	966.78	977.52	984.84	994.42	1,002.76	1,011.14	44.36	**4.6%**
Year-over-year Impact - Delivery Bill ($)		0.29	2.60	5.59	7.55	7.59	23.62	
Year-over-year Impact - Delivery Bill (%)		**0.1%**	**0.6%**	**1.2%**	**1.6%**	**1.6%**	5.1%	
Year-over-year Impact - Total Bill ($)		10.74	7.32	9.58	8.34	8.38	44.36	
Year-over-year Impact - Total Bill (%)		1.1%	0.7%	1.0%	0.8%	0.8%	4.6%	

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union North
Excludes Weather-related Volume Adjustments for 20-year Declining Trend

		EB-2013-0033 April 2013 QRAM (1)		2018 Forecast		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate 10							
4	Delivery Charges	4,781	7.9675	4,971	8.2845	0.3170	190	4.0%
5	Gas Supply Charges	10,215	17.0256	10,683	17.8051			
6	Total Bill	14,996	24.9931	15,654	26.0896	0.3170	190	1.3%
	Large Rate 10							
7	Delivery Charges	15,548	6.2193	16,207	6.4829	0.2636	659	4.2%
8	Gas Supply Charges	42,564	17.0256	44,513	17.8051			
9	Total Bill	58,112	23.2449	60,720	24.2879	0.2636	659	1.1%
	Small Rate 20							
10	Delivery Charges	74,816	2.4939	79,189	2.6396	0.1458	4,374	5.8%
11	Gas Supply Charges	617,378	20.5793	636,124	21.2041			
12	Total Bill	692,194	23.0731	715,313	23.8438	0.1458	4,374	0.6%
	Large Rate 20							
13	Delivery Charges	285,803	1.9054	302,602	2.0173	0.1120	16,799	5.9%
14	Gas Supply Charges	2,881,670	19.2111	2,962,010	19.7467			
15	Total Bill	3,167,473	21.1165	3,264,613	21.7641	0.1120	16,799	0.5%
	Average Rate 25							
16	Delivery Charges	63,659	2.7982	68,215	2.9985	0.2002	4,556	7.2%
17	Gas Supply Charges	344,604	15.1475	350,769	15.4184			
18	Total Bill	408,264	17.9457	418,984	18.4169	0.2002	4,556	1.1%
	Small Rate 100							
19	Delivery Charges	259,798	0.9622	278,597	1.0318	0.0696	18,800	7.2%
20	Gas Supply Charges	5,760,139	21.3338	5,760,139	21.3338			
21	Total Bill	6,019,937	22.2961	6,038,737	22.3657	0.0696	18,800	0.3%
	Large Rate 100							
22	Delivery Charges	2,095,718	0.8732	2,249,498	0.9373	0.0641	153,780	7.3%
23	Gas Supply Charges	50,116,431	20.8818	50,116,431	20.8818			
24	Total Bill	52,212,149	21.7551	52,365,929	21.8191	0.0641	153,780	0.3%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED

Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South

Excludes Weather-related Volume Adjustments for 20-year Declining Trend

		EB-2013-0033 April 2013 QRAM (1)		2018 Forecast		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M2							
4	Delivery Charges	4,190	6.9832	4,450	7.4174	0.4342	261	6.2%
5	Gas Supply Charges	7,785	12.9744	7,954	13.2568			
6	Total Bill	11,975	19.9575	12,404	20.6741	0.4342	261	2.2%
	Large Rate M2							
7	Delivery Charges	14,250	5.7001	15,272	6.1090	0.4088	1,022	7.2%
8	Gas Supply Charges	32,436	12.9744	33,142	13.2568			
9	Total Bill	46,686	18.6745	48,414	19.3658	0.4088	1,022	2.2%
	Small Rate M4							
10	Delivery Charges	35,237	4.0271	38,170	4.3623	0.3351	2,932	8.3%
11	Gas Supply Charges	113,526	12.9744	115,997	13.2568			
12	Total Bill	148,763	17.0015	154,167	17.6190	0.3351	2,932	2.0%
	Large Rate M4							
13	Delivery Charges	270,978	2.2581	291,076	2.4256	0.1675	20,098	7.4%
14	Gas Supply Charges	1,556,923	12.9744	1,590,811	13.2568			
15	Total Bill	1,827,901	15.2325	1,881,888	15.6824	0.1675	20,098	1.1%
	Small Rate M5							
16	Delivery Charges	29,255	3.5461	31,151	3.7759	0.2298	1,896	6.5%
17	Gas Supply Charges	107,038	12.9744	109,368	13.2568			
18	Total Bill	136,294	16.5204	140,519	17.0327	0.2298	1,896	1.4%
	Large Rate M5							
19	Delivery Charges	155,313	2.3894	166,621	2.5634	0.1740	11,309	7.3%
20	Gas Supply Charges	843,333	12.9744	861,689	13.2568			
21	Total Bill	998,646	15.3638	1,028,311	15.8202	0.1740	11,309	1.1%
	Small Rate M7							
22	Delivery Charges	616,645	1.7129	666,936	1.8526	0.1397	50,290	8.2%
23	Gas Supply Charges	4,670,770	12.9744	4,772,434	13.2568			
24	Total Bill	5,287,415	14.6873	5,439,369	15.1094	0.1397	50,290	1.0%
	Large Rate M7							
25	Delivery Charges	2,358,392	4.5354	2,558,316	4.9198	0.3845	199,924	8.5%
26	Gas Supply Charges	6,746,667	12.9744	6,893,515	13.2568			
27	Total Bill	9,105,059	17.5097	9,451,831	18.1766	0.3845	199,924	2.2%

Notes:

(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South
Excludes Weather-related Volume Adjustments for 20-year Declining Trend

		EB-2013-0033 April 2013 QRAM (1)		2018 Forecast		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M9							
1	Delivery Charges	116,256	1.6727	127,801	1.8389	0.1661	11,545	9.9%
2	Gas Supply Charges	901,718	12.9744	921,345	13.2568			
3	Total Bill	1,017,974	14.6471	1,049,145	15.0956	0.1661	11,545	1.1%
	Large Rate M9							
4	Delivery Charges	345,244	1.7110	379,591	1.8812	0.1702	34,347	9.9%
5	Gas Supply Charges	2,617,966	12.9744	2,674,949	13.2568			
6	Total Bill	2,963,210	14.6854	3,054,540	15.1380	0.1702	34,347	1.2%
	Small Rate T1							
7	Delivery Charges	127,339	1.6895	137,556	1.8251	0.1356	10,217	8.0%
8	Gas Supply Charges	977,878	12.9744	999,162	13.2568			
9	Total Bill	1,105,217	14.6639	1,136,718	15.0818	0.1356	10,217	0.9%
	Average Rate T1							
10	Delivery Charges	193,986	1.6772	209,037	1.8073	0.1301	15,051	7.8%
11	Gas Supply Charges	1,500,606	12.9744	1,533,269	13.2568			
12	Total Bill	1,694,592	14.6516	1,742,306	15.0641	0.1301	15,051	0.9%
	Large Rate T1							
13	Delivery Charges	427,194	1.6672	458,782	1.7904	0.1233	31,587	7.4%
14	Gas Supply Charges	3,324,560	12.9744	3,396,923	13.2568			
15	Total Bill	3,751,754	14.6415	3,855,704	15.0472	0.1233	31,587	0.8%
	Small Rate T2							
16	Delivery Charges	480,912	0.8116	524,582	0.8853	0.0737	43,670	9.1%
17	Gas Supply Charges	7,688,087	12.9744	7,855,426	13.2568			
18	Total Bill	8,168,998	13.7859	8,380,008	14.1420	0.0737	43,670	0.5%
	Average Rate T2							
19	Delivery Charges	1,105,628	0.5590	1,191,154	0.6022	0.0432	85,526	7.7%
20	Gas Supply Charges	25,661,967	12.9744	26,220,525	13.2568			
21	Total Bill	26,767,595	13.5334	27,411,680	13.8590	0.0432	85,526	0.3%
	Large Rate T2							
22	Delivery Charges	1,799,626	0.4863	1,931,569	0.5219	0.0357	131,943	7.3%
23	Gas Supply Charges	48,016,679	12.9744	49,061,810	13.2568			
24	Total Bill	49,816,305	13.4606	50,993,379	13.7787	0.0357	131,943	0.3%
	Large Rate T3							
25	Delivery Charges	2,912,694	1.0680	3,245,844	1.1902	0.1222	333,150	11.4%
26	Gas Supply Charges	35,382,636	12.9744	36,152,775	13.2568			
27	Total Bill	38,295,330	14.0424	39,398,619	14.4470	0.1222	333,150	0.9%

Notes:
(1) Reflects approved rates per Union's April 2013 QRAM filing (EB-2013-0033).

Union Gas
Incentive Regulation 2014-2018
Supplement Questions and Responses – June 7, 2013

BOMA Questions

1. **Could you provide the data contained in Tables entitled Summary of Average Residential Bill Impacts for Rate 01 and Rate M1, 2014-2018 Res Forecast for each of the rates/bills listed on the Tables listed "Calculation of Delivery Rate Charges on Delivery and Total Bill for Typical Small and Large Customers" – Union North (p1) and Union South (pp 2 and 3)?**

   Please see Attachment 1 for the detailed bill calculations associated with the 'Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers' schedule.

2. **Why have you assumed a constant unit rate for gas supply (commodity and fuel) charge [19.331] for the residential customers in M1 and 01, while showing increases in "gas supply charges" for the other rates in the previous three pages?**

   Union has assumed a constant gas commodity and fuel rate for all rate classes, consistent with the 'Summary of Average Residential Bill Impacts for Rate 01 and Rate M1' schedule. Gas supply charges are changing over the 2014-2018 IR term for three reasons:

   1. Union's proposal to remove exchange revenues from gas costs and include the revenues in delivery rates.
   2. Union's proposal for capital pass-through of the Parkway West, Parkway Growth and Burlington-Oakville projects.
   3. Gas supply margins that are subject to PCI escalation.

   For Union North rate classes, the Gas Supply Charges line consists of gas commodity and fuel, transportation and storage charges. It is the transportation and storage rates that are changing over the IR term for Union North.

   For Union South rate classes, the Gas Supply Charges line consists of gas commodity and fuel and transportation charges. It is the transportation rate that is changing over the IR term.

   Please see Union's response to BOMA 1 for the detailed bill calculations associated with the 'Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers' schedule.

3. **On the page entitled "Assumptions" (Union memo May 9, 2013), please explain the implications of the statement "no other billing unit or demand adjustments (including Dawn to Kirkwall turnback)".**

   The statement noted above on the "List of Assumptions" page means:

   - Union has not forecasted in-franchise volumes as part of the IR rates forecast. The 2014 to 2018 in-franchise rates forecast is based on the 2013 Board-approved volume forecast, plus the weather-related volume adjustments for the 20-year declining trend weather proposal only.
   - Union has not forecasted M12 demand changes (turnback or growth) as part of the IR rates forecast. The 2014 to 2018 M12 rates forecast is based on 2013 Board-approved demands, plus the M12 demand increase of 363,000 GJ/day associated with the Brantford to Kirkwall and Parkway D Compressor Project only.

4. **Please show the rate impacts for all rate classes for Union's capital pass through proposals in each of the years in the IRM period. Please show each of Parkway West, Brantford/Hamilton and Burlington to Oakville separately.**

   Please see Attachment 2.

5. **Please provide the promised data on the impact of NAC/LRAM reductions on the general service customers by year, by rate class. Also, provide a display of the change to average use forecasts, stated in EB-2011-0210 based on retention of the 50-50 weather methodology in that case, and in line with Board comment at p14 of the case. Please explain the operation of the average use deferral account and a copy of the official description of the account.**

   Please see Attachment 3 for an explanation of the Average Use deferral account (Interrogatory J.DV-4-2-2). Please see Attachment 4 for a copy of the Accounting Order. Please see Attachment 5 for the Average Use reductions by year, by rate class for years 2008-2012. Please see Attachment 6 for the LRAM reductions by year, by rate class for years 2008-2012. Please see the table below for the change to average use forecasts based on retention of the 50-50 weather methodology.

2013 Normalized Average Consumption / Customer: m^3

Normal	Rate M1	Rate M2	Rate 01	Rate 10
B.A. 50:50 Blend	2,778	143,867	2,765	157,381
20 Yr Trend	2,718	141,078	2,680	154,520
Change	60	2,789	85	2,861
% Change	2.2%	2.0%	3.2%	1.9%

<u>Unaccounted For Gas ("UFG")</u>

6. **Is there currently a UFG deferral account? In addition, please provide a reference to, or include excerpts from the Board's recent Enbridge decision/evidence that outlines its treatment of UFG.**

   No, Union does not have a UFG volume deferral account. UFG price variances are passed through as part of the QRAM.

   In its 2013 rates application (EB-2011-0354), Enbridge applied for approval to establish a 2013 Unaccounted for Gas Variance Account. This was a continuation of the Unaccounted for Gas Variance Account that was first approved for Enbridge by the Board in 2002 (RP-2001-0032). In the Settlement Agreement accepted by the Board on October 15, 2012 (EB-2011-0354 - Decision on Settlement Agreement and Procedural Order No. 5), all parties accepted the establishment of Enbridge's proposed deferral and variance accounts including the 2013 Unaccounted for Gas Variance Account.

   Enbridge's pre-filed evidence in EB-2011-0354 (Exhibit D1, Tab 8, Schedule 1) describes the purpose of its 2013 Unaccounted for Gas Variance Account.

   Enbridge's response to an APPrO interrogatory (Exhibit I, Issue C5, Schedule 2.1) further describes how Enbridge forecasts it's unaccounted for gas and how it is allocated to its customers.

7. **Please outline the manner in which UFG is currently handled by Union, both in cost of service cases and the previous IRM. Is it made part of the revenue request in the test year? Show how it contributed to earnings in each year of the last IRM term (see Union's April 29, presentation p9).**

   Under Union's current treatment of UFG:

   - Union is at risk for any volume variance between actual UFG volumes and the forecast UFG volumes in Board-approved rates. Actual UFG volumes that are lower than forecast will have a positive impact on utility earnings, while actual UFG volumes that are higher than forecast will have a negative impact on utility earnings.
   - Union is not at risk for any variance between the actual cost of gas and the approved cost of gas associated with UFG volumes. The cost of gas associated with UFG volumes is a pass through item to ratepayers. As part of the QRAM, Union updates the cost of gas in rates for in-franchise and ex-franchise customers to reflect the current weighted average cost of gas (WACOG). Similarly, Union expenses UFG volumes based on the same WACOG included in rates. Accordingly, there is no impact on utility earnings associated with the cost of gas for UFG; revenues and expenses reflect the same cost of gas.

The table below shows how UFG contributed to earnings in each year of the last IR term.

Line No.		Unaccounted For Gas ($ millions) 2007	2008	2009	2010	2011	2012
1	Regulated Revenue (net of price changes)	47.7	57.3	35.1	27.5	29.9	23.0
2	Regulated Cost of Gas	61.7	48.9	48.7	11.5	6.7	11.3
3	**Variance**	**(14.0)**	**8.5**	**(13.6)**	**16.0**	**23.2**	**11.7**

8. **Please provide an explanation of how UFG arises, how it is calculated, and how it is used within the volume forecasts and gas accounts.**

   UFG represents 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 could include 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.

   Union currently recovers an estimate of the cost of UFG from customers in rates. Union's forecast UFG is included in rates based on forecast throughput volumes multiplied by a UFG ratio. The UFG ratio is determined using a Board-approved weighted average of the most recent three years of actual UFG volumes. The most recent year has a weighting of 3/6ths, the second year has a 2/6ths weighting and the first year has a 1/6th weighting. The volumes are multiplied by WACOG to calculate the UFG costs to be included in rates.

   Actual UFG is the difference between the total gas available from all sources (incoming gas), and the total gas accounted for as delivery, net interchange, and company use (outgoing gas), multiplied by WACOG.

9. **Please provide evidence, or cite from, previous cases, for example, 0210 where UFG is discussed.**

   See EB-2011-0210 Exhibit D3, Tab 2, Schedule 2 for the UFG volume schedule filed in Union's 2013 rates proceeding. See the following interrogatories filed in EB-2011-0210: J.D-5-2-1, J.D-5-2-2, J.D-5-3-1, J.D-13-2-1, J.D-16-13-2, J.D-13-2-1.

10. Please explain how Union's proposed treatment of UFG differs from the current treatment.

For Union's current treatment of UFG please see the response at BOMA 7.

Under Union's proposed UFG deferral account:

- Union would track the variance between Union's actual UFG ratio (actual UFG volumes/actual activity) and the forecast UFG ratio (forecast UFG volumes/forecast activity) included in Board-approved rates. The UFG ratio variance would be recovered from/refunded to ratepayers as part of Union's annual deferral account disposition proceeding. With a UFG deferral account, any variance between the actual and forecast UFG ratio would not impact utility earnings.
- As described above, the cost of gas associated with UFG volumes would continue to be a pass through item to ratepayers and would not impact utility earnings.

11. Please provide reference to the most recent Board pronouncements, Union or Enbridge, on UFG.

In its 2013 rates application (EB-2011-0354), Enbridge requested acceptance of the recommendation and conclusion in its report on unaccounted for gas volumes (Exhibit D2, Tab 6, Schedule 1), that Enbridge's approach to, and forecasting methods for, unaccounted for gas continue to produce acceptable results, and that the submission of the unaccounted for gas report satisfies the obligations undertaken by Enbridge in the Settlement Agreement in the 2010 ESM proceeding.

In the Settlement Agreement accepted by the Board on October 15, 2012 (EB-2011-0354 - Decision on Settlement Agreement and Procedural Order No. 5), all parties accepted the level of unaccounted for gas forecast by Enbridge. On November 2, 2012, the Board accepted a revised Settlement Agreement which included revised wording related to pension costs (EB-2011-0354 - Decision on Revised Settlement Agreement and Procedural Order No. 6).

The Board approved Union's EB-2011-0210 Settlement Agreement which included Union's UFG volume forecast. Please see the response at BOMA 9 for the evidence references.

12. Please confirm that only the gas price changes for UFG, and not volume charges, are dealt with in the QRAM proceedings. Is the price of UFG handled any differently than the price of the utility's system gas costs, including "own use" costs for compressor fuel or other purposes?

Confirmed. Please see the response at BOMA 10.

Deferral Tax Drawdown

13. Please provide a further explanation of the defined tax drawdown, including the circumstances which gave rise to the need to begin the "deferral tax drawdown", how the accounts are established, available options, etc.

In 1997, Union changed its accounting for income taxes for utility operations from the tax allocation (or accrual) method to flow through (or cash-basis) tax accounting. The change to flow through tax accounting was adopted for rate-making purposes on a prospective basis in EBRO 493/494 (Union's 1997 rate case). The tax allocation method of tax accounting used for rate-making purposes prior to EBRO 493/494 resulted in an accumulated deferred tax balance. In the EBRO 499 (Union's 1999 rate case) settlement agreement, parties agreed that the accumulated deferred tax balance would be used to reduce Union's cost of service in future years.

Union is required to include the amounts in its deferral account balances in the determination of taxable income. This creates a temporary difference when amounts are accumulated in deferral accounts and when these amounts are disposed of to customers. As the deferral account balances change, the corresponding deferred income tax balance also changes. The deferred income tax balances are non-utility (i.e. not included in the calculation of rate base and revenue requirement). The temporary differences reverse themselves when the accumulated deferrals are disposed of to customers. This reversal results in no net impact to customers arising from these temporary differences.

For the proposed IRM, Union is considering a similar adjustment mechanism to that applied during the 2008-2012 IRM. Specifically, this would involve adjusting base rates to reflect the difference in the deferred tax credit in 2013 base rates and the average of the deferred tax drawdown over the 2014-2018 IRM term. The purpose of this adjustment is to provide a levelized tax benefit over the 2014-2018 period. At the end of that period, ratepayers and Union will be in the same position as they would have been without the normalization adjustment but without the inter-year volatility.

As context, Union's 2013 rates contain a deferred tax credit of $15.169 million. The remaining accumulated deferred tax balance to be credited to customers after 2013 is $64.094 million. Without adjusting the deferred tax credit in rates during the IRM period, Union would over-refund the accumulated deferred tax balance which would then have to be collected from customers upon rebasing. Accordingly, an adjustment should be made to avoid this circumstance.

There are two options to address the deferred tax issue:

The first option is consistent with the method used during the 2008-2012 IRM. As noted above, it involves levelizing the amount for each year of the IRM term. The levelized amount would be $12.819 million (i.e. $64.094 million accumulated balance / 5 years), requiring a base rate increase of $2.350 million (i.e. $15.169 million in rates less $12.821 million levelized credit)($3.154 million pre-tax).

The second option involves adjusting rates annually for the change in the deferred tax credit. The annual changes would be:

a. 2014: $1.704 million increase ($2.287 million pre-tax)
b. 2015: $0.090 million decrease ($0.121 million pre-tax)
c. 2016: $0.454 million increase ($0.609 million pre-tax)
d. 2017: $0.040 million decrease ($0.054 million pre-tax)
e. 2018: $2.309 million increase ($3.099 million pre-tax)

Please see Attachment 7 for the calculation of the deferred tax adjustment.

14. Please explain how the GDP-IPI-FDD is used to set rates each year of the IRM.

As was the case in Union's 2008-2012 IRM, Union is proposing to use the GDP IPI FDD as the inflation factor used in the price cap formula for 2014-2018. For the purposes of Union's annual rate filing application, the GDP IPI FDD is calculated using the average of annualized quarterly changes of the last four quarters ending June.

For example (ignoring Y and Z factors and AU for simplicity), during Union's 2008-2012 IRM, Union's price cap formula was:

Price % change = I – X, where I is the inflation (GDP IPI FDD) factor and X is the productivity factor (fixed at 1.82% for the 2008-2012 IRM)

I = 2.0%

X = 1.82%

Price % change = 2.0% – 1.82% = 0.18%

Delivery rates would be increased by 0.18%

<u>Rate Design</u>

15. Please describe what Union means by the phrase "maintain existing flexibility" at p13 of April 29 proposal. Does Union need to come to the Board for approval for any rate change during the IRM regime?

During the IRM term, Union needs to maintain flexibility to propose new regulated rates or services or rate structure adjustments. Union would file an application and evidence for Board approval for any new rate or new service. Also, it is Union's intention to present any new rates or services at the annual stakeholder meeting, well in advance of the annual IRM rate-setting process.

<u>Billing Unit Adjustments (Union Assumption, May 9, 2013)</u>

16. Does the phrase "no LRAM or average use volume-related adjustment" mean these items are not included in the escalation factor, but will be dealt with in a deferral account? How will that work?

For the purposes of calculating the rate impacts of Union's proposed IR parameters, Union assumed no LRAM and AU impacts over the IR term. This was a simplifying assumption to calculate the rate impacts of Union's proposals.

During the 2014-2018 IRM, Union is proposing a deferral account for the general service rate classes that would capture the difference between the normalized average consumption in rates compared to the actual normalized average consumption. Changes in average use and in LRAM would be captured in the normalized average consumption deferral account. This approach is similar to that used for 2008-2012, and for 2013, for general service AU variances only.

17. Are the average use forecast based on a normalized three year volume loss? Please explain.

No. The 2013 average use is based on the forecast variance between the 2013 test year weather normalized usage (NAC) estimates and the actual 2013 weather normalized usage adjusted for the net total DSM LRAM saved volumes for 2013. The NAC is weather normalized at the 50:50 blended 2013 Board-approved weather normal. The net DSM LRAM saved volumes for 2013 are the difference between the audited actual volumes and the 2013 planned volumes that are incorporated in the test year NAC estimates.

18. Does deferral account capture the difference from forecast average use, use actively, or normalized results? (See EB-2007-0606, Settlement Agreement, s4.1).

Please see Attachment 3.

FRPO Questions

1. **May 27th answers, Response 5: Please provide the Board-approved heating degree days for the respective territories for each of the months Jan. to Mar.**

YEAR 2013 UNION GAS WEATHER DATA
Actual vs B.A. Normal Heating Degree-Days below 18C

Southern	Jan	Feb	Mar	Total
actual HDD	645.0	632.8	572.1	1,849.9
Normal HDD	694.1	610.3	530.7	1,835.1
Variance	-49.1	22.5	41.4	14.8
% Variance	-7.1%	3.7%	7.8%	0.8%

Northern	Jan	Feb	Mar	Total
actual HDD	840.7	768.4	674.9	2,284.1
Normal HDD	884.0	754.3	656.1	2,294.5
Variance	-43.3	14.1	18.8	-10.5
% Variance	-4.9%	1.9%	2.9%	-0.5%

Union Gas	Jan	Feb	Mar	Total
actual HDD	693.9	666.7	597.8	1,958.4
Normal HDD	741.6	646.3	562.0	1,949.9
Variance	-47.7	20.4	35.8	8.5
% Variance	-6.4%	3.2%	6.4%	0.4%

note: Board Approved (B.A.) is from blended 50:50 weather of 30-year average and the 20- year declining trend methods.

2. **May 27th answers, Response 11: I realize your answer to this inquiry may be covered in your response to BOMA but could you help me/us with a reconciliation of how the respective annual increases and decreases in 1 could be rolled into the $2.4 million (increase or decrease?) described in 2?**

   Please see the response at BOMA 13.

3. **May 27th answers, Response 12: The last sentence in this response says "excluding weather" but earlier in the sentence (and in the question) it says without the weather normalization adjustment. Please clarify: Is the second set of tables without the move to the 100% 20 year declining trend? Do they include any impact of the Normalized Actual Consumptions ie., using the currently approved weather methodology? Just want to ensure that we are clear.**

The rate impacts in these schedules titled “2014-2018 IR schedules excluding weather.pdf” do not include Union’s proposed weather adjustment (change the weather normal methodology to the 20-year declining trend). For clarity, these schedules provide the 2014-2018 rate impacts using weather normalized volumes based on the Board’s decision in Union’s 2013 rate proceeding (50:50 weighting between the 30-year average and the 20-year declining trend).

UNION GAS LIMITED
2014-2018 Incentive Regulation - Bill Impact Detail for Typical Small and Large Customers
Board-approved April 2013 QRAM vs. 2018 Forecast

(Eastern)
Rate 10 - Commercial / Industrial
(Annual Consumption of **60,000 m³**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	3,940.53	4,209.30	268.77	
3	Total Delivery Charge	4,780.53	5,049.30	268.77	5.6%
	Supply Charges				
4	Transportation to Union	4,736.12	4,985.24	249.11	
5	Prospective Recovery - Transportation	(2,398.08)	(2,398.08)	-	
6	Storage Services	1,578.42	1,796.99	218.57	
7	Prospective Recovery - Storage	-	-	-	
8	Subtotal	3,916.46	4,384.15	467.68	11.9%
9	Commodity & Fuel	7,426.30	7,426.30	-	
10	Prospective Recovery - Commodity & Fuel	(1,127.41)	(1,127.41)	-	
11	Subtotal	6,298.89	6,298.89	-	
12	Total Gas Supply Charge (line 8 + line 11)	10,215.35	10,683.03	467.68	
13	Total Bill	14,995.88	15,732.33	736.45	4.9%
14	Impacts for Customer Notices - Sales (line 13)			736.45	
15	Impacts for Customer Notices - Direct Purchase (line 3 + line 8)			736.45	

(Eastern)
Rate 10 - Commercial / Industrial
(Annual Consumption of **250,000 m³**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	14,708.22	15,659.27	951.05	
3	Total Delivery Charge	15,548.22	16,499.27	951.05	6.1%
	Supply Charges				
4	Transportation to Union	19,733.85	20,771.82	1,037.97	
5	Prospective Recovery - Transportation	(9,992.00)	(9,992.00)	-	
6	Storage Services	6,576.75	7,487.46	910.71	
7	Prospective Recovery - Storage	-	-	-	
8	Subtotal	16,318.60	18,267.28	1,948.68	11.9%
9	Commodity & Fuel	30,942.90	30,942.90	-	
10	Prospective Recovery - Commodity & Fuel	(4,697.54)	(4,697.54)	-	
11	Subtotal	26,245.36	26,245.36	-	
12	Total Gas Supply Charge (line 8 + line 11)	42,563.96	44,512.64	1,948.68	
13	Total Bill	58,112.18	61,011.91	2,899.73	5.0%
14	Impacts for Customer Notices - Sales (line 13)			2,899.73	
15	Impacts for Customer Notices - Direct Purchase (line 3 + line 8)			2,899.73	

(Eastern)
Rate 20 - Commercial / Industrial
(Firm Contract Demand of **14,000 m^3/day** &
Annual Consumption of **3,000,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	12,000.00	12,619.88	619.88	
2	Monthly Demand Charge	46,734.12	49,754.54	3,020.42	
3	Delivery Commodity Charge	16,081.74	16,863.00	781.26	
4	Total Delivery Charge	74,815.86	79,237.43	4,421.57	5.9%
	Supply Charges				
5	Monthly Gas Supply Demand Charge	178,197.54	191,619.90	13,422.37	
6	Commodity Transportation 1	110,568.83	115,892.58	5,323.75	
7	Commodity Transportation 1 - Price Adjustment	9,594.18	9,594.18	-	
8	Commodity Transportation 2	5,125.51	5,125.51	-	
9	Subtotal	303,486.05	322,232.17	18,746.12	6.2%
10	Commodity & Fuel	369,586.80	369,586.80	-	
11	Prospective Recovery - Commodity & Fuel	(55,695.00)	(55,695.00)	-	
12	Subtotal	313,891.80	313,891.80	-	
13	Total Gas Supply Charge (line 9 + line 12)	617,377.85	636,123.96	18,746.12	
14	Total Bill	692,193.70	715,361.39	23,167.69	3.3%
15	Impacts for Customer Notices - Sales (line 14)			23,167.69	
16	Impacts for Customer Notices - Direct Purchase (line 4 + line 9)			23,167.69	

(Eastern)
Rate 20 - Commercial / Industrial
(Firm Contract Demand of **60,000 m^3/day** &
Annual Consumption of **15,000,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	12,000.00	12,619.88	619.88	
2	Monthly Demand Charge	200,289.08	213,233.76	12,944.68	
3	Delivery Commodity Charge	73,513.76	76,959.96	3,446.20	
4	Total Delivery Charge	285,802.84	302,813.60	17,010.76	6.0%
	Supply Charges				
5	Monthly Gas Supply Demand Charge	763,703.73	821,228.15	57,524.42	
6	Commodity Transportation 1	473,866.41	496,682.50	22,816.09	
7	Commodity Transportation 1 - Price Adjustment	41,117.90	41,117.90	-	
8	Commodity Transportation 2	33,522.89	33,522.89	-	
9	Subtotal	1,312,210.93	1,392,551.44	80,340.51	6.1%
10	Commodity & Fuel	1,847,933.98	1,847,933.98	-	
11	Prospective Recovery - Commodity & Fuel	(278,475.00)	(278,475.00)	-	
12	Subtotal	1,569,458.98	1,569,458.98	-	
13	Total Gas Supply Charge (line 9 + line 12)	2,881,669.91	2,962,010.42	80,340.51	
14	Total Bill	3,167,472.75	3,264,824.02	97,351.27	3.1%
15	Impacts for Customer Notices - Sales (line 14)			97,351.27	
16	Impacts for Customer Notices - Direct Purchase (line 4 + line 9)			97,351.27	

(Eastern)
Rate 25 - Commercial / Industrial
Annual Consumption of **2,275,000 m³**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	4,500.00	4,653.71	153.71	
2	Delivery Commodity Charge	59,159.36	63,561.23	4,401.86	
3	Total Delivery Charge	63,659.36	68,214.94	4,555.57	7.2%
	Supply Charges				
4	Gas Supply Transportation	106,569.88	112,734.34	6,164.46	
5	Subtotal	106,569.88	112,734.34	6,164.46	5.8%
6	Commodity & Fuel	280,269.99	280,269.99	-	
7	Prospective Recovery - Commodity & Fuel	(42,235.38)	(42,235.38)	-	
8	Subtotal	238,034.61	238,034.61	-	
9	Total Gas Supply Charge (line 9 + line 12)	344,604.49	350,768.95	6,164.46	
10	Total Bill	408,263.85	418,983.89	10,720.04	2.6%
11	Impacts for Customer Notices - Sales (line 14)			10,720.04	
12	Impacts for Customer Notices - Direct Purchase (line 4 + line 9)			10,720.04	

(Eastern)
Rate 100 - Industrial
(Firm Contract Demand of **100,000 m³/day** &
Annual Consumption of **27,000,000 m³**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	18,000.00	19,023.36	1,023.36	
2	Monthly Demand Charge	184,097.47	197,608.80	13,511.33	
3	Delivery Commodity Charge	57,700.12	61,965.00	4,264.88	
4	Total Delivery Charge	259,797.59	278,597.16	18,799.57	7.2%
	Supply Charges				
5	Monthly Gas Supply Demand Charge	1,913,542.80	1,913,542.80	-	
6	Commodity Transportation 1	935,177.58	935,177.58	-	
7	Commodity Transportation 1 - Price Adjustment	-	-	-	
8	Commodity Transportation 2	86,392.86	86,392.86	-	
9	Subtotal	2,935,113.24	2,935,113.24	-	0.0%
10	Commodity & Fuel	3,326,281.16	3,326,281.16	-	
11	Prospective Recovery - Commodity & Fuel	(501,255.00)	(501,255.00)	-	
12	Subtotal	2,825,026.16	2,825,026.16	-	
13	Total Gas Supply Charge (line 9 + line 12)	5,760,139.40	5,760,139.40	-	
14	Total Bill	6,019,936.99	6,038,736.56	18,799.57	0.3%
15	Impacts for Customer Notices - Sales (line 14)			18,799.57	
16	Impacts for Customer Notices - Direct Purchase (line 4 + line 9)			18,799.57	

(Eastern)
Rate 100 - Industrial
(Firm Contract Demand of **850,000 m^3/day** & Annual Consumption of **240,000,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	18,000.00	19,023.36	1,023.36	
2	Monthly Demand Charge	1,564,828.51	1,679,674.80	114,846.29	
3	Delivery Commodity Charge	512,889.95	550,800.00	37,910.05	
4	Total Delivery Charge	2,095,718.46	2,249,498.16	153,779.70	7.3%
	Supply Charges				
5	Monthly Gas Supply Demand Charge	16,265,113.80	16,265,113.80	-	
6	Commodity Transportation 1	7,949,009.43	7,949,009.43	-	
7	Commodity Transportation 1 - Price Adjustment	-	-	-	
8	Commodity Transportation 2	790,963.84	790,963.84	-	
9	Subtotal	25,005,087.07	25,005,087.07	-	0.0%
10	Commodity & Fuel	29,566,943.67	29,566,943.67	-	
11	Prospective Recovery - Commodity & Fuel	(4,455,600.00)	(4,455,600.00)	-	
12	Subtotal	25,111,343.67	25,111,343.67	-	
13	Total Gas Supply Charge (line 9 + line 12)	50,116,430.74	50,116,430.74	-	
14	Total Bill	52,212,149.20	52,365,928.90	153,779.70	0.3%
15	Impacts for Customer Notices - Sales (line 14)			153,779.70	
16	Impacts for Customer Notices - Direct Purchase (line 4 + line 9)			153,779.70	

Rate M2 - Commercial
(Annual Consumption of **60,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	2,422.69	2,705.21	282.53	
3	Prospective Recovery - Delivery	474.18	474.18	-	
4	Storage Services	453.02	493.08	40.06	
5	Total Delivery Charge	4,189.89	4,512.47	322.58	7.7%
	Supply Charges				
6	Transportation to Union	2,512.62	2,682.06	169.44	
7	Commodity & Fuel	7,426.30	7,426.30	-	
8	Prospective Recovery - Commodity & Fuel	(2,154.30)	(2,154.30)	-	
9	Subtotal	5,272.00	5,272.00	-	
10	Total Gas Supply Charge (line 6 + line 9)	7,784.62	7,954.06	169.44	
11	Total Bill	11,974.51	12,466.53	492.02	4.1%
12	Impacts for Customer Notices - Sales (line 11)			492.02	
13	Impacts for Customer Notices - Direct Purchase (line 5)			322.58	

Line No.	Particulars	Rate M2 - Commercial (Annual Consumption of **250,000 m³**) EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Charge	840.00	840.00	-	
2	Delivery Commodity Charge	9,547.01	10,648.60	1,101.59	
3	Prospective Recovery - Delivery	1,975.75	1,975.75	-	
4	Storage Services	1,887.60	2,054.50	166.90	
5	Total Delivery Charge	14,250.36	15,518.85	1,268.49	8.9%
	Supply Charges				
6	Transportation to Union	10,469.25	11,175.25	706.00	
7	Commodity & Fuel	30,942.90	30,942.90	-	
8	Prospective Recovery - Commodity & Fuel	(8,976.25)	(8,976.25)	-	
9	Subtotal	21,966.65	21,966.65	-	
10	Total Gas Supply Charge (line 6 + line 9)	32,435.90	33,141.90	706.00	
11	Total Bill	46,686.26	48,660.75	1,974.49	4.2%
12	Impacts for Customer Notices - Sales (line 11)			1,974.49	
13	Impacts for Customer Notices - Direct Purchase (line 5)			1,268.49	

Line No.	Particulars	Rate M4 - Commercial (Firm Contract Demand of **4,800 m³/day** & Annual Consumption of **875,000 m³**) EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Demand Charge	26,855.37	29,131.14	2,275.78	
2	Delivery Commodity Charge	8,380.30	9,146.38	766.08	
3	Prospective Recovery - Delivery	1.75	1.75	-	
4	Total Delivery Charge	35,237.41	38,279.27	3,041.86	8.6%
	Supply Charges				
5	Transportation to Union	36,642.38	39,113.38	2,471.00	
6	Commodity & Fuel	108,300.15	108,300.15	-	
7	Prospective Recovery - Commodity & Fuel	(31,416.88)	(31,416.88)	-	
8	Subtotal	76,883.27	76,883.27	-	
9	Total Gas Supply Charge (line 5 + line 8)	113,525.65	115,996.65	2,471.00	
10	Total Bill	148,763.06	154,275.92	5,512.86	3.7%
11	Impacts for Customer Notices - Sales (line 10)			5,512.86	
12	Impacts for Customer Notices - Direct Purchase (line 4)			3,041.86	

Rate M4 - Commercial

(Firm Contract Demand of **50,000 m^3/day** & Annual Consumption of **12,000,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Demand Charge	156,024.19	167,116.37	11,092.18	
2	Delivery Commodity Charge	114,929.79	125,436.00	10,506.21	
3	Prospective Recovery - Delivery	24.00	24.00	-	
4	Total Delivery Charge	270,977.98	292,576.37	21,598.39	8.0%
	Supply Charges				
5	Transportation to Union	502,524.00	536,412.00	33,888.00	
6	Commodity & Fuel	1,485,259.18	1,485,259.18	-	
7	Prospective Recovery - Commodity & Fuel	(430,860.00)	(430,860.00)	-	
8	Subtotal	1,054,399.18	1,054,399.18	-	
9	Total Gas Supply Charge (line 5 + line 8)	1,556,923.18	1,590,811.18	33,888.00	
10	Total Bill	1,827,901.16	1,883,387.55	55,486.39	3.0%
11	Impacts for Customer Notices - Sales (line 10)			55,486.39	
12	Impacts for Customer Notices - Direct Purchase (line 4)			21,598.39	

Rate M5 - Commercial

(Interruptible Contract Demand of **7,500 m^3/day** & Annual Consumption of **825,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	8,280.00	8,807.73	527.73	
2	Delivery Commodity Charge	20,973.49	22,442.50	1,469.01	
3	Prospective Recovery - Delivery	1.65	1.65	-	
4	Total Delivery Charge	29,255.14	31,251.88	1,996.74	6.8%
	Supply Charges				
5	Transportation to Union	34,548.53	36,878.33	2,329.80	
6	Commodity & Fuel	102,111.57	102,111.57	-	
7	Prospective Recovery - Commodity & Fuel	(29,621.63)	(29,621.63)	-	
8	Subtotal	72,489.94	72,489.94	-	
9	Total Gas Supply Charge (line 5 + line 8)	107,038.47	109,368.27	2,329.80	
10	Total Bill	136,293.61	140,620.15	4,326.54	3.2%
11	Impacts for Customer Notices - Sales (line 10)			4,326.54	
12	Impacts for Customer Notices - Direct Purchase (line 4)			1,996.74	

Rate M5 - Commercial
(Contract Demand of **70,000 m^3/day** & Annual Consumption of **6,500,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	8,280.00	8,807.73	527.73	
2	Delivery Commodity Charge	147,019.70	158,593.73	11,574.03	
3	Prospective Recovery - Delivery	13.00	13.00	-	
4	Total Delivery Charge	155,312.70	167,414.45	12,101.75	7.8%
	Supply Charges				
5	Transportation to Union	272,200.50	290,556.50	18,356.00	
6	Commodity & Fuel	804,515.39	804,515.39	-	
7	Prospective Recovery - Commodity & Fuel	(233,382.50)	(233,382.50)	-	
8	Subtotal	571,132.89	571,132.89	-	
9	Total Gas Supply Charge (line 5 + line 8)	843,333.39	861,689.39	18,356.00	
10	Total Bill	998,646.09	1,029,103.84	30,457.75	3.0%
11	Impacts for Customer Notices - Sales (line 10)			30,457.75	
12	Impacts for Customer Notices - Direct Purchase (line 4)			12,101.75	

Rate M7 - Industrial
(Firm Contract Demand of **165,000 m^3/day** & Annual Consumption of **36,000,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Demand Charge	502,770.04	546,371.91	43,601.87	
2	Delivery Commodity Charge	113,803.38	120,492.00	6,688.62	
3	Prospective Recovery - Delivery	72.00	72.00	-	
4	Total Delivery Charge	616,645.43	666,935.91	50,290.49	8.2%
	Supply Charges				
5	Transportation to Union	1,507,572.00	1,609,236.00	101,664.00	
6	Commodity & Fuel	4,455,777.55	4,455,777.55	-	
7	Prospective Recovery - Commodity & Fuel	(1,292,580.00)	(1,292,580.00)	-	
8	Subtotal	3,163,197.55	3,163,197.55	-	
9	Total Gas Supply Charge (line 5 + line 8)	4,670,769.55	4,772,433.55	101,664.00	
10	Total Bill	5,287,414.98	5,439,369.46	151,954.49	2.9%
11	Impacts for Customer Notices - Sales (line 10)			151,954.49	
12	Impacts for Customer Notices - Direct Purchase (line 4)			50,290.49	

Rate M7 - Industrial
(Firm Contract Demand of **720,000 m^3/day** & Annual Consumption of **52,000,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Demand Charge	2,193,905.64	2,384,168.34	190,262.70	
2	Delivery Commodity Charge	164,382.66	174,044.00	9,661.34	
3	Prospective Recovery - Delivery	104.00	104.00	-	
4	Total Delivery Charge	2,358,392.31	2,558,316.34	199,924.04	8.5%
	Supply Charges				
5	Transportation to Union	2,177,604.00	2,324,452.00	146,848.00	
6	Commodity & Fuel	6,436,123.13	6,436,123.13	-	
7	Prospective Recovery - Commodity & Fuel	(1,867,060.00)	(1,867,060.00)	-	
8	Subtotal	4,569,063.13	4,569,063.13	-	
9	Total Gas Supply Charge (line 5 + line 8)	6,746,667.13	6,893,515.13	146,848.00	
10	Total Bill	9,105,059.44	9,451,831.47	346,772.04	3.8%
11	Impacts for Customer Notices - Sales (line 10)			346,772.04	
12	Impacts for Customer Notices - Direct Purchase (line 4)			199,924.04	

Rate M9 - Wholesale
(Firm Contract Demand of **56,439 m^3/day** & Annual Consumption of **6,950,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Demand Charge	102,733.19	113,754.61	11,021.42	
2	Delivery Commodity Charge	13,508.52	14,032.05	523.53	
3	Prospective Recovery - Delivery	13.90	13.90	-	
4	Total Delivery Charge	116,255.60	127,800.56	11,544.96	9.9%
	Supply Charges				
5	Transportation to Union	291,045.15	310,671.95	19,626.80	
6	Commodity & Fuel	860,212.61	860,212.61	-	
7	Prospective Recovery - Commodity & Fuel	(249,539.75)	(249,539.75)	-	
8	Subtotal	610,672.86	610,672.86	-	
9	Total Gas Supply Charge (line 5 + line 8)	901,718.01	921,344.81	19,626.80	
10	Total Bill	1,017,973.61	1,049,145.37	31,171.76	3.1%
11	Impacts for Customer Notices - Sales (line 10)			31,171.76	
12	Impacts for Customer Notices - Direct Purchase (line 4)			11,544.96	

Rate M9 - Wholesale
(Firm Contract Demand of **168,100 m^3/day** & Annual Consumption of **20,178,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Apr-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Demand Charge	305,984.31	338,810.93	32,826.62	
2	Delivery Commodity Charge	39,219.40	40,739.38	1,519.98	
3	Prospective Recovery - Delivery	40.36	40.36	-	
4	Total Delivery Charge	345,244.07	379,590.67	34,346.60	9.9%
	Supply Charges				
5	Transportation to Union	844,994.11	901,976.78	56,982.67	
6	Commodity & Fuel	2,497,463.32	2,497,463.32	-	
7	Prospective Recovery - Commodity & Fuel	(724,491.09)	(724,491.09)	-	
8	Subtotal	1,772,972.23	1,772,972.23	-	
9	Total Gas Supply Charge (line 5 + line 8)	2,617,966.33	2,674,949.00	56,982.67	
10	Total Bill	2,963,210.40	3,054,539.67	91,329.27	3.1%
11	Impacts for Customer Notices - Sales (line 10)			91,329.27	
12	Impacts for Customer Notices - Direct Purchase (line 4)			34,346.60	

Rate T1 - Industrial
(Firm Contract Demand of **25,750 m^3/day** & Annual Consumption of **7,537,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Jan-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	23,233.57	24,917.56	1,683.99	
2	Monthly Transportation Demand Charge	98,742.05	107,023.39	8,281.33	
3	Monthly Transportation Commodity Charge	5,363.84	5,615.07	251.23	
4	Total Delivery Charge	127,339.46	137,556.01	10,216.55	8.0%
	Supply Charges				
5	Transportation to Union	315,626.95	336,911.44	21,284.49	
6	Commodity & Fuel	932,866.54	932,866.54	-	
7	Prospective Recovery - Commodity & Fuel	(270,615.99)	(270,615.99)	-	
8	Subtotal	662,250.55	662,250.55	-	
9	Total Gas Supply Charge (line 5 + line 8)	977,877.50	999,161.99	21,284.49	
10	Total Bill	1,105,216.97	1,136,718.00	31,501.04	2.9%
11	Impacts for Customer Notices - Sales (line 10)			31,501.04	
12	Impacts for Customer Notices - Direct Purchase (line 4)			10,216.55	

Rate T1 - Industrial

(Firm Contract Demand of **48,750 m^3/day** & Annual Consumption of **11,565,938 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Jan-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	23,233.57	24,917.56	1,683.99	
2	Monthly Transportation Demand Charge	162,520.86	175,502.71	12,981.85	
3	Monthly Transportation Commodity Charge	8,231.10	8,616.62	385.52	
4	Total Delivery Charge	193,985.54	209,036.90	15,051.36	7.8%
	Supply Charges				
5	Transportation to Union	484,346.79	517,008.99	32,662.21	
6	Commodity & Fuel	1,431,534.64	1,431,534.64	-	
7	Prospective Recovery - Commodity & Fuel	(415,275.00)	(415,275.00)	-	
8	Subtotal	1,016,259.63	1,016,259.63	-	
9	Total Gas Supply Charge (line 5 + line 8)	1,500,606.42	1,533,268.63	32,662.21	
10	Total Bill	1,694,591.95	1,742,305.52	47,713.57	2.8%
11	Impacts for Customer Notices - Sales (line 10)			47,713.57	
12	Impacts for Customer Notices - Direct Purchase (line 4)			15,051.36	

Rate T1 - Industrial

(Firm Contract Demand of **133,000 m^3/day** & Annual Consumption of **25,624,080 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Jan-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	23,233.57	24,917.56	1,683.99	
2	Monthly Transportation Demand Charge	385,724.74	414,774.06	29,049.31	
3	Monthly Transportation Commodity Charge	18,235.82	19,089.94	854.12	
4	Total Delivery Charge	427,194.14	458,781.56	31,587.42	7.4%
	Supply Charges				
5	Transportation to Union	1,073,059.60	1,145,422.00	72,362.40	
6	Commodity & Fuel	3,171,533.34	3,171,533.34	-	
7	Prospective Recovery - Commodity & Fuel	(920,032.59)	(920,032.59)	-	
8	Subtotal	2,251,500.75	2,251,500.75	-	
9	Total Gas Supply Charge (line 5 + line 8)	3,324,560.35	3,396,922.75	72,362.40	
10	Total Bill	3,751,754.49	3,855,704.31	103,949.83	2.8%
11	Impacts for Customer Notices - Sales (line 10)			103,949.83	
12	Impacts for Customer Notices - Direct Purchase (line 4)			31,587.42	

Rate T2 - Industrial
(Firm Contract Demand of **190,000 m^3/day** & Annual Consumption of **59,256,000 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Jan-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	72,000.00	76,382.61	4,382.61	
2	Monthly Transportation Demand Charge	404,283.67	443,518.05	39,234.38	
3	Monthly Transportation Commodity Charge	4,628.02	4,681.22	53.21	
4	Total Delivery Charge	480,911.69	524,581.88	43,670.19	9.1%
	Supply Charges				
5	Transportation to Union	2,481,463.51	2,648,802.46	167,338.94	
6	Commodity & Fuel	7,334,209.85	7,334,209.85	-	
7	Prospective Recovery - Commodity & Fuel	(2,127,586.68)	(2,127,586.68)	-	
8	Subtotal	5,206,623.17	5,206,623.17	-	
9	Total Gas Supply Charge (line 5 + line 8)	7,688,086.68	7,855,425.62	167,338.94	
10	Total Bill	8,168,998.37	8,380,007.51	211,009.14	2.6%
11	Impacts for Customer Notices - Sales (line 10)			211,009.14	
12	Impacts for Customer Notices - Direct Purchase (line 4)			43,670.19	

Rate T2 - Industrial
(Firm Contract Demand of **669,000 m^3/day** & Annual Consumption of **197,789,850 m^3**)

Line No.	Particulars	EB-2013-0033 Approved 01-Jan-13 Total Bill ($) (a)	Forecast 01-Jan-18 Total Bill ($) (b)	Impact ($) (c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	72,000.00	76,382.61	4,382.61	
2	Monthly Transportation Demand Charge	1,018,180.36	1,099,146.43	80,966.07	
3	Monthly Transportation Commodity Charge	15,447.79	15,625.40	177.60	
4	Total Delivery Charge	1,105,628.15	1,191,154.43	85,526.28	7.7%
	Supply Charges				
5	Transportation to Union	8,282,845.55	8,841,404.08	558,558.54	
6	Commodity & Fuel	24,480,765.92	24,480,765.92	-	
7	Prospective Recovery - Commodity & Fuel	(7,101,644.56)	(7,101,644.56)	-	
8	Subtotal	17,379,121.36	17,379,121.36	-	
9	Total Gas Supply Charge (line 5 + line 8)	25,661,966.91	26,220,525.45	558,558.54	
10	Total Bill	26,767,595.06	27,411,679.88	644,084.82	2.4%
11	Impacts for Customer Notices - Sales (line 10)			644,084.82	
12	Impacts for Customer Notices - Direct Purchase (line 4)			85,526.28	

Rate T2 - Industrial

(Firm Contract Demand of **1,200,000 m^3/day** & Annual Consumption of **370,089,000 m³**)

Line No.	Particulars	EB-2013-0033 Approved 01-Jan-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	72,000.00	76,382.61	4,382.61	
2	Monthly Transportation Demand Charge	1,698,721.35	1,825,949.49	127,228.14	
3	Monthly Transportation Commodity Charge	28,904.71	29,237.03	332.32	
4	Total Delivery Charge	1,799,626.07	1,931,569.13	131,943.06	7.3%
	Supply Charges				
5	Transportation to Union	15,498,217.05	16,543,348.39	1,045,131.34	
6	Commodity & Fuel	45,806,507.16	45,806,507.16	-	
7	Prospective Recovery - Commodity & Fuel	(13,288,045.55)	(13,288,045.55)	-	
8	Subtotal	32,518,461.62	32,518,461.62	-	
9	Total Gas Supply Charge (line 5 + line 8)	48,016,678.67	49,061,810.00	1,045,131.34	
10	Total Bill	49,816,304.73	50,993,379.13	1,177,074.40	2.4%
11	Impacts for Customer Notices - Sales (line 10)			1,177,074.40	
12	Impacts for Customer Notices - Direct Purchase (line 4)			131,943.06	

Rate T3 - Wholesale

(Firm Contract Demand of **2,350,000 m^3/day** & Annual Consumption of **272,712,000 m³**)

Line No.	Particulars	EB-2013-0033 Approved 01-Jan-13 Total Bill ($)	Forecast 01-Jan-18 Total Bill ($)	Impact ($)	
		(a)	(b)	(c) = (b) - (a)	
	Delivery Charges				
1	Monthly Customer Charge	244,456.20	261,861.46	17,405.26	
2	Monthly Transportation Demand Charge	2,638,998.38	2,954,802.78	315,804.40	
3	Monthly Transportation Commodity Charge	29,239.41	29,180.18	(59.23)	
4	Total Delivery Charge	2,912,693.99	3,245,844.42	333,150.43	11.4%
	Supply Charges				
5	Transportation to Union	11,420,360.42	12,190,499.11	770,138.69	
6	Commodity & Fuel	33,754,000.20	33,754,000.20	-	
7	Prospective Recovery - Commodity & Fuel	(9,791,724.36)	(9,791,724.36)	-	
8	Subtotal	23,962,275.84	23,962,275.84	-	
9	Total Gas Supply Charge (line 5 + line 8)	35,382,636.27	36,152,774.95	770,138.69	
10	Total Bill	38,295,330.26	39,398,619.38	1,103,289.12	2.9%
11	Impacts for Customer Notices - Sales (line 10)			1,103,289.12	
12	Impacts for Customer Notices - Direct Purchase (line 4)			333,150.43	

UNION GAS LIMITED
2014-2018 IR Forecast - Rate Impact Continuity
Effective January 1, 2014

Line No.	Particulars		2013 Current Approved Revenue	Ratepayer Portion of Base Exchanges	Application of Price Cap Index	2014 DSM	2014 Capital Pass Throughs: Parkway West Project	Brantford-Kirkwall & Parkway D Compressor Project	Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-Franchise North Delivery											
1	R01	Revenue ($000's)	161,158	(2,238)	2,454	60	(234)	-	-	161,198		161,198
2		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	884,421	884,421	(5,462)	878,960
3		Average rate (cents / m^3)	18.2218	(0.2531)	0.2774	0.0068	(0.0265)	-	-	18.2264	0.1133	18.3397
4		Average rate change (1)		-1.4%	1.5%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.6%	0.6%
5	R10	Revenue ($000's)	19,951	(586)	283	19	(30)	-	-	19,637		19,637
6		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	322,887	322,887	(1,205)	321,682
7		Average rate (cents / m^3)	6.1790	(0.1815)	0.0877	0.0059	(0.0094)	-	-	6.0816	0.0228	6.1044
8		Average rate change (1)		-2.9%	1.4%	0.1%	-0.2%	0.0%	0.0%	-1.6%	0.4%	-1.2%
9	R20	Revenue ($000's)	13,487	(157)	196	16	(23)	-	-	13,518		13,518
10		Volumes (10^3m^3)	629,802	629,802	629,802	629,802	629,802	629,802	629,802	629,802	(328)	629,474
11		Average rate (cents / m^3)	2.1415	(0.0249)	0.0311	0.0025	(0.0037)	-	-	2.1465	0.0011	2.1476
12		Average rate change (1)		-1.2%	1.5%	0.1%	-0.2%	0.0%	0.0%	0.2%	0.1%	0.3%
13	R25	Revenue ($000's)	4,473	-	72	-	(7)	-	-	4,537		4,537
14		Volumes (10^3m^3)	159,555	159,555	159,555	159,555	159,555	159,555	159,555	159,555	-	159,555
15		Average rate (cents / m^3)	2.8033	-	0.0449	-	(0.0044)	-	-	2.8438	-	2.8438
16		Average rate change (1)		0.0%	1.6%	0.0%	-0.2%	0.0%	0.0%	1.4%	0.0%	1.4%
17	R100	Revenue ($000's)	15,481	(11)	219	29	(19)	-	-	15,699		15,699
18		Volumes (10^3m^3)	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	-	1,895,488
19		Average rate (cents / m^3)	0.8167	(0.0006)	0.0115	0.0015	(0.0010)	-	-	0.8282	-	0.8282
20		Average rate change (1)		-0.1%	1.4%	0.2%	-0.1%	0.0%	0.0%	1.4%	0.0%	1.4%
	In-franchise South Delivery and Storage											
21	M1 - Delivery	Revenue ($000's)	367,338	(2,211)	5,675	167	(425)	-	-	370,544		370,544
22		Volumes (10^3m^3)	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	(12,626)	2,926,917
23		Average rate (cents / m^3)	12.4964	(0.0752)	0.1931	0.0057	(0.0145)	-	-	12.6055	0.0544	12.6599
24	M1 - Storage	Revenue ($000's)	21,660	-	347	-	(67)	-	-	21,939		21,939
25		Volumes (10^3m^3)	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	(12,626)	2,926,917
26		Average rate (cents / m^3)	0.7368	-	0.0118	-	(0.0023)	-	-	0.7464	0.0032	0.7496
27	M1	Total Revenue ($000's)	388,998	(2,211)	6,021	167	(492)	-	-	392,483		392,483
28		Total Average rate (cents / m^3)	13.2333	(0.0752)	0.2048	0.0057	(0.0167)	-	-	13.3518	0.0576	13.4094
29		Average rate change (1)		-0.6%	1.5%	0.0%	-0.1%	0.0%	0.0%	0.9%	0.4%	1.3%
30	M2 - Delivery	Revenue ($000's)	42,817	(743)	611	62	(35)	-	-	42,713		42,713
31		Volumes (10^3m^3)	975,571	975,571	975,571	975,571	975,571	975,571	975,571	975,571	(3,784)	971,787
32		Average rate (cents / m^3)	4.3889	(0.0761)	0.0626	0.0064	(0.0036)	-	-	4.3782	0.0170	4.3953
33	M2 - Storage	Revenue ($000's)	7,366	-	118	-	(23)	-	-	7,461		7,461
34		Volumes (10^3m^3)	975,571	975,571	975,571	975,571	975,571	975,571	975,571	975,571	(3,784)	971,787
35		Average rate (cents / m^3)	0.7550	-	0.0121	-	(0.0023)	-	-	0.7648	0.0030	0.7678
36	M2	Total Revenue ($000's)	50,183	(743)	729	62	(58)	-	-	50,174		50,174
37		Total Average rate (cents / m^3)	5.1440	(0.0761)	0.0747	0.0064	(0.0059)	-	-	5.1430	0.0200	5.1631
38		Average rate change (1)		-1.5%	1.5%	0.1%	-0.1%	0.0%	0.0%	0.0%	0.4%	0.4%
39	M4	Revenue ($000's)	12,282	(240)	167	26	(13)	-	-	12,223		12,223
40		Volumes (10^3m^3)	404,678	404,678	404,678	404,678	404,678	404,678	404,678	404,678	(983)	403,695
41		Average rate (cents / m^3)	3.0351	(0.0592)	0.0413	0.0064	(0.0031)	-	-	3.0204	0.0074	3.0277
42		Average rate change (1)		-2.0%	1.4%	0.2%	-0.1%	0.0%	0.0%	-0.5%	0.2%	-0.2%
43	M5	Revenue ($000's)	13,265	(4)	169	43	(17)	-	-	13,457		13,457
44		Volumes (10^3m^3)	535,132	535,132	535,132	535,132	535,132	535,132	535,132	535,132	(536)	534,596
45		Average rate (cents / m^3)	2.4789	(0.0007)	0.0316	0.0080	(0.0032)	-	-	2.5146	0.0025	2.5171
46		Average rate change (1)		0.0%	1.3%	0.3%	-0.1%	0.0%	0.0%	1.4%	0.1%	1.5%

Notes:
(1) Average rate change is compared to column (a).

UNION GAS LIMITED
2014-2018 IR Forecast - Rate Impact Continuity
Effective January 1, 2014

Line No.	Particulars		2013 Current Approved Revenue	Ratepayer Portion of Base Exchanges	Application of Price Cap Index	2014 DSM	2014 Capital Pass Throughs: Parkway West Project	2014 Capital Pass Throughs: Brantford-Kirkwall & Parkway D Compressor Project	2014 Capital Pass Throughs: Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-franchise South Delivery and Storage (Con't)											
1	M7	Revenue ($000's)	4,120	(87)	50	14	(4)	-	-	4,094		4,094
2		Volumes (10^3m^3)	147,143	147,143	147,143	147,143	147,143	147,143	147,143	147,143	-	147,143
3		Average rate (cents / m^3)	2.8002	(0.0590)	0.0340	0.0098	(0.0026)	-	-	2.7825	-	2.7825
4		Average rate change (1)		-2.1%	1.2%	0.4%	-0.1%	0.0%	0.0%	-0.6%	0.0%	-0.6%
5	M9	Revenue ($000's)	724	(28)	11	-	(0)	-	-	707		707
6		Volumes (10^3m^3)	60,750	60,750	60,750	60,750	60,750	60,750	60,750	60,750	-	60,750
7		Average rate (cents / m^3)	1.1913	(0.0459)	0.0183	-	(0.0004)	-	-	1.1633	-	1.1633
8		Average rate change (1)		-3.9%	1.5%	0.0%	0.0%	0.0%	0.0%	-2.3%	0.0%	-2.3%
9	M10	Revenue ($000's)	10	(1)	0	-	(0)	-	-	9		9
10		Volumes (10^3m^3)	189	189	189	189	189	189	189	189	-	189
11		Average rate (cents / m^3)	5.1666	(0.4480)	0.0755	-	(0.0118)	-	-	4.8088	-	4.8088
12		Average rate change (1)		-8.7%	1.5%	0.0%	-0.2%	0.0%	0.0%	-6.9%	0.0%	-6.9%
13	T1	Revenue ($000's)	10,637	(204)	138	29	(9)	-	-	10,590		10,590
14		Volumes (10^3m^3)	548,986	548,986	548,986	548,986	548,986	548,986	548,986	548,986	-	548,986
15		Average rate (cents / m^3)	1.9376	(0.0372)	0.0252	0.0052	(0.0016)	-	-	1.9290	-	1.9290
16		Average rate change (1)		-1.9%	1.3%	0.3%	-0.1%	0.0%	0.0%	-0.4%	0.0%	-0.4%
17	T2	Revenue ($000's)	42,154	(1,504)	609	42	(31)	-	-	41,268		41,268
18		Volumes (10^3m^3)	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	-	4,880,298
19		Average rate (cents / m^3)	0.8638	(0.0308)	0.0125	0.0009	(0.0006)	-	-	0.8456	-	0.8456
20		Average rate change (1)		-3.6%	1.4%	0.1%	-0.1%	0.0%	0.0%	-2.1%	0.0%	-2.1%
21	T3	Revenue ($000's)	4,400	(193)	67	-	(0)	-	-	4,273		4,273
22		Volumes (10^3m^3)	272,712	272,712	272,712	272,712	272,712	272,712	272,712	272,712	-	272,712
23		Average rate (cents / m^3)	1.6133	(0.0709)	0.0247	-	(0.0001)	-	-	1.5670	-	1.5670
24		Average rate change (1)		-4.4%	1.5%	0.0%	0.0%	0.0%	0.0%	-2.9%	0.0%	-2.9%
	Northern Transportation and Storage											
25	R01	Revenue ($000's)	98,362	-	243	-	10	-	-	98,615		98,615
26		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	884,421	884,421	-	884,421
27		Average rate (cents / m^3)	11.1216	-	0.0274	-	0.0011	-	-	11.1502	-	11.1502
28		Average rate change (1)		0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.3%
29	R10	Revenue ($000's)	31,679	-	65	-	1	-	-	31,745		31,745
30		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	322,887	322,887	-	322,887
31		Average rate (cents / m^3)	9.8113	-	0.0200	-	0.0004	-	-	9.8318	-	9.8318
32		Average rate change (1)		0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.2%
33	R20	Revenue ($000's)	10,532	-	19	-	0	-	-	10,551		10,551
34		Volumes (10^3m^3)	121,935	121,935	121,935	121,935	121,935	121,935	121,935	121,935	-	121,935
35		Average rate (cents / m^3)	8.6375	-	0.0153	-	0.0003	-	-	8.6531	-	8.6531
36		Average rate change (1)		0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.2%
37	R25	Revenue ($000's)	2,127	-	0	-	(0)	-	-	2,127		2,127
38		Volumes (10^3m^3)	42,913	42,913	42,913	42,913	42,913	42,913	42,913	42,913	-	42,913
39		Average rate (cents / m^3)	4.9564	-	0.0008	-	(0.0001)	-	-	4.9571	-	4.9571
40		Average rate change (1)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
41	R100	Revenue ($000's)	166	-	2	-	0	-	-	168		168
42		Change (1)		0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	1.0%
	Ex-franchise - Cost Based											
43	M12	Revenue ($000's)	160,467	-	2,567	-	660	-	-	163,694		163,694
44		Change (1)		0.0%	1.6%	0.0%	0.4%	0.0%	0.0%	2.0%	0.0%	2.0%
45	M13	Revenue ($000's)	417	-	7	-	-	-	-	423		423
46		Change (1)		0.0%	1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
47	M16	Revenue ($000's)	755	-	12	-	-	-	-	768		768
48		Change (1)		0.0%	1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
49	C1	Revenue ($000's)	45,096	-	123	-	-	-	-	45,218		45,218
50		Change (1)		0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.3%

Notes:
(1) Average rate change is compared to column (a).

UNION GAS LIMITED
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Line No.	Particulars		2014 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2015 DSM	2015 Capital Pass Throughs: Parkway West Project	Brantford-Kirkwall & Parkway D Compressor Project	Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-Franchise North Delivery											
1	R01	Revenue ($000's)	161,198	234	2,493	61	(880)	(701)	(203)	162,203		162,203
2		Volumes (10^3m^3)	878,960	878,960	878,960	878,960	878,960	878,960	878,960	878,960	(5,462)	873,498
3		Average rate (cents / m^3)	18.3397	0.0267	0.2836	0.0069	(0.1001)	(0.0797)	(0.0231)	18.4539	0.1154	18.5693
4		Average rate change (1)			1.5%	0.0%	-0.5%	-0.4%	-0.1%	0.6%	0.6%	1.3%
5	R10	Revenue ($000's)	19,637	30	288	19	(108)	(92)	(27)	19,747		19,747
6		Volumes (10^3m^3)	321,682	321,682	321,682	321,682	321,682	321,682	321,682	321,682	(1,205)	320,477
7		Average rate (cents / m^3)	6.1044	0.0095	0.0894	0.0060	(0.0336)	(0.0286)	(0.0083)	6.1387	0.0231	6.1618
8		Average rate change (1)			1.5%	0.1%	-0.6%	-0.5%	-0.1%	0.6%	0.4%	0.9%
9	R20	Revenue ($000's)	13,518	23	199	16	(88)	(78)	(23)	13,567		13,567
10		Volumes (10^3m^3)	629,474	629,474	629,474	629,474	629,474	629,474	629,474	629,474	(328)	629,147
11		Average rate (cents / m^3)	2.1476	0.0037	0.0316	0.0025	(0.0140)	(0.0124)	(0.0036)	2.1553	0.0011	2.1564
12		Average rate change (1)			1.5%	0.1%	-0.7%	-0.6%	-0.2%	0.4%	0.1%	0.4%
13	R25	Revenue ($000's)	4,537	7	73	-	(27)	(24)	(7)	4,559		4,559
14		Volumes (10^3m^3)	159,555	159,555	159,555	159,555	159,555	159,555	159,555	159,555	-	159,555
15		Average rate (cents / m^3)	2.8438	0.0044	0.0456	-	(0.0172)	(0.0147)	(0.0043)	2.8574	-	2.8574
16		Average rate change (1)			1.6%	0.0%	-0.6%	-0.5%	-0.2%	0.5%	0.0%	0.5%
17	R100	Revenue ($000's)	15,698	19	222	29	(76)	(66)	(19)	15,808		15,808
18		Volumes (10^3m^3)	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	-	1,895,488
19		Average rate (cents / m^3)	0.8282	0.0010	0.0117	0.0015	(0.0040)	(0.0035)	(0.0010)	0.8340	-	0.8340
20		Average rate change (1)			1.4%	0.2%	-0.5%	-0.4%	-0.1%	0.7%	0.0%	0.7%
	In-franchise South Delivery and Storage											
21	M1 - Delivery	Revenue ($000's)	370,544	425	5,766	170	(1,448)	(2,128)	76	373,405		373,405
22		Volumes (10^3m^3)	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	(12,626)	2,914,290
23		Average rate (cents / m^3)	12.6599	0.0145	0.1970	0.0058	(0.0495)	(0.0727)	0.0026	12.7576	0.0553	12.8129
24	M1 - Storage	Revenue ($000's)	21,940	67	352	-	(200)	(185)	(55)	21,919		21,919
25		Volumes (10^3m^3)	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	2,926,917	(12,626)	2,914,290
26		Average rate (cents / m^3)	0.7496	0.0023	0.0120	-	(0.0068)	(0.0063)	(0.0019)	0.7489	0.0032	0.7521
27	M1	Total Revenue ($000's)	392,484	492	6,118	170	(1,648)	(2,313)	21	395,324		395,324
28		Total Average rate (cents / m^3)	13.4095	0.0168	0.2090	0.0058	(0.0563)	(0.0790)	0.0007	13.5065	0.0585	13.5650
29		Average rate change (1)			1.6%	0.0%	-0.4%	-0.6%	0.0%	0.7%	0.4%	1.2%
30	M2 - Delivery	Revenue ($000's)	42,713	35	621	63	(49)	(385)	120	43,118		43,118
31		Volumes (10^3m^3)	971,787	971,787	971,787	971,787	971,787	971,787	971,787	971,787	(3,784)	968,003
32		Average rate (cents / m^3)	4.3953	0.0036	0.0639	0.0065	(0.0050)	(0.0396)	0.0124	4.4370	0.0173	4.4544
33	M2 - Storage	Revenue ($000's)	7,461	23	120	-	(68)	(63)	(19)	7,454		7,454
34		Volumes (10^3m^3)	971,787	971,787	971,787	971,787	971,787	971,787	971,787	971,787	(3,784)	968,003
35		Average rate (cents / m^3)	0.7678	0.0023	0.0123	-	(0.0070)	(0.0065)	(0.0019)	0.7670	0.0030	0.7700
36	M2	Total Revenue ($000's)	50,174	58	740	63	(117)	(448)	101	50,572		50,572
37		Total Average rate (cents / m^3)	5.1631	0.0059	0.0762	0.0065	(0.0120)	(0.0461)	0.0104	5.2040	0.0203	5.2244
38		Average rate change (1)			1.5%	0.1%	-0.2%	-0.9%	0.2%	0.8%	0.4%	1.2%
39	M4	Revenue ($000's)	12,223	13	170	26	(25)	(120)	38	12,324		12,324
40		Volumes (10^3m^3)	403,695	403,695	403,695	403,695	403,695	403,695	403,695	403,695	(983)	402,712
41		Average rate (cents / m^3)	3.0277	0.0031	0.0420	0.0065	(0.0063)	(0.0297)	0.0095	3.0529	0.0075	3.0603
42		Average rate change (1)			1.4%	0.2%	-0.2%	-1.0%	0.3%	0.8%	0.2%	1.1%
43	M5	Revenue ($000's)	13,457	17	172	44	(70)	(56)	(15)	13,549		13,549
44		Volumes (10^3m^3)	534,596	534,596	534,596	534,596	534,596	534,596	534,596	534,596	(536)	534,060
45		Average rate (cents / m^3)	2.5172	0.0032	0.0322	0.0082	(0.0130)	(0.0105)	(0.0028)	2.5344	0.0025	2.5370
46		Average rate change (1)			1.3%	0.3%	-0.5%	-0.4%	-0.1%	0.7%	0.1%	0.8%

Notes:
(1) Average rate change is compared to column (a).

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Line No.	Particulars		2014 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2015 DSM	2015 Capital Pass Throughs: Parkway West Project	Brantford-Kirkwall & Parkway D Compressor Project	Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-franchise South Delivery and Storage (Con't)											
1	M7	Revenue ($000's)	4,094	4	51	15	(2)	(48)	14	4,128		4,128
2		Volumes (10^3m^3)	147,143	147,143	147,143	147,143	147,143	147,143	147,143	147,143	-	147,143
3		Average rate (cents / m^3)	2.7825	0.0026	0.0346	0.0100	(0.0010)	(0.0325)	0.0096	2.8057	-	2.8057
4		Average rate change (1)			1.2%	0.4%	0.0%	-1.2%	0.3%	0.8%	0.0%	0.8%
5	M9	Revenue ($000's)	707	0	11	-	4	(13)	5	715		715
6		Volumes (10^3m^3)	60,750	60,750	60,750	60,750	60,750	60,750	60,750	60,750	-	60,750
7		Average rate (cents / m^3)	1.1634	0.0004	0.0186	-	0.0070	(0.0219)	0.0089	1.1764	-	1.1764
8		Average rate change (1)			1.6%	0.0%	0.6%	-1.9%	0.8%	1.1%	0.0%	1.1%
9	M10	Revenue ($000's)	9	0	0	-	(0)	(0)	0	9		9
10		Volumes (10^3m^3)	189	189	189	189	189	189	189	189	-	189
11		Average rate (cents / m^3)	4.7823	0.0118	0.0767	-	(0.0072)	(0.2437)	0.0797	4.7260	-	4.7260
12		Average rate change (1)			1.6%	0.0%	-0.1%	-5.1%	1.7%	-1.2%	0.0%	-1.2%
13	T1	Revenue ($000's)	10,581	9	140	29	(31)	(72)	36	10,692		10,692
14		Volumes (10^3m^3)	548,986	548,986	548,986	548,986	548,986	548,986	548,986	548,986	-	548,986
15		Average rate (cents / m^3)	1.9275	0.0016	0.0255	0.0053	(0.0056)	(0.0132)	0.0065	1.9476	-	1.9476
16		Average rate change (1)			1.3%	0.3%	-0.3%	-0.7%	0.3%	1.0%	0.0%	1.0%
17	T2	Revenue ($000's)	41,223	31	618	42	(72)	(374)	299	41,768		41,768
18		Volumes (10^3m^3)	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	-	4,880,298
19		Average rate (cents / m^3)	0.8447	0.0006	0.0127	0.0009	(0.0015)	(0.0077)	0.0061	0.8558	-	0.8558
20		Average rate change (1)			1.5%	0.1%	-0.2%	-0.9%	0.7%	1.3%	0.0%	1.3%
21	T3	Revenue ($000's)	4,273	0	68	-	34	(90)	38	4,325		4,325
22		Volumes (10^3m^3)	272,712	272,712	272,712	272,712	272,712	272,712	272,712	272,712	-	272,712
23		Average rate (cents / m^3)	1.5670	0.0001	0.0251	-	0.0125	(0.0329)	0.0141	1.5858	-	1.5858
24		Average rate change (1)			1.6%	0.0%	0.8%	-2.1%	0.9%	1.2%	0.0%	1.2%
	Northern Transportation and Storage											
25	R01	Revenue ($000's)	98,615	(10)	247	-	286	1,188	(29)	100,296		100,296
26		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	884,421	884,421	-	884,421
27		Average rate (cents / m^3)	11.1502	(0.0011)	0.0279	-	0.0323	0.1343	(0.0033)	11.3403	-	11.3403
28		Average rate change (1)			0.3%	0.0%	0.3%	1.2%	0.0%	1.7%	0.0%	1.7%
29	R10	Revenue ($000's)	31,745	(1)	66	-	72	308	(9)	32,181		32,181
30		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	322,887	322,887	-	322,887
31		Average rate (cents / m^3)	9.8318	(0.0004)	0.0204	-	0.0222	0.0953	(0.0027)	9.9665	-	9.9665
32		Average rate change (1)			0.2%	0.0%	0.2%	1.0%	0.0%	1.4%	0.0%	1.4%
33	R20	Revenue ($000's)	10,551	(0)	19	-	18	82	(2)	10,667		10,667
34		Volumes (10^3m^3)	121,935	121,935	121,935	121,935	121,935	121,935	121,935	121,935	-	121,935
35		Average rate (cents / m^3)	8.6530	(0.0003)	0.0156	-	0.0147	0.0672	(0.0020)	8.7482	-	8.7482
36		Average rate change (1)			0.2%	0.0%	0.2%	0.8%	0.0%	1.1%	0.0%	1.1%
37	R25	Revenue ($000's)	2,127	0	0	-	(1)	(0)	(0)	2,127		2,127
38		Volumes (10^3m^3)	42,913	42,913	42,913	42,913	42,913	42,913	42,913	42,913	-	42,913
39		Average rate (cents / m^3)	4.9571	0.0001	0.0008	-	(0.0019)	(0.0005)	(0.0001)	4.9555	-	4.9555
40		Average rate change (1)			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
41	R100	Revenue ($000's)	168	(0)	2	-	1	6	(0)	176		176
42		Change (1)			1.0%	0.0%	0.6%	3.4%	-0.1%	4.8%	0.0%	4.8%
	Ex-franchise - Cost Based											
43	M12	Revenue ($000's)	163,694	(660)	2,609	-	7,632	2,808	(248)	175,836		175,836
44		Change (1)			1.6%	0.0%	4.7%	1.7%	-0.2%	7.4%	0.0%	7.4%
45	M13	Revenue ($000's)	423	-	7	-	-	-	-	430		430
46		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
47	M16	Revenue ($000's)	768	-	12	-	-	-	-	780		780
48		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
49	C1	Revenue ($000's)	45,218	-	125	-	162	61	(5)	45,561		45,561
50		Change (1)			0.3%	0.0%	0.4%	0.1%	0.0%	0.8%	0.0%	0.8%

Notes:
(1) Average rate change is compared to column (a).

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Line No.	Particulars		2015 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2016 DSM	2016 Capital Pass Throughs: Parkway West Project	Brantford-Kirkwall & Parkway D Compressor Project	Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-Franchise North Delivery											
1	R01	Revenue ($000's)	162,204	1,782	2,533	62	(1,102)	(796)	(305)	164,378		164,378
2		Volumes (10^3m^3)	873,498	873,498	873,498	873,498	873,498	873,498	873,498	873,498	(5,462)	868,036
3		Average rate (cents / m^3)	18.5695	0.2041	0.2900	0.0071	(0.1262)	(0.0912)	(0.0349)	18.8183	0.1184	18.9368
4		Average rate change (1)			1.6%	0.0%	-0.7%	-0.5%	-0.2%	1.3%	0.6%	2.0%
5	R10	Revenue ($000's)	19,747	228	292	20	(126)	(95)	(38)	20,026		20,026
6		Volumes (10^3m^3)	320,477	320,477	320,477	320,477	320,477	320,477	320,477	320,477	(1,205)	319,273
7		Average rate (cents / m^3)	6.1616	0.0710	0.0912	0.0061	(0.0394)	(0.0298)	(0.0119)	6.2488	0.0236	6.2724
8		Average rate change (1)			1.5%	0.1%	-0.6%	-0.5%	-0.2%	1.4%	0.4%	1.8%
9	R20	Revenue ($000's)	13,566	189	202	16	(104)	(82)	(32)	13,756		13,756
10		Volumes (10^3m^3)	629,147	629,147	629,147	629,147	629,147	629,147	629,147	629,147	(328)	628,819
11		Average rate (cents / m^3)	2.1563	0.0301	0.0321	0.0026	(0.0165)	(0.0130)	(0.0051)	2.1864	0.0011	2.1876
12		Average rate change (1)			1.5%	0.1%	-0.8%	-0.6%	-0.2%	1.4%	0.1%	1.4%
13	R25	Revenue ($000's)	4,559	58	74	-	(33)	(26)	(10)	4,622		4,622
14		Volumes (10^3m^3)	159,555	159,555	159,555	159,555	159,555	159,555	159,555	159,555	-	159,555
15		Average rate (cents / m^3)	2.8574	0.0362	0.0463	-	(0.0209)	(0.0161)	(0.0063)	2.8968	-	2.8968
16		Average rate change (1)			1.6%	0.0%	-0.7%	-0.6%	-0.2%	1.4%	0.0%	1.4%
17	R100	Revenue ($000's)	15,808	160	226	30	(90)	(69)	(28)	16,037		16,037
18		Volumes (10^3m^3)	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	-	1,895,488
19		Average rate (cents / m^3)	0.8340	0.0085	0.0119	0.0016	(0.0048)	(0.0037)	(0.0015)	0.8460	-	0.8460
20		Average rate change (1)			1.4%	0.2%	-0.6%	-0.4%	-0.2%	1.4%	0.0%	1.4%
	In-franchise South Delivery and Storage											
21	M1 - Delivery	Revenue ($000's)	373,406	3,500	5,858	173	(1,432)	(1,643)	1,509	381,371		381,371
22		Volumes (10^3m^3)	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	(12,626)	2,901,664
23		Average rate (cents / m^3)	12.8129	0.1201	0.2010	0.0059	(0.0491)	(0.0564)	0.0518	13.0862	0.0569	13.1432
24	M1 - Storage	Revenue ($000's)	21,918	440	358	-	(221)	(202)	(64)	22,231		22,231
25		Volumes (10^3m^3)	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	2,914,290	(12,626)	2,901,664
26		Average rate (cents / m^3)	0.7521	0.0151	0.0123	-	(0.0076)	(0.0069)	(0.0022)	0.7628	0.0033	0.7661
27	M1	Total Revenue ($000's)	395,324	3,940	6,216	173	(1,652)	(1,844)	1,446	403,602		403,602
28		Total Average rate (cents / m^3)	13.5650	0.1352	0.2133	0.0059	(0.0567)	(0.0633)	0.0496	13.8491	0.0603	13.9093
29		Average rate change (1)			1.6%	0.0%	-0.4%	-0.5%	0.4%	2.1%	0.4%	2.5%
30	M2 - Delivery	Revenue ($000's)	43,118	313	631	64	101	(146)	658	44,739		44,739
31		Volumes (10^3m^3)	968,003	968,003	968,003	968,003	968,003	968,003	968,003	968,003	(3,784)	964,219
32		Average rate (cents / m^3)	4.4543	0.0324	0.0651	0.0066	0.0104	(0.0150)	0.0679	4.6218	0.0181	4.6399
33	M2 - Storage	Revenue ($000's)	7,454	150	122	-	(75)	(69)	(22)	7,560		7,560
34		Volumes (10^3m^3)	968,003	968,003	968,003	968,003	968,003	968,003	968,003	968,003	(3,784)	964,219
35		Average rate (cents / m^3)	0.7700	0.0155	0.0126	-	(0.0078)	(0.0071)	(0.0022)	0.7810	0.0031	0.7840
36	M2	Total Revenue ($000's)	50,572	464	752	64	26	(214)	636	52,299		52,299
37		Total Average rate (cents / m^3)	5.2243	0.0479	0.0777	0.0066	0.0026	(0.0221)	0.0657	5.4028	0.0212	5.4240
38		Average rate change (1)			1.5%	0.1%	0.1%	-0.4%	1.3%	3.4%	0.4%	3.8%
39	M4	Revenue ($000's)	12,324	107	172	27	13	(53)	211	12,801		12,801
40		Volumes (10^3m^3)	402,712	402,712	402,712	402,712	402,712	402,712	402,712	402,712	(983)	401,730
41		Average rate (cents / m^3)	3.0603	0.0265	0.0428	0.0066	0.0033	(0.0131)	0.0524	3.1788	0.0078	3.1866
42		Average rate change (1)			1.4%	0.2%	0.1%	-0.4%	1.7%	3.9%	0.3%	4.1%
43	M5	Revenue ($000's)	13,549	140	175	44	(87)	(59)	(21)	13,741		13,741
44		Volumes (10^3m^3)	534,060	534,060	534,060	534,060	534,060	534,060	534,060	534,060	(536)	533,523
45		Average rate (cents / m^3)	2.5370	0.0263	0.0327	0.0083	(0.0164)	(0.0110)	(0.0040)	2.5729	0.0026	2.5755
46		Average rate change (1)			1.3%	0.3%	-0.6%	-0.4%	-0.2%	1.4%	0.1%	1.5%

Notes:
(1) Average rate change is compared to column (a).

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Line No.	Particulars		2015 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2016 DSM	2016 Capital Pass Throughs: Parkway West Project	Brantford-Kirkwall & Parkway D Compressor Project	Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-franchise South Delivery and Storage (Con't)											
1	M7	Revenue ($000's)	4,128	35	52	15	20	(16)	78	4,312		4,312
2		Volumes (10^3m^3)	147,143	147,143	147,143	147,143	147,143	147,143	147,143	147,143	-	147,143
3		Average rate (cents / m^3)	2.8057	0.0239	0.0351	0.0102	0.0136	(0.0109)	0.0527	2.9304	-	2.9304
4		Average rate change (1)			1.3%	0.4%	0.5%	-0.4%	1.9%	4.4%	0.0%	4.4%
5	M9	Revenue ($000's)	715	4	11	-	13	(2)	26	768		768
6		Volumes (10^3m^3)	60,750	60,750	60,750	60,750	60,750	60,750	60,750	60,750	-	60,750
7		Average rate (cents / m^3)	1.1764	0.0060	0.0189	-	0.0217	(0.0029)	0.0434	1.2635	-	1.2635
8		Average rate change (1)			1.6%	0.0%	1.8%	-0.2%	3.7%	7.4%	0.0%	7.4%
9	M10	Revenue ($000's)	9	0	0	-	0	(0)	1	10		10
10		Volumes (10^3m^3)	189	189	189	189	189	189	189	189	-	189
11		Average rate (cents / m^3)	4.6996	0.1712	0.0779	-	0.0686	(0.0985)	0.3966	5.3419	-	5.3419
12		Average rate change (1)			1.7%	0.0%	1.5%	-2.1%	8.4%	13.7%	0.0%	13.7%
13	T1	Revenue ($000's)	10,692	67	142	30	(19)	(41)	183	11,053		11,053
14		Volumes (10^3m^3)	548,986	548,986	548,986	548,986	548,986	548,986	548,986	548,986	-	548,986
15		Average rate (cents / m^3)	1.9476	0.0121	0.0259	0.0054	(0.0035)	(0.0075)	0.0333	2.0134	-	2.0134
16		Average rate change (1)			1.3%	0.3%	-0.2%	-0.4%	1.7%	3.4%	0.0%	3.4%
17	T2	Revenue ($000's)	41,763	147	627	43	38	(166)	1,410	43,862		43,862
18		Volumes (10^3m^3)	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	-	4,880,298
19		Average rate (cents / m^3)	0.8558	0.0030	0.0129	0.0009	0.0008	(0.0034)	0.0289	0.8988	-	0.8988
20		Average rate change (1)			1.5%	0.1%	0.1%	-0.4%	3.4%	5.0%	0.0%	5.0%
21	T3	Revenue ($000's)	4,324	17	69	-	98	(8)	184	4,684		4,684
22		Volumes (10^3m^3)	272,712	272,712	272,712	272,712	272,712	272,712	272,712	272,712	-	272,712
23		Average rate (cents / m^3)	1.5857	0.0064	0.0255	-	0.0358	(0.0031)	0.0673	1.7176	-	1.7176
24		Average rate change (1)			1.6%	0.0%	2.3%	-0.2%	4.2%	8.3%	0.0%	8.3%
	Northern Transportation and Storage											
25	R01	Revenue ($000's)	100,295	(1,443)	250	-	708	1,926	(15)	101,720		101,720
26		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	884,421	884,421	-	884,421
27		Average rate (cents / m^3)	11.3401	(0.1632)	0.0283	-	0.0800	0.2177	(0.0017)	11.5013	-	11.5013
28		Average rate change (1)			0.2%	0.0%	0.7%	1.9%	0.0%	1.4%	0.0%	1.4%
29	R10	Revenue ($000's)	32,181	(371)	67	-	183	501	(5)	32,555		32,555
30		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	322,887	322,887	-	322,887
31		Average rate (cents / m^3)	9.9667	(0.1150)	0.0207	-	0.0565	0.1551	(0.0015)	10.0825	-	10.0825
32		Average rate change (1)			0.2%	0.0%	0.6%	1.6%	0.0%	1.2%	0.0%	1.2%
33	R20	Revenue ($000's)	10,668	(98)	19	-	46	133	(2)	10,767		10,767
34		Volumes (10^3m^3)	121,935	121,935	121,935	121,935	121,935	121,935	121,935	121,935	-	121,935
35		Average rate (cents / m^3)	8.7490	(0.0804)	0.0158	-	0.0380	0.1091	(0.0014)	8.8302	-	8.8302
36		Average rate change (1)			0.2%	0.0%	0.4%	1.2%	0.0%	0.9%	0.0%	0.9%
37	R25	Revenue ($000's)	2,127	1	0	-	(2)	(1)	(0)	2,126		2,126
38		Volumes (10^3m^3)	42,913	42,913	42,913	42,913	42,913	42,913	42,913	42,913	-	42,913
39		Average rate (cents / m^3)	4.9555	0.0025	0.0009	-	(0.0036)	(0.0012)	(0.0005)	4.9535	-	4.9535
40		Average rate change (1)			0.0%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
41	R100	Revenue ($000's)	176	(6)	2	-	3	9	(0)	183		183
42		Change (1)			1.0%	0.0%	1.5%	5.2%	-0.1%	3.9%	0.0%	3.9%
	Ex-franchise - Cost Based											
43	M12	Revenue ($000's)	175,836	(10,193)	2,650	-	17,104	15,570	102	201,069		201,069
44		Change (1)			1.5%	0.0%	9.7%	8.9%	0.1%	14.4%	0.0%	14.4%
45	M13	Revenue ($000's)	430	-	7	-	-	-	-	437		437
46		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
47	M16	Revenue ($000's)	780	-	12	-	-	-	-	792		792
48		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
49	C1	Revenue ($000's)	45,561	(219)	127	-	362	99	3	45,933		45,933
50		Change (1)			0.3%	0.0%	0.8%	0.2%	0.0%	0.8%	0.0%	0.8%

Notes:
(1) Average rate change is compared to column (a).

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Line No.	Particulars		2016 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2017 DSM	2017 Capital Pass Throughs: Parkway West Project	2017 Capital Pass Throughs: Brantford-Kirkwall & Parkway D Compressor Project	2017 Capital Pass Throughs: Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-Franchise North Delivery											
1	R01	Revenue ($000's)	164,380	2,201	2,573	63	(987)	(750)	(159)	167,320		167,320
2		Volumes (10^3m^3)	868,036	868,036	868,036	868,036	868,036	868,036	868,036	868,036	(5,462)	862,574
3		Average rate (cents / m^3)	18.9370	0.2536	0.2965	0.0072	(0.1137)	(0.0864)	(0.0184)	19.2757	0.1221	19.3978
4		Average rate change (1)			1.6%	0.0%	-0.6%	-0.5%	-0.1%	1.8%	0.6%	2.4%
5	R10	Revenue ($000's)	20,025	261	297	20	(111)	(88)	(19)	20,384		20,384
6		Volumes (10^3m^3)	319,273	319,273	319,273	319,273	319,273	319,273	319,273	319,273	(1,205)	318,068
7		Average rate (cents / m^3)	6.2721	0.0816	0.0930	0.0062	(0.0347)	(0.0277)	(0.0060)	6.3846	0.0242	6.4088
8		Average rate change (1)			1.5%	0.1%	-0.6%	-0.4%	-0.1%	1.8%	0.4%	2.2%
9	R20	Revenue ($000's)	13,755	219	205	16	(91)	(76)	(17)	14,012		14,012
10		Volumes (10^3m^3)	628,819	628,819	628,819	628,819	628,819	628,819	628,819	628,819	(328)	628,492
11		Average rate (cents / m^3)	2.1874	0.0348	0.0326	0.0026	(0.0145)	(0.0121)	(0.0026)	2.2283	0.0012	2.2295
12		Average rate change (1)			1.5%	0.1%	-0.7%	-0.6%	-0.1%	1.9%	0.1%	1.9%
13	R25	Revenue ($000's)	4,622	69	75	-	(29)	(24)	(5)	4,707		4,707
14		Volumes (10^3m^3)	159,555	159,555	159,555	159,555	159,555	159,555	159,555	159,555	-	159,555
15		Average rate (cents / m^3)	2.8967	0.0432	0.0470	-	(0.0185)	(0.0150)	(0.0032)	2.9503	-	2.9503
16		Average rate change (1)			1.6%	0.0%	-0.6%	-0.5%	-0.1%	1.8%	0.0%	1.8%
17	R100	Revenue ($000's)	16,037	187	229	30	(80)	(65)	(14)	16,325		16,325
18		Volumes (10^3m^3)	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	-	1,895,488
19		Average rate (cents / m^3)	0.8460	0.0099	0.0121	0.0016	(0.0042)	(0.0034)	(0.0007)	0.8613	-	0.8613
20		Average rate change (1)			1.4%	0.2%	-0.5%	-0.4%	-0.1%	1.8%	0.0%	1.8%
	In-franchise South Delivery and Storage											
21	M1 - Delivery	Revenue ($000's)	381,371	1,565	5,952	175	(1,170)	(1,509)	1,751	388,135		388,135
22		Volumes (10^3m^3)	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	(12,626)	2,889,038
23		Average rate (cents / m^3)	13.1432	0.0539	0.2051	0.0060	(0.0403)	(0.0520)	0.0603	13.3763	0.0585	13.4347
24	M1 - Storage	Revenue ($000's)	22,230	486	363	-	(184)	(173)	(47)	22,675		22,675
25		Volumes (10^3m^3)	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	2,901,664	(12,626)	2,889,038
26		Average rate (cents / m^3)	0.7661	0.0167	0.0125	-	(0.0063)	(0.0060)	(0.0016)	0.7814	0.0034	0.7849
27	M1	Total Revenue ($000's)	403,600	2,051	6,315	175	(1,354)	(1,683)	1,704	410,809		410,809
28		Total Average rate (cents / m^3)	13.9093	0.0707	0.2176	0.0060	(0.0467)	(0.0580)	0.0587	14.1577	0.0619	14.2196
29		Average rate change (1)			1.6%	0.0%	-0.3%	-0.4%	0.4%	1.8%	0.4%	2.2%
30	M2 - Delivery	Revenue ($000's)	44,739	(613)	641	65	136	(118)	669	45,518		45,518
31		Volumes (10^3m^3)	964,219	964,219	964,219	964,219	964,219	964,219	964,219	964,219	(3,784)	960,435
32		Average rate (cents / m^3)	4.6399	(0.0635)	0.0664	0.0068	0.0141	(0.0123)	0.0694	4.7208	0.0186	4.7394
33	M2 - Storage	Revenue ($000's)	7,559	166	124	-	(63)	(59)	(16)	7,711		7,711
34		Volumes (10^3m^3)	964,219	964,219	964,219	964,219	964,219	964,219	964,219	964,219	(3,784)	960,435
35		Average rate (cents / m^3)	0.7840	0.0172	0.0128	-	(0.0065)	(0.0061)	(0.0017)	0.7997	0.0032	0.8029
36	M2	Total Revenue ($000's)	52,298	(447)	764	65	73	(177)	653	53,229		53,229
37		Total Average rate (cents / m^3)	5.4239	(0.0464)	0.0793	0.0068	0.0076	(0.0184)	0.0677	5.5205	0.0217	5.5422
38		Average rate change (1)			1.5%	0.1%	0.1%	-0.3%	1.2%	1.8%	0.4%	2.2%
39	M4	Revenue ($000's)	12,801	(172)	175	27	25	(44)	215	13,028		13,028
40		Volumes (10^3m^3)	401,730	401,730	401,730	401,730	401,730	401,730	401,730	401,730	(983)	400,747
41		Average rate (cents / m^3)	3.1866	(0.0427)	0.0436	0.0067	0.0062	(0.0109)	0.0535	3.2429	0.0080	3.2508
42		Average rate change (1)			1.4%	0.2%	0.2%	-0.3%	1.7%	1.8%	0.2%	2.0%
43	M5	Revenue ($000's)	13,741	167	178	45	(79)	(57)	(7)	13,988		13,988
44		Volumes (10^3m^3)	533,523	533,523	533,523	533,523	533,523	533,523	533,523	533,523	(536)	532,987
45		Average rate (cents / m^3)	2.5756	0.0314	0.0333	0.0084	(0.0148)	(0.0107)	(0.0013)	2.6218	0.0026	2.6245
46		Average rate change (1)			1.3%	0.3%	-0.6%	-0.4%	-0.1%	1.8%	0.1%	1.9%

Notes:
(1) Average rate change is compared to column (a).

UNION GAS LIMITED
2014-2018 IR Forecast - Rate Impact Continuity
Effective January 1, 2017

Line No.	Particulars		2016 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2017 DSM	2017 Capital Pass Throughs: Parkway West Project	2017 Capital Pass Throughs: Brantford-Kirkwall & Parkway D Compressor Project	2017 Capital Pass Throughs: Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-franchise South Delivery and Storage (Con't)											
1	M7	Revenue ($000's)	4,312	(82)	52	15	24	(12)	78	4,388		4,388
2		Volumes (10^3m^3)	147,143	147,143	147,143	147,143	147,143	147,143	147,143	147,143	-	147,143
3		Average rate (cents / m^3)	2.9304	(0.0555)	0.0357	0.0103	0.0165	(0.0084)	0.0530	2.9820	-	2.9820
4		Average rate change (1)			1.2%	0.4%	0.6%	-0.3%	1.8%	1.8%	0.0%	1.8%
5	M9	Revenue ($000's)	768	(38)	12	-	14	(1)	26	781		781
6		Volumes (10^3m^3)	60,750	60,750	60,750	60,750	60,750	60,750	60,750	60,750	-	60,750
7		Average rate (cents / m^3)	1.2635	(0.0622)	0.0192	-	0.0232	(0.0010)	0.0421	1.2849	-	1.2849
8		Average rate change (1)			1.5%	0.0%	1.8%	-0.1%	3.3%	1.7%	0.0%	1.7%
9	M10	Revenue ($000's)	10	(1)	0	-	0	(0)	1	10		10
10		Volumes (10^3m^3)	189	189	189	189	189	189	189	189	-	189
11		Average rate (cents / m^3)	5.3155	(0.3667)	0.0792	-	0.0854	(0.0891)	0.3984	5.4491	-	5.4491
12		Average rate change (1)			1.5%	0.0%	1.6%	-1.7%	7.5%	2.5%	0.0%	2.5%
13	T1	Revenue ($000's)	11,050	(123)	145	30	(11)	(35)	185	11,241		11,241
14		Volumes (10^3m^3)	548,986	548,986	548,986	548,986	548,986	548,986	548,986	548,986	-	548,986
15		Average rate (cents / m^3)	2.0129	(0.0224)	0.0263	0.0055	(0.0020)	(0.0064)	0.0337	2.0476	-	2.0476
16		Average rate change (1)			1.3%	0.3%	-0.1%	-0.3%	1.7%	1.7%	0.0%	1.7%
17	T2	Revenue ($000's)	43,846	(1,281)	637	44	80	(122)	1,387	44,591		44,591
18		Volumes (10^3m^3)	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	-	4,880,298
19		Average rate (cents / m^3)	0.8984	(0.0263)	0.0131	0.0009	0.0016	(0.0025)	0.0284	0.9137	-	0.9137
20		Average rate change (1)			1.5%	0.1%	0.2%	-0.3%	3.2%	1.7%	0.0%	1.7%
21	T3	Revenue ($000's)	4,684	(273)	71	-	103	(1)	178	4,762		4,762
22		Volumes (10^3m^3)	272,712	272,712	272,712	272,712	272,712	272,712	272,712	272,712	-	272,712
23		Average rate (cents / m^3)	1.7176	(0.1000)	0.0259	-	0.0378	(0.0003)	0.0653	1.7463	-	1.7463
24		Average rate change (1)			1.5%	0.0%	2.2%	0.0%	3.8%	1.7%	0.0%	1.7%
	Northern Transportation and Storage											
25	R01	Revenue ($000's)	101,718	(2,617)	254	-	723	1,951	(20)	102,010		102,010
26		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	884,421	884,421	-	884,421
27		Average rate (cents / m^3)	11.5011	(0.2959)	0.0288	-	0.0818	0.2206	(0.0022)	11.5341	-	11.5341
28		Average rate change (1)			0.3%	0.0%	0.7%	1.9%	0.0%	0.3%	0.0%	0.3%
29	R10	Revenue ($000's)	32,556	(679)	68	-	187	508	(6)	32,634		32,634
30		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	322,887	322,887	-	322,887
31		Average rate (cents / m^3)	10.0828	(0.2104)	0.0210	-	0.0580	0.1574	(0.0019)	10.1070	-	10.1070
32		Average rate change (1)			0.2%	0.0%	0.6%	1.6%	0.0%	0.2%	0.0%	0.2%
33	R20	Revenue ($000's)	10,768	(179)	20	-	48	135	(2)	10,790		10,790
34		Volumes (10^3m^3)	121,935	121,935	121,935	121,935	121,935	121,935	121,935	121,935	-	121,935
35		Average rate (cents / m^3)	8.8311	(0.1465)	0.0161	-	0.0390	0.1105	(0.0014)	8.8489	-	8.8489
36		Average rate change (1)			0.2%	0.0%	0.4%	1.3%	0.0%	0.2%	0.0%	0.2%
37	R25	Revenue ($000's)	2,126	2	0	-	(2)	(1)	(0)	2,126		2,126
38		Volumes (10^3m^3)	42,913	42,913	42,913	42,913	42,913	42,913	42,913	42,913	-	42,913
39		Average rate (cents / m^3)	4.9535	0.0054	0.0009	-	(0.0036)	(0.0016)	(0.0001)	4.9544	-	4.9544
40		Average rate change (1)			0.0%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
41	R100	Revenue ($000's)	182	(12)	2	-	3	9	(0)	184		184
42		Change (1)			0.9%	0.0%	1.5%	5.0%	-0.1%	1.1%	0.0%	1.1%
	Ex-franchise - Cost Based											
43	M12	Revenue ($000's)	201,069	(32,776)	2,693	-	17,216	15,901	(109)	203,993		203,993
44		Change (1)			1.3%	0.0%	8.6%	7.9%	-0.1%	1.5%	0.0%	1.5%
45	M13	Revenue ($000's)	437	-	7	-	-	-	-	444		444
46		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
47	M16	Revenue ($000's)	792	-	13	-	-	-	-	805		805
48		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
49	C1	Revenue ($000's)	45,933	(463)	129	-	364	105	(2)	46,065		46,065
50		Change (1)			0.3%	0.0%	0.8%	0.2%	0.0%	0.3%	0.0%	0.3%

Notes:
(1) Average rate change is compared to column (a).

UNION GAS LIMITED
2014-2018 IR Forecast - Rate Impact Continuity
Effective January 1, 2018

Line No.	Particulars		2017 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2018 DSM	2018 Capital Pass Throughs: Parkway West Project	2018 Capital Pass Throughs: Brantford-Kirkwall & Parkway D Compressor Project	2018 Capital Pass Throughs: Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-Franchise North Delivery											
1	R01	Revenue ($000's)	167,322	1,895	2,614	64	(865)	(637)	(124)	170,269		170,269
2		Volumes (10^3m^3)	862,574	862,574	862,574	862,574	862,574	862,574	862,574	862,574	(5,462)	857,112
3		Average rate (cents / m^3)	19.3980	0.2197	0.3031	0.0074	(0.1002)	(0.0739)	(0.0143)	19.7397	0.1258	19.8655
4		Average rate change (1)			1.6%	0.0%	-0.5%	-0.4%	-0.1%	1.8%	0.6%	2.4%
5	R10	Revenue ($000's)	20,384	219	302	20	(94)	(73)	(14)	20,743		20,743
6		Volumes (10^3m^3)	318,068	318,068	318,068	318,068	318,068	318,068	318,068	318,068	(1,205)	316,863
7		Average rate (cents / m^3)	6.4086	0.0689	0.0948	0.0064	(0.0296)	(0.0231)	(0.0045)	6.5215	0.0248	6.5463
8		Average rate change (1)			1.5%	0.1%	-0.5%	-0.4%	-0.1%	1.8%	0.4%	2.1%
9	R20	Revenue ($000's)	14,011	184	208	17	(77)	(63)	(13)	14,268		14,268
10		Volumes (10^3m^3)	628,492	628,492	628,492	628,492	628,492	628,492	628,492	628,492	(328)	628,164
11		Average rate (cents / m^3)	2.2293	0.0293	0.0332	0.0026	(0.0122)	(0.0100)	(0.0020)	2.2702	0.0012	2.2714
12		Average rate change (1)			1.5%	0.1%	-0.5%	-0.5%	-0.1%	1.8%	0.1%	1.9%
13	R25	Revenue ($000's)	4,707	59	76	-	(25)	(20)	(4)	4,793		4,793
14		Volumes (10^3m^3)	159,555	159,555	159,555	159,555	159,555	159,555	159,555	159,555	-	159,555
15		Average rate (cents / m^3)	2.9503	0.0367	0.0478	-	(0.0158)	(0.0126)	(0.0025)	3.0039	-	3.0039
16		Average rate change (1)			1.6%	0.0%	-0.5%	-0.4%	-0.1%	1.8%	0.0%	1.8%
17	R100	Revenue ($000's)	16,324	158	233	31	(68)	(54)	(10)	16,614		16,614
18		Volumes (10^3m^3)	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	-	1,895,488
19		Average rate (cents / m^3)	0.8612	0.0083	0.0123	0.0016	(0.0036)	(0.0029)	(0.0005)	0.8765	-	0.8765
20		Average rate change (1)			1.4%	0.2%	-0.4%	-0.3%	-0.1%	1.8%	0.0%	1.8%
	In-franchise South Delivery and Storage											
21	M1 - Delivery	Revenue ($000's)	388,134	928	6,047	178	(920)	(1,272)	1,807	394,903		394,903
22		Volumes (10^3m^3)	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	(12,626)	2,876,411
23		Average rate (cents / m^3)	13.4347	0.0321	0.2093	0.0062	(0.0318)	(0.0440)	0.0625	13.6690	0.0600	13.7290
24	M1 - Storage	Revenue ($000's)	22,676	404	369	-	(151)	(144)	(38)	23,117		23,117
25		Volumes (10^3m^3)	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	2,889,038	(12,626)	2,876,411
26		Average rate (cents / m^3)	0.7849	0.0140	0.0128	-	(0.0052)	(0.0050)	(0.0013)	0.8002	0.0035	0.8037
27	M1	Total Revenue ($000's)	410,811	1,333	6,416	178	(1,071)	(1,416)	1,769	418,020		418,020
28		Total Average rate (cents / m^3)	14.2196	0.0461	0.2221	0.0062	(0.0371)	(0.0490)	0.0612	14.4692	0.0635	14.5327
29		Average rate change (1)			1.6%	0.0%	-0.3%	-0.3%	0.4%	1.8%	0.4%	2.2%
30	M2 - Delivery	Revenue ($000's)	45,518	(686)	651	66	164	(91)	672	46,294		46,294
31		Volumes (10^3m^3)	960,435	960,435	960,435	960,435	960,435	960,435	960,435	960,435	(3,784)	956,651
32		Average rate (cents / m^3)	4.7393	(0.0715)	0.0678	0.0069	0.0171	(0.0095)	0.0699	4.8201	0.0191	4.8392
33	M2 - Storage	Revenue ($000's)	7,711	138	126	-	(51)	(49)	(13)	7,861		7,861
34		Volumes (10^3m^3)	960,435	960,435	960,435	960,435	960,435	960,435	960,435	960,435	(3,784)	956,651
35		Average rate (cents / m^3)	0.8029	0.0143	0.0131	-	(0.0054)	(0.0051)	(0.0013)	0.8185	0.0032	0.8218
36	M2	Total Revenue ($000's)	53,230	(549)	776	66	113	(140)	659	54,155		54,155
37		Total Average rate (cents / m^3)	5.5422	(0.0571)	0.0808	0.0069	0.0117	(0.0146)	0.0686	5.6386	0.0223	5.6609
38		Average rate change (1)			1.5%	0.1%	0.2%	-0.3%	1.2%	1.7%	0.4%	2.1%
39	M4	Revenue ($000's)	13,028	(196)	178	27	34	(35)	216	13,252		13,252
40		Volumes (10^3m^3)	400,747	400,747	400,747	400,747	400,747	400,747	400,747	400,747	(983)	399,764
41		Average rate (cents / m^3)	3.2508	(0.0489)	0.0444	0.0068	0.0086	(0.0087)	0.0538	3.3069	0.0081	3.3150
42		Average rate change (1)			1.4%	0.2%	0.3%	-0.3%	1.7%	1.7%	0.3%	2.0%
43	M5	Revenue ($000's)	13,988	143	180	46	(70)	(48)	(4)	14,236		14,236
44		Volumes (10^3m^3)	532,987	532,987	532,987	532,987	532,987	532,987	532,987	532,987	(536)	532,451
45		Average rate (cents / m^3)	2.6245	0.0269	0.0338	0.0086	(0.0130)	(0.0091)	(0.0008)	2.6709	0.0027	2.6736
46		Average rate change (1)			1.3%	0.3%	-0.5%	-0.3%	0.0%	1.8%	0.1%	1.9%

Notes:
(1) Average rate change is compared to column (a).

UNION GAS LIMITED
2014-2018 IR Forecast - Rate Impact Continuity
Effective January 1, 2018

Line No.	Particulars		2017 Forecast Revenue	Removal of Prior Years Capital Pass-Throughs	Application of Price Cap Index	2018 DSM	2018 Capital Pass Throughs: Parkway West Project	2018 Capital Pass Throughs: Brantford-Kirkwall & Parkway D Compressor Project	2018 Capital Pass Throughs: Burlington to Oakville Project	Total Excluding Weather Adjustment	Weather Adjustment	Total Including Weather Adjustment
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = sum (a to g)	(i)	(j) = (h + i)
	In-franchise South Delivery and Storage (Con't)											
1	M7	Revenue ($000's)	4,388	(90)	53	15	27	(9)	78	4,463		4,463
2		Volumes (10^3m^3)	147,143	147,143	147,143	147,143	147,143	147,143	147,143	147,143	-	147,143
3		Average rate (cents / m^3)	2.9820	(0.0611)	0.0362	0.0105	0.0186	(0.0063)	0.0531	3.0331	-	3.0331
4		Average rate change (1)			1.2%	0.4%	0.6%	-0.2%	1.8%	1.7%	0.0%	1.7%
5	M9	Revenue ($000's)	781	(39)	12	-	15	(0)	25	793		793
6		Volumes (10^3m^3)	60,750	60,750	60,750	60,750	60,750	60,750	60,750	60,750	-	60,750
7		Average rate (cents / m^3)	1.2849	(0.0643)	0.0195	-	0.0240	(0.0002)	0.0420	1.3058	-	1.3058
8		Average rate change (1)			1.5%	0.0%	1.9%	0.0%	3.3%	1.6%	0.0%	1.6%
9	M10	Revenue ($000's)	10	(1)	0	-	0	(0)	1	10		10
10		Volumes (10^3m^3)	189	189	189	189	189	189	189	189	-	189
11		Average rate (cents / m^3)	5.4227	(0.3947)	0.0804	-	0.0947	(0.0783)	0.3982	5.5494	-	5.5494
12		Average rate change (1)			1.5%	0.0%	1.7%	-1.4%	7.3%	2.3%	0.0%	2.3%
13	T1	Revenue ($000's)	11,237	(139)	147	31	(5)	(29)	185	11,427		11,427
14		Volumes (10^3m^3)	548,986	548,986	548,986	548,986	548,986	548,986	548,986	548,986	-	548,986
15		Average rate (cents / m^3)	2.0469	(0.0254)	0.0268	0.0056	(0.0008)	(0.0052)	0.0337	2.0815	-	2.0815
16		Average rate change (1)			1.3%	0.3%	0.0%	-0.3%	1.6%	1.7%	0.0%	1.7%
17	T2	Revenue ($000's)	44,567	(1,345)	647	44	106	(94)	1,381	45,306		45,306
18		Volumes (10^3m^3)	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	-	4,880,298
19		Average rate (cents / m^3)	0.9132	(0.0276)	0.0133	0.0009	0.0022	(0.0019)	0.0283	0.9284	-	0.9284
20		Average rate change (1)			1.5%	0.1%	0.2%	-0.2%	3.1%	1.7%	0.0%	1.7%
21	T3	Revenue ($000's)	4,762	(280)	72	-	106	2	177	4,839		4,839
22		Volumes (10^3m^3)	272,712	272,712	272,712	272,712	272,712	272,712	272,712	272,712	-	272,712
23		Average rate (cents / m^3)	1.7463	(0.1028)	0.0263	-	0.0388	0.0006	0.0651	1.7743	-	1.7743
24		Average rate change (1)			1.5%	0.0%	2.2%	0.0%	3.7%	1.6%	0.0%	1.6%
	Northern Transportation and Storage											
25	R01	Revenue ($000's)	102,009	(2,653)	259	-	732	1,956	(14)	102,289		102,289
26		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	884,421	884,421	-	884,421
27		Average rate (cents / m^3)	11.5339	(0.2999)	0.0292	-	0.0827	0.2212	(0.0015)	11.5657	-	11.5657
28		Average rate change (1)			0.3%	0.0%	0.7%	1.9%	0.0%	0.3%	0.0%	0.3%
29	R10	Revenue ($000's)	32,635	(690)	69	-	190	510	(4)	32,710		32,710
30		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	322,887	322,887	-	322,887
31		Average rate (cents / m^3)	10.1072	(0.2138)	0.0214	-	0.0589	0.1580	(0.0013)	10.1304	-	10.1304
32		Average rate change (1)			0.2%	0.0%	0.6%	1.6%	0.0%	0.2%	0.0%	0.2%
33	R20	Revenue ($000's)	10,791	(182)	20	-	48	135	(1)	10,812		10,812
34		Volumes (10^3m^3)	121,935	121,935	121,935	121,935	121,935	121,935	121,935	121,935	-	121,935
35		Average rate (cents / m^3)	8.8499	(0.1489)	0.0164	-	0.0397	0.1110	(0.0010)	8.8670	-	8.8670
36		Average rate change (1)			0.2%	0.0%	0.4%	1.3%	0.0%	0.2%	0.0%	0.2%
37	R25	Revenue ($000's)	2,126	2	0	-	(2)	(1)	(0)	2,126		2,126
38		Volumes (10^3m^3)	42,913	42,913	42,913	42,913	42,913	42,913	42,913	42,913	-	42,913
39		Average rate (cents / m^3)	4.9544	0.0053	0.0009	-	(0.0037)	(0.0015)	(0.0001)	4.9554	-	4.9554
40		Average rate change (1)			0.0%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
41	R100	Revenue ($000's)	184	(12)	2	-	3	9	(0)	186		186
42		Change (1)			0.9%	0.0%	1.5%	5.0%	-0.1%	1.0%	0.0%	1.0%
	Ex-franchise - Cost Based											
43	M12	Revenue ($000's)	203,993	(33,008)	2,736	-	17,201	15,841	(44)	206,719		206,719
44		Change (1)			1.3%	0.0%	8.4%	7.8%	0.0%	1.3%	0.0%	1.3%
45	M13	Revenue ($000's)	444	-	7	-	-	-	-	451		451
46		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
47	M16	Revenue ($000's)	805	-	13	-	-	-	-	818		818
48		Change (1)			1.6%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	1.6%
49	C1	Revenue ($000's)	46,065	(467)	131	-	364	103	(1)	46,195		46,195
50		Change (1)			0.3%	0.0%	0.8%	0.2%	0.0%	0.3%	0.0%	0.3%

Notes:
(1) Average rate change is compared to column (a).

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: Exhibit H1, Tab 4, page 3, Updated

Union is proposing to continue the average use per customer deferral account for the general service classes.

a) Please explain why Union is not proposing an average use deferral account for contract rate classes.

b) Does the average use per customer deferral account applied to the general service rate classes have impact on the weather risk? If the answer is yes, please explain.

c) Does the use of an average use per customer deferral account for some rate classes and not for others reduce the business (forecast) risk for some rate classes relative to other rate classes? If the response is no, please explain and confirm that removal of the average use per customer deferral account for the general service rate classes does not increase the business (forecast) risk for those rate classes relative to the other rate classes that do not have a similar deferral account.

Response:

a) The average use ("AU") deferral account for the general service rate classes was established to address declining revenues attributable primarily to non-DSM related efficiency gains over the incentive regulation term. Union's general service rate classes are homogenous in that gas is primarily used for space and water heating (i.e. common load profile and technology). Also, factors that influence consumption are generally applicable across the class.

   Contract customers are not homogenous varying dramatically in consumption and load factor. Over the current incentive regulation, Union has been required to manage consumption variances for contract rate classes Union will consider as part of its proposals related to the next generation incentive regulation framework whether or not to propose a variance account to capture volume changes in the contract market.

b) No. The average use deferral account does not impact weather risk as the average use is calculated based on weather normalized data.

c) Please see the response at Exhibit J.DV-4-2-1 b).

UNION GAS LIMITED

Accounting Entries for
Average Use Per Customer
Deferral Account No. 179-118

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

Debit	-	Account No. 500 Sales Revenue
Credit	-	Account No. 179-118 Other Deferred Charges - Declining Average Use

To record as a debit (credit) in Deferral Account No. 179-118 the margin variance resulting from the difference between the actual rate of decline in use-per-customer and forecast rate of decline in use-per-customer included in gas delivery rates as approved by the Board in each year of the incentive regulation plan, 2008 through 2012. Actual and forecast rate of declines in use-per-customer will be calculated on a percentage and rate class specific basis for rate classes M1, M2, 01 and 10, be normalized for weather and exclude the impacts attributed to DSM which are captured in the Lost Revenue Adjustment Mechanism Deferral Account No. 179-75.

Debit	-	Account No. 179-118 Other Deferred Charges - Declining Average Use
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-118, interest on the balance in Deferral Account No. 179-118. 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.

Attachment 5

Filed: 2013-05-08
EB-2013-0109
Exhibit A
Tab 1
Appendix A
Schedule 8

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

Line No.	Particulars (m^3)		Rate 01		Rate 10		Rate M1/M2		Net Account Balance
			(a)	(b)	(c)	(d)	(e)	(f)	(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

Filed: 2012-03-30
EB-2012-0087
Exhibit A
Tab 1
Schedule 6

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

Line No.	Particulars (m^3)		Rate 01 (a)	(b)	Rate 10 (c)	(d)	Rate M1/M2 (e)	(f)	Net Account Balance (g)
1	2010 Target Average Use		3,128	(0.0%)	148,852	6.5%	4,239	(0.6%)	
2	2010 Actual Average Use	(1)	3,175	(1.2%)	171,877	6.6%	4,104	(1.9%)	
3	2011 Target Average Use		3,128	0.0%	159,570	7.2%	4,179	(1.4%)	
4	2011 Actual Average Use		3,189	0.4%	180,161	4.8%	4,208	2.5%	
5	Forecast decline in Average Use per customer (line 3 - line 2)	(2)	(47)		(12,307)		76		
6	Actual decline in Average Use per customer (line 4 - line 2)		14		8,283		104		
7	Change in Average Use - Forecast vs. Actual (line 5 - line 6)	(3)	(61)		(20,591)		(28)		
8	2007 Board Approved Number of Customers		295,672		2,966		987,063		
9	Volume Impact (10^3m^3)		(18,091.5)		(60,955.0)		(28,495.7)		
10	2011 Board Approved Average Delivery Rate ($\$/10^3m^3$)	(4)	70.36		46.44		34.11		
11	Average Use Deferral ($) (line 9 x line 10)	(5)	(1,272,856)		(2,830,869)		(972,025)		(5,075,750)

Notes:
(1) Updated for 2010 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 2011 un-audited LRAM Volume Savings.

(4) Obtained from Union's 2011 QRAM applications.
(5) EB-2012-0087, Exhibit A, Tab 1, Schedule 1 excluding interest.

UNION GAS LIMITED
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	2009 Target Average Use		3,128	(0.8%)	139,768	1.3%	4,264	(0.5%)	
2	2009 Actual Average Use	(1)	3,213	(1.2%)	161,203	(0.3%)	4,182	(2.1%)	
3	2010 Target Average Use		3,128	(0.0%)	148,852	6.5%	4,239	(0.6%)	
4	2010 Actual Average Use		3,175	(1.2%)	171,877	6.6%	4,104	(1.9%)	
5	Forecast decline in Average Use per customer (line 3 - line 2)	(2)	(85)		(12,351)		57		
6	Actual decline in Average Use per customer (line 4 - line 2)		(38)		10,674		(78)		
7	Change in Average Use - Forecast vs. Actual (line 5 - line 6)	(3)	(47)		(23,025)		135		
8	2007 Board Approved Number of Customers		295,672		2,966		987,063		
9	Volume Impact (10^3m^3)		(14,076.6)		(68,166.8)		132,872.5		
10	2010 Board Approved Average Delivery Rate ($/$10^3m^3$)	(4)	75.300		49.131		37.706		
11	Average Use Deferral ($) (line 9 x line 10)	(5)	$ (1,059,974)		$ (3,349,127)		$ 5,010,077		$600,976

Notes:
(1) Updated for 2009 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 #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 2010 unaudited LRAM volume savings.
(4) Obtained from the four quarterly approved rates.
(5) EB-2011-0038, Exhibit A, Tab 1, Schedule 1.

Attachment 5

Filed: 2010-04-22
EB-2010-0039
Exhibit A
Tab 1
Schedule 5

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	2008 Target Average Use		3,153	(2.4%)	137,974	(1.8%)	4,286	(1.7%)	
2	2008 Actual Average Use	(1)	3,252	0.7%	161,615	15.0%	4,271	(2.0%)	
3	2009 Target Average Use		3,128	(0.8%)	139,768	1.3%	4,264	(0.5%)	
4	2009 Actual Average Use		3,214	(1.2%)	161,276	(0.2%)	4,184	(2.0%)	
5	Forecast decline in Average Use per customer (line 3 - line 2)	(2)	-124		-21,847		-7		
6	Actual decline in Average Use per customer (line 4 - line 2)		-38		-339		-87		
7	Change in Average Use - Forecast vs. Actual (line 5 - line 6)	(3)	-86		-21,508		80		
8	2007 Board Approved Number of Customers		295,672		2,966		987,063		
9	Volume Impact (10^3m^3) (line 7 x line 8)		(25,491.1)		(63,653.7)		78,690.0		
10	2009 Board Approved Average Delivery Rate ($/$10^3m^3$)		79.381		52.083		40.595		
11	Average Use Deferral ($ millions) (line 9 x line 10)	(4)	$ (2.024)		$ (3.315)		$ 3.194		$ (2.144)

Notes:

(1) Updated for 2008 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 #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 2009 un-audited LRAM Volume Savings

(4) EB-2010-0039, Exhibit A, Tab 1, Schedule 1

YEAR 2008

Calculation of Balances by Rate Class in Deferral Account No. 179-118
for 2008 Deferral Disposition (EB-2009-0052)

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	2007 Actual Average Use		3,230		140,491		4,359		
2	2008 Target Average Use		3,153	-2.4%	137,974	-1.8%	4,286	-1.7%	
3	2008 Actual Average Use		3,252	0.7%	161,629	15.0%	4,272	-2.0%	
4	Forecast decline in Average Use per customer (line 2 - line 1)	(1)	-77		-2,517		-73		
5	Actual decline in Average Use per customer (line 3 - line 1)		22		21,138		-88		
6	Change in Average Use - Forecast vs. Actual (line 4 - line 5)	(2)	-99		-23,655		14		
7	2007 Board Approved Number of Customers		295,672		2,966		987,063		
8	Volume Impact (10^3m^3) (line 6 x line 7)		-29,297		-70,152		13,932		
9	2008 Board Approved Average Delivery Rate ($/$10^3m^3$)		81.091		51.256		42.303		
10	Average Use Deferral ($000's) (line 8 x line 9)	(3)	-2,376		-3,591		577		-5,390

Notes:
(1) Calculated volume variance by rate class after applying the Average Use percentage identified in Board Approved Accounting Order for Deferral Account #179-118
(2) Change in Average Use is calculated as the year-over-year volume variance after actual 2008 volumes are weather normalized and DSM adjusted
(3) EB-2009-0052, Exhibit A, Tab 2, Schedule 1

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
Lost Revenue Adjustment Mechanism
Breakdown of 2011 LRAM Deferral Account Balance

Line No.	Particulars ($)	Amounts by DSM Plan Year 2010 [1]	2011 [2] [3]	Total Amount in LRAM Deferral Account
		(a)	(b)	(c)
	South			
1	M1 Residential	160,212	110,808	271,020
2	M1 Commercial	184,427	90,443	274,871
3	M1 Industrial	1,472	25,387	26,859
4	M2 Commercial	178,864	123,716	302,580
5	M2 Industrial	143,192	63,791	206,984
	Industrial			
6	M4	63,357	34,973	98,330
7	M5	118,901	105,037	223,938
8	M7	27,797	15,450	43,248
9	T1	29,942	39,565	69,507
10		908,164	609,171	1,517,335
	North			
11	Residential 01	73,581	76,588	150,168
12	Commercial 01	48,945	53,618	102,563
13	Commercial 10	41,903	48,178	90,081
14	Industrial 10	16,990	13,808	30,798
	Industrial			
15	Rate 20	24,880	8,429	33,309
16	Rate 100	72,278	12,459	84,737
17		278,577	213,080	491,657
18	Total	1,186,741	822,251	2,008,992

Notes:
(1) EB-2012-0087, Exhibit A, Tab 1, Schedule 2, page 2 of 3, column (g).
(2) EB-2012-0087, Exhibit A, Tab 1, Schedule 2, page 3 of 3, column (c).
(3) Includes $0.0124 million related to incremental Low-income DSM activities per EB-2010-0055.

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2010 - Audited

Line No.	Particulars	2010 Audited Volumes (1)	2010 Unaudited Volumes (2)	Delivery Rates: 2010 Rates	Delivery Rates: 2011 Rates	Net Revenue Impact: 2010 (3)	Net Revenue Impact: 2011	Net LRAM Deferral Account Balance Proposed for Disposition
		$10^3 m^3$	$10^3 m^3$	$\$/10^3 m^3$	$\$/10^3 m^3$	($)	($)	($)
		(a)	(b)	(c)	(d)	(e) = [(a)-(b)]x (c) x 50%	(f) = (a) x (d)	(g) = (e) + (f)
	South							
1	M1 Residential	4,105	4,423	44.749	40.757	(7,108)	167,320	160,212
2	M1 Commercial	4,920	5,639	44.749	40.757	(16,095)	200,522	184,427
3	M1 Industrial	36	36	44.749	40.757	(1)	1,473	1,472
4	M2 Commercial	4,505	4,740	40.470	40.763	(4,763)	183,627	178,864
5	M2 Industrial	3,515	3,519	40.470	40.763	(85)	143,277	143,192
	Industrial							
6	M4	7,254	7,304	8.545	8.764	(216)	63,573	63,357
7	M5	8,174	8,205	14.783	14.574	(230)	119,131	118,901
8	M7	11,495	11,491	2.411	2.418	4	27,794	27,797
9	T1	32,818	32,867	0.884	0.913	(22)	29,963	29,942
10		76,822	78,226			(28,517)	936,680	908,164
	North							
11	Residential 01	843	923	96.673	91.828	(3,867)	77,448	73,581
12	Commercial 01	666	845	90.054	85.583	(8,050)	56,995	48,945
13	Commercial 10	706	766	64.910	62.162	(1,953)	43,856	41,903
14	Industrial 10	298	297	59.486	57.001	13	16,977	16,990
	Industrial							
15	Rate 20	6,759	6,767	3.404	3.683	(13)	24,894	24,880
16	Rate 100	35,022	35,064	2.027	2.065	(42)	72,320	72,278
17		44,294	44,662			(13,912)	292,490	278,577
18	Total	121,116	122,888			(42,429)	1,229,170	1,186,741

Notes:
(1) Audited Demand Side Management 2010 Annual Report, page 76 (submitted by Union to the OEB Secretary on July 29, 2011 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements).
(2) EB-2011-0038, 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
2011 - Unaudited

Line No.	Particulars	2011 Unaudited Volumes (1) 10^3 m^3	2011 Delivery Rates $\$/10^3$ m^3	Revenue Impact(2) ($)
		(a)	(b)	(c) = (a) x (b) x 50%
	South			
1	M1 Residential	5,438	40.757	110,808
2	M1 Commercial	4,438	40.757	90,443
3	M1 Industrial	1,246	40.757	25,387
4	M2 Commercial	6,070	40.763	123,716
5	M2 Industrial	3,130	40.763	63,791
	Industrial			
6	M4	7,981	8.764	34,973
7	M5	14,414	14.574	105,037
8	M7	12,780	2.418	15,450
9	T1	86,670	0.913	39,565
10		142,167		609,171
	North			
11	Residential 01	1,668	91.828	76,588
12	Commercial 01	1,253	85.583	53,618
13	Commercial 10	1,550	62.162	48,178
14	Industrial 10	484	57.001	13,808
	Industrial			
15	Rate 20	4,577	3.683	8,429
16	Rate 100	12,067	2.065	12,459
17		21,600		213,080
18	Total	163,766		822,251

Notes:

(1) Based on unaudited 2011 DSM evaluation results.

(2) Includes 514 $10^3 m^3$ related to incremental Low-income DSM activities per EB-2010-0055. The revenue impact associated with these volumes is $0.0124 million.

(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

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
Breakdown of 2010 LRAM Deferral Account Balance

Line No.	Particulars ($)	Amounts by DSM Plan Year 2009 [1]	2010 [2]	Total Amount in LRAM Deferral Account
		(a)	(b)	(c)
	South			
1	M1 Residential	217,259	98,962	316,221
2	M1 Commercial	267,665	126,176	393,841
3	M1 Industrial	22,354	810	23,164
4	M2 Commercial	350,470	95,916	446,387
5	M2 Industrial	75,368	71,209	146,577
	Industrial			
6	M4	26,847	31,208	58,055
7	M5	88,740	60,650	149,390
8	M7	2,921	13,853	16,774
9	T1	20,622	14,527	35,149
10		1,072,246	513,312	1,585,558
	North			
11	Residential 01	92,195	44,634	136,829
12	Commercial 01	126,963	38,036	164,999
13	Commercial 10	68,549	24,850	93,399
14	Industrial 10	299,976	8,846	308,822
	Industrial			
15	Rate 20	16,541	11,517	28,058
16	Rate 100	30,790	35,537	66,327
17		635,014	163,420	798,434
18	Total	1,707,260	676,732	2,383,992

Notes:
(1) EB-2011-0038, Exhibit A, Tab 1, Schedule 2, page 2 of 3, column (g).
(2) EB-2011-0038, Exhibit A, Tab 1, Schedule 2, page 3 of 3, column (c).

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2009 - Audited

Line No.	Particulars	2009 Audited Volumes (1)	2009 Unaudited Volumes	Delivery Rates: 2009 Rates	Delivery Rates: 2010 Rates	Net Revenue Impact: 2009 (2)	Net Revenue Impact: 2010	Net LRAM Deferral Account Balance Proposed for Disposition Including Interest
		$10^3 m^3$	$10^3 m^3$	$\$/10^3 m^3$	$\$/10^3 m^3$	($)	($)	($)
		(a)	(b)	(c)	(d)	(e) = [(a)-(b)]x (c) x 50%	(f) = (a) x (d)	(g) = (e) + (f)
	South							
1	M1 Residential	6,066	8,301	48.500	44.749	(54,189)	271,447	217,259
2	M1 Commercial	6,355	7,044	48.500	44.749	(16,715)	284,380	267,665
3	M1 Industrial	537	606	48.500	44.749	(1,676)	24,030	22,354
4	M2 Commercial	9,233	10,338	41.989	40.470	(23,189)	373,660	350,470
5	M2 Industrial	2,065	2,456	41.989	40.470	(8,203)	83,571	75,368
	Industrial							
6	M4	3,631	4,502	9.602	8.545	(4,180)	31,027	26,847
7	M5	6,411	7,157	16.182	14.783	(6,034)	94,774	88,740
8	M7	1,218	1,226	3.812	2.411	(15)	2,937	2,921
9	T1	26,145	32,032	0.846	0.884	(2,490)	23,112	20,622
10		61,661	73,661			(116,691)	1,188,937	1,072,246
	North							
11	Residential 01	1,196	1,662	100.505	96.673	(23,426)	115,621	92,195
12	Commercial 01	1,464	1,568	93.755	90.054	(4,876)	131,839	126,963
13	Commercial 10	1,206	1,493	67.834	64.910	(9,732)	78,281	68,549
14	Industrial 10	5,072	5,128	62.218	59.486	(1,737)	301,713	299,976
	Industrial							
15	Rate 20	4,652	4,222	3.280	3.404	706	15,835	16,541
16	Rate 100	17,353	21,242	2.255	2.027	(4,384)	35,175	30,790
17		30,943	35,314			(43,450)	678,464	635,014
18	Total	92,604	108,975			(160,141)	1,867,401	1,707,260

Notes:

(1) Audited Demand Side Management 2009 Annual Report, page 60 (submitted by Union to the OEB Secretary on August 20, 2010 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements).

(2) 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
2010 - Unaudited

Line No.	Particulars	2010 Unaudited Volumes (1) 10^3 m^3	2010 Delivery Rates $/$10^3$ m^3	Revenue Impact(2) ($)
		(a)	(b)	(c) = (a) x (b) x 50%
	South			
1	M1 Residential	4,423	44.749	98,962
2	M1 Commercial	5,639	44.749	126,176
3	M1 Industrial	36	44.749	810
4	M2 Commercial	4,740	40.470	95,916
5	M2 Industrial	3,519	40.470	71,209
	Industrial			
6	M4	7,304	8.545	31,208
7	M5	8,205	14.783	60,650
8	M7	11,491	2.411	13,853
9	T1	32,867	0.884	14,527
10		78,226		513,312
	North			
11	Residential 01	923	96.673	44,634
12	Commercial 01	845	90.054	38,036
13	Commercial 10	766	64.910	24,850
14	Industrial 10	297	59.486	8,846
	Industrial			
15	Rate 20	6,767	3.404	11,517
16	Rate 100	35,064	2.027	35,537
17		44,662		163,420
18	Total	122,888		676,732

Notes:
(1) Based on unaudited 2010 DSM evaluation results.
(2) 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.

Filed: 2010-04-22
EB-2010-0039
Exhibit A
Tab 1
Schedule 2
Page 1 of 3

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
Breakdown of 2009 LRAM Deferral Account Balance

Line No.	Particulars	Amounts by DSM Plan Year 2008 [1] ($)	2009 [2] ($)	Total Amount in LRAM Deferral Account ($)
		(a)	(b)	(c)
	South			
1	M1 Residential	288,369	201,289	489,658
2	M1 Commercial	279,412	170,823	450,236
3	M1 Industrial	-	14,698	14,698
4	M2 Commercial	99,818	217,031	316,849
5	M2 Industrial	21,978	51,556	73,534
	Industrial			
6	M4	55,106	21,612	76,718
7	M5	74,006	57,905	131,912
8	M7	2	2,337	2,339
9	T1	15,756	13,550	29,305
10		834,446	750,803	1,585,249
	North			
11	Residential 01	141,282	83,528	224,810
12	Commercial 01	94,718	73,505	168,222
13	Commercial 10	81,123	50,636	131,759
14	Industrial 10	66,285	159,522	225,807
	Industrial			
15	Rate 20	5,152	6,924	12,075
16	Rate 100	22,432	23,950	46,382
17		410,991	398,065	809,056
18	Total	1,245,437	1,148,868	2,394,305

Notes:
[1] EB-2010-0039, Exhibit A, Tab 1, Schedule 2, page 2 of 3, column (i)
[2] EB-2010-0039, Exhibit A, Tab 1, Schedule 2, page 3 of 3, column (c)

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2008 - Audited

Line No.	Particulars	2008 Audited Volumes (1) 10³ m³ (a)	2008 Lost Volumes in 2008 Rates 10³ m³ (b)	Delivery Rates: 2008 Rates $/10³ m³ (c)	Delivery Rates: 2009 Rates $/10³ m³ (d)	Net Revenue Impact: 2008 (2) ($) (e) = [(a)-(b)]x (c) x 50%	Net Revenue Impact: 2009 ($) (f) = (a) x (d)	Net Revenue Impact: Total ($) (g) = (e) + (f)	Interest ($) (h)	Net LRAM Deferral Account Balance Proposed for Disposition Including Interest ($) (i) = (g) + (h)
	South									
1	M1 Residential	6,477	7,490	50.87	48.500	(25,766)	314,135	288,369	-	288,369
2	M1 Commercial	7,101	9,656	50.87	48.500	(64,986)	344,399	279,412	-	279,412
3	M2 Commercial	3,103	4,581	41.237	41.989	(30,474)	130,292	99,818	-	99,818
4	M2 Industrial	574	677	41.237	41.989	(2,124)	24,102	21,978	-	21,978
	Industrial									
5	M4	5,610	5,343	9.277	9.602	1,238	53,867	55,106	-	55,106
6	M5	4,468	4,255	16.009	16.182	1,705	72,301	74,006	-	74,006
7	M7	1	2	3.531	3.812	(2)	4	2	-	2
8	T1	18,204	17,337	0.819	0.846	355	15,401	15,756	-	15,756
9		45,538	49,341			(120,053)	954,499	834,446	-	834,446
	North									
10	Residential 01	1,361	1,273	102.147	100.505	4,494	136,787	141,282	-	141,282
11	Commercial 01	1,248	1,716	95.251	93.755	(22,289)	117,006	94,718	-	94,718
12	Commercial 10	1,389	1,780	66.998	67.834	(13,098)	94,221	81,123	-	81,123
13	Industrial 10	1,054	1,031	61.471	62.218	707	65,578	66,285	-	66,285
	Industrial									
14	Rate 20	1,536	1,462	3.068	3.280	114	5,038	5,152	-	5,152
15	Rate 100	9,725	9,262	2.17	2.255	502	21,930	22,432	-	22,432
16		16,313	16,524			(29,570)	440,561	410,991	-	410,991
17	Total	61,851	65,865			(149,623)	1,395,060	1,245,437	-	1,245,437

Notes:

(1) Demand Side Management 2008 Annual Report - Final Audited Report, page 56 (submitted by Union to the OEB Secretary on June 30, 2009 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements).

(2) 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
2009 - Unaudited

Line No.	Particulars	2009 Unaudited Volumes (1) 10^3 m^3	2009 Delivery Rates $\$/10^3$ m^3	Revenue Impact(2) ($)
		(a)	(b)	(c) = (a) x (b) x 50%
	South			
1	M1 Residential	8,301	48.500	201,289
2	M1 Commercial	7,044	48.500	170,823
3	M1 Industrial	606	48.500	14,698
3	M2 Commercial	10,338	41.989	217,031
4	M2 Industrial	2,456	41.989	51,556
	Industrial			
5	M4	4,502	9.602	21,612
6	M5	7,157	16.182	57,905
7	M7	1,226	3.812	2,337
8	T1	32,032	0.846	13,550
9		73,661		750,803
	North			
10	Residential 01	1,662	100.505	83,528
11	Commercial 01	1,568	93.755	73,505
12	Commercial 10	1,493	67.834	50,636
13	Industrial 10	5,128	62.218	159,522
	Industrial			
14	Rate 20	4,222	3.280	6,924
15	Rate 100	21,242	2.255	23,950
16		35,314		398,065
17	Total	108,975		1,148,868

Notes:

(1) Based on unaudited 2009 DSM evaluation results.

(2) 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
Breakdown of 2007 LRAM Deferral Account Balance

Line No.	Particulars	Amounts by DSM Plan Year 2007 [1]	2008 [2]	Total Amount in LRAM Deferral Account
		(c)	(b)	(d)
	South			
1	M1 Residential	($260,491)	$190,508	($69,983)
2	M1 Commercial	$0	$245,593	$245,593
3	M2 Commercial	($665,627)	$94,455	($571,171)
4	M2 Industrial	($60,959)	$13,967	($46,992)
	Industrial			
5	M4	($149,984)	$24,785	($125,199)
6	M5	$8,471	$34,060	$42,531
7	M7	($13,997)	$3	($13,995)
8	T1	$1,088	$7,100	$8,187
9		($1,141,500)	$610,472	($531,028)
	North			
10	Residential 01	($222,714)	$65,001	($157,713)
11	Commercial 01	$22,367	$81,739	$104,106
12	Commercial 10	($75,227)	$59,625	($15,601)
13	Industrial 10	$177,991	$31,694	$209,685
	Industrial			
14	Rate 20	($24,428)	$2,243	($22,185)
15	Rate 100	($18,238)	$10,050	($8,189)
16		($140,249)	$250,352	$110,103
17	Total	($1,281,749)	$860,824	($420,925)

Notes:
(1) EB-2009-0052, Exhibit A, Tab 1, Schedule 2, page 2 of 3, Col. (k)
(2) EB-2009-0052, Exhibit A, Tab 1, Schedule 2, page 3 of 3, column (c)

Attachment 6

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2007 - Audited

Line No.	Particulars	Audited Volumes [1]	2007 Lost Volumes in 2007 Rates	2007 Lost Volumes in 2008 Rates	Delivery Rates: 2007 Rates	Delivery Rates: 2008 Rates	Net Revenue Impact: 2007 [2]	Net Revenue Impact: 2008	Net Revenue Impact: Total	LRAM Deferral Account Balance Disposed of in EB-2006-0034 [3]	Interest	Net LRAM Deferral Account Balance Proposed for Disposition Including Interest
		10^3 m^3	10^3 m^3	10^3 m^3	$/$10^3$ m^3	$/$10^3$ m^3	($)	($)	($)	($)	($)	($)
		(a)	(b)	(c)	(d)	(e)	(f) = [(a)-(b)]x (d) x 50%	(g) = [(a) - (c)] x (e)	(h) = (f) + (g)	(i)	(j)	(k) = (h) - (i) +(j)
	South											
1	M1 Residential	4,662	5,232	5,232	61.01	50.87	(17,388)	(28,996)	(46,384)	211,533	(2,574)	(260,491)
2	M2 Commercial	10,659	20,096	20,096	50.736	50.87	(239,398)	(480,060)	(719,458)	(93,754)	(39,923)	(665,627)
3	M2 Industrial	732	2,021	2,021	40.168	41.237	(25,888)	(53,154)	(79,043)	(22,470)	(4,386)	(60,959)
	Industrial											
4	M4	3,730	17,681	17,681	9.291	9.277	(64,809)	(129,423)	(194,233)	(55,027)	(10,778)	(149,984)
5	M5	638	-	-	15.631	16.009	4,986	10,214	15,200	7,573	843	8,471
6	M7	4,283	6,840	6,840	3.344	3.531	(4,275)	(9,029)	(13,304)	(45)	(738)	(13,997)
7	T1	16,582	10,944	10,944	0.798	0.819	2,250	4,618	6,867	6,160	381	1,088
8		41,286	62,814	62,814			(344,523)	(685,832)	(1,030,354)	53,971	(57,175)	(1,141,500)
	North											
9	Residential 01	943	2,197	2,197	112.971	102.147	(70,833)	(128,092)	(198,925)	12,751	(11,038)	(222,714)
10	Commercial 01	1,440	1,048	1,048	105.147	95.251	20,609	37,338	57,947	38,796	3,216	22,367
11	Commercial 10	1,355	2,066	2,066	66.749	66.998	(23,729)	(47,636)	(71,365)	(98)	(3,960)	(75,227)
12	Industrial 10	3,997	237	237	61.265	61.471	115,178	231,131	346,309	187,535	19,217	177,991
							-				-	
	Industrial						-				-	
13	Rate 20	652	7,845	7,845	2.877	3.068	(10,347)	(22,068)	(32,415)	(9,786)	(1,799)	(24,428)
14	Rate 100	6,181	12,312	12,312	2.102	2.17	(6,444)	(13,304)	(19,748)	(2,605)	(1,096)	(18,238)
15		14,568	25,705	25,705			24,434	57,369	81,803	226,591	4,539	(140,249)
16	Total	55,854	88,519	88,519			(320,089)	(628,462)	(948,551)	280,562	(52,636)	(1,281,749)

Notes:

(1) Summary of the Results of the 2007 Evaluation Report Audit, page 47(submitted by Union to the OEB Secretary on July 3rd, 2008 in compliance with section 2.1.12 of the Board's Reporting and Record Keeping Requirements), updated for M1/M2 split.

(2) 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.

(3) EB-2008-0034 Exhibit A, Tab 1, Schedule 2, Page 4 of 4, Col.(e).

UNION GAS LIMITED
Lost Revenue Adjustment Mechanism
2008 - Unaudited

Line No.	Particulars	Unaudited Volumes (1) 10^3 m^3	2008 Delivery Rates $\$/10^3$ m^3	Revenue Impact(2) ($)
		(a)	(b)	(c) = (a) x (b) x 50%
	South			
1	M1 Residential	7,490	50.870	190,508
2	M2 Residential	-	41.237	-
3	M1 Commercial	9,656	50.870	245,593
4	M2 Commercial	4,581	41.237	94,455
5	M2 Industrial	677	41.237	13,967
	Industrial			
6	M4	5,343	9.277	24,785
7	M5	4,255	16.009	34,060
8	M7	2	3.531	3
9	T1	17,337	0.819	7,100
10		49,342	255	610,472
	North			
11	Residential 01	1,273	102.147	65,001
12	Commercial 01	1,716	95.251	81,739
13	Commercial 10	1,780	66.998	59,625
14	Industrial 10	1,031	61.471	31,694
	Industrial			
15	Rate 20	1,462	3.068	2,243
16	Rate 100	9,262	2.170	10,050
17		16,525	331	250,352
18	Total	65,867	586	860,824

Notes:

(1) Based on unaudited 2008 DSM evaluation results.

(2) 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 Ltd.
Amortization of Accumulated Deferred Tax Balance

Line No.	Particulars (000's)	2013	2014	2015	2016	2017	2018
1	Drawdown amount	15,169	13,465	13,555	13,101	13,141	10,832
2	Difference from 2013		(1,704)	(1,613)	(2,068)	(2,028)	(4,337)
3	Tax Rate - Board Approved Rate	25.50%	25.50%	25.50%	25.50%	25.50%	25.50%
4	Pre-tax revenue requirement impact (1)		(2,287)	(2,166)	(2,776)	(2,722)	(5,822)
5	Average		(3,154)				

Notes:
(1) Line 2/(1-Line3)

Union Gas
Incentive Regulation 2014-2018
Supplement Questions and Responses – June 7, 2013
CONFIDENTIAL

1. **CME 4 Page 2: does the "below the line" negative cost for customer supplied fuel represent a systemic over-recovery of fuel relative to the actual cost of the fuel. If not, please provide an explanation of this line item and how it relates to the above the line revenue and the actual cost.**

   The below the line negative cost for customer supplied fuel represents all of the CSF fuel received from ex-franchise customers. There is no relationship to the positive revenue above the line item Customer Supplied Fuel which represents the CSF fuel from in-franchise customers. There is an equal offset to CSF revenue in the Cost of Gas expenses.

2. **CME 4 Page 3: There does not appear to be a Storage (Regulated) section so I am presuming that the "(Unregulated)" section includes the regulated storage also (e.g., up to 100PJ). If not, please clarify.**

   The referenced "Unregulated" section includes all ex-franchise storage revenue. The difference between the amount required for in-franchise customers for storage and the 100 PJ is accounted for in the Unregulated Short Term Storage & Balancing section ($13.7 million). Revenue associated with storage space required for in-franchise customers is in the Distribution Margin Operating Revenue.

3. **2012 actuals show a total of $13.7M in ST Storage & Balancing and a deferral account negative cost of (2.8) M. Is that Union's share? If so, how was it calculated versus the $13.7M?**

   The $13.7 million is the revenue associated with the excess utility storage space (the difference between the storage space required for in-franchise customers and 100 PJ). The $2.8 million is the deferral balance owed to customers.

   The $2.781 million included in the 2012 income statement includes the 2012 Deferral Collectible from ratepayers as filed in EB-2013-0109 at Exhibit A, Tab 1, Appendix A, Schedule 2 and adjustments for 2010 and 2011 arising from the Board's decision in EB-2011-0038. The table below shows the $2.8 million calculation.

1.879	2012 Deferral Receivable (EB-2013-0109)
(4.659)	EB-2011-0038 Adjustment Payable
(2.780)	Total ST Storage Deferral Payable

4. **Union just completed a solicitation for expression of interest for service for the Northern T-service Supply at Dawn. If all of the expressions were contracted, how much Dawn-Parkway capacity would be committed to this service? What would the revenue impact be in 2017?**

   If all of the expressions of interest were contracted, approximately 67,000 GJ of Kirkwall – Parkway capacity and 25,000 GJ of Dawn - Parkway transmission capacity would be required. A full year of revenue would be approximately $0.975 million (67,000 GJ x 365 x $0.01 + 25,000 x 365 x $0.08). The proposed Northern T-service Supply at Dawn service is contingent upon TCPL relieving the Parkway – Maple constraint and then customers contracting for the service.

Union Gas
Weather Normal Review

Prepared by

Sussex Economic Advisors, LLC & Harbourfront Group, Inc.

June, 2013

DRAFT

Background

Union Gas Limited ("Union" or the "Company"), a Canadian natural gas utility regulated by the Ontario Energy Board ("OEB"), 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, southwestern 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.

Weather normalization is used to determine Union's demand forecast, storage and transportation allocations, and rate design. Weather, in this instance, is defined by heating degree-days ("HDD"), which represent temperatures below 18°C.

The current weather normal computation used by Union is a blended method that combines the 20-year declining trend method (i.e., the simple trend of HDDs over the past 20 years) with the 30-year simple average method (i.e., the average of the annual HDDs over the specified 30-year period). Union then weights each of the two methods by 50% to determine the weather normal value.

The primary objective of an acceptable weather normalization method is to set a weather normal level that will best reflect future weather without a bias. In past Union regulatory filings, certain parties have arrived at evaluation criteria for judging the quality of competing weather normal methods. Those statistical qualities[1] are defined as follows:

- *Symmetry* - equal expectation of positive and negative variations
- *Accuracy* - minimum variance between normal and actual values
- *Stability* - minimum variance year to year

While all three attributes are important in the evaluation of a weather normal, it is the position of Union that Symmetry (i.e., equal expectation of positive and negative variations, or what can be called *unbiased accuracy*) is of paramount importance.

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[1] In addition to these statistical measures, simplicity (i.e., easily understood and administered) and sustainability (i.e., ease of maintaining) are also considered in the evaluation of weather normal methods.

Project Approach

Sussex Economic Advisors, LLC ("Sussex") was retained by Union to perform a statistically based analysis of the various methodologies, which may be employed to determine the weather normal for a given year. The Sussex project team was led by George Fitzpatrick, an Executive Advisor with Sussex. Mr. Fitzpatrick is the President of Harbourfront Group, Inc. ("Harbourfront") and has over 35 years of electric and gas utility consulting experience related to this assignment. Mr. Fitzpatrick has previously provided weather normalization and forecasting related consulting services to Union and has submitted statistical-related testimony to the Ontario Energy Board. For this assignment, Mr. Fitzpatrick provided all of the statistical analysis contained in this report and Sussex performed the industry benchmarking analysis.

The methodologies reviewed and analyzed include:

- All methodologies previously proposed by Union in prior rate cases, including the 50:50 blended method ordered by the OEB and currently employed by Union in its weather normalization activities.
- All methodologies previously proposed by Enbridge Gas Distribution in prior rate cases.
- A robust survey of the methodologies used by certain similar utilities in Canada or the United States.
- Other methodologies identified by Sussex/Harbourfront that may have merit for consideration by the OEB and Union.

The analysis of the methodologies using the Union North and South Annual HDD databases through calendar 2012 included:

- A statistical analysis of each methodology considering the following criteria: accuracy, symmetry and stability. Additional criteria, such as sustainability and simplicity were also considered.
- Statistical measures suitable for assessing each criteria.
- A discussion on the advantages and disadvantages of each methodology, as it relates to demand forecasting.

Additionally, Sussex/Harbourfront considered attributes identified by both the OEB and Union, and the relative weights assigned to each. Sussex/Harbourfront will present its independent perspectives on the value of each attribute, which differs from both the OEB's and Union's perspectives. Additionally, Sussex/Harbourfront will offer its perspectives on additional attributes that are important for the OEB to consider going forward.

Results of Analysis

Symmetry, Accuracy and Stability Weights

The first task in the Sussex/Harbourfront process was an evaluation of the overall logic and statistical merit of certain weighting schemes (e.g., Union Gas and Equal Weighting). While the logic regarding the selection of weights was reasonable given the different objectives of the schemes, the Equal Weighting Scheme weights are problematic from a statistical perspective. The first objective of any weather normal methodology is to select that weather normal which provides the most accurate representation of the recent past, (i.e., for the purposes of this analysis, the last ten years). Closely tied to the “accuracy” objective is a measurement of the symmetry of the weather normal methodology over the recent past, which again is determined with regard to the most recent ten years.

In general, statisticians/econometricians evaluate models that can be demonstrated to be the best linear (or non-linear) unbiased estimators. This evaluation should result in the most accurate and unbiased estimator, not necessarily the most stable. While accuracy and symmetry are the objectives of the statistician and are within the statistician’s control via the model selection process, the stability of the data series modeled is a function of the data itself, and, frankly, “is what it is”.

Selecting the Best, Unbiased Weather Normal

In order to facilitate the Sussex/Harbourfront analysis, Union Gas provided an update to their prior weather normal analysis that was performed in 2010, adding data for the years 2011 and 2012 and re-computing the approaches the Company previously analyzed in developing a symmetric, accurate and stable weather normal for both the Union North and South climatic regions. The following tables show the results of that analysis using three weighting schemes:

- Sussex/Harbourfront Alternative: Symmetry-40.0%; Accuracy-40.0%; Stability-20.0%.
- Union Gas: Symmetry-50.0%, Accuracy-35.0% and Stability-15.0%.
- Equal Weighting: Symmetry-33.3%; Accuracy-33.3% and Stability-33.3%.

Table 1: Sussex/Harbourfront Alternative Approach – Union South

SOUTHERN METHOD	Accuracy MAPE	RMSPE	Symmetry MPE	% OFrcst	Stability STD	TOTAL SCORE	RANK	2012 Estimate HDD
Weighting		**40.0%**		**40.0%**	**20.0%**	**100.0%**		
Energy Probe		4.8		4.0	0.2	9.0	35	3,621
30 Yr		0.4		2.4	5.2	8.0	36	3,824
50:50Nrml		4.4		5.6	5.6	15.6	22	3,719
55:45Nrml		4.0		5.6	5.8	15.4	23	3,730
45:55 Nrml		5.2		0.4	5.4	11.0	34	3,708
35:65Nrml		6.4		0.4	5.0	11.8	32	3,687
25:75 Nrml		8.8		0.4	4.8	14.0	25	3,666
15:85Nrml		11.2		0.4	4.6	16.2	21	3,645
50:50 20DT 10 Avg		9.2		0.4	3.4	13.0	29	3,663
10 Yr. Avg.		5.6		5.6	2.0	13.2	27	3,713
20 Yr. Avg.		2.8		2.8	6.0	11.6	33	3,781
Naïve		2.0		4.0	0.4	6.4	38	3,574
Leo de Bever		8.0		4.8	6.2	19.0	16	3,598
35 Year Trend		14.8		10.4	2.2	27.4	6	3,598
10 Year TREND		0.8		5.6	0.6	7.0	37	3,744
11 Year TREND		1.2		10.4	0.8	12.4	30	3,720
12 Year TREND		2.4		10.4	1.0	13.8	26	3,754
13 Year TREND		1.6		10.4	1.2	13.2	28	3,846
14 Year TREND		3.2		10.4	1.4	15.0	24	3,760
15 Year TREND		3.6		7.2	1.6	12.4	31	3,677
16 Year TREND		6.0		10.4	1.8	18.2	18	3,644
17 Year TREND		10.8		3.6	2.8	17.2	19	3,611
18 Year TREND		12.4		7.2	3.0	22.6	11	3,583
19 Year TREND		11.6		10.4	2.6	24.6	9	3,573
20 Year TREND		13.2		10.4	4.0	27.6	5	3,614
21 Year TREND		12.8		10.4	6.8	30.0	3	3,653
22 Year TREND		**14.4**		**10.4**	**7.6**	**32.4**	**1**	**3,624**
23 Year TREND		13.6		10.4	7.0	31.0	2	3,620
24 Year TREND		10.0		10.4	7.4	27.8	4	3,646
25 Year TREND		9.6		10.4	6.6	26.6	7	3,650
26 Year TREND		7.2		7.2	6.4	20.8	14	3,650
27 Year TREND		8.4		7.2	4.4	20.0	15	3,645
28 Year TREND		7.6		7.2	4.2	19.0	16	3,650
29 Year TREND		10.4		7.2	3.6	21.2	12	3,646
30 Year TREND		6.8		7.2	2.4	16.4	20	3,645
31 Year TREND		15.2		4.8	3.2	23.2	10	3,625
32 Year TREND		14.0		3.2	3.8	21.0	13	3,618
1978Base		12.0		7.2	7.2	26.4	8	3,598

Table 2: Sussex/Harbourfront Alternative Approach – Union North

NORTHERN METHOD	Accuracy MAPE	RMSPE	Symmetry MPE	% OFrcst	Stability STD	TOTAL SCORE	RANK	2012 Estimate HDD
Weighting		**40.0%**		**40.0%**	**20.0%**	**100.0%**		
Energy Probe		3.2		3.2	0.4	6.8	36	4,867
30 Yr		1.6		2.4	7.2	11.2	33	5,093
50:50Nrml		4.4		3.6	5.4	13.4	25	4,875
55:45Nrml		2.8		3.6	6.2	12.6	27	4,897
45:55 Nrml		5.2		0.4	4.4	10.0	35	4,854
35:65Nrml		6.8		0.4	4.2	11.4	31	4,810
25:75 Nrml		7.6		0.4	3.4	11.4	32	4,767
15:85Nrml		10.0		0.4	2.6	13.0	26	4,723
50:50 20DT 10 Avg		8.0		0.4	2.4	10.8	34	4,767
10 Yr. Avg.		4.8		3.6	3.2	11.6	30	4,876
20 Yr. Avg.		2.0		2.8	7.0	11.8	29	5,029
Naïve		2.4		9.6	0.2	12.2	28	4,462
10 Year TREND		3.6		10.4	1.2	15.2	23	4,759
11 Year TREND		4.0		10.4	2.0	16.4	22	4,738
12 Year TREND		5.6		10.4	3.6	19.6	13	4,794
13 Year TREND		6.0		10.4	3.8	20.2	11	4,887
14 Year TREND		6.4		12.0	2.2	20.6	5	4,790
15 Year TREND		7.2		12.0	1.6	20.8	4	4,698
16 Year TREND		12.8		12.0	1.4	26.2	2	4,666
17 Year TREND		**14.4**		**12.0**	**1.0**	**27.4**	**1**	**4,656**
18 Year TREND		12.0		12.0	0.8	24.8	3	4,631
19 Year TREND		10.4		3.6	0.6	14.6	24	4,613
20 Year TREND		13.2		3.6	1.8	18.6	17	4,658
21 Year TREND		14.0		3.6	2.8	20.4	6	4,698
22 Year TREND		13.6		3.6	3.0	20.2	10	4,665
23 Year TREND		12.4		3.6	4.0	20.0	12	4,675
24 Year TREND		11.2		3.6	5.6	20.4	6	4,741
25 Year TREND		9.6		3.6	5.8	19.0	15	4,756
26 Year TREND		10.8		3.6	6.0	20.4	9	4,747
27 Year TREND		8.8		3.6	5.0	17.4	19	4,764
28 Year TREND		8.4		3.6	4.8	16.8	21	4,777
29 Year TREND		9.2		3.6	4.6	17.4	18	4,772
30 Year TREND		1.2		9.6	6.4	17.2	20	4,794
31 Year TREND		0.8		12.0	6.8	19.6	13	4,781
32 Year TREND		0.4		12.0	6.6	19.0	15	4,778
1978Base		11.6		3.6	5.2	20.4	6	4,815

Table 3: Union Approach – Union South

SOUTHERN	Accuracy		Symmetry		Stability	TOTAL	RANK	2012 Estimate
METHOD	MAPE	RMSPE	MPE	% OFrcst	STD	SCORE		HDD
Weighting		**35.0%**		**50.0%**	**15.0%**	**100.0%**		
Energy Probe		4.2		5.0	0.2	9.4	34	3,621
30 Yr		0.4		3.0	3.9	7.3	37	3,824
50:50Nrml		3.9		7.0	4.2	15.1	24	3,719
55:45Nrml		3.5		7.0	4.4	14.9	25	3,730
45:55 Nrml		4.6		0.5	4.1	9.1	35	3,708
35:65Nrml		5.6		0.5	3.8	9.9	33	3,687
25:75 Nrml		7.7		0.5	3.6	11.8	30	3,666
15:85Nrml		9.8		0.5	3.5	13.8	27	3,645
50:50 20DT 10 Avg		8.1		0.5	2.6	11.1	31	3,663
10 Yr. Avg.		4.9		7.0	1.5	13.4	28	3,713
20 Yr. Avg.		2.5		3.5	4.5	10.5	32	3,781
Naïve		1.8		5.0	0.3	7.1	38	3,574
Leo de Bever		7.0		6.0	4.7	17.7	18	3,598
35 Year Trend		13.0		13.0	1.7	27.6	4	3,598
10 Year TREND		0.7		7.0	0.5	8.2	36	3,744
11 Year TREND		1.1		13.0	0.6	14.7	26	3,720
12 Year TREND		2.1		13.0	0.8	15.9	22	3,754
13 Year TREND		1.4		13.0	0.9	15.3	23	3,846
14 Year TREND		2.8		13.0	1.1	16.9	19	3,760
15 Year TREND		3.2		9.0	1.2	13.4	29	3,677
16 Year TREND		5.3		13.0	1.4	19.6	15	3,644
17 Year TREND		9.5		4.5	2.1	16.1	21	3,611
18 Year TREND		10.9		9.0	2.3	22.1	10	3,583
19 Year TREND		10.2		13.0	2.0	25.1	8	3,573
20 Year TREND		11.6		13.0	3.0	27.6	5	3,614
21 Year TREND		11.2		13.0	5.1	29.3	3	3,653
22 Year TREND		**12.6**		**13.0**	**5.7**	**31.3**	**1**	3,624
23 Year TREND		11.9		13.0	5.3	30.2	2	3,620
24 Year TREND		8.8		13.0	5.6	27.3	6	3,646
25 Year TREND		8.4		13.0	5.0	26.4	7	3,650
26 Year TREND		6.3		9.0	4.8	20.1	13	3,650
27 Year TREND		7.4		9.0	3.3	19.7	14	3,645
28 Year TREND		6.7		9.0	3.2	18.8	17	3,650
29 Year TREND		9.1		9.0	2.7	20.8	12	3,646
30 Year TREND		6.0		9.0	1.8	16.8	20	3,645
31 Year TREND		13.3		6.0	2.4	21.7	11	3,625
32 Year TREND		12.3		4.0	2.9	19.1	16	3,618
1978Base		10.5		9.0	5.4	24.9	9	3,598

Table 4: Union Approach – Union North

NORTHERN	Accuracy		Symmetry		Stability	TOTAL	RANK	2012 Estimate
METHOD	MAPE	RMSPE	MPE	% OFrcst	STD	SCORE		HDD
Weighting		**35.0%**		**50.0%**	**15.0%**	**100.0%**		
Energy Probe		2.8		4.0	0.3	7.1	36	4,867
30 Yr		1.4		3.0	5.4	9.8	31	5,093
50:50Nrml		3.9		4.5	4.1	12.4	26	4,875
55:45Nrml		2.5		4.5	4.7	11.6	27	4,897
45:55 Nrml		4.6		0.5	3.3	8.4	35	4,854
35:65Nrml		6.0		0.5	3.2	9.6	33	4,810
25:75 Nrml		6.7		0.5	2.6	9.7	32	4,767
15:85Nrml		8.8		0.5	2.0	11.2	28	4,723
50:50 20DT 10 Avg		7.0		0.5	1.8	9.3	34	4,767
10 Yr. Avg.		4.2		4.5	2.4	11.1	29	4,876
20 Yr. Avg.		1.8		3.5	5.3	10.5	30	5,029
Naïve		2.1		12.0	0.2	14.3	24	4,462
10 Year TREND		3.2		13.0	0.9	17.1	20	4,759
11 Year TREND		3.5		13.0	1.5	18.0	16	4,738
12 Year TREND		4.9		13.0	2.7	20.6	8	4,794
13 Year TREND		5.3		13.0	2.9	21.1	6	4,887
14 Year TREND		5.6		15.0	1.7	22.3	5	4,790
15 Year TREND		6.3		15.0	1.2	22.5	4	4,698
16 Year TREND		11.2		15.0	1.1	27.3	2	4,666
17 Year TREND		**12.6**		**15.0**	**0.8**	**28.4**	**1**	**4,656**
18 Year TREND		10.5		15.0	0.6	26.1	3	4,631
19 Year TREND		9.1		4.5	0.5	14.1	25	4,613
20 Year TREND		11.6		4.5	1.4	17.4	18	4,658
21 Year TREND		12.3		4.5	2.1	18.9	10	4,698
22 Year TREND		11.9		4.5	2.3	18.7	11	4,665
23 Year TREND		10.9		4.5	3.0	18.4	15	4,675
24 Year TREND		9.8		4.5	4.2	18.5	13	4,741
25 Year TREND		8.4		4.5	4.4	17.3	19	4,756
26 Year TREND		9.5		4.5	4.5	18.5	14	4,747
27 Year TREND		7.7		4.5	3.8	16.0	22	4,764
28 Year TREND		7.4		4.5	3.6	15.5	23	4,777
29 Year TREND		8.1		4.5	3.5	16.0	21	4,772
30 Year TREND		1.1		12.0	4.8	17.9	17	4,794
31 Year TREND		0.7		15.0	5.1	20.8	7	4,781
32 Year TREND		0.4		15.0	5.0	20.3	9	4,778
1978Base		10.2		4.5	3.9	18.6	12	4,815

Table 5: Equal Weighting – Union South

SOUTHERN	Accuracy		Symmetry		Stability	TOTAL	RANK	2012 Estimate HDD
METHOD	MAPE	RMSPE	MPE	% OFrcst	STD	SCORE		
Weighting		**33.3%**		**33.3%**	**33.3%**	**100.0%**		
Energy Probe		4.0		3.3	0.3	7.7	36	3,621
30 Yr		0.3		2.0	8.7	11.0	34	3,824
50:50Nrml		3.7		4.7	9.3	17.7	18	3,719
55:45Nrml		3.3		4.7	9.7	17.7	18	3,730
45:55 Nrml		4.3		0.3	9.0	13.7	27	3,708
35:65Nrml		5.3		0.3	8.3	14.0	26	3,687
25:75 Nrml		7.3		0.3	8.0	15.7	23	3,666
15:85Nrml		9.3		0.3	7.7	17.3	20	3,645
50:50 20DT 10 Avg		7.7		0.3	5.7	13.7	28	3,663
10 Yr. Avg.		4.7		4.7	3.3	12.7	30	3,713
20 Yr. Avg.		2.3		2.3	10.0	14.7	25	3,781
Naïve		1.7		3.3	0.7	5.7	38	3,574
Leo de Bever		6.7		4.0	10.3	21.0	13	3,598
35 Year Trend		12.3		8.7	3.7	24.7	8	3,598
10 Year TREND		0.7		4.7	1.0	6.3	37	3,744
11 Year TREND		1.0		8.7	1.3	11.0	34	3,720
12 Year TREND		2.0		8.7	1.7	12.3	31	3,754
13 Year TREND		1.3		8.7	2.0	12.0	32	3,846
14 Year TREND		2.7		8.7	2.3	13.7	28	3,760
15 Year TREND		3.0		6.0	2.7	11.7	33	3,677
16 Year TREND		5.0		8.7	3.0	16.7	21	3,644
17 Year TREND		9.0		3.0	4.7	16.7	21	3,611
18 Year TREND		10.3		6.0	5.0	21.3	12	3,583
19 Year TREND		9.7		8.7	4.3	22.7	9	3,573
20 Year TREND		11.0		8.7	6.7	26.3	7	3,614
21 Year TREND		10.7		8.7	11.3	30.7	3	3,653
22 Year TREND		**12.0**		**8.7**	**12.7**	**33.3**	**1**	**3,624**
23 Year TREND		11.3		8.7	11.7	31.7	2	3,620
24 Year TREND		8.3		8.7	12.3	29.3	4	3,646
25 Year TREND		8.0		8.7	11.0	27.7	6	3,650
26 Year TREND		6.0		6.0	10.7	22.7	9	3,650
27 Year TREND		7.0		6.0	7.3	20.3	16	3,645
28 Year TREND		6.3		6.0	7.0	19.3	17	3,650
29 Year TREND		8.7		6.0	6.0	20.7	14	3,646
30 Year TREND		5.7		6.0	4.0	15.7	23	3,645
31 Year TREND		12.7		4.0	5.3	22.0	11	3,625
32 Year TREND		11.7		2.7	6.3	20.7	14	3,618
1978Base		10.0		6.0	12.0	28.0	5	3,598

Table 6: Equal Weighting – Union North

NORTHERN	Accuracy		Symmetry		Stability	TOTAL	RANK	2012 Estimate HDD
METHOD	MAPE	RMSPE	MPE	% OFrcst	STD	SCORE		
Weighting		**33.3%**		**33.3%**	**33.3%**	**100.0%**		
Energy Probe		2.7		2.7	0.7	6.0	36	4,867
30 Yr		1.3		2.0	12.0	15.3	25	5,093
50:50Nrml		3.7		3.0	9.0	15.7	22	4,875
55:45Nrml		2.3		3.0	10.3	15.7	24	4,897
45:55 Nrml		4.3		0.3	7.3	12.0	33	4,854
35:65Nrml		5.7		0.3	7.0	13.0	28	4,810
25:75 Nrml		6.3		0.3	5.7	12.3	31	4,767
15:85Nrml		8.3		0.3	4.3	13.0	28	4,723
50:50 20DT 10 Avg		6.7		0.3	4.0	11.0	34	4,767
10 Yr. Avg.		4.0		3.0	5.3	12.3	31	4,876
20 Yr. Avg.		1.7		2.3	11.7	15.7	22	5,029
Naïve		2.0		8.0	0.3	10.3	35	4,462
10 Year TREND		3.0		8.7	2.0	13.7	27	4,759
11 Year TREND		3.3		8.7	3.3	15.3	25	4,738
12 Year TREND		4.7		8.7	6.0	19.3	13	4,794
13 Year TREND		5.0		8.7	6.3	20.0	10	4,887
14 Year TREND		5.3		10.0	3.7	19.0	16	4,790
15 Year TREND		6.0		10.0	2.7	18.7	17	4,698
16 Year TREND		10.7		10.0	2.3	23.0	2	4,666
17 Year TREND		**12.0**		**10.0**	**1.7**	**23.7**	**1**	**4,656**
18 Year TREND		10.0		10.0	1.3	21.3	7	4,631
19 Year TREND		8.7		3.0	1.0	12.7	30	4,613
20 Year TREND		11.0		3.0	3.0	17.0	21	4,658
21 Year TREND		11.7		3.0	4.7	19.3	13	4,698
22 Year TREND		11.3		3.0	5.0	19.3	13	4,665
23 Year TREND		10.3		3.0	6.7	20.0	10	4,675
24 Year TREND		9.3		3.0	9.3	21.7	5	4,741
25 Year TREND		8.0		3.0	9.7	20.7	9	4,756
26 Year TREND		9.0		3.0	10.0	22.0	3	4,747
27 Year TREND		7.3		3.0	8.3	18.7	18	4,764
28 Year TREND		7.0		3.0	8.0	18.0	20	4,777
29 Year TREND		7.7		3.0	7.7	18.3	19	4,772
30 Year TREND		1.0		8.0	10.7	19.7	12	4,794
31 Year TREND		0.7		10.0	11.3	22.0	3	4,781
32 Year TREND		0.3		10.0	11.0	21.3	6	4,778
1978Base		9.7		3.0	8.7	21.3	7	4,815

Under each of the three weighting schemes evaluated, the superior weather normal was observed to be a 17-year declining trend for Union North and a 22-year declining trend for Union South. In other words, both of these weather normals (i.e., the 17-year declining trend in Union North and the 22-year declining trend in Union South) ranked first regardless of which of the three weighting schemes were used.

In addition to reviewing the statistical tests used by Union to evaluate and score the weather normals under consideration, Sussex/Harbourfront reviewed the performance of these normals had they been in effect for the last ten years. This comparative performance analysis is best undertaken through the use of the Cox J-Test. The result of this analysis is presented in the next section of this report.

Cox J-Test Statistical Analysis

Sussex/Harbourfront performed a comparative analysis of the major competing approaches proposed for modeling and predicting changes in annual heating degree days in the South and North climatic zones of Union's service territory. The models and methods examined, for each zone, included the following:

Union South:

1. Union's 20-year Declining Trend ("DT") model that fits a linear trend to annual HDD, for the period 1993 through 2012 (N=20) (i.e., the Company's South Model).
2. A blended approach which combines fitted values for annual HDD generated by the Company's South Model, with a 30-year average (Mean) estimate of annual HDD (1983-2012), in equal proportions (i.e., 50% weightings to each), over the most recent 20-year period.
3. An alternative linear DT model specification, estimated over a 22-year period (1991-2012), based on the updated 2013 analyses described in the previous section, which found that the 22 year DT ranked as the best overall measure in Union South when 2011 and 2012 HDD data were added to the historical database.

Union North:

1. Union's 20-year DT model that fits a linear trend to annual HDD, for the period 1993 through 2012 (N=20) (i.e., the Company's North Model).
2. A blended approach which combines fitted values for annual HDD generated by the Company's North Model, with a 30-year average (Mean) estimate of annual HDD (1983-

2012), in equal proportions (i.e., 50% weightings to each), over the most recent 20-year period.

3. An alternative linear DT model specification, estimated over a 17-year period (1996-2012), based on the updated 2013 analyses described in the previous section, which found that the 17-year DT ranked as the best overall measure in the Union North when 2011 and 2012 HDD data were added to the historical database.

As discussed in prior sections of this report, a central question is which of these methods provides the best representation of the underlying rate of change in annual heating degree days, over the most recent 10 years of history and, presumably, into future (forecast) periods.

This is an important issue, but by no means the sole issue addressed by Union and the OEB in deriving forecasts of annual HDD. Balanced against the need for Accuracy, are other important factors, most notably, Stability and Symmetry, as discussed above. The OEB, in particular, places significant weight on these other forecast objectives, as evidenced by the inclusion of the 30-year mean estimate of annual HDD, in their blending algorithm applied to Union's 20-year DT model. The question is, what does this blending of a trend model with a constant parameter value do to Accuracy, and relatedly, does the blended approach provide any new information about changes in recent declines in annual HDD that improves forecast accuracy going forward?

Sussex/Harbourfront used the Cox J-Test to compare the relative performance of each model in explaining actual annual HDD in each geographical zone, based on the fitted values generated by the models. The Cox J-Test provides a method for numerically measuring how competing model structures "fit-the-facts", i.e., explain the proportion of variance in annual HDD over a historical period of interest.

The period of interest explored in this analysis are the last ten years covering the period 2003 through 2012. This ten-year period includes not only three of the warmest years on record in many regions of North America (2010-2012), but also some of the greatest periods of year-to-year variations in average recorded temperatures. This period is also of special interest because it figures heavily into driving the coefficient estimates on the trend variable in each regression model, i.e., the pivoting angle(s) on the coefficient estimate for trend in each DT model, for both Union North and South.

The Cox J-Test for a non-linear equation (such as EQ1, below) can be characterized as follows:

$$Y_{Series} = \rho*[\hat{Y}_{Model\text{-}A}] + (1-\rho)*[\hat{Y}_{Model\text{-}B}], \quad 0 <= \rho <= 1.0$$

The Cox J-Test provides a technique for comparing how two alternative models perform against each other, according to which one does a better job of "fitting the facts".

By way of example, Model-A, which may be the utility description of what drives energy demand is estimated to obtain the set of $\hat{Y}$s representing the fit of Model-A to the dependent variable (i.e., the Y_{Series}). Model-B stands as an alternative (i.e., competing) equation statement about what drives Y_{Series}. This model may include a different functional form, and/or different representation of weather variables, etc.

The Cox J-Test can be utilized to evaluate which model does a better job of covering the observed variance in Y_{Series}. Specifically, the Cox J-Test fits the nonlinear equation above, to the Y_{Series} using the $\hat{Y}$s from each model structure:

1. If ρ is close to 1.0, it means that Model-A does a superior job of explaining the dependent variable.
2. If ρ is closer to 0.0 ($1-\rho \sim 1.0$), it means that Model-B does a better job of explaining Y_{Series}.

This is the simplest description of the Cox J-Test to compare two competing hypotheses about the relative performance of alternative model structures.

Results of the Cox J-Test Model Comparisons: Union South

Table 7, below, compares the Cox J-Test model estimation results applied to the three pairings of models discussed above, for Union South.

Table 7: Cox J-Test – Union South Results

Model Pairings:	20-year:	Blended:	22-year Alternative
20-yr vs. Blended	$\rho = 0.62$	$(1-\rho) = 0.38$	
22-yr Alt vs. Blended		$(1-\rho) = 0.40$	$\rho = 0.60$
20-yr vs. 22-yr Alt.	$\rho = 1.00$		$(1-\rho) = 0.00$

These results can be interpreted as follows:

- When compared against the blending algorithm proposed by the OEB, the Cox J-Test reveals the estimate based on the 20-year DT model does a much better job of explaining the variation in HDD over the last 10 years (62% vs. 38%).
- Similarly, a side-by-side analysis of the DT model estimated over a 22-year period versus the blended algorithm reveals similar results in terms of relative explanatory power for each.
- Interestingly, the 20-year DT model, with its shorter estimation period, is preferred over the alternative, highest scoring, DT model estimated over 22 years, when called upon to explain the trend in annual HDD over the last 10 years.

Results of the Cox J-Test Model Comparisons: Union North

The same comparison was made to model results obtained for Union North, and are reported in Table 8, below.

Table 8: Cox J-Test – Union North Results

Model Pairings:	20-year:	Blended:	17-year Alternative
20-yr vs. Blended	ρ = 1.00	(1- ρ) = 0.00	
17-yr Alt vs. Blended		(1- ρ) = 0.17	ρ = 0.83
20-yr vs. 17-yr Alt.	ρ = 0.59		(1- ρ) = 0.41

- For Union North, when the relative performance and contribution of the Union and the OEB blended models are compared, the Cox J-Test reveals a clear weighting preference towards the 20-year DT model in explaining the observed variation in annual HDD, over the most recent 10-year period (2003-2012), i.e. 100% vs. 0% weighting factors.
- Similarly, our alternative model, estimated over the last 17 years of annual HDD data (1996-2012) is heavily favored in a scoring of relative performance over the blending algorithm, using the Cox J-Test (83% vs. 17%).
- It can be observed that the 20-year DT model is preferred over the alternative, highest scoring, DT model estimated over 17 years, when called upon to explain the trend in annual HDD over the last 10 years.

Collectively, the sets of findings from this pair-wise comparison of different DT models and a blending approach favored by the OEB, reveal the following general results:

1. In no instance does the blended approach that combines a 30-year HDD average with the Union DT model estimated over a 20-year period in equal proportions, outperform the other models examined in this analysis.
2. This finding implies that Accuracy in prediction is substantially lower under the OEB blending approach.
3. Generally speaking, the DT model performance is improved by shortening the estimation period to 22 years or less to better reflect structural changes in trend evident in each geographical zone.
4. As far as stability is concerned, the analytical objective is purely a function of the historical data set and efforts to artificially create a stable normal calculation metric comes at the expense of statistical considerations. In performing the Cox J-Test analysis it was observed that the Blended method, originally developed in a quest to create a more stable weather normal, actually produced the most extreme residuals over the ten-year analysis period than did the 20-year DT method or the 17 and 22-year DT methods. This observation tends to contradict the notion that the Blended method would add stability to the weather normal calculation process.

<u>Results of Hinge-Fit Analysis on Union North and South HDD Data</u>

An additional analysis was performed on Union North and South HDD data using a statistical method known as the Hinge-Fit Method. This method, developed by Robert Livezey (et al) is an iterative statistical analysis that allows the analyst to statistically estimate the hinge point, when a random series began to show evidence of the appearance of a trend, and then the declining trend velocity from that point.

In the case of Union North, the Hinge-Fit analysis showed the annual HDD data series transitioned from a random series around a mean value to a declining trend series in 1993. This finding is consistent with our recommendation of the use of a declining trend of 20 years, as our attribute-weighted and Cox J-Test analyses suggest.

In the case of Union South, the Hinge-Fit analysis showed the annual HDD data series transitioned from a random series around a mean value to a declining trend series beginning in

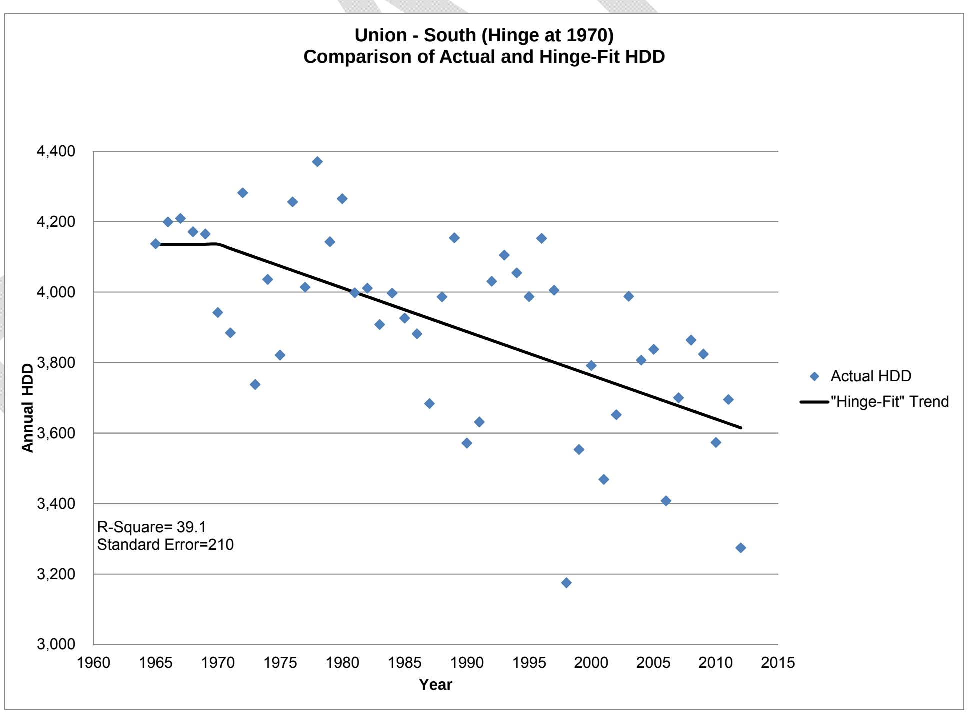
1978. This finding would be consistent with either the use of a declining trend series beginning in 1978, or a shorter declining trend series, if the statistical properties (attribute weighting and Cox J-Test results) of that shorter declining trend are superior to the 1978 series.

In summary, our evaluation of the 20-year declining trend series shows this series does a much better job at predicting the recent past 10 years for both Union North and Union South.

The following is a summary of the Hinge-Fit analysis performed on Union HDD data for this report:

- For Union South, the analysis used annual HDD data from 1965 to 2012. The first test used 1970 as the pivot point of the two segments, where segment one was 1965-1970 and segment two was 1971-2012. Chart 1 shows graphically the results of the first year tested. Chart 1 contains the actual HDD's from 1965-2012 and the calculated Hinge-Fit trend lines using 1970 as the pivot year, or break point of the two segments.

Chart 1: Union South Hinge-Fit Analysis



- The Hinge-Fit analysis can be interpreted as having a period that is in a stationary state and a period that is time-dependent (i.e., does not rely on averaging). The regression line after 1970 can be considered a time-dependent normal. The point in time through which the regression line passes is the normal value for that year. The analysis then increases segment one to 1965-1971 and decrease segment two to 1972-2012. This is done for each year until 2002 in order to find the pivot point which produces the highest R-Square and lowest Standard Errors.

- The Hinge-Fit analysis is designed to use the complete historical data set. It does not limit the historical data set to the exact years of study as a trend analysis does. Therefore, the comparisons of the R-Square and Standard Error for each pivot year are statistically consistent.
- The results for both Union North and South are presented in Table 9. Specifically, Table 9 identifies the R-Square and Standard Error for 1973, 1978, 1983 and 1993. These years represent a time-dependent segment, which includes 40, 35, 30, and 20 years respectively.

Table 9: Hinge-Fit Statistical Results

Union South Hinge-Fit Analysis				
Hinge-Fit Pivot	R-Square	Standard	Standard	Difference
Year		Error	Deviation	Dev-Err
1973	39.13%	209	268	59
1978	**40.45%**	**207**	**268**	**61**
1983	38.64%	210	268	58
1993	33.45%	219	268	49
Union North Hinge-Fit Analysis				
Hinge-Fit Pivot	R-Square	Standard	Standard	Difference
Year		Error	Deviation	Dev-Err
1973	38.30%	280	356	76
1978	40.23%	275	356	81
1983	40.73%	274	356	82
1993	**43.17%**	**268**	**356**	**88**

For Union South, Table 9 identifies 1978 as the best statistically based pivot point, however the analysis has little change between a range of 40 to 30 years. However, the Cox-J Test shows that the superiority of the 20-year DT as the best predictor of recent history—a result that trumps the Hinge-Fit result. For Union North, the result clearly shows the pivot point as 1993. This confirms a 20-Year trend analysis that has been evaluated as superior by our Cox-J analysis shown above.

The results for Union South are also shown in Chart 2. Chart 2 presents the Hinge-Fit trend line with a pivot point at 1978 and also presents a 40, 30, 20 and 10 year average and a simple 20-Year least-fit trend. This Chart not only shows a clear downward trend in Annual HDD's, but also how the longer the historical period the higher the average value. Chart 2 also identifies the slope of the Hinge-Fit Trend line to be negative 14.7 HDD per years. Chart 3 presents the same information for the Union North, however the Hinge-Fit pivot year is 1993.

Chart 2: Union South Weather Normal Method Comparison

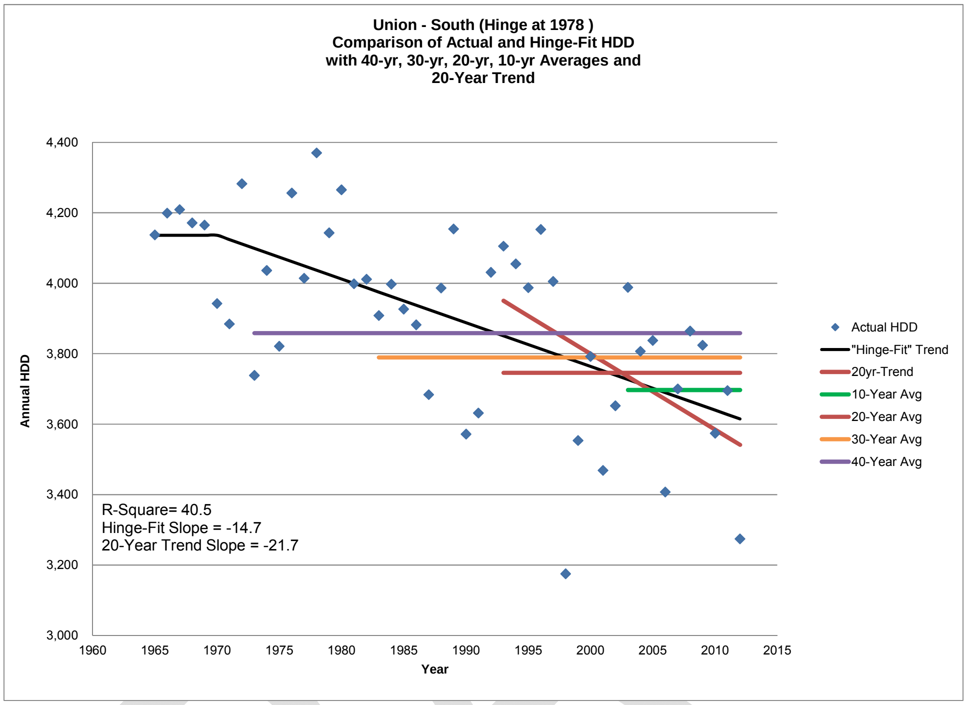
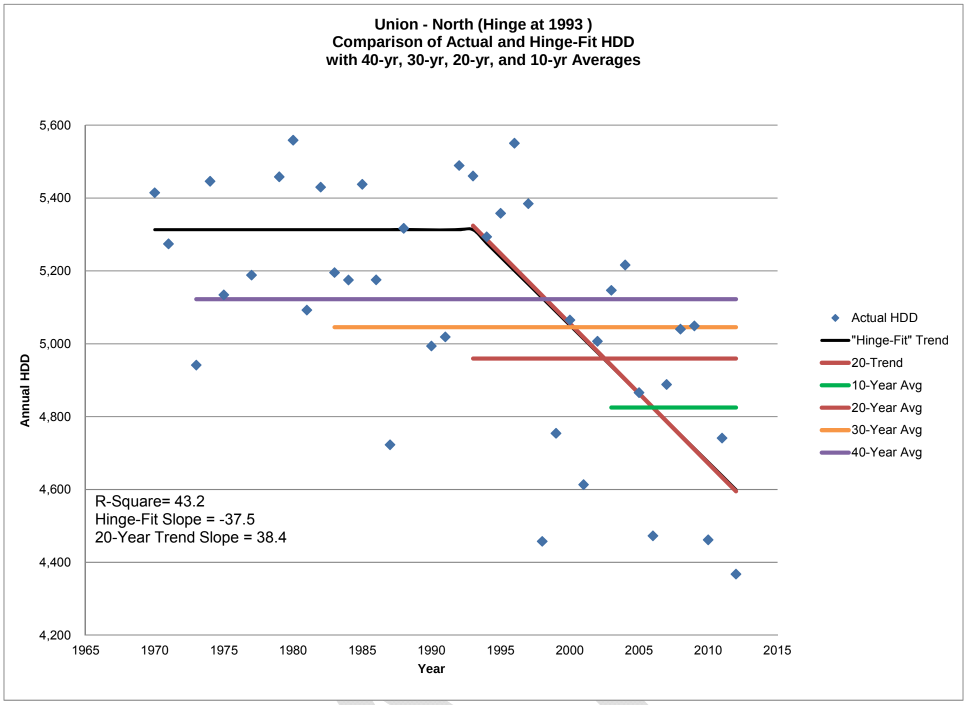


Chart 3: Union North Weather Normal Method Comparison



Industry Benchmarking Analysis

Overview

In order to assess current industry practice regarding weather normalization, Sussex/Harbourfront performed a benchmarking analysis of the weather normalization methods employed by a representative sample of utilities in Canada and the United States (*see* Appendix A). Specifically, Sussex/Harbourfront reviewed regulatory filings for fourteen natural gas utilities[2] in seven jurisdictions, including the Canadian Provinces of Ontario, New Brunswick, Manitoba, Nova Scotia and Alberta, and the States of New York and Michigan (both of which border Union's service territory).

Sussex/Harbourfront focused its benchmarking analysis on four areas:

1. The set of methods reviewed by each utility to calculate normal weather;
2. Conclusions drawn by the utilities from their review of those methods;
3. The method recommended by the utilities to their respective regulators; and
4. The method approved by the presiding regulatory commission (if available).

2 Union's previous normal weather methods are not included in the benchmarking analysis, however they are included in Appendix A to provide context.

As discussed in more detail below, our review indicates that most utilities rely on weather normalization methods that include data over ten to twenty years, rather than the thirty year average that historically had been viewed as the prevailing standard.

Summary

The utilities included in the benchmarking analysis in Appendix A reviewed a number of alternative weather normalization methods, which were applied to a range of weather data ending December 31, 2007 through December 31, 2011.[3] The methods reviewed include simple averages based on a specified number of years (ranging from ten to thirty years), a 20-Year Trend, de Bever, de Bever with Trend, a five-year weighted average, ARCH/Garch, Optimal Climate Normal, Energy Probe, Hinge-Fit, and a weighting of multiple methods. Please note that the benchmarking analysis included methods reviewed and used; for example, Centra Gas Manitoba reviewed the results of six different weather normalization methods and ultimately chose the 25-year average approach.

The number of utilities in the benchmarking analysis employing each method is provided in Table 10, below.

[3] The one exception to this is the National Oceanic and Atmospheric Administration ("NOAA") 30-year normal weather average. The 30-year normal weather data provided by NOAA is updated every ten years. The data that was reviewed by the two utilities using the NOAA method was through December 31, 2000.

Table 10: Frequency of Method[4]

Method	Number of Utilities
30-Year Average	3
25-Year Average	1
20-Year Average	3
15-Year Average	3
10-Year Average	4
de Bever with Trend	1
5-Year Weighted Average	1

As Table 10 demonstrates, the 30-year average was used in only three cases; all three were in the same jurisdiction (New York). Since the 20, 15 and 10-year averaging periods were just as likely to be used, it appears that the 30-year convention no longer is the prevailing standard. The majority of the weather normalization methods eventually implemented by the utilities in the benchmarking analysis rely on a time period of less than thirty years. The trend toward shorter normalization periods was addressed in the various jurisdictions reviewed by Sussex/Harbourfront. For example, the Manitoba Public Utilities Board ("MPUB") stated that, "…there are two definite warming trends: one covers the period 1900 to 1935, while the other is a recent trend from 1975 to the present."[5]

In a similar vein, Dr. Robert Livezey, on behalf of Michigan Consolidated Gas ("Mich Con"), noted that:

> While there may be controversy over the cause of climate change or the seriousness of its impacts, there is virtually no reasonable controversy remaining over the fact that measurable climate change has taken place since the 1970s, globally as well as over the United States, and that the

4 The total number of utilities in the benchmarking analysis does not equal the total number of methods employed in Table 10 because Enbridge Gas Distribution ("Enbridge") in Ontario determines the appropriate method for each of its three weather zones independent of each other.

5 Manitoba Public Utilities Board, Order No. 65/11, Centra Gas Manitoba Inc. 2011/12 Cost of Gas Application and May 1, 2011 Primary Gas Rate, April 28, 2011, at 53.

> temperature increase is greatest over Northern Hemisphere continents in the wintertime.[6]

Paul Raab on behalf of SEMCO Energy Gas Company ("SEMCO") noted:

> There is a growing realization that normal weather, as it has been traditionally defined, is not likely to produce that set of temperatures that most closely corresponds to the temperatures that will be experienced in the rate effective period.[7]

Those points are consistent with our observation that the utilities in the benchmarking analysis have moved toward weather normalization methods that place a greater emphasis on more recent data.

The following section includes a brief summary, by jurisdiction, of the weather normalization methods employed by the utilities included in the benchmarking analysis.

Ontario

Enbridge uses two different methods, which were determined separately for each of the company's three weather zones. Enbridge reviewed several methods for each weather zone and applied a series of statistical tests to determine the relative rank of each method. Based on those analyses, Enbridge recommended the normal weather for the Central, Eastern and Niagara weather zones should be determined based on a 20-year Trend, the de Bever with Trend, and a 10-year average, respectively. Enbridge subsequently updated its analysis based on more recent data and continued to recommend the same methods for each weather zone. However, the updated results suggested the 10-year average ranked higher than the 20-year Trend for the Central weather zone. As part of a settlement agreement, Enbridge agreed to rely on the 10-year average for its Central weather zone. The methods proposed for the Eastern and Niagara weather zones were accepted as filed.

In addition to Enbridge, Sussex/Harbourfront also reviewed the weather normalization approach for Natural Resource Gas, which relied on a five-year weighted average. That five-year weather

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6 Direct Testimony of Robert Livezey, On Behalf of Michigan Consolidated Gas, Case No. U-15985, at 10.

7 Direct Testimony of Paul Raab, On Behalf of SEMCO Energy Gas Company, Case No. U-16169, at 7.

normalization method has remained unchanged over, at least, Natural Resource Gas' previous three rate cases.

Alberta

AltaGas Utilities and ATCO Gas relied on 20 and 10-year averages, respectively; and neither company reviewed alternative approaches.

Nova Scotia

Heritage Gas Limited relied on a 20-year average, and the company did not review alternative approaches.

Manitoba

Centra Gas Manitoba (doing business as Manitoba Hydro) relied on a 25-year average. In addition to the 25-Year average, Centra Gas Manitoba reviewed five different methods including: (1) the Olympic Average (i.e., develop the average by eliminating the highest and lowest HDD years from the previous twelve years of data); (2) the 10-year average; (3) the 30-year average based on the Environment Canada method[8]; (4) the five-year Fixed (i.e., initially averaging the most recent ten years of data and updating every five years); and (5) the Statistical Significance Method (i.e., initially averaging the most recent ten years of data and not updating until statistical evidence suggests the result is no longer valid). The MPUB noted that there has been a warming trend since 1975, and that while the 25-year average lagged other methods in capturing that trend, it still reflected the shift. In an effort to provide stability to the forecast, the MPUB approved the 25-year average, even though that approach may decrease accuracy relative to averages calculated over shorter time periods.[9]

New Brunswick

Enbridge Gas New Brunswick relied on a 20-year average, and did not review alternative approaches.

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8 Environment Canada, similar to the NOAA, uses a 30-year average, which is updated every ten years, based on the most recent thirty years of data.

9 Manitoba Public Utilities Board, Order No. 65/11, Centra Gas Manitoba Inc. 2011/12 Cost of Gas Application and May 1, 2011 Primary Gas Rate, April 28, 2011, at 53-54.

Michigan

Mich Con, SEMCO and Consumers Energy all relied on 15-year averages to calculate normal weather. However, Mich Con applied for the use of the Hinge-Fit method.[10] The Michigan Public Service Commission ("MPSC") denied the use of the Hinge-Fit method because it was "untested in the area of utility regulation", and Mich Con's application of the method appeared to overestimate the warming trend.[11] In that case, the MPSC directed Mich Con to provide projections based on the 15-year average, and in future cases both 15 and 30 year averages. All three Michigan companies reviewed multiple weather normalization methods in their assessment of the appropriate weather normalization method.

New York

Consolidated Edison Company of New York, Niagara Mohawk, and Orange and Rockland all relied on 30-year averages, while Central Hudson Gas and Electric used a 10-year average. None of those companies reviewed alternative approaches.

<u>Observations and Recommendations:</u>

In summary, the following Observations and Recommendations are offered:

1. On the question of the analytical objectives of Accuracy vs. Symmetry vs. Stability, the quest for Stability in a period of instability can prove elusive, challenging its worth as a statistical objective. From a statistician's perspective, unbiased accuracy should be the primary objective.
2. The Declining Trend (linear as well as non-linear) statistical construct has many features to recommend it as the statistical method of choice, for selecting and updating the Union North and South weather normals. Simplicity is an important attribute for any statistical analysis, and, while other methods, such as Hinge-Fit analysis, can be used to inform a statistical investigation, the ultimate result should be based upon a relatively simple, easy to understand, approach.

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[10] The Mich Con rate case was not the most recent rate case for the utility; however, it set the precedent.

[11] Michigan Public Service Commission, Opinion and Order, Case No. U-15985, at 41.

3. Selection of a weather normal should be an ongoing process until a level of stability is identified, and it is logical to expect that weather normal uncertainty will continue for some time.
4. Finally, it is our recommendation that Union use a 20-year Declining Trend as the weather normal for the Union North and a 20-year Declining Trend as the weather normal for Union South. Based upon all of the analysis performed in this study, the 20-year DT best meets the objectives of accuracy, symmetry, simplicity and sustainability for both the North and South.

Company	Jurisdiction/ Docket No.	Witness	Analyses Performed	Date of Analyses	Testimony Conclusions
Central Hudson Gas & Electric	New York/ 09-G-0589	Forecasting & Rates Panel	10-Year Moving Average.	December 31, 2008	
Consolidated Edison Co. of NY	New York/ 09-G-0795	Forecasting Panel	30-Year Moving Average.	December 31, 2008	
Niagara Mohawk	New York/ 12-G-0202	A. Leo Silvestrini	30-Year Moving Average.	December 31, 2011	
Orange & Rockland	New York/ 08-G-1398	Forecasting Panel	30-Year Moving Average.	December 31, 2007	
Michigan Consolidated Gas	Michigan/ U-15985	Dr. Robert Livezey & George Chapel	10-Year Moving Average, 30-Year Moving Average, NOAA 30-Year Average (based on end of decade data), Hinge-Fit, Optimum Climate Normal (11-Years).	December 31, 2008 and December 31, 2000 (NOAA 30-Year Average)	30-Year Average is not a reasonable estimate of normal temperatures. OCN and Hinge-Fit are both superior to 30-Year average. Hinge-fit uses a long record of data (almost 60 years in this case). Both the OCN and Hinge-Fit methods are relatively simple to implement and routine to compute. Both will produce estimates with similar expected error in all instances, but the Hinge-Fit will outperform OCN for most of the locations in the service area.

Company	Jurisdiction/ Docket No.	Witness	Analyses Performed	Date of Analyses	Testimony Conclusions
SEMCO Energy Gas Co.	Michigan/ U-16169	Paul Raab	30-Year Moving Average, NOAA 30-Year Average (based on end of decade data), 15-Year Moving Average, 10-Year Moving Average, ARCH/Garch	December 31, 2009 and December 31, 2000 (NOAA 30-Year Average)	15-Year Moving Average represents a compromise from the current NOAA normals, the shorter averaging periods and the statistically-based ARCH/GARCH approach. However, because of the very real possibility that even a fifteen-year average will result in a definition of normal weather that is too cold, the results using the ARCH/GARCH normals were provided for comparison purposes.
Consumers Energy	Michigan/ U-16855	Hubert Miller III	15-Year Moving Average and 30-Year Moving Average.	December 31, 2010	15-Year Moving Average was used. Using a 30-year heating index would decrease the 2012 total consumption by 0.2% from 278,843 Million Cubic Feet ("MMcf") to 278,801 MMcf.
Enbridge Gas New Brunswick	New Brunswick/ 0178		20-Year Moving Average.	Not explicitly noted. Application was filed May 31, 2012.	
Centra Gas (Manitoba Hydro)	Manitoba/ 2011/12 Cost of Gas Application		25-Year Moving Average, Olympic Average (*i.e.,* eliminating the highest and lowest HDDs from the previous twelve years of data), 10-Year Moving Average, Environment Canada (*i.e.*, 30-years of data is averaged and updated every 10-years), 5-Year Fixed (*i.e.,* initially averaging the most recent ten years of data and updating every five years), Statistical Significance Method (*i.e.,* initially averaging the most recent	December 31, 2009	The 25 Year Average method accomplishes the goal of reducing the variability of the normal weather calculation, as the method has about 50% lower variability than the 10 Year Average method which is currently in use. The use of the 25 Year Average method compared to the 10 Year Average Method, reduces the maximum difference of forecast to actual by 6%, however, it increases the difference between average forecast and actual by 8%. Of the methods considered, the 25 Year Average method had the greatest impact in reducing the year-to-year variability, while minimizing

Company	Jurisdiction/ Docket No.	Witness	Analyses Performed	Date of Analyses	Testimony Conclusions
			ten years of data and not updating until statistical evidence suggests the result is no longer valid).		the impact on accuracy.
Heritage Gas Limited	Nova Scotia/ M04196		20-Year Moving Average.	Not explicitly noted. Other historical data provided in filing was through 2010. Application was filed June 15, 2011.	
AltaGas Utilities	Alberta/ 904		20-Year Moving Average.	December 31, 2009	
ATCO Gas	Alberta/ 969		10-Year Moving Average.	December 31, 2009	
Enbridge Gas Distribution	Ontario/ EB-2011-0354	Hulya Sayyan & Margaritz Suarez-Sharma	Naïve, 10-Year Moving Average, 20-Year Moving Average, 20-Year Trend, 30-Year Moving Average, 50/50 (Average of 20-Year Trend and 30-Year Moving Average), de Bever, de Bever with Trend, and the Energy Probe. Each method was ranked relative to the others based on MAPE, RMSPE, MPE, POF and Standard Deviation (*i.e.,* accuracy, symmetry and stability). Forecasts were reviewed over most recent periods	December 31, 2010; Updated through December 31, 2011	In the Central weather zone the 20-Year Trend method, the 10-Year Moving Average and the 50/50 method all performed similarly well in the analysis based on data ending 2011. In the historical analysis, the 20-Year Trend method ranked among the top three methods more years than the 10-Year Moving Average and the 50/50 method. In the Eastern and Niagara weather zones the de Bever with Trend and 10-Year Moving Average, respectively, outperformed the other methods in both the recent and historical analyses.

Company	Jurisdiction/ Docket No.	Witness	Analyses Performed	Date of Analyses	Testimony Conclusions
			of 20 years, 10 years and 5 years. Lower combined scores were seen as more favorable. In order to validate the rankings, Enbridge reviewed the rankings of each method for each year over a 22 year historical period. Methods which were consistently ranked highly were seen as favorable.		
Natural Resource Gas	Ontario/ EB-2010-0018		5-Year weighted average forecast methodology. $W_t = (5 \times D_{t-12} + 4 \times D_{t-24} + 3 \times D_{t-36} + 2 \times D_{t-48} + 1 \times D_{t-60}) / 15$, where W is the weighted five year average, D is the monthly HDDs and t is the current monthly time period. The simple 5-Year Moving Average was also calculated, but appears to be more of a check than a potential method to rely upon.	September 30, 2009	Methodology is unchanged from previous two cases.
Union Gas	Ontario/ RP-2003-0063		20-year trend with forecast information, 20-year trend, 30-year trend, 38-year trend, 20-year average, 10-year average, and 30-year average. Compared methods based on symmetry, accuracy, stability, sustainability and simplicity. Ranked each	October 31, 2001	Union ranked the methods in order, from best to worst, as follows: 20-year trend with forecast information, 20-year trend, 30-year trend, 38-year trend, 20-year average, 10-year average, and 30-year average. Union proposed the 20-year trend method rather than the 20-year trend with forecast information method, arguing the latter was far more

Company	Jurisdiction/ Docket No.	Witness	Analyses Performed	Date of Analyses	Testimony Conclusions
			method based on scores for each measure. Symmetry was given the largest weight, then accuracy. Stability, sustainability, and simplicity were all given the lowest (and equal) weight.		complex and it relied upon a third party's proprietary model and therefore might not be sustainable. Union's evidence states that, based on data from 1985 to 2000, the 30-year average weather normalization methodology consistently overestimates the heating demand by customers by about 7.6%.
Union Gas	Ontario/ EB-2005-0520		30-Year Average, 20-Year Trend, 55:45 weighting 30-Year Average, and 20-Year Trend.	October 31, 2005	

Company	Jurisdiction/ Docket No.	Recommended Normal Weather Methodology	Observed Changes in Long Term Weather Trends	Reference in Order?	Notes
Central Hudson Gas & Electric	New York/ 09-G-0589	10-year average of monthly HDD or CDD based on hourly temperature readings.		No	
Consolidated Edison Co. of NY	New York/ 09-G-0795	Average weather condition over 30 calendar years.		Only in context of Steam earnings calculation, not LDC sales forecast	Within the context of a WNA. Same methodology in Steam earnings calculation.
Niagara Mohawk	New York/ 12-G-0202	30-year average. Forecast HDD equals average of past 30 years of HDD on any given day (i.e., forecast HDD for Jan 5th = average of past 30 years of HDDs for Jan 5th).		No	The testimony notes that it is using the same methodology the Company used in the 08-G-0609 filing.
Orange & Rockland	New York/	Average weather condition over 30 calendar years.		No	Within the context of a WNA
Michigan Consolidated Gas	Michigan/ U-15985	Hinge-Fit.	While there may be controversy over the cause of climate change or the seriousness of its impacts, there is virtually no reasonable controversy remaining over the fact that measurable climate change has taken place since the 1970s. The increase is greatest over the Northern Hemisphere. Trends, likely tied to global scale changes, have been and will likely continue to be a source of considerable error when 30-	Yes	The Commission decided to rely upon the 15-Year Moving Average, however in future cases Mich Con must include projections based on 15- and 30-year weather normalization methods. This case was finalized in 2010 and is not Mich Con's most recent case, however, the weather normalization methodology was a major issue and a number of methods were discussed.

Company	Jurisdiction/ Docket No.	Recommended Normal Weather Methodology	Observed Changes in Long Term Weather Trends	Reference in Order?	Notes
			year normals (whether rolling or official) are used to estimate current and immediate future temperature for the cold half of the year. Temperatures increased from 1910-1940, then leveled off and have been increasing again since the mid-1970s.		
SEMCO Energy Gas Co.	Michigan/ U-16169	15-Year Moving Average, to be consistent with previous order.	There is a growing realization that normal weather, as it has been traditionally defined, is not likely to produce a set of temperatures that most closely corresponds to the temperatures that will be experienced in the rate effective period. Testimony references a publication from members of the NOAA and NCDC calling into question the usefulness of NOAA's climate normals which are released every 10 years.	Case was settled. No mention of weather.	
Consumers Energy	Michigan/ U-16855	15-Year Moving Average.		No	Exhibits rely upon 15-Year Moving Average in settlement, but there isn't a specific mention to the method being approved in settlement or order. The company was previously directed to provide the 15 and 30-Year Moving Averages.

Company	Jurisdiction/ Docket No.	Recommended Normal Weather Methodology	Observed Changes in Long Term Weather Trends	Reference in Order?	Notes
Enbridge Gas New Brunswick	New Brunswick/ 0178	20-Year Moving Average.		No	
Centra Gas (Manitoba Hydro)	Manitoba/ 2011/12 Cost of Gas Application	25-Year Moving Average.		Yes	The Manitoba Public Utilities Board noted that there were warming trends from 1900-1935 and 1975 to the present. The 25-Year Average captured the trend, although it lagged other methodologies. Given the desire for stability, the 25-Year Average was approved.
Heritage Gas Limited	Nova Scotia/ M04196	20-Year Moving Average.		Case was settled. No mention of weather.	
AltaGas Utilities	Alberta/ 904	20-Year Moving Average.		Yes	The Commission recognized the method used to normalize HDDs and approved the forecast. It did not make a direct statement as to the appropriate normalization methodology.
ATCO Gas	Alberta/ 969	10-Year Moving Average.		No	
Enbridge Gas Distribution	Ontario/ EB-2011-0354	Central weather zone relies upon a 20-Year Trend method, Eastern weather zone relies upon the de Bever with Trend method and the Niagara weather zone relies upon a 10-Year Moving Average method.		Yes, within context of approved settlement	During settlement negotiations the parties agreed that Enbridge should use the 10-Year Moving Average for its Central weather zone instead of the previously approved 20-Year Trend method, which

Company	Jurisdiction/ Docket No.	Recommended Normal Weather Methodology	Observed Changes in Long Term Weather Trends	Reference in Order?	Notes
					Enbridge continued to recommend. Based on the updated 2011 data the 10-Year Moving Average ranked higher than the 20-Year Trend method. The Eastern and Niagara weather zones rely upon the de Bever with Trend and 10-Year Moving Average, respectively, as recommended by Enbridge in the application.
Natural Resource Gas	Ontario/ EB-2010-0018	5-Year Weighted Average.		No	NRG is a private company with approximately 7,000 customers.
Union Gas	Ontario/ RP-2003-0063	20-Year Trend.	There was an increase in global average temperature of approximately 0.6 degrees Centigrade (+/- 2°) over the twentieth century. The warming trend occurred during two periods, 1901-1945 and 1976-2000 and were separated by a cooling period between 1945-1976. Union stated that 0.6 degrees per century corresponded to 1.6 HDDs per year. The global average temperature increase was approximately	Yes	Board approved 70:30 weighting of the 30-year average forecast and 20-year trend forecast respectively. For each year thereafter, the Board will consider 5% declines and inclines to the weighting of the 30-year and 20-year methodology respectively until such time as a 50:50 weighting is in place.

Company	Jurisdiction/ Docket No.	Recommended Normal Weather Methodology	Observed Changes in Long Term Weather Trends	Reference in Order?	Notes
			2°C, but qualified this figure as it applies to Ontario, due to the amplification effect of Ontario geography. Extreme weather events had become much more common over the last 20 years.		
Union Gas	Ontario/ EB-2005-0520	55:45 weighting 30-Year Moving Average, and 20-Year Trend.		Yes	Settlement called for a 55:45 weighting of 30-year average and 20-year trend.

Calculation of Union Revenues Subject to PCI Escalator Net of Pass Throughs and Deferrals

Line No.	Particular ($millions)			
1	2013 Approved revenue (net of delivered gas cost)		1,090.9	
2	Less: Upstream transporation in gas supply margin		-124.8	
3	2013 Approved delivery revenue		966.1	100.0%
4	Other pass through/deferrals			
5	DSM	-31.6		
6	S&T *	-18.0		
7	UFG	-14.2		
8	Total pass through/deferrals		-63.81	
9	Amount subject to PCI net of pass through/deferrals		902.29	93.4%

* S&T revenues = $14.9 million * 0.9 of exchanges and $4.6 million of Short-term storage and balancing

Total Compressor Fuel Revenue vs. Cost
($millions)

	2007 Br App'd	2010	2011	2012
Revenue				
Board approved	57.3			
storage allocation	- 4.1			
utility allocation	53.1	53.1	53.1	53.1
QRAM change		- 18.2	- 23.1	- 26.5
change in activity	YCR	1.0	- 1.8	- 0.7
		36.0	28.2	25.9
Cost of gas				
actual expense		38.4	31.1	22.9
storage allocation		- 3.7	- 2.9	- 1.4
optimization deferral		-	- 0.6	-
		34.7	27.6	21.6
Variance		**1.3**	**0.6**	**4.3**

Burlington to Oakville Project Revenue Requirement

Line No.	Particulars ($000's)	Revenue Requirement 2016	2017	2018
	Operating Expenses:			
1	Operating and Maintenance Expenses (1)	26	27	27
2	Depreciation Expense (2)	1,467	1,472	1,472
3	Property Taxes	564	576	587
4	Total Operating Expenses	2,057	2,075	2,086
5	Required Return (3)	4,227	4,158	4,077
	Income Taxes:			
6	Income Taxes - Equity Return (4)	848	834	817
7	Income Taxes - Utility Timing Differences (5)	(1,685)	(1,430)	(1,205)
8	Total Income Taxes	(837)	(596)	(388)
9	Burlington to Oakville Revenue Requirement	5,447	5,637	5,775

Notes:

Assumes capital expenditure of $75 million.

(1) O&M expenses are $0.027 million for pipeline related O&M.

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

(3) The required return for 2018 assumes total rate base of $70.596 million and a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:

$70.596 million * 64% * 4% = $1.807 million plus
$70.596 million * 36% * 8.93% = $2.270 million for a total of $4.077 million.

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

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

SCHEDULE 1

Burlington to Oakville Project Revenue Requirement ($000's)

Line No.	Particulars ($000's)	2015 (a)	2016 (b)	2017 (c)	2018 (d)
	Operating Expenses:				
1	Operating and Maintenance Expenses (1)	4	25	26	26
2	Depreciation Expense (2)	628	1,257	1,257	1,257
3	Property Taxes	72	433	441	450
4	Total Operating Expenses	705	1,715	1,724	1,733
5	Required Return (3)	535	3,248	3,175	3,103
	Income Taxes:				
6	Income Taxes - Equity Return (4)	107	651	636	622
7	Income Taxes - Utility Timing Differences (5)	(1,389)	(1,806)	(1,479)	(1,208)
8	Total Income Taxes	(1,282)	(1,155)	(843)	(586)
9	Revenue Requirement	(42)	3,807	4,056	4,250

Notes:

Assumes capital expenditure of $57.5 million. Project costs under review.

(1) O&M expenses are projected for incremental pipeline-related operating and maintenance expenses.

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

(3) The required return for 2018 assumes total rate base of $53.731 million and a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:

$53.731 million * 64% * 4% = $1.38 million plus
$53.731 million * 36% * 8.93% = $1.73 million for a total of $3.103 million.

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

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

SCHEDULE 2

Burlington to Oakville Project Cost Allocation by Rate Class ($000's)

Line No.	Particulars ($000's)	2015	Variance	2016	Variance	2017	Variance	2018
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)	(f) = (g - e)	(g)
	Cost Allocation by Rate Class (1)							
1	Rate M1	4	1,518	1,522	97	1,619	75	1,695
2	Rate M2	101	538	639	9	647	5	652
3	Rate M4	38	174	213	1	214	0	215
4	Rate M5	(16)	1	(15)	4	(11)	3	(7)
5	Rate M7	14	63	77	0	78	0	78
6	Rate M9	5	20	26	(0)	26	(0)	26
7	Rate M10	0	1	1	(0)	1	(0)	1
8	Rate T1	36	149	185	0	185	(0)	185
9	Rate T2	306	1,098	1,404	(7)	1,397	(10)	1,386
10	Rate T3	39	142	180	(1)	179	(1)	178
11	Subtotal - Union South	529	3,703	4,232	103	4,335	73	4,408
12	Excess Utility Space	(8)	(2)	(10)	2	(8)	2	(7)
13	Rate C1	(0)	(0)	(0)	0	0	0	0
14	Rate M12	(233)	202	(31)	62	31	51	82
15	Rate M13	0	(2)	(2)	0	(2)	0	(2)
16	Rate M16	0	(0)	0	0	0	0	0
17	Subtotal - Ex-franchise	(240)	197	(43)	65	21	53	74
18	Rate 01	(245)	(40)	(285)	59	(227)	49	(177)
19	Rate 10	(37)	(3)	(40)	9	(31)	8	(23)
20	Rate 20	(24)	(4)	(27)	6	(21)	5	(15)
21	Rate 100	(18)	(3)	(21)	5	(16)	4	(12)
22	Rate 25	(6)	(1)	(8)	2	(6)	1	(5)
23	Subtotal - Union North	(330)	(51)	(381)	81	(300)	68	(232)
24	In-franchise	198	3,652	3,851	184	4,035	141	4,176
25	Ex-franchise	(240)	197	(43)	65	21	53	74
26	Total Revenue Requirement	(42)	3,849	3,807	249	4,056	194	4,250

Note:

(1) The annual revenue requirement represents the total project costs for the respective year.

UNION GAS LIMITED

Brantford to Kirkwall and Parkway D Compressor Project - Annual Revenue Requirement

Line No.	Particulars ($000's)	Revenue Requirement 2015	2016	2017	2018
		(a)	(b)	(c)	(d)
	Operating Expenses:				
1	Operating and Maintenance Expenses (1)	107	642	642	642
2	Depreciation Expense (2)	2,622	5,287	5,329	5,329
3	Property Taxes (3)	142	853	853	853
4	Total Operating Expenses	2,871	6,782	6,824	6,824
5	Required Return (4)	1,359	11,383	11,176	10,868
	Income Taxes:				
6	Income Taxes - Equity Return (5)	272	2,281	2,240	2,178
7	Income Taxes - Utility Timing Differences (6)	(4,580)	(5,726)	(4,808)	(3,969)
8	Total Income Taxes	(4,307)	(3,445)	(2,568)	(1,791)
9	Parkway Growth Revenue Requirement	(77)	14,720	15,433	15,902

Notes:

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

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

(3) Property taxes include $0.188 million for compression and $0.665 million for pipeline and building taxes.

(4) The required return for 2018 assumes total rate base of $188.206 million and a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:

$188.206 million * 64% * 4% = $4.818 million plus
$188.206 million * 36% * 8.93% = $6.050 million for a total of $10.868 million.

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

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

UNION GAS LIMITED

Brantford to Kirkwall and Parkway D Compressor Project - Annual Rate Adjustments by Rate Class

Line No.	Particulars ($000's)	2015	Variance	2016	Variance	2017	Variance	2018
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)	(f) = (g - e)	(g)
1	Rate M1	(2,310)	280	(2,029)	331	(1,698)	295	(1,403)
2	Rate M2	(440)	230	(210)	48	(162)	40	(121)
3	Rate M4	(117)	66	(51)	12	(39)	10	(29)
4	Rate M5	(57)	(13)	(70)	11	(59)	10	(49)
5	Rate M7	(46)	33	(14)	4	(10)	3	(7)
6	Rate M9	(13)	13	(0)	1	0	0	1
7	Rate M10	(0)	0	(0)	0	(0)	0	(0)
8	Rate T1	(71)	29	(42)	8	(34)	7	(27)
9	Rate T2	(364)	217	(146)	35	(111)	29	(83)
10	Rate T3	(86)	89	3	4	7	2	9
11	Subtotal - Union South	(3,504)	945	(2,559)	454	(2,105)	397	(1,708)
12	Excess Utility Space	(27)	(8)	(34)	5	(29)	5	(25)
13	Rate C1	(6)	(5)	(11)	1	(10)	1	(8)
14	Rate M12	2,934	13,218	16,152	44	16,197	(114)	16,083
15	Rate M13	(1)	0	(0)	0	(0)	0	(0)
16	Rate M16	(1)	0	(1)	0	(0)	0	(0)
17	Subtotal - Ex-franchise	2,900	13,206	16,106	51	16,157	(108)	16,050
18	R01	410	470	881	151	1,032	131	1,162
19	R10	198	161	359	22	382	19	400
20	R20	1	32	32	17	49	15	64
21	R100	(59)	(10)	(70)	13	(57)	12	(45)
22	R25	(24)	(6)	(30)	5	(25)	4	(21)
23	Subtotal - Union North	527	646	1,173	208	1,381	180	1,561
			0		0		0	
24	In-franchise	(2,977)	1,591	(1,386)	661	(724)	577	(147)
25	Ex-franchise	2,900	13,206	16,106	51	16,157	(108)	16,050
			0		0		0	
26	Total	(77)	14,797	14,720	712	15,433	469	15,902

UNION GAS LIMITED

Answer to Interrogatory from
London Property Management Association ("LPMA")

Ref: EB-2012-0433, Section 1, First Paragraph 14 (between paragraphs 8 and 9)

a) Please provide a schedule that shows that amount of the capital expenditures that are forecast to be closed to rate base in each of 2013 through 2016. For each year, please show the revenue requirement associated with the amounts closed to rate base (similar to Schedule 10-1 in EB-2013-0074), along with the amount in each year allocated to in-franchise customers and to ex-franchise customers.

b) Please provide a breakdown of the amounts for each year in 2013 through 2016 that is allocated to in-franchise customers to amounts allocated to Union North and East in-franchise customers and to Union South in-franchise customers.

c) How does Union propose to recover/rebate any revenue requirement for 2013 through 2015, prior to the January 1, 2016 proposal to build the impact into in-franchise and ex-franchise rates?

Response:

a) The Parkway West Project capital expenditures that are forecast to be closed to rate base in 2014 to 2016 and the associated revenue requirement are provided at Attachment 1. There are no forecasted capital expenditures in 2013.

   The allocation of the 2014 to 2018 Parkway West Project revenue requirements to in-franchise and ex-franchise rate classes is provided at Attachment 2.

b) Please see the response to part a) above.

c) As filed in EB-2012-0433, Union proposed to build the first full-year revenue requirement associated with developing Parkway West into in-franchise and ex-franchise rates based on the cost estimates included in the application, effective January 1, 2016. Union also proposed to track any variance between what is approved in rates for Parkway West and the actual costs for the project in a new deferral account until such time that the deferral account balance can be reviewed and disposed of.

   Union will be filing an update to its Parkway West evidence by the end of June to modify its rate implementation proposal. In the evidence update, Union will propose to build the annual costs associated with the Parkway West Project into in-franchise and ex-franchise rates, based on the cost estimates included in the application, effective January 1, 2014. There is no revenue requirement associated with the Project in 2013.

Union will also propose to adjust in-franchise and ex-franchise rates on an annual basis from 2015 to 2018 in order to recover the estimated annual costs associated with the Project. Lastly, Union will propose to track any variance between what is approved in rates for the Project and the actual annual revenue requirement for the Project in a new deferral account. Union will dispose of any balance in the deferral account as part of its annual non-commodity deferral account proceeding.

UNION GAS LIMITED
Parkway West Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2014 (a)	2015 (b)	2016 (c)	2017 (d)	2018 (e)
	Rate Base Investment					
1	Capital Expenditures	64,721	137,545	850	0	0
2	Average Investment	10,623	85,929	197,189	192,824	188,028
	Revenue Requirement Calculation:					
	Operating Expenses:					
3	Operating and Maintenance Expenses (1)	0	739	1,615	1,649	1,683
4	Depreciation Expense (2)	402	2,789	4,786	4,798	4,798
5	Property Taxes (3)	236	290	510	521	532
6	Total Operating Expenses	638	3,818	6,911	6,967	7,013
7	Required Return (4)	611	4,960	11,387	11,135	10,858
	Income Taxes:					
8	Income Taxes - Equity Return (5)	123	994	2,282	2,232	2,176
9	Income Taxes - Utility Timing Differences (6)	(1,648)	(4,752)	(5,244)	(4,270)	(3,431)
10	Total Income Taxes	(1,526)	(3,758)	(2,962)	(2,039)	(1,255)
11	Total Revenue Requirement	(277)	5,020	15,336	16,064	16,616

Notes:

(1) 2018 O&M expenses include $0.488 million in salary, wages and employee expenses, $0.711 million in contract services and $0.485 million in materials, utility costs, and company used fuel.

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

(3) Property taxes include $0.247 million for land purchases, $0.195 million for LCU compression and $0.090 million for pipeline and building taxes.

(4) The required return assumes a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:

$188.028 million * 64% * 4% = $4.814 million plus

$188.028 million * 36% * 8.93% = $6.045 million for a total of $10.858 million.

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

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

UNION GAS LIMITED

Parkway West Project Revenue Requirement by Rate Class

Line No.	Particulars ($000's)	2014 (a)	Variance (b) = (c - a)	2015 (c)	Variance (d) = (e - c)	2016 (e)	Variance (f) = (g - e)	2017 (g)	Variance (h) = (i - g)	2018 (i)
1	Rate M1	(492)	(1,156)	(1,648)	(4)	(1,652)	299	(1,354)	283	(1,071)
2	Rate M2	(58)	(59)	(117)	143	26	47	73	40	113
3	Rate M4	(13)	(13)	(25)	39	13	12	25	9	34
4	Rate M5	(17)	(53)	(70)	(18)	(87)	8	(79)	10	(70)
5	Rate M7	(4)	2	(2)	22	20	4	24	3	27
6	Rate M9	(0)	4	4	9	13	1	14	0	15
7	Rate M10	(0)	0	(0)	0	0	0	0	0	0
8	Rate T1	(9)	(21)	(31)	11	(19)	8	(11)	7	(5)
9	Rate T2	(31)	(41)	(72)	110	38	42	80	26	106
10	Rate T3	(0)	34	34	63	98	6	103	3	106
11	Subtotal - Union South	(624)	(1,302)	(1,926)	374	(1,552)	427	(1,125)	381	(744)
12	Excess Utility Space	(9)	(21)	(30)	(6)	(36)	5	(31)	5	(27)
13	Rate C1	(1)	(12)	(13)	(8)	(21)	1	(20)	1	(19)
14	Rate M12	660	7,135	7,795	9,671	17,466	115	17,580	(15)	17,565
15	Rate M13	(0)	(0)	(1)	0	(1)	0	(0)	0	(0)
16	Rate M16	0	(1)	(1)	(0)	(1)	0	(1)	0	(1)
17	Subtotal - Ex-franchise	650	7,100	7,750	9,657	17,407	120	17,527	(10)	17,517
18	Rate 01	(224)	(370)	(594)	200	(395)	131	(264)	131	(133)
19	Rate 10	(29)	(7)	(36)	93	56	20	76	20	96
20	Rate 20	(23)	(48)	(70)	13	(58)	14	(43)	15	(28)
21	Rate 100	(19)	(56)	(75)	(13)	(88)	11	(77)	12	(65)
22	Rate 25	(7)	(21)	(28)	(7)	(35)	4	(31)	4	(27)
23	Subtotal - Union North	(302)	(502)	(804)	285	(519)	180	(339)	181	(157)
24	In-franchise (line 11 + line 23)	(927)	(1,803)	(2,730)	660	(2,071)	607	(1,463)	562	(901)
25	Ex-franchise (line 17)	650	7,100	7,750	9,657	17,407	120	17,527	(10)	17,517
26	Total (line 24 + line 25)	(277)	5,297	5,020	10,316	15,336	727	16,064	553	16,616

Burlington to Oakville Project Cost Allocation by Rate Class

Line No.	Particulars ($000's)	2016	Variance	2017	Variance	2018
		(a)	(b) = (c - a)	(c)	(d) = (e - c)	(e)
1	Rate M1	2,199	74	2,273	53	2,326
2	Rate M2	856	6	862	1	863
3	Rate M4	282	1	283	(1)	282
4	Rate M5	(11)	3	(8)	3	(5)
5	Rate M7	102	0	103	(0)	102
6	Rate M9	34	(0)	34	(0)	33
7	Rate M10	1	(0)	1	(0)	1
8	Rate T1	243	0	243	(1)	242
9	Rate T2	1,828	(8)	1,820	(16)	1,804
10	Rate T3	235	(1)	234	(2)	232
11	Subtotal - Union South	5,768	75	5,844	37	5,880
12	Excess Utility Space	(10)	1	(8)	1	(7)
13	Rate C1	(0)	0	0	0	1
14	Rate M12	26	49	75	42	117
15	Rate M13	(2)	0	(2)	0	(2)
16	Rate M16	0	0	0	0	0
17	Subtotal - Ex-franchise	14	51	65	44	109
18	R01	(254)	47	(207)	42	(166)
19	R10	(34)	7	(27)	6	(21)
20	R20	(23)	5	(18)	5	(14)
21	R100	(18)	4	(14)	4	(10)
22	R25	(7)	1	(5)	1	(4)
23	Subtotal - Union North	(336)	64	(272)	57	(214)
24	In-franchise	5,432	140	5,572	94	5,666
25	Ex-franchise	14	51	65	44	109
			0		0	
26	Total	5,447	191	5,637	137	5,775

Burlington to Oakville Project Revenue Requirement

Line No.	Particulars ($000's)	2016	2017	2018
	Operating Expenses:			
1	Operating and Maintenance Expenses (1)	26	27	27
2	Depreciation Expense (2)	1,467	1,472	1,472
3	Property Taxes (3)	564	576	587
4	Total Operating Expenses	2,057	2,074	2,086
5	Required Return (4)	4,227	4,158	4,076
	Income Taxes:			
6	Income Taxes - Equity Return (5)	848	834	817
7	Income Taxes - Utility Timing Differences (6)	(1,685)	(1,430)	(1,205)
8	Total Income Taxes	(837)	(595)	(388)
9	Parkway CDA Revenue Requirement	5,447	5,637	5,775

Notes:

Assumes capital expenditure of $75 million.

(1) O&M expenses are $0.027 million for pipeline related O&M.

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

(3) The required return for 2018 assumes total rate base of $70.596 million and a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:

$70.596 million * 64% * 4% = $1.807 million plus
$70.596 million * 36% * 8.93% = $2.270 million for a total of $4.077 million.

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

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

Comparison of M5 revenue requirement - EB-2005-0520 to EB-2011-0210

REVENUE REQUIREMENT SUMMARY	2007 BA Cost Allocation Study			2013 BA Cost Allocation Study			Difference		% Change		
	Total	M5 - F	M5 - I	Total	M5 - F	M5 - I	M5 - F	M5 - I	M5 - F	M5 - I	Comments
RATE OF RETURN ON RATE BASE	7.93%	7.93%	7.93%	7.32%	7.32%	7.32%	-0.61%	-0.61%	-8%	-8%	
RATE BASE	3,377,197	3,754	28,861	3,712,759	890	45,144	(2,864)	16,283	-76%	56%	Service Replacement Cost allocator update
RETURN ON RATE BASE	267,921	298	2,290	271,756	65	3,304	(233)	1,015	-78%	44%	
OPERATING EXPENSES											
TOTAL COST OF GAS	1,147,433	148	704	707,860	50	2,777	(98)	2,073	-66%	295%	Sales service gas supply costs
LOCAL STORAGE	1,697	0	0	1,520	0	0	0	0			
UNDERGROUND STORAGE	44,058	75	415	22,808	8	259	(67)	(156)	-90%	-38%	
TRANSMISSION	38,676	37	108	30,242	5	20	(31)	(88)	-86%	-81%	
DISTRIBUTION (Southern Ontario)	36,890	41	513	39,246	11	828	(30)	315	-73%	61%	Service Replacement Cost Allocator update
DISTRIBUTION (Northern Ontario)	18,263	0	0	22,097	0	0	0	0			
GENERAL OPERATING AND ENGINEERING	34,093	74	346	39,121	45	533	(29)	188	-39%	54%	
SALES PROMOTION AND MERCHANDISE	34,435	80	744	40,318	316	3,424	235	2,679	294%	360%	DSM - EB-2011-0327 Settlement Agreement
DISTRIBUTION CUSTOMER ACCOUNTING	64,826	58	139	57,276	18	125	(40)	(14)	-68%	-10%	
ADMINISTRATIVE AND GENERAL	117,258	167	1,003	158,663	341	2,790	174	1,787	104%	178%	Increase in DSM and increase in Admin and General Costs
TOTAL OPERATING EXPENSES	1,537,629	680	3,971	1,119,149	794	10,756	114	6,785	17%	171%	
DEPRECIATION EXPENSE	178,503	242	1,360	196,091	64	2,270	(178)	911	-73%	67%	Based on rate base allocation -- see Service Replacement Costs
ACCUMULATED DEFERRED TAX DRAWDOW	(16,565)	(19)	(111)	(15,169)	(4)	(147)	15	(36)	-79%	33%	
TAXES											
CAPITAL TAX	8,612	10	74	0	0	0	(10)	(74)	-100%	-100%	
PROPERTY TAX	60,059	69	527	63,272	20	974	(49)	447	-71%	85%	Based on rate base allocation -- see Service Replacement Costs
INCOME TAX	37,530	42	321	31,531	8	383	(34)	63	-82%	20%	
TOTAL TAXES	106,201	121	922	94,803	28	1,357	(93)	436	-77%	47%	
TOTAL REVENUE REQUIREMENT	2,073,689	1,322	8,431	1,666,630	947	17,540	(374)	9,109	-28%	108%	

Return and Tax	1,451
Depreciation	911
DSM	2,679
DSM and ADMIN	1,787
Cost of gas	2,073
	8,901

Per the Board's EB-2011-0210 Decision, the revenue to cost ratio could not fall below the revenue to cost ratio in EB-2005-0520. As a result, Union increased the recovery to move the revenue to cost ratio from the proposed level of 0.746 to the 2007 Board-approved level of 0.824.

APPENDIX C

LIST OF ASSUMPTIONS

For 2014-2018 Incentive Regulation (IR) Forecast

Calculation of Estimated Rate and Bill Impacts

- 5 year Incentive Regulation term (2014-2018)
- Inflation factor ('I' factor) of 1.63%
- Productivity factor ('X' factor) equal to 60% of inflation factor or 0.98%
- Resulting PCI factor equal to 0.65% (1.63% less 0.98%)

Y-Factors

- Escalate DSM each year by the inflation factor of 1.63%
- Inclusion of Capital pass-throughs each year related to Brantford to Kirkwall and Parkway D Compressor and Parkway West Projects
    - Not subject to PCI escalation

Billing Unit Adjustments

- NAC volume-related adjustments to in-franchise general service rate classes
    - Union North delivery, transportation and storage billing units
    - Union South delivery and storage billing units
- No LRAM volume-related adjustments to in-franchise contract rate classes
- M12 Demands for Dawn to Parkway – increase of 363,000 GJ/day for Brantford to Kirkwall and Parkway D Compressor Project
    - 2 months of demand included in 2015, full amount in each year thereafter
- No other billing unit or demand adjustments (including Dawn to Kirkwall turnback)

Others

- Base rate adjustment in 2014 to decrease rates by $4.5 million related to O&M expenses
- Deferred Tax drawdown adjustment in 2014 to increase rates by $3.154 million
- Gas Supply Optimization margin of $13.426 million
- No change for ROE, UFG or S&T transactional margin
- No Z-factors
- Based on 2013 Board-approved Gas Supply Plan
    - No cost of gas adjustments related to Intra-period WACOG or Upstream Transportation costs (e.g. TCPL toll changes)
    - Does not include changes associated with the Long-term contracting proposal filed in the Brantford to Kirkwall and Parkway D Compressor Project application
- No 2014 General Service rate design proposals included
- General Service customer charges – maintain 2013 approved levels ($21.00/month for Rate 01 & Rate M1 and $70.00/month for Rate 10 & Rate M2)
    - Revenue neutral adjustment to delivery commodity rates, applied to first block delivery commodity in Rate 01 and Rate M1 and first and second block delivery commodity in Rate 10 and Rate M2
- Gas Supply Administration revenue included

Note:

- July 2013 QRAM (EB-2013-0215) used as the base for current approved revenue

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast

Line No.	Particulars	Current Approved Revenue ($000's) (a)	2014 Proposed Revenue ($000's) (b)	Δ in Revenue ($000's) (c) = (b - a)	2015 Proposed Revenue ($000's) (d)	Δ in Revenue ($000's) (e) = (d - b)	2016 Proposed Revenue ($000's) (f)	Δ in Revenue ($000's) (g) = (f - d)	2017 Proposed Revenue ($000's) (h)	Δ in Revenue ($000's) (i) = (h - f)	2018 Proposed Revenue ($000's) (j)	Δ in Revenue ($000's) (k) = (j - h)	Total Δ in Revenue ($000's) (l) = (j - a)	Total Δ in Revenue (%) (m) = (l / a)	Average Δ per Year (%) (n) = (m / 5)
	North Delivery														
1	Rate 01	161,653	161,649	(4)	161,380	(269)	162,045	665	163,401	1,357	164,737	1,336	3,084	1.9%	0.4%
2	Rate 10	20,100	20,150	50	20,120	(30)	20,226	106	20,404	178	20,579	175	478	2.4%	0.5%
3	Rate 20	13,537	13,563	26	13,517	(46)	13,585	68	13,714	129	13,840	126	303	2.2%	0.4%
4	Rate 25	4,473	4,476	4	4,461	(15)	4,479	18	4,518	38	4,556	38	83	1.9%	0.4%
5	Rate 100	15,483	15,531	48	15,528	(3)	15,620	92	15,766	146	15,911	145	428	2.8%	0.6%
6	Total North Delivery	215,246	215,370	124	215,007	(363)	215,955	948	217,803	1,847	219,622	1,820	4,376	2.0%	0.4%
	South Delivery & Storage														
7	Rate M1	389,918	391,012	1,094	390,201	(811)	393,169	2,969	396,488	3,319	399,745	3,256	9,827	2.5%	0.5%
8	Rate M2	50,493	50,803	310	50,666	(137)	51,408	742	51,875	467	52,331	456	1,838	3.6%	0.7%
9	Rate M4	12,378	12,445	67	12,410	(35)	12,611	202	12,733	121	12,851	118	473	3.8%	0.8%
10	Rate M5A	13,387	13,436	49	13,442	6	13,526	84	13,663	137	13,799	136	412	3.1%	0.6%
11	Rate M7	4,156	4,185	29	4,176	(9)	4,266	90	4,311	45	4,354	44	199	4.8%	1.0%
12	Rate M9	739	745	6	741	(4)	767	26	773	6	779	6	40	5.4%	1.1%
13	Rate M10	10	9	(0)	9	(0)	9	0	10	0	10	0	(0)	-1.3%	-0.3%
14	Rate T1	10,655	10,723	69	10,717	(7)	10,845	129	10,951	106	11,055	104	400	3.8%	0.8%
15	Rate T2	42,209	42,538	330	42,422	(116)	43,062	640	43,436	374	43,802	367	1,594	3.8%	0.8%
16	Rate T3	4,400	4,443	44	4,419	(25)	4,598	179	4,635	37	4,670	35	270	6.1%	1.2%
17	Total South Delivery & Storage	528,343	530,340	1,997	529,200	(1,140)	534,262	5,061	538,875	4,613	543,396	4,521	15,053	2.8%	0.6%
18	Total In-Franchise Delivery	743,589	745,710	2,121	744,207	(1,502)	750,217	6,010	756,678	6,461	763,018	6,340	19,429	2.6%	0.5%

UNION GAS LIMITED
Revenue Summary for 2014-2018 IR Forecast

Line No.	Particulars	Current Approved Revenue ($000's) (a)	2014 Proposed Revenue ($000's) (b)	Δ in Revenue ($000's) (c) = (b - a)	2015 Proposed Revenue ($000's) (d)	Δ in Revenue ($000's) (e) = (d - b)	2016 Proposed Revenue ($000's) (f)	Δ in Revenue ($000's) (g) = (f - d)	2017 Proposed Revenue ($000's) (h)	Δ in Revenue ($000's) (i) = (h - f)	2018 Proposed Revenue ($000's) (j)	Δ in Revenue ($000's) (k) = (j - h)	Total Δ in Revenue ($000's) (l) = (j - a)	Total Δ in Revenue (%) (m) = (l / a)	Average Δ per Year (%) (n) = (m / 5)
	North Transportation & Storage														
19	Rate 01	94,442	94,593	151	96,159	1,566	97,433	1,275	97,563	129	97,678	115	3,236	3.4%	0.7%
20	Rate 10	30,338	30,378	40	30,783	405	31,118	335	31,153	36	31,185	32	848	2.8%	0.6%
21	Rate 20	10,055	10,061	6	10,168	107	10,256	88	10,266	10	10,275	9	220	2.2%	0.4%
22	Rate 25	2,010	2,007	(3)	2,007	(1)	2,006	(1)	2,006	0	2,006	0	(4)	-0.2%	0.0%
23	Rate 100	166	167	1	168	1	169	1	170	1	172	1	6	3.3%	0.7%
24	Total North Transportation & Storage	137,011	137,206	195	139,285	2,079	140,982	1,697	141,158	176	141,316	158	4,305	3.1%	0.6%
25	Gas Supply Admin Charge	6,830	6,791	(38)	6,777	(14)	6,761	(15)	6,762	1	6,762	0	(67)	-1.0%	-0.2%
26	Total In-Franchise	887,429	889,707	2,278	890,269	562	897,960	7,691	904,598	6,638	911,097	6,499	23,667	2.7%	0.5%
	Ex-Franchise														
27	Rate M12	157,532	159,880	2,348	170,463	10,583	194,190	23,727	195,431	1,241	196,463	1,032	38,931	24.7%	4.9%
28	Rate M13	421	424	4	426	2	427	0	430	3	433	3	12	2.9%	0.6%
29	Rate M16	771	777	7	780	3	785	5	790	6	796	6	25	3.3%	0.7%
30	Rate C1	45,034	45,115	81	45,293	178	45,560	267	45,626	66	45,687	60	653	1.4%	0.3%
31	Total Ex-Franchise	203,758	206,197	2,439	216,963	10,766	240,962	23,999	242,277	1,315	243,379	1,101	39,621	19.4%	3.9%
32	Total Company	1,091,187	1,095,904	4,717	1,107,232	11,328	1,138,922	31,690	1,146,875	7,953	1,154,475	7,600	63,288	5.8%	1.2%

M12/C1 Demand Charge Impacts 2014-2018

Line No.	Services	2013 Current Approved ($/GJ/day) (1)	2014 Forecast ($/GJ/day)	2015 Forecast ($/GJ/day)	2016 Forecast ($/GJ/day)	2017 Forecast ($/GJ/day)	2018 Forecast ($/GJ/day)	Δ in Rates ($/GJ/day)	% Δ in Rates
		(a)	(b)	(c)	(d)	(e)	(f)	(g) = (f-a)	(h) = (g/a)
1	M12/C1 Dawn to Kirkwall	0.0661	0.0672	0.0715	0.0776	0.0780	0.0784	0.0123	19%
2	M12/C1 Dawn to Parkway	0.0783	0.0796	0.0859	0.0923	0.0929	0.0934	0.0150	19%
3	M12/C1 Kirkwall to Parkway	0.0122	0.0124	0.0133	0.0148	0.0149	0.0149	0.0027	22%
4	C1 Parkway to Kirkwall	0.0190	0.0194	0.0211	0.0230	0.0232	0.0233	0.0042	22%
5	C1 Kirkwall to Dawn	0.0336	0.0342	0.0367	0.0406	0.0408	0.0410	0.0074	22%
6	C1 Parkway to Dawn	0.0190	0.0194	0.0211	0.0230	0.0232	0.0233	0.0042	22%
7	M12-X	0.0974	0.0990	0.1070	0.1154	0.1161	0.1166	0.0192	20%

Notes:
(1) EB-2013-0215, Appendix A, Pages 13-15, column (c), effective July 1, 2013.

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union North

Line No.	Particulars	EB-2013-0215 July 2013 QRAM (1) Bill ($) (a)	Unit Rate (cents/m^3) (b)	2018 Forecast Bill ($) (c)	Unit Rate (cents/m^3) (d)	Impact Unit Rate (cents/m^3) (e) = (d-b)	Delivery Rate Change ($) (f) = (c-a)	Bill (%) (g) = (f/a)
	Small Rate 10							
1	Delivery Charges	4,808	8.0137	4,637	7.7279	(0.2858)	(171)	-3.6%
2	Gas Supply Charges	11,811	19.6848	11,556	19.2608			
3	Total Bill	16,619	27.6985	16,193	26.9887	(0.2858)	(171)	-1.0%
	Large Rate 10							
4	Delivery Charges	15,664	6.2654	15,037	6.0148	(0.2506)	(627)	-4.0%
5	Gas Supply Charges	49,212	19.6848	48,152	19.2608			
6	Total Bill	64,876	25.9502	63,189	25.2756	(0.2506)	(627)	-1.0%
	Small Rate 20							
7	Delivery Charges	75,054	2.5018	76,447	2.5482	0.0464	1,393	1.9%
8	Gas Supply Charges	699,592	23.3197	705,804	23.5268			
9	Total Bill	774,646	25.8215	782,251	26.0750	0.0464	1,393	0.2%
	Large Rate 20							
10	Delivery Charges	286,992	1.9133	293,456	1.9564	0.0431	6,463	2.3%
11	Gas Supply Charges	3,296,895	21.9793	3,323,475	22.1565			
12	Total Bill	3,583,887	23.8926	3,616,931	24.1129	0.0431	6,463	0.2%
	Average Rate 25							
13	Delivery Charges	63,659	2.7982	64,836	2.8499	0.0517	1,177	1.8%
14	Gas Supply Charges	411,360	18.0818	411,097	18.0702			
15	Total Bill	475,019	20.8800	475,933	20.9201	0.0517	1,177	0.2%
	Small Rate 100							
16	Delivery Charges	259,825	0.9623	266,547	0.9872	0.0249	6,722	2.6%
17	Gas Supply Charges	6,552,400	24.2681	6,551,886	24.2662			
18	Total Bill	6,812,226	25.2305	6,818,433	25.2535	0.0249	6,722	0.1%
	Large Rate 100							
19	Delivery Charges	2,095,964	0.8733	2,154,960	0.8979	0.0246	58,996	2.8%
20	Gas Supply Charges	57,158,751	23.8161	57,154,181	23.8142			
21	Total Bill	59,254,714	24.6895	59,309,141	24.7121	0.0246	58,996	0.1%

Notes:
(1) Reflects approved rates per Union's July 2013 QRAM filing (EB-2013-0215).

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South

		EB-2013-0215 July 2013 QRAM (1)		2018 Forecast		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M2							
1	Delivery Charges	4,209	7.0149	3,924	6.5397	(0.4753)	(285)	-6.8%
2	Gas Supply Charges	9,925	16.5415	9,924	16.5396			
3	Total Bill	14,134	23.5564	13,848	23.0792	(0.4753)	(285)	-2.0%
	Large Rate M2							
4	Delivery Charges	14,330	5.7319	13,172	5.2689	(0.4631)	(1,158)	-8.1%
5	Gas Supply Charges	41,354	16.5415	41,349	16.5396			
6	Total Bill	55,683	22.2734	54,521	21.8084	(0.4631)	(1,158)	-2.1%
	Small Rate M4							
7	Delivery Charges	35,444	4.0507	36,793	4.2049	0.1542	1,349	3.8%
8	Gas Supply Charges	144,738	16.5415	144,721	16.5396			
9	Total Bill	180,181	20.5922	181,514	20.7444	0.1542	1,349	0.7%
	Large Rate M4							
10	Delivery Charges	273,805	2.2817	284,333	2.3694	0.0877	10,528	3.8%
11	Gas Supply Charges	1,984,975	16.5415	1,984,747	16.5396			
12	Total Bill	2,258,780	18.8232	2,269,080	18.9090	0.0877	10,528	0.5%
	Small Rate M5							
13	Delivery Charges	29,443	3.5688	30,103	3.6488	0.0800	660	2.2%
14	Gas Supply Charges	136,467	16.5415	136,451	16.5396			
15	Total Bill	165,910	20.1103	166,554	20.1884	0.0800	660	0.4%
	Large Rate M5							
16	Delivery Charges	156,790	2.4122	161,828	2.4897	0.0775	5,037	3.2%
17	Gas Supply Charges	1,075,195	16.5415	1,075,071	16.5396			
18	Total Bill	1,231,985	18.9536	1,236,899	19.0292	0.0775	5,037	0.4%
	Small Rate M7							
19	Delivery Charges	625,305	1.7370	655,242	1.8201	0.0832	29,936	4.8%
20	Gas Supply Charges	5,954,926	16.5415	5,954,240	16.5396			
21	Total Bill	6,580,231	18.2784	6,609,482	18.3597	0.0832	29,936	0.5%
	Large Rate M7							
22	Delivery Charges	2,370,901	4.5594	2,486,164	4.7811	0.2217	115,263	4.9%
23	Gas Supply Charges	8,601,559	16.5415	8,600,569	16.5396			
24	Total Bill	10,972,460	21.1009	11,086,733	21.3206	0.2217	115,263	1.1%

Notes:
(1) Reflects approved rates per Union's July 2013 QRAM filing (EB-2013-0215).

UNION GAS LIMITED
Calculation of Delivery Rate Change on Delivery and Total Bill for Typical Small and Large Customers - Union South

		EB-2013-0215 July 2013 QRAM (1)		2018 Forecast		Impact		
Line No.	Particulars	Bill ($)	Unit Rate (cents/m^3)	Bill ($)	Unit Rate (cents/m^3)	Unit Rate (cents/m^3)	Delivery Rate Change ($)	Bill (%)
		(a)	(b)	(c)	(d)	(e) = (d-b)	(f) = (c-a)	(g) = (f/a)
	Small Rate M9							
1	Delivery Charges	118,006	1.6979	124,551	1.7921	0.0942	6,545	5.5%
2	Gas Supply Charges	1,149,631	16.5415	1,149,499	16.5396			
3	Total Bill	1,267,638	18.2394	1,274,050	18.3317	0.0942	6,545	0.5%
	Large Rate M9							
4	Delivery Charges	350,327	1.7362	369,783	1.8326	0.0964	19,456	5.6%
5	Gas Supply Charges	3,337,736	16.5415	3,337,352	16.5396			
6	Total Bill	3,688,062	18.2776	3,707,134	18.3722	0.0964	19,456	0.5%
	Small Rate T1							
7	Delivery Charges	127,339	1.6895	132,270	1.7549	0.0654	4,931	3.9%
8	Gas Supply Charges	1,246,730	16.5415	1,246,586	16.5396			
9	Total Bill	1,374,069	18.2310	1,378,857	18.2945	0.0654	4,931	0.4%
	Average Rate T1							
10	Delivery Charges	193,986	1.6772	201,828	1.7450	0.0678	7,843	4.0%
11	Gas Supply Charges	1,913,175	16.5415	1,912,955	16.5396			
12	Total Bill	2,107,161	18.2187	2,114,783	18.2846	0.0678	7,843	0.4%
	Large Rate T1							
13	Delivery Charges	427,194	1.6672	445,225	1.7375	0.0704	18,031	4.2%
14	Gas Supply Charges	4,238,597	16.5415	4,238,109	16.5396			
15	Total Bill	4,665,791	18.2086	4,683,334	18.2771	0.0704	18,031	0.4%
	Small Rate T2							
16	Delivery Charges	480,912	0.8116	499,920	0.8437	0.0321	19,008	4.0%
17	Gas Supply Charges	9,801,807	16.5415	9,800,679	16.5396			
18	Total Bill	10,282,719	17.3530	10,300,599	17.3832	0.0321	19,008	0.2%
	Average Rate T2							
19	Delivery Charges	1,105,628	0.5590	1,152,192	0.5825	0.0235	46,564	4.2%
20	Gas Supply Charges	32,717,329	16.5415	32,713,563	16.5396			
21	Total Bill	33,822,957	17.1005	33,865,755	17.1221	0.0235	46,564	0.1%
	Large Rate T2							
22	Delivery Charges	1,799,626	0.4863	1,876,772	0.5071	0.0208	77,146	4.3%
23	Gas Supply Charges	61,218,123	16.5415	61,211,077	16.5396			
24	Total Bill	63,017,749	17.0277	63,087,849	17.0467	0.0208	77,146	0.1%
	Large Rate T3							
25	Delivery Charges	2,912,694	1.0680	3,140,869	1.1517	0.0837	228,175	7.8%
26	Gas Supply Charges	45,110,546	16.5415	45,105,353	16.5396			
27	Total Bill	48,023,240	17.6095	48,246,222	17.6913	0.0837	228,175	0.5%

Notes:
(1) Reflects approved rates per Union's July 2013 QRAM filing (EB-2013-0215).

UNION GAS LIMITED
Summary of Average Residential Bill Impacts for Rate 01 and Rate M1
2014-2018 Incentive Regulation Forecast

	2013 Current Approved (a)	2014 Forecast (b)	2015 Forecast (c)	2016 Forecast (d)	2017 Forecast (e)	2018 Forecast (f)	Cumulative Bill Impact (g) = (f - a)	Percent Bill Impact (h) = (g / a)
Rate M1 Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	90.24	90.91	90.25	92.79	95.99	99.13	8.89	9.9%
Storage Services	16.23	16.28	16.16	16.24	16.40	16.55	0.32	2.0%
Total Delivery Charge	358.47	359.19	358.41	361.03	364.39	367.69	9.22	**2.6%**
Supply Charges								
Transportation to Union	103.27	103.27	103.27	103.27	103.27	103.27	(0.00)	-
Commodity & Fuel	260.64	260.62	260.61	260.60	260.60	260.60	(0.04)	-
Total Supply Charge	363.91	363.89	363.88	363.87	363.87	363.87	(0.04)	0.0%
Total Bill	722.38	723.08	722.29	724.90	728.26	731.56	9.18	**1.3%**
Year-over-year Impact - Delivery Bill ($)		0.72	(0.78)	2.62	3.36	3.30	9.22	
Year-over-year Impact - Delivery Bill (%)		**0.2%**	**-0.2%**	**0.7%**	**0.9%**	**0.9%**	2.6%	
Year-over-year Impact - Total Bill ($)		0.70	(0.79)	2.61	3.36	3.30	9.18	
Year-over-year Impact - Total Bill (%)		0.1%	-0.1%	0.4%	0.5%	0.5%	1.3%	
Rate 01 (EZ) Particulars ($)								
Delivery Charges								
Monthly Charge	252.00	252.00	252.00	252.00	252.00	252.00	-	-
Delivery Commodity Charge	208.14	196.53	195.33	197.14	201.31	205.39	(2.75)	-1.3%
Total Delivery Charge	460.14	448.53	447.33	449.14	453.31	457.39	(2.75)	**-0.6%**
Supply Charges								
Transportation to Union	191.40	181.29	181.32	181.32	181.31	181.31	(10.09)	-5.3%
Storage Services	78.75	74.96	79.05	82.46	82.81	83.13	4.38	5.6%
Commodity & Fuel	296.19	296.16	296.17	296.16	296.16	296.16	(0.03)	0.0%
Total Supply Charge	566.34	552.41	556.54	559.94	560.28	560.60	(5.74)	-1.0%
Total Bill	1,026.48	1,000.94	1,003.87	1,009.08	1,013.59	1,017.99	(8.49)	**-0.8%**
Year-over-year Impact - Delivery Bill ($)		(11.61)	(1.20)	1.81	4.17	4.08	(2.75)	
Year-over-year Impact - Delivery Bill (%)		**-2.5%**	**-0.3%**	**0.4%**	**0.9%**	**0.9%**	-0.6%	
Year-over-year Impact - Total Bill ($)		(25.53)	2.93	5.21	4.51	4.40	(8.49)	
Year-over-year Impact - Total Bill (%)		-2.5%	0.3%	0.5%	0.4%	0.4%	-0.8%	

APPENDIX D

Union Gas Limited
Amortization of Accumulated Deferred Tax Balance
(2013-2018)

Line No.	Particulars (000's)	2013	2014	2015	2016	2017	2018
1	Drawdown amount	15,169	13,465	13,555	13,101	13,141	10,832
2	Difference from 2013		(1,704)	(1,613)	(2,068)	(2,028)	(4,337)
3	Tax Rate - Board Approved Rate	25.50%	25.50%	25.50%	25.50%	25.50%	25.50%
4	Pre-tax revenue requirement impact (1)		(2,287)	(2,166)	(2,776)	(2,722)	(5,822)
5	Average		(3,154)				

Notes:
(1) Line 2/(1-Line3)

APPENDIX E

UNION GAS LIMITED
Allocation of One-time Adjustments
($000's)

Line No.	Particulars	Deferred Tax Drawdown: 2013 Approved Allocation (1)	Deferred Tax Drawdown: Adjustment (2)	Administrative & General O&M Expense: 2013 Approved Allocation (3)	Administrative & General O&M Expense: Adjustment (4)	Total Adjustment
		(a)	(b)	(c)	(d)	(e) = (b + d)
1	Rate M1	(5,973)	1,242	46,272	(2,311)	(1,069)
2	Rate M2	(995)	207	4,279	(210)	(3)
3	Rate M4	(268)	56	1,482	(72)	(16)
4	Rate M5	(151)	31	1,627	(79)	(47)
5	Rate M7	(96)	20	450	(23)	(3)
6	Rate M9	(20)	4	59	(3)	1
7	Rate M10	(1)	0	13	(1)	(0)
8	Rate T1	(215)	45	1,118	(55)	(11)
9	Rate T2	(1,067)	222	3,239	(163)	59
10	Rate T3	(167)	35	364	(18)	16
11	Subtotal - Union South	(8,952)	1,861	58,904	(2,934)	(1,073)
12	Excess Utility Space	(172)	36	363	(18)	17
13	Rate C1	(32)	7	182	(9)	(3)
14	Rate M12	(5,365)	1,115	8,447	(429)	686
15	Rate M13	(3)	1	0	(0)	1
16	Rate M16	(6)	1	12	(1)	1
17	Subtotal - Ex-franchise	(5,578)	1,160	9,004	(457)	703
18	R01	(478)	99	18,086	(904)	(804)
19	R10	(125)	26	1,524	(74)	(48)
20	R20	(33)	7	1,206	(56)	(49)
21	R100	(2)	0	1,092	(53)	(52)
22	R25	-	-	480	(22)	(22)
23	Subtotal - Union North	(639)	133	22,387	(1,108)	(976)
24	In-franchise (line 11 + line 23)	(9,591)	1,994	81,291	(4,043)	(2,049)
25	Ex-franchise (line 17)	(5,578)	1,160	9,004	(457)	703
26	Total (line 24 + line 25)	(15,169)	3,154	90,295	(4,500)	(1,346)

Notes:
(1) The 2013 Board-approved allocation of the Deferred Tax Drawdown, per EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, Updated for the EB-2011-0210 Board Decision.

(2) The one-time adjustment to the Deferred Tax Drawdown is allocated to rate classes in proportion to the 2013 Board-approved allocation of the Deferred Tax Drawdown in approved rates per column (a).

(3) The 2013 Board-approved allocation of Administrative O&M Expense within A&G O&M Expense, per EB-2011-0210, Exhibit G3, Tab 2, Schedule 2 Updated for the EB-2011-0210 Board Decision.

(4) The one-time adjustment to A&G O&M Expense is allocated to rate classes in proportion to the 2013 Board-approved allocation of Administrative O&M Expense in approved rates per column (c).

APPENDIX F

UNION GAS LIMITED

Accounting Entries for
Normalized Average Consumption (NAC) Account
Deferral Account No. 179-xxx

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-xxx Normalized Average Consumption Account
Credit	-	Account No. 500 Sales Revenue

To record as a debit (credit) in Deferral Account No. 179-xxx the variance in revenue resulting from the difference between forecast normalized average consumption (NAC) included in rates as approved by the Board and actual NAC for general service rate classes Rate M1, Rate M2, Rate 01, and Rate 10.

Debit	-	Account No. 179-xxx Normalized Average Consumption Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-xxx, interest on the balance in Deferral Account No. 179-xxx. 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
Tax Variance Deferral Account
Deferral Account No. 179-xxx

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-xxx Tax Variance Deferral Account
Credit	-	Account No. 300 Operating Revenues

To record as a debit (credit) in Deferral Account No. 179-xxx 50% of the variance in costs resulting from the difference between the actual tax rates and the approved tax rates included in rates as approved by the Board.

Debit	-	Account No. 179-xxx Tax Variance Deferral Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-xxx, interest on the balance in Deferral Account No. 179-xxx. 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
Unaccounted for Gas (UFG) Volume Variance Account
Deferral Account No. 179-xxx

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-xxx UFG Volume Variance Account
Credit	-	Account No. 654 Gas Losses

To record as a debit (credit) in Deferral Account No. 179-xxx the difference between the UFG recovered in revenue at rates approved by the Board and the actual cost of UFG expensed, in excess of $5 million.

Debit	-	Account No. 179-xxx UFG Volume Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-xxx, interest on the balance in Deferral Account No. 179-xxx. 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.

APPENDIX G

Filed: 2013-07-05
EB-2013-0202
Appendix G

Parkway West Project Rate Base and Revenue Requirement

Line No.	Particulars ($000's)	2014	2015	2016	2017	2018
		(a)	(b)	(c)	(d)	(e)
	Rate Base Investment					
1	Capital Expenditures	64,721	137,545	850	0	0
2	Average Investment	10,623	85,929	197,189	192,824	188,028
	Revenue Requirement Calculation:					
	Operating Expenses:					
3	Operating and Maintenance Expenses (1)	0	739	1,615	1,649	1,683
4	Depreciation Expense (2)	402	2,789	4,786	4,798	4,798
5	Property Taxes (3)	236	290	510	521	532
6	Total Operating Expenses	638	3,818	6,911	6,967	7,013
7	Required Return (4)	611	4,960	11,387	11,135	10,858
8	Total Operating Expenses and Return	1,249	8,778	18,298	18,102	17,871
	Income Taxes:					
9	Income Taxes - Equity Return (5)	123	994	2,282	2,232	2,176
10	Income Taxes - Utility Timing Differences (6)	(1,648)	(4,752)	(5,244)	(4,270)	(3,431)
11	Total Income Taxes	(1,526)	(3,758)	(2,962)	(2,039)	(1,255)
12	Total Revenue Requirement (7)	(277)	5,020	15,336	16,064	16,616
13	Incremental Project Revenue	0	0	0	0	0
14	Net Revenue Requirement	(277)	5,020	15,336	16,064	16,616

Notes:

(1) 2018 O&M expenses include $0.488 million in salary, wages and employee expenses, $0.711 million in contract services and $0.485 million in materials, utility costs, and company used fuel.

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

(3) Property taxes include $0.247 million for land purchases, $0.195 million for LCU compression and $0.090 million for pipeline and building taxes.

(4) The required return assumes a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:

$188.028 million * 64% * 4% = $4.814 million plus
$188.028 million * 36% * 8.93% = $6.045 million for a total of $10.858 million.

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

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

(7) As per EB-2012-0433 Schedule 12-1 line 9.

Parkway Growth Project Revenue Requirement

Line No.	Particulars ($000's)	Revenue Requirement 2015	2016	2017	2018
	Operating Expenses:				
1	Operating and Maintenance Expenses (1)	107	642	642	642
2	Depreciation Expense (2)	2,622	5,287	5,329	5,329
3	Property Taxes (3)	142	853	853	853
4	Total Operating Expenses	2,871	6,782	6,824	6,824
5	Required Return (4)	1,359	11,383	11,176	10,868
6	Total Operating Expenses and Return	4,230	18,165	18,001	17,693
	Income Taxes:				
7	Income Taxes - Equity Return (5)	272	2,281	2,240	2,178
8	Income Taxes - Utility Timing Differences (6)	(4,580)	(5,726)	(4,808)	(3,969)
9	Total Income Taxes	(4,307)	(3,445)	(2,568)	(1,791)
10	Parkway Growth Revenue Requirement (7)	(77)	14,720	15,433	15,902
11	Incremental Project Revenue (8)	1,534	9,204	9,204	9,204
12	Net Revenue Requirement	(1,611)	5,516	6,229	6,698

Notes:

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

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

(3) Property taxes include $0.187 million for compression and $0.665 million for pipeline and building taxes.

(4) The required return for 2018 assumes total rate base of $188.206 million and a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%. The 2018 required return calculation is as follows:

$188.206 million * 64% * 4% = $4.818 million plus
$188.206 million * 36% * 8.93% = $6.050 million for a total of $10.868 million.

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

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

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

(8) As per EB-2013-0074 Schedule 9-4.

APPENDIX H

Union Gas Deferral Account Summary

Short-term Storage and Other Balancing Services (No. 179-70)

Captures the utility portion of actual net revenues for Short-term Storage and Other Balancing Services, less the 10% shareholder incentive to provide these services and less the net revenue forecast for these services as approved by the Board for ratemaking purposes.

Lost Revenue Adjustment Mechanism (No. 179-75)

Captures the difference between actual margin reductions related to Union's DSM plans and the margin reduction included in gas delivery rates as approved by the Board.

Transportation Tolls and Fuel – Northern and Eastern Operations Area (No. 179-100)

Captures 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 rates as approved by the Board.

Unbundled Services Unauthorized Storage Overrun (No. 179-103)

Captures any unauthorized storage overrun charges incurred by customers electing unbundled service.

North Purchase Gas Variance Account (No. 179-105)

Captures the difference between the unit cost of gas purchased each month for the Northern and Eastern Operations Area and 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.

South Purchase Gas Variance Account (No. 179-106)

Captures the difference between the unit cost of gas purchased each month for the Southern Operations Area and 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.

Spot Gas Variance Account (No. 179-107)

Captures the difference between the unit cost of spot gas purchased each month and unit cost of gas included in gas sales rates as approved by the Board on the spot volumes purchased in excess of planned purchases.

Unabsorbed Demand Cost (UDC) Variance Account (No. 179-108)

Captures 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.

Inventory Revaluation Account (No. 179-109)

Captures the decrease (increase) in the value of gas inventory available for sales to sales service customers due to changes in Union's weighted average cost of gas approved by the Board for rate making purposes.

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

Captures the difference between actual and the approved direct DSM expenditure budget currently approved for recovery in rates.

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

Captures 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.

Shared Savings Mechanism (No. 179-115)

Captures the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) programs.

Carbon Dioxide Offset Credits (No. 179-117)

Captures the amounts representing proceeds from the sale of or other dealings in carbon dioxide offset credits earned as a result of Union’s DSM activity.

Average Use Per Customer (No. 179-118)

Captures the margin variance resulting from the difference between the actual rate of decline in use-per-customer and forecast rate of decline in use-per-customer included in gas delivery rates as approved by the Board in 2013.

CGAAP to IFRS Conversion Costs (No. 179-120)

Captures the difference between the actual incremental one-time administrative costs incurred to convert accounting policies and process from their current compliance with CGAAP to the future compliance with IFRS and the costs included in rates as approved by the Board.

Conservation Demand Management (No. 179-123)

Captures 50% of the actual revenues generated from the Conservation Demand Side Management (CDM) program that will be paid to customers upon approval by the Board for ratemaking purposes.

Demand Side Management Incentive (No. 179-126)

Captures the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) Programs.

Pension Charge on Transition to US GAAP (No. 179-127)

Captures the amount recognized in retained earnings associated with transitioning accounting standards and reporting to US GAAP for previously unrecorded pension expenses.

Gas Supply Plan Review – Consultant Cost (No. 179-128)

Captures the costs of hiring a consultant to undertake a review of the gas supply plan, gas supply planning process and gas supply planning methodology as directed by the Board in EB-2011-0210.

Preparation of Audited Utility Financial Statements (No. 179-129)

Captures the costs of the annual preparation of audited utility financial statements as directed by the Board in EB-2011-0210.

Upstream Transportation FT-RAM Optimization (No. 179-130)

Captures the ratepayer portion of net revenues related to FT-RAM optimization as ordered by the Board in EB-2012-0087. Net revenue is defined as FT-RAM optimization revenue less third party costs and incremental compressor fuel and UFG costs directly attributable to the provision of FT-RAM optimization transportation services.

Upstream Transportation Optimization (No. 179-131)

Captures 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 volumes. Captures 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.

UNION GAS LIMITED

Accounting Entries for
Short-term Storage and Other Balancing Services
Deferral Account No. 179-70

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

Debit	-	Account No. 571 Storage Revenue
Credit	-	Account No. 179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services

To record, as a debit (credit) in Deferral Account No. 179-70 the utility portion of actual net revenues for Short-term Storage and Other Balancing Services, less the 10% shareholder incentive to provide these services and less the net revenue forecast for these services as approved by the Board for ratemaking purposes. The utility portion of actual net revenues for Short-term Storage and Other Balancing Services is determined by allocating total margins received from the sale of these services based on the utility share of the total quantity of the services sold each calendar year. The utility share reflects the transactions supported by utility storage space (up to the 100 PJ cap – both planned and excess over planned).

Debit	-	Account No. 571 Storage Revenue
Credit	-	Account No. 179-70 Other Deferred Charges – Short-term Storage and Other Balancing Services

To record, as a credit in Deferral Account No. 179-70 payments by Union Gas Limited's non-utility business to its utility business for storage encroachment.

Debit	-	Account No.179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-70, interest on the balance in Deferral Account No. 179-70. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Lost Revenue Adjustment Mechanism
Deferral Account No. 179-75

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

Debit	-	Account No.179-75 Other Deferred Charges - Lost Revenue Adjustment Mechanism
Credit	-	Account No. 529 Other Sales

To record, as a debit (credit) in Deferral Account No. 179-75, the difference between actual margin reductions related to Union’s DSM plans and the margin reduction included in gas delivery rates as approved by the Board.

Debit	-	Income Account No. 179-75 Other Deferred Charges - Lost Revenue Adjustment Mechanism
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-75, interest expense on the balance in Deferral Account No. 179-75. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Transportation 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 - Transportation Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 663 Transportation of Gas by Others

To record, as a debit (credit) in Deferral Account No. 179-100, the difference in the 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.

Debit	-	Account No. 179-100 Other Deferred Charges - Transportation Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 663 Transportation of Gas by Others

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

Debit	-	Account No. 500 Sales Revenue
Credit	-	Account No. 179-100 Other Deferred Charges - Transportation 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.

Debit	-	Account No. 179-100 Other Deferred Charges - Transportation 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
Unbundled Services Unauthorized Storage Overrun
Deferral Account No. 179-103

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

Debit	-	Account No.571 Storage Revenue
Credit	-	Account No. 179-103 Other Deferred Charges – Unbundled Services Unauthorized Storage Overrun

To record as a credit (debit) in Deferral Account No. 179-103 any unauthorized storage overrun charges incurred by customers electing unbundled service.

Debit	-	Account No. 179-103 Other Deferred Charges – Unbundled Services Unauthorized Storage Overrun
Credit	-	Account No. 323 Other Interest Expense

To record as a debit (credit) in Deferral Account No. 179-103, interest on the balance in Deferral Account No. 179-103. Simple interest will be computed on the monthly opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

<u>UNION GAS LIMITED</u>

Accounting Entries for
North Purchase Gas Variance Account
<u>Deferral Account No. 179-105</u>

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.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Spot Gas Variance Account
<u>Deferral Account No. 179-107</u>

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. 663 Transportation of Gas by Others

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. 663 Transportation of Gas by Others
Credit	-	Account No.179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account

To record, as a credit (debit) in Deferral Account No. 179-108, 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 sales rates.

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 in Storage - Available for Sale

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.

UNION GAS LIMITED

Accounting Entries for
Demand Side Management Variance Account
Deferral Account No. 179-111

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

Debit	-	Account No.179-111 Demand Side Management Variance Account
Credit	-	Account No. 728 General Expense

To record as a debit (credit) in Deferral Account No. 179-111, the difference between actual and the approved direct DSM expenditure budget currently approved for recovery in rates, provided that any excess over the approved direct DSM expenditure budget does not exceed 15% of the direct DSM expenditure budget. Any excess over the approved direct DSM expenditure budget for the year must be for incremental DSM volume savings that are cost effective as determined by the Total Resource Cost Test.

Debit	-	Account No.179-111 Other Deferred Charges – Demand Side Management Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-111, interest expense on the balance in Deferral Account No. 179-111. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Gas Distribution Access Rule (GDAR) Costs
Deferral Account No. 179-112

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

Debit	-	Account No. 179-112 Other Deferred Charges - Deferred Gas Distribution Access Rule (GDAR) Costs
Credit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-112 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.

Debit	-	Account No.179-112 Other Deferred Charges - Deferred Gas Distribution Access Rule (GDAR) Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-112, interest on the balance in Deferral Account No. 179-112. 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
Shared Savings Mechanism
Deferral Account No. 179-115

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 -115 Shared Savings Mechanism
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit in Deferral Account No. 179-115, the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) Programs.

Debit	-	Account No.179- 115 Other Deferred Charges – Shared Savings Mechanism
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179 -115, interest expense on the balance in Deferral Account No. 179-115. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Carbon Dioxide Offset Credits
Deferral Account No. 179-117

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 -117 Carbon Dioxide Offset Credits
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit in Deferral Account No. 179-117, the amounts representing proceeds from the sale of or other dealings in carbon dioxide offset credits earned as a result of Union's DSM activity.

Debit	-	Account No.179 -117 Other Deferred Charges – Carbon Dioxide Offset Credits
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179 -117, interest expense on the balance in Deferral Account No. 179-117. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Average Use Per Customer
Deferral Account No. 179-118

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

Debit	-	Account No. 500 Sales Revenue
Credit	-	Account No. 179-118 Other Deferred Charges - Average Use Per Customer

To record as a debit (credit) in Deferral Account No. 179-118 the margin variance resulting from the difference between the actual rate of decline in use-per-customer and forecast rate of decline in use-per-customer included in gas delivery rates as approved by the Board in 2013. Actual and forecast rate of declines in use-per-customer will be calculated on a percentage and rate class specific basis for rate classes M1, M2, 01 and 10, be normalized for weather and exclude the impacts attributed to DSM which are captured in the Lost Revenue Adjustment Mechanism Deferral Account No. 179-75.

Debit	-	Account No. 179-118 Other Deferred Charges - Average Use Per Customer
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-118, interest on the balance in Deferral Account No. 179-118. 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
CGAAP to IFRS Conversion Costs
Deferral Account No. 179-120

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

Debit	-	Account No. 179-120 Other Deferred Charges - CGAAP to IFRS Conversion Costs
Credit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-120 the difference between the actual incremental one-time administrative costs incurred to convert accounting policies and processes from their current compliance with Canadian Generally Accepted Accounting Principles (CGAAP) to their future compliance with International Financial Reporting Standards (IFRS) and the costs included in rates as approved by the Board.

Debit	-	Account No.179-120 Other Deferred Charges - CGAAP to IFRS Conversion Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-120, interest on the balance in Deferral Account No. 179-120. 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
Conservation Demand Management
Deferral Account No. 179-123

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

Debit	-	Account No. 312 Non-Gas Operating Revenue
Credit	-	Account No.179-123 Other Deferred Charges – Conservation Demand Management

To record, as a credit in Deferral Account No. 179-123, 50% of the actual revenues generated from the Conservation Demand Management (CDM) program that will be paid to customers upon approval by the Board for rate making purposes.

Debit	-	Account No.179-123 Other Deferred Charges – Conservation Demand Management
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-123, interest expense on the balance in Deferral Account No. 179-123. Simple interest will be computed monthly on the opening balance in the said account at the short term debt rate as approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Demand Side Management Incentive
Deferral Account No. 179-126

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

Debit	-	Account No. 179-126 Other Deferred Charges – Demand Side Management Incentive
Credit	-	Account No. 319 Other Income

To record, as a debit in Deferral Account No. 179-126, the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) Programs.

Debit	-	Account No.179-126 Other Deferred Charges – Demand Side Management Incentive
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-126, interest on the balance in Deferral Account No. 179-126. Simple interest will be computed monthly on the opening balance in the said account at the short term debt rate as approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Pension Charge on Transition to US GAAP
Deferral Account No. 179-127

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

Debit	-	Account No. 179-127 Other Deferred Charges – Pension Charge on Transition to US GAAP
Credit	-	Account No. 212 Retained Earnings

To record, as a debit in Deferral Account No. 179-127, the amount recognized in retained earnings associated with transitioning accounting standards and reporting to US Generally Accepted Accounting Principles (GAAP) for previously unrecorded pension expenses.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Gas Supply Plan Review – Consultant Cost
<u>Deferral Account No. 179-128</u>

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

Debit	-	Account No. 179-128 Other Deferred Charges – Gas Supply Plan Review – Consultant Cost
Credit	-	Account No. 728 General Expense

To record as a debit in Deferral Account No. 179-128 the costs of hiring a consultant to undertake a review of the gas supply plan, gas supply planning process and gas supply planning methodology as directed by the Board in EB-2011-0210.

Debit	-	Account No. 179-128 Other Deferred Charges – Gas Supply Plan Review – Consultant Cost
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179-128, interest on the balance in Deferral Account No. 179-128. 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.

<u>UNION GAS LIMITED</u>

Accounting Entries for
Preparation of Audited Utility Financial Statements
<u>Deferral Account No. 179-129</u>

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

Debit	-	Account No. 179-129 Other Deferred Charges – Preparation of Audited Utility Financial Statements
Credit	-	Account No. 728 General Expense

To record as a debit in Deferral Account No. 179-129 the costs of the annual preparation of audited utility financial statements as directed by the Board in EB-2011-0210.

Debit	-	Account No. 179-129 Other Deferred Charges – Preparation of Audited Utility Financial Statements
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179-129, interest on the balance in Deferral Account No. 179-129. 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
Upstream Transportation FT-RAM Optimization
Deferral Account No. 179-130

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

Debit	-	Account No. 579 Miscellaneous Operating Revenue
Credit	-	Account No. 179-130 Other Deferred Charges – Upstream Transportation FT-RAM Optimization

To record as a credit in Deferral Account No. 179-130 the ratepayer portion of net revenues related to FT-RAM optimization as ordered by the Board in EB-2012-0087. Net revenue is defined as FT-RAM optimization revenue less related third party costs and incremental compressor fuel and UFG costs directly attributable to the provision of FT-RAM optimization transportation services.

Debit	-	Account No. 323 Other Interest Expense
Credit	-	Account No. 179-130 Other Deferred Charges – Upstream Transportation FT-RAM Optimization

To record, as a credit in Deferral Account No. 179-130, interest on the balance in Deferral Account No. 179-130. Simple interest will be computed monthly upon finalization of the year- end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Upstream Transportation Optimization
Deferral Account No. 179-131

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

Debit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization
Credit	-	Account No. 626 Exchange Gas

To record as a debit in Deferral Account No. 179-131 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.

Debit	-	Account No. 579 Miscellaneous Operating Revenue
Credit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization

To record as a credit in Deferral Account No. 179-131 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.

Debit	-	Account No. 323 Other Interest Expense
Credit	-	Account No. 179-131 Other Deferred Charges – Upstream Transportation Optimization

To record, as a debit (credit) in Deferral Account No. 179-131, interest on the balance in Deferral Account No. 179-131. Simple interest will be computed monthly upon finalization of the year- end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

APPENDIX I

UNION GAS LIMITED
Calculation of Price Cap Index
For the Year Ended December 31, 2014

Line No.	Particulars		
	Annual % Change in GDP IPI FDD (1)		
1	January - March 2012		2.16%
2	April - June 2012		1.86%
3	July - September 2012		1.57%
4	October - December 2012		0.92%
5	Average % Change		1.63%

		Average % Change	X Factor (2)	PCI
		(a)	(b)	(c) = (a-b)
6	2014 Price Cap Index	1.63%	0.98%	0.65%

Notes:
(1) Statistics Canada, National Income and Expenditure Accounts,
Table 30 - Cansim Table No 3800003 Fourth Quarter 2012.
(2) Equal to 60% of the Inflation factor in column (a) per Settlement Agreement.

UNION GAS LIMITED
Calculation of Price Cap Adjustment
For the Year Ended December 31, 2014

Line No.	Particulars ($000's)	General Service (a)	In-franchise Contract (b)	Total In-franchise (c) = (a+b)	Ex-franchise (d)		Total Company (e) = (c+d)	
	Calculation of Price Cap Base Revenue							
1	2013 Approved Revenue (1)	746,943	133,657	880,600	166,311	(5)	1,046,911	
	Current year's pre-cap adjustments:							
2	2013 DSM	(19,264)	(12,377)	(31,641)	-		(31,641)	(2)
3	Upstream Transportation	(107,888)	(11,079)	(118,967)	-		(118,967)	(3)
4	One-Time Adjustments - Settlement Agreement	(1,888)	(123)	(2,011)	703		(1,308)	(4)
5	Price Cap Base Revenue	617,902	110,078	727,980	167,015		894,995	
6	2014 Price Cap Adjustment (Line 5 * PCI %)	4,016	716	4,732	1,086		5,817	
7	2014 PCI %	0.65% (6)						

Notes:
(1) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 8, column (e). Rates per July 1, 2013 QRAM (EB-2013-0215).
(2) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 11.
(3) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 15.
(4) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 9. Excludes $0.038 million related to Gas Supply Administration charge adjustment.
(5) Excludes C1 Market based Storage Services, Short-term Transporation, Exchanges and Other Transactional revenue not subject to escalation.
(6) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 1, column (c).

UNION GAS LIMITED
Summary of 2014 Proposed Rates

				Adjustments to 2013 Base Rates													
Line No.	Particulars	Current Approved Revenue ($000's)	Current Approved Rates (cents / m^3)	2013 DSM ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	One-Time Adjustments Settlement Agreement ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	Rate Change (%)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	North Delivery																
1	Rate 01	161,653	18.2778	(3,732)	-	(1,836)	(840)	155,247	1,009	0.65%	-	3,792	(234)	1,836	161,649	17.2953	-5.4%
2	Rate 10	20,100	6.2251	(1,186)	-	(485)	(59)	18,371	119	0.65%	-	1,206	(30)	485	20,150	5.8246	-6.4%
3	Rate 20	13,537	2.1494	(974)	-	(132)	(47)	12,384	80	0.65%	-	990	(23)	132	13,563	2.1536	0.2%
4	Rate 25	4,473	2.8033	-	-	-	(18)	4,454	29	0.65%	-	-	(7)	-	4,476	2.8055	0.1%
5	Rate 100	15,483	0.8168	(1,798)	-	(9)	(51)	13,626	89	0.65%	-	1,827	(19)	9	15,531	0.8194	0.3%
6	Total North Delivery	215,246		(7,690)	-	(2,461)	(1,014)	204,081	1,327		-	7,816	(314)	2,461	215,370		
	South Delivery & Storage																
7	Rate M1	389,918	13.2646	(10,451)	-	-	(1,045)	378,422	2,460	0.65%	-	10,621	(492)	-	391,012	13.2827	0.1%
8	Rate M2	50,493	5.1758	(3,896)	-	-	1	46,598	303	0.65%	-	3,959	(58)	-	50,803	4.4993	-13.1%
9	Rate M4	12,378	3.0587	(1,607)	-	-	(16)	10,755	70	0.65%	-	1,633	(13)	-	12,445	3.0753	0.5%
10	Rate M5A	13,387	2.5016	(2,683)	-	-	(47)	10,658	69	0.65%	-	2,726	(17)	-	13,436	2.5108	0.4%
11	Rate M7	4,156	2.8243	(906)	-	-	(3)	3,248	21	0.65%	-	920	(4)	-	4,185	2.8443	0.7%
12	Rate M9	739	1.2165	-	-	-	1	740	5	0.65%	-	-	(0)	-	745	1.2259	0.8%
13	Rate M10	10	5.2035	-	-	-	(0)	9	0	0.65%	-	-	(0)	-	9	4.9767	-4.4%
14	Rate T1	10,655	1.9408	(1,801)	-	-	(10)	8,844	57	0.65%	-	1,830	(9)	-	10,723	1.9533	0.6%
15	Rate T2	42,209	0.8649	(2,609)	-	-	59	39,659	258	0.65%	-	2,651	(31)	-	42,538	0.8716	0.8%
16	Rate T3	4,400	1.6133	-	-	-	16	4,416	29	0.65%	-	-	(0)	-	4,443	1.6293	1.0%
17	Total South Delivery & Storage	528,343		(23,951)	-	-	(1,045)	503,348	3,272		-	24,341	(623)	-	530,340		
18	Total In-Franchise Delivery	743,589		(31,641)	-	(2,461)	(2,059)	707,429	4,598		-	32,157	(938)	2,461	745,710		

UNION GAS LIMITED
Summary of 2014 Proposed Rates

Line No.	Particulars	Current Approved Revenue ($000's)	Current Approved Rates (cents / m^3)	Adjustments to 2013 Base Rates: 2013 DSM ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	One-Time Adjustments Settlement Agreement ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	Rate Change (%)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	North Transportation & Storage																
19	Rate 01	94,442	10.6784	-	-	(79,275)	42	15,209	99	0.65%	-	-	10	79,275	94,593	10.1208	-5.2%
20	Rate 10	30,338	9.3957	-	-	(26,293)	12	4,057	26	0.65%	-	-	1	26,293	30,378	8.7812	-6.5%
21	Rate 20	10,055	8.2463	-	-	(8,886)	(2)	1,167	8	0.65%	-	-	0	8,886	10,061	8.2510	0.1%
22	Rate 25	2,010	4.6844	-	-	(1,988)	(3)	19	0	0.65%	-	-	(0)	1,988	2,007	4.6778	-0.1%
23	Rate 100	166	-	-	-	(64)	(2)	101	1	0.65%	-	-	0	64	167	-	
24	Total North Transportatiion & Storage	137,011		-	-	(116,506)	48	20,552	134		-	-	12	116,506	137,206		
25	Gas Supply Admin Charge	6,830		-	-	-	(38)	6,792	-		-	-	(1)	-	6,791		
26	Total In-Franchise	887,429		(31,641)	-	(118,967)	(2,049)	734,773	4,732		-	32,157	(926)	118,967	889,707		
	Ex-Franchise																
27	Rate M12	157,532		-	-	-	674	158,206	1,028	0.65%	-	-	646	-	159,880		1.5%
28	Rate M13	421		-	-	-	1	422	3	0.65%	-	-	(0)	-	424		0.9%
29	Rate M16	771		-	-	-	1	772	5	0.65%	-	-	(0)	-	777		0.9%
30	Rate C1	45,034		-	-	-	28	45,062	49		-	-	4	-	45,115		0.2%
31	Total Ex-Franchise	203,758		-	-	-	703	204,461	1,086		-	-	650	-	206,197		
32	Total Company	1,091,187		(31,641)	-	(118,967)	(1,346)	939,234	5,817		-	32,157	(277)	118,967	1,095,904		

UNION GAS LIMITED
Union North
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Line No.	Particulars	Billing Units	Current Approved Forecast Usage	Current Approved Revenue ($000's)	Current Approved Rates (cents / m^3)	Adjustments to 2013 Base Rates: 2013 DSM ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	One-Time Adjustments Settlement Agreement ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (b+d+e+f+g)	(i)	(j)
	Rate 01 General Service											
1	Monthly Charge	bills	3,839,732	80,634	$21.00	-	-	-	(709)	79,925	520	
	Monthly Delivery Charge - All Zones											
2	First 100 m^3	10^3m^3	260,791	25,506	9.7803	(1,175)	-	(578)	(41)	23,713	154	
3	Next 200 m^3	10^3m^3	296,122	27,409	9.2558	(1,262)	-	(621)	(44)	25,481	166	
4	Next 200 m^3	10^3m^3	129,180	11,475	8.8831	(529)	-	(260)	(18)	10,668	69	
5	Next 500 m^3	10^3m^3	88,231	7,536	8.5411	(347)	-	(171)	(12)	7,006	46	
6	Over 1,000 m^3	10^3m^3	110,097	9,093	8.2586	(419)	-	(206)	(15)	8,453	55	
7	Delivery Commodity charge - 01		884,421	81,019	9.1606	(3,732)	-	(1,836)	(130)	75,321	490	
8	Total Delivery - 01		884,421	161,653	18.2778	(3,732)	-	(1,836)	(839)	155,247	1,009	0.65%
	Gas Transportation											
9	Fort Frances	10^3m^3	12,297	607	4.9387	-	-	(606)	(0)	1	0	
10	Western	10^3m^3	171,280	9,489	5.5401	-	-	(9,474)	(2)	13	0	
11	Northern	10^3m^3	384,941	29,361	7.6275	-	-	(29,316)	(7)	39	0	
12	Eastern	10^3m^3	315,903	26,900	8.5153	-	-	(26,858)	(6)	36	0	
13	Transportation - 01		884,421	66,358	7.5030	-	-	(66,255)	(15)	88	1	0.65%
	Storage											
14	Fort Frances	10^3m^3	12,297	264	2.1507	-	-	(123)	1	142	1	
15	Western	10^3m^3	171,280	4,095	2.3910	-	-	(1,899)	8	2,205	14	
16	Northern	10^3m^3	384,941	12,415	3.2252	-	-	(5,756)	25	6,684	43	
17	Eastern	10^3m^3	315,903	11,309	3.5799	-	-	(5,243)	23	6,089	40	
18	Storage - 01		884,421	28,084	3.1754	-	-	(13,021)	57	15,120	98	0.65%
19	Total Rate 01		884,421	256,095	-	(3,732)	-	(81,111)	(797)	170,455	1,108	0.65%

UNION GAS LIMITED
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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Prior to MCC Change: Proposed Revenue ($000's)	Prior to MCC Change: Proposed Rates (cents / m^3)	MCC Change: Proposed Revenue ($000's)	MCC Change: Proposed Rates (cents / m^3)	Volume Adjustments: NAC Adjustment (10^3m^3)	Volume Adjustments: LRAM Adjustment (10^3m^3)	Proposed: Usage including NAC & LRAM	Proposed: Revenue ($000's)	Proposed: Rates (cents / m^3)	Rate Change (%)
			(k)	(l)	(m)	(n) = (-f)	(o) = (h+i+k+l+m+n)	(p) = (o / a)	(q)	(r) = (q / a)	(s)	(t)	(u) = (a + s + t)	(v)	(w) = (v / u)	(x)
	Rate 01 General Service															
1	Monthly Charge	bills	-	-	(172)	-	80,273	$20.91	80,634	$21.00	-	-	3,839,732	80,634	$21.00	
	Monthly Delivery Charge - All Zones															
2	First 100 m^3	10^3m^3	-	1,194	(20)	578	25,619	9.8235	25,257	9.6849	14,808	-	275,599	25,257	9.1645	
3	Next 200 m^3	10^3m^3	-	1,283	(21)	621	27,530	9.2967	27,530	9.2967	16,814	-	312,936	27,530	8.7972	
4	Next 200 m^3	10^3m^3	-	537	(9)	260	11,526	8.9224	11,526	8.9224	7,335	-	136,515	11,526	8.4430	
5	Next 500 m^3	10^3m^3	-	353	(6)	171	7,569	8.5789	7,569	8.5789	5,010	-	93,241	7,569	8.1179	
6	Over 1,000 m^3	10^3m^3	-	426	(7)	206	9,133	8.2951	9,133	8.2951	6,251	-	116,349	9,133	7.8494	
7	Delivery Commodity charge - 01		-	3,792	(62)	1,836	81,376	9.2011	81,015	9.1602	50,219	-	934,640	81,015	8.6680	
8	Total Delivery - 01		-	3,792	(234)	1,836	161,649	18.2774	161,649	18.2774	50,219	-	934,640	161,649	17.2953	-5.4%
	Gas Transportation															
9	Fort Frances	10^3m^3	-	-	0	606	607	4.9380			698	-	12,995	607	4.6726	
10	Western	10^3m^3	-	-	1	9,474	9,488	5.5393			9,725	-	181,005	9,488	5.2417	
11	Northern	10^3m^3	-	-	2	29,316	29,357	7.6264			21,857	-	406,799	29,357	7.2166	
12	Eastern	10^3m^3	-	-	2	26,858	26,896	8.5140			17,937	-	333,841	26,896	8.0565	
13	Transportation - 01		-	-	5	66,255	66,348	7.5019			50,219	-	934,640	66,348	7.0988	-5.4%
	Storage															
14	Fort Frances	10^3m^3	-	-	0	123	266	2.1630			698	-	12,995	266	2.0468	
15	Western	10^3m^3	-	-	1	1,899	4,119	2.4047			9,725	-	181,005	4,119	2.2755	
16	Northern	10^3m^3	-	-	2	5,756	12,486	3.2437			21,857	-	406,799	12,486	3.0694	
17	Eastern	10^3m^3	-	-	2	5,243	11,374	3.6004			17,937	-	333,841	11,374	3.4070	
18	Storage - 01		-	-	6	13,021	28,245	3.1936			50,219	-	934,640	28,245	3.0220	-4.8%
19	Total Rate 01		-	3,792	(224)	81,111	256,242	-			50,219	-	934,640	256,242	-	

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage	Current Approved Revenue ($000's)	Current Approved Rates (cents / m^3)	Adjustments to 2013 Base Rates: 2013 DSM ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	One-Time Adjustments Settlement Agreement ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (b+d+e+f+g)	(i)	(j)
	Rate 10 General Service											
1	Monthly Charge	bills	24,629	1,724	$70.00	-	-	-	(19)	1,705	11	
	Monthly Delivery Charge - All Zones											
2	First 1 000 m^3	10^3m^3	23,682	1,834	7.7446	(118)	-	(48)	(4)	1,663	11	
3	Next 9 000 m^3	10^3m^3	127,854	8,094	6.3310	(523)	-	(213)	(18)	7,341	48	
4	Next 20 000 m^3	10^3m^3	81,326	4,493	5.5248	(290)	-	(119)	(10)	4,075	26	
5	Next 70 000 m^3	10^3m^3	61,664	3,089	5.0087	(199)	-	(81)	(7)	2,801	18	
6	Over 100 000 m^3	10^3m^3	28,362	866	3.0535	(56)	-	(23)	(2)	785	5	
7	Delivery Commodity charge - 10		322,887	18,376	5.6912	(1,186)	-	(485)	(40)	16,665	108	
8	Total Delivery - 10		322,887	20,100	6.2251	(1,186)	-	(485)	(59)	18,371	119	0.65%
	Gas Transportation											
9	Fort Frances	10^3m^3	2,654	115	4.3170	-	-	(115)	(0)	0	0	
10	Western	10^3m^3	45,232	2,225	4.9184	-	-	(2,223)	(0)	1	0	
11	Northern	10^3m^3	130,990	9,177	7.0058	-	-	(9,171)	(1)	5	0	
12	Eastern	10^3m^3	144,011	11,368	7.8935	-	-	(11,360)	(1)	6	0	
13	Transportation - 10		322,887	22,884	7.0872	-	-	(22,868)	(3)	13	0	0.65%
	Storage											
14	Fort Frances	10^3m^3	2,654	32	1.2015	-	-	(15)	0	17	0	
15	Western	10^3m^3	45,232	652	1.4418	-	-	(300)	1	354	2	
16	Northern	10^3m^3	130,990	2,981	2.2760	-	-	(1,370)	6	1,617	11	
17	Eastern	10^3m^3	144,011	3,788	2.6307	-	-	(1,741)	8	2,055	13	
18	Storage - 10		322,887	7,454	2.3085	-	-	(3,425)	15	4,044	26	0.65%
19	Total Rate 10		322,887	50,438	-	(1,186)	-	(26,778)	(46)	22,428	146	0.65%

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Prior to MCC Change: Proposed Revenue ($000's)	Prior to MCC Change: Proposed Rates (cents / m^3)	MCC Change: Proposed Revenue ($000's)	MCC Change: Proposed Rates (cents / m^3)	Volume Adjustments: NAC Adjustment (10^3m^3)	Volume Adjustments: LRAM Adjustment (10^3m^3)	Proposed: Usage including NAC & LRAM	Proposed: Revenue ($000's)	Proposed: Rates (cents / m^3)	Rate Change (%)
			(k)	(l)	(m)	(n) = (-f)	(o) = (h+i+k+l+m+n)	(p) = (o / a)	(q)	(r) = (q / a)	(s)	(t)	(u) = (a + s + t)	(v)	(w) = (v / u)	(x)
	Rate 10 General Service															
1	Monthly Charge	bills	-	-	(11)	-	1,706	$69.26	1,724	$70.00	-	-	24,629	1,724	$70.00	
	Monthly Delivery Charge - All Zones															
2	First 1 000 m^3	10^3m^3	-	120	(2)	48	1,841	7.7731	1,837	7.7590	1,691	-	25,373	1,837	7.2419	
3	Next 9 000 m^3	10^3m^3	-	531	(9)	213	8,124	6.3543	8,109	6.3428	9,129	-	136,983	8,109	5.9201	
4	Next 20 000 m^3	10^3m^3	-	295	(5)	119	4,510	5.5452	4,510	5.5452	5,807	-	87,132	4,510	5.1756	
5	Next 70 000 m^3	10^3m^3	-	203	(3)	81	3,100	5.0272	3,100	5.0272	4,403	-	66,066	3,100	4.6921	
6	Over 100 000 m^3	10^3m^3	-	57	(1)	23	869	3.0647	869	3.0647	2,025	-	30,387	869	2.8605	
7	Delivery Commodity charge - 10		-	1,206	(20)	485	18,444	5.7122	18,426	5.7066	23,054	-	345,941	18,426	5.3263	
8	Total Delivery - 10		-	1,206	(30)	485	20,150	6.2405	20,150	6.2405	23,054	-	345,941	20,150	5.8246	-6.4%
	Gas Transportation															
9	Fort Frances	10^3m^3	-	-	0	115	115	4.3165			190	-	2,844	115	4.0289	
10	Western	10^3m^3	-	-	0	2,223	2,224	4.9179			3,230	-	48,462	2,224	4.5902	
11	Northern	10^3m^3	-	-	0	9,171	9,176	7.0050			9,353	-	140,342	9,176	6.5382	
12	Eastern	10^3m^3	-	-	0	11,360	11,366	7.8927			10,282	-	154,293	11,366	7.3667	
13	Transportation - 10		-	-	0	22,868	22,881	7.0865			23,054	-	345,941	22,881	6.6142	-6.7%
	Storage															
14	Fort Frances	10^3m^3	-	-	0	15	32	1.2084			190	-	2,844	32	1.1278	
15	Western	10^3m^3	-	-	0	300	656	1.4500			3,230	-	48,462	656	1.3534	
16	Northern	10^3m^3	-	-	1	1,370	2,998	2.2890			9,353	-	140,342	2,998	2.1365	
17	Eastern	10^3m^3	-	-	1	1,741	3,810	2.6457			10,282	-	154,293	3,810	2.4694	
18	Storage - 10		-	-	1	3,425	7,496	2.3217			23,054	-	345,941	7,496	2.1670	-6.1%
19	Total Rate 10		-	1,206	(29)	26,778	50,528	-			23,054	-	345,941	50,528	-	

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage (a)	Current Approved Revenue ($000's) (b)	Current Approved Rates (cents / m^3) (c)	Adjustments to 2013 Base Rates: 2013 DSM ($000's) (d)	2013 Capital Pass-Throughs ($000's) (e)	Upstream Transportation ($000's) (f)	One-Time Adjustments Settlement Agreement ($000's) (g)	Adjusted Revenue ($000's) (h) = (b+d+e+f+g)	Price Cap Index ($000's) (i)	Price Cap Index (%) (j)
	Rate 20 Medium Volume Firm Service											
1	Monthly Charge	bills	748	748	$1,000.00	-	-	-	(11)	737	5	
	Monthly Demand Charge											
2	First 70,000 m^3	$10^3m^3/d$	23,260	6,470	27.8179	(423)	-	-	(16)	6,032	39	
3	All over 70,000 m^3	$10^3m^3/d$	19,701	3,223	16.3583	(211)	-	-	(8)	3,004	20	
	Monthly Commodity Charge											
4	First 852,000 m^3	10^3m^3	331,197	1,802	0.5440	(205)	-	(79)	(8)	1,510	10	
5	All over 852,000 m^3	10^3m^3	298,605	1,193	0.3996	(136)	-	(52)	(5)	1,000	6	
6	Delivery (Commodity/Demand)		629,802	12,688	2.0146	(974)	-	(132)	(36)	11,546	75	
7	Transportation Account Charge	10^3m^3	460	101	$219.43	-	-	-	-	101	1	
8	Total Delivery - 20		629,802	13,537	2.1494	(974)	-	(132)	(47)	12,384	80	0.65%
	Gas Supply Demand Charge											
9	Fort Frances		-	-	21.7512	-	-	-	-	-	-	
10	Western	10^3m^3	2,650	929	35.0467	-	-	(909)	(0)	19	0	
11	Northern	10^3m^3	702	602	85.6936	-	-	(589)	(0)	13	0	
12	Eastern	10^3m^3	3,521	3,735	106.0700	-	-	(3,655)	(2)	78	1	
	Commodity Transportation 1											
13	Fort Frances	10^3m^3	-	-	3.3924	-	-	-	-	-	-	
14	Western	10^3m^3	24,899	928	3.7291	-	-	(928)	-	-	-	
15	Northern	10^3m^3	7,775	381	4.8977	-	-	(381)	-	-	-	
16	Eastern	10^3m^3	40,782	2,200	5.3947	-	-	(2,200)	-	-	-	
	Commodity Transportation 2											
17	Fort Frances		-	-	0.1535	-	-	-	-	-	-	
18	Western	10^3m^3	10,903	29	0.2673	-	-	(29)	-	-	-	
19	Northern	10^3m^3	6,194	26	0.4138	-	-	(26)	-	-	-	
20	Eastern	10^3m^3	31,381	169	0.5393	-	-	(169)	-	-	-	
	Storage (GJ's)											
21	Demand	GJ/d	99,288	957	9.643	-	-	-	-	957	6	
22	Commodity	GJ	639,477	100	0.156	-	-	-	-	100	1	
23	Gas Supply Transportation - 20		121,935	10,055	8.2463	-	-	(8,886)	(2)	1,167	8	0.65%
24	Total Rate 20		629,802	23,592	-	(974)	-	(9,018)	(49)	13,551	88	0.65%

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's) (k)	2014 DSM ($000's) (l)	2014 Capital Pass-Throughs ($000's) (m)	Add Back Upstream Transportation ($000's) (n) = (-f)	Prior to MCC Change: Proposed Revenue ($000's) (o) = (h+i+k+l+m+n)	Prior to MCC Change: Proposed Rates (cents / m^3) (p) = (o / a)	MCC Change: Proposed Revenue ($000's) (q)	MCC Change: Proposed Rates (cents / m^3) (r) = (q / a)	Volume Adjustments: NAC Adjustment (10^3m^3) (s)	Volume Adjustments: LRAM Adjustment (10^3m^3) (t)	Proposed: Usage including NAC & LRAM (u) = (a + s + t)	Proposed: Revenue ($000's) (v)	Proposed: Rates (cents / m^3) (w) = (v / u)	Rate Change (%) (x)
	Rate 20 Medium Volume Firm Service															
1	Monthly Charge	bills	-	-	(3)	-	739	$987.48			-	-	748	739	$987.48	
	Monthly Demand Charge															
2	First 70,000 m^3	$10^3m^3/d$	-	430	(9)	-	6,492	27.9120			-	-	23,260	6,492	27.9120	
3	All over 70,000 m^3	$10^3m^3/d$	-	214	(4)	-	3,234	16.4137			-	-	19,701	3,234	16.4137	
	Monthly Commodity Charge															
4	First 852,000 m^3	10^3m^3	-	209	(4)	79	1,803	0.5444			-	-	331,197	1,803	0.5444	
5	All over 852,000 m^3	10^3m^3	-	138	(3)	52	1,194	0.3999			-	-	298,605	1,194	0.3999	
6	Delivery (Commodity/Demand)		-	990	(20)	132	12,723	2.0202			-	-	629,802	12,723	2.0202	0.3%
7	Transportation Account Charge	10^3m^3	-	-	-	-	102	$220.85			-	-	460	102	$220.85	
8	Total Delivery - 20		-	990	(23)	132	13,563	2.1536			-	-	629,802	13,563	2.1536	0.2%
	Gas Supply Demand Charge															
9	Fort Frances		-	-	-	-	-	21.7512			-	-	-	-	21.7512	
10	Western	10^3m^3	-	-	0	909	929	35.0386			-	-	2,650	929	35.0386	
11	Northern	10^3m^3	-	-	0	589	601	85.6738			-	-	702	601	85.6738	
12	Eastern	10^3m^3	-	-	0	3,655	3,734	106.0455			-	-	3,521	3,734	106.0455	
	Commodity Transportation 1															
13	Fort Frances	10^3m^3	-	-	-	-	-	3.3924			-	-	-	-	3.3924	
14	Western	10^3m^3	-	-	-	928	928	3.7291			-	-	24,899	928	3.7291	
15	Northern	10^3m^3	-	-	-	381	381	4.8977			-	-	7,775	381	4.8977	
16	Eastern	10^3m^3	-	-	-	2,200	2,200	5.3947			-	-	40,782	2,200	5.3947	
	Commodity Transportation 2															
17	Fort Frances		-	-	-	-	-	0.1535			-	-	-	-	0.1535	
18	Western	10^3m^3	-	-	-	29	29	0.2673			-	-	10,903	29	0.2673	
19	Northern	10^3m^3	-	-	-	26	26	0.4138			-	-	6,194	26	0.4138	
20	Eastern	10^3m^3	-	-	-	169	169	0.5393			-	-	31,381	169	0.5393	
	Storage (GJ's)															
21	Demand	GJ/d	-	-	-	-	964	9.705			-	-	99,288	964	9.705	
22	Commodity	GJ	-	-	-	-	100	0.157			-	-	639,477	100	0.157	
23	Gas Supply Transportation - 20		-	-	0	8,886	10,061	8.2510			-	-	121,935	10,061	8.2510	0.1%
24	Total Rate 20		-	990	(23)	9,018	23,624	-			-	-	629,802	23,624	-	

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage (a)	Current Approved Revenue ($000's) (b)	Current Approved Rates (cents / m^3) (c)	Adjustments to 2013 Base Rates: 2013 DSM ($000's) (d)	2013 Capital Pass-Throughs ($000's) (e)	Upstream Transportation ($000's) (f)	One-Time Adjustments Settlement Agreement ($000's) (g)	Adjusted Revenue ($000's) (h) = (b+d+e+f+g)	Price Cap Index ($000's) (i)	Price Cap Index (%) (j)
	Rate 25 Large Volume Interruptible Service											
1	Monthly Charge	bills	842	316	$375.00	-	-	-	(12)	304	2	
2	Monthly Delivery Charge	10^3m^3	159,555	4,149	2.6004	-	-	-	(6)	4,143	27	
3	Transportation Account Charge	bills	36	8	$219.43	-	-	-	-	8	0	
4	Total Delivery - 25		159,555	4,473	2.8033	-	-	-	(18)	4,454	29	0.65%
5	Gas Supply Transportation	10^3m^3	42,913	2,010	4.6844	-	-	(1,988)	(3)	19	0	
6	Total Rate 25		159,555	6,483	-	-	-	(1,988)	(21)	4,474	29	0.65%
	Rate 100 Large Volume Firm Service											
7	Monthly Charge	bills	226	339	$1,500.00	-	-	-	(6)	333	2	
8	Demand	$10^3m^3/d$	71,975	11,042	15.3415	(1,349)	-	-	(34)	9,660	63	
9	Commodity	10^3m^3	1,895,488	4,053	0.2138	(450)	-	(9)	(11)	3,583	23	
10	Delivery (Commodity/Demand)		1,895,488	15,095	0.7963	(1,798)	-	(9)	(45)	13,243	86	
11	Transportation Account Charge	bills	226	50	$219.43	-	-	-	-	50	0	
12	Total Delivery - 100		1,895,488	15,483	0.8168	(1,798)	-	(9)	(51)	13,626	89	0.65%
	Gas Supply Demand Charge											
13	Fort Frances	$10^3m^3/d$	-	-	61.0900	-	-	-	-	-	-	
14	Western	$10^3m^3/d$	-	-	76.6014	-	-	-	-	-	-	
15	Northern	$10^3m^3/d$	-	-	135.6895	-	-	-	-	-	-	
16	Eastern	$10^3m^3/d$	-	-	159.4619	-	-	-	-	-	-	
	Commodity Transportation 1											
17	Fort Frances	-	-	-	7.0154	-	-	-	-	-	-	
18	Western	10^3m^3	-	-	7.2679	-	-	-	-	-	-	
19	Northern	10^3m^3	-	-	8.1444	-	-	-	-	-	-	
20	Eastern	10^3m^3	-	-	8.5171	-	-	-	-	-	-	
	Commodity Transportation 2											
21	Fort Frances	-	-	-	0.1535	-	-	-	-	-	-	
22	Western	10^3m^3	-	-	0.2673	-	-	-	-	-	-	
23	Northern	10^3m^3	-	-	0.4138	-	-	-	-	-	-	
24	Eastern	10^3m^3	-	-	0.5393	-	-	-	-	-	-	
	Storage (GJ's)											
25	Demand	GJ/d	15,600	150	9.643	-	-	(64)	(1)	85	1	
26	Commodity	GJ	100,000	16	0.156	-	-	-	(0)	15	0	
27	Gas Supply - 100		-	166	-	-	-	(64)	(2)	101	1	0.65%
28	Total Rate 100		1,895,488	15,649	-	(1,798)	-	(73)	(52)	13,726	89	0.65%

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's) (k)	2014 DSM ($000's) (l)	2014 Capital Pass-Throughs ($000's) (m)	Add Back Upstream Transportation ($000's) (n) = (-f)	Prior to MCC Change: Proposed Revenue ($000's) (o) = (h+i+k+l+m+n)	Prior to MCC Change: Proposed Rates (cents / m^3) (p) = (o / a)	MCC Change: Proposed Revenue ($000's) (q)	MCC Change: Proposed Rates (cents / m^3) (r) = (q / a)	Volume Adjustments: NAC Adjustment (10^3m^3) (s)	Volume Adjustments: LRAM Adjustment (10^3m^3) (t)	Proposed: Usage including NAC & LRAM (u) = (a + s + t)	Proposed: Revenue ($000's) (v)	Proposed: Rates (cents / m^3) (w) = (v / u)	Rate Change (%) (x)
	Rate 25 Large Volume Interruptible Service															
1	Monthly Charge	bills	-	-	(1)	-	304	$361.02			-	-	842	304	$361.02	
2	Monthly Delivery Charge	10^3m^3	-	-	(5)	-	4,164	2.6100			-	-	159,555	4,164	2.6100	
3	Transportation Account Charge	bills	-	-	-	-	8	$220.85			-	-	36	8	$220.85	
4	Total Delivery - 25		-	-	(7)	-	4,476	2.8055			-	-	159,555	4,476	2.8055	0.1%
5	Gas Supply Transportation	10^3m^3	-	-	(0)	1,988	2,007	4.6778			-	-	42,913	2,007	4.6778	
6	Total Rate 25		-	-	(7)	1,988	6,484	-			-	-	159,555	6,484	-	
	Rate 100 Large Volume Firm Service															
7	Monthly Charge	bills	-	-	(1)	-	334	$1,478.76			-	-	226	334	$1,478.76	
8	Demand	10^3m^3/d	-	1,370	(14)	-	11,080	15.3936			-	-	71,975	11,080	15.3936	
9	Commodity	10^3m^3	-	457	(5)	9	4,068	0.2146			-	-	1,895,488	4,068	0.2146	
10	Delivery (Commodity/Demand)		-	1,827	(18)	9	15,147	0.7991			-	-	1,895,488	15,147	0.7991	0.3%
11	Transportation Account Charge	bills	-	-	-	-	50	$220.85			-	-	226	50	$220.85	
12	Total Delivery - 100		-	1,827	(19)	9	15,531	0.8194			-	-	1,895,488	15,531	0.8194	0.3%
	Gas Supply Demand Charge															
13	Fort Frances	10^3m^3/d	-	-	-	-	-	61.0900			-	-	-	-	61.0900	
14	Western	10^3m^3/d	-	-	-	-	-	76.6014			-	-	-	-	76.6014	
15	Northern	10^3m^3/d	-	-	-	-	-	135.6895			-	-	-	-	135.6895	
16	Eastern	10^3m^3/d	-	-	-	-	-	159.4619			-	-	-	-	159.4619	
	Commodity Transportation 1															
17	Fort Frances	-	-	-	-	-	-	7.0154			-	-	-	-	7.0154	
18	Western	10^3m^3	-	-	-	-	-	7.2679			-	-	-	-	7.2679	
19	Northern	10^3m^3	-	-	-	-	-	8.1444			-	-	-	-	8.1444	
20	Eastern	10^3m^3	-	-	-	-	-	8.5171			-	-	-	-	8.5171	
	Commodity Transportation 2															
21	Fort Frances	-	-	-	-	-	-	0.1535			-	-	-	-	0.1535	
22	Western	10^3m^3	-	-	-	-	-	0.2673			-	-	-	-	0.2673	
23	Northern	10^3m^3	-	-	-	-	-	0.4138			-	-	-	-	0.4138	
24	Eastern	10^3m^3	-	-	-	-	-	0.5393			-	-	-	-	0.5393	
	Storage (GJ's)															
25	Demand	GJ/d	-	-	0	64	151	9.705			-	-	15,600	151	9.705	
26	Commodity	GJ	-	-	0	-	16	0.157			-	-	100,000	16	0.157	
27	Gas Supply - 100		-	-	0	64	167	-			-	-	-	167	-	
28	Total Rate 100		-	1,827	(19)	73	15,698	-			-	-	1,895,488	15,698	-	-

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage (a)	Current Approved Revenue ($000's) (b)	Current Approved Rates (cents / m^3) (c)	Adjustments to 2013 Base Rates: 2013 DSM ($000's) (d)	Adjustments to 2013 Base Rates: 2013 Capital Pass-Throughs ($000's) (e)	Adjustments to 2013 Base Rates: Upstream Transportation ($000's) (f)	Adjustments to 2013 Base Rates: One-Time Adjustments Settlement Agreement ($000's) (g)	Adjusted Revenue ($000's) (h) = (b+d+e+f+g)	Price Cap Index ($000's) (i)	Price Cap Index (%) (j)
	M1											
1	Monthly Charge	bills	12,706,802	266,843	$21.00	-	-	-	(1,178)	265,665	1,727	
	Monthly Delivery Commodity Charge											
2	First 100 m^3	10^3m^3	885,353	33,688	3.8051	(3,472)	-	-	21	30,238	197	
3	Next 150 m^3	10^3m^3	786,168	28,291	3.5986	(2,915)	-	-	18	25,393	165	
4	All over 250 m^3	10^3m^3	1,268,023	39,436	3.1101	(4,064)	-	-	24	35,397	230	
5	Total Delivery - M1		2,939,543	368,258	12.5277	(10,451)	-	-	(1,115)	356,692	2,318	0.65%
6	Storage	10^3m^3	2,939,543	21,660	0.7368	-	-	-	71	21,730	141	0.65%
7	Total Rate M1		2,939,543	389,918	-	(10,451)	-	-	(1,045)	378,422	2,460	0.65%
	M2											
8	Monthly Charge	bills	81,451	5,702	$70.00	-	-	-	(36)	5,665	37	
	Monthly Delivery Commodity Charge											
9	First 1 000 m^3	10^3m^3	53,047	2,211	4.1675	(230)	-	-	1	1,981	13	
10	Next 6 000 m^3	10^3m^3	258,156	10,562	4.0912	(1,099)	-	-	4	9,466	62	
11	Next 13 000 m^3	10^3m^3	291,703	11,271	3.8638	(1,173)	-	-	4	10,102	66	
12	All over 20 000 m^3	10^3m^3	372,665	13,382	3.5909	(1,393)	-	-	5	11,994	78	
13	Total Delivery - M2		975,571	43,127	4.4207	(3,896)	-	-	(23)	39,208	255	0.65%
14	Storage	10^3m^3	975,571	7,366	0.7550	-	-	-	24	7,390	48	0.65%
15	Total Rate M2		975,571	50,493	-	(3,896)	-	-	1	46,598	303	0.65%

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							Prior to MCC Change		MCC Change		Volume Adjustments		Proposed			
Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	NAC Adjustment (10^3m^3)	LRAM Adjustment (10^3m^3)	Usage including NAC & LRAM	Revenue ($000's)	Rates (cents / m^3)	Rate Change (%)
			(k)	(l)	(m)	(n) = (-f)	(o) = (h+i+k+l+m+n)	(p) = (o / a)	(q)	(r) = (q / a)	(s)	(t)	(u) = (a + s + t)	(v)	(w) = (v / u)	(x)
	M1															
1	Monthly Charge	bills	-	-	(370)	-	267,022	$21.01	266,843	$21.00	-	-	12,706,802	266,843	$21.00	
	Monthly Delivery Commodity Charge															
2	First 100 m^3	10^3m^3	-	3,528	(18)	-	33,944	3.8340	34,123	3.8541	1,275	-	886,627	34,123	3.8486	
3	Next 150 m^3	10^3m^3	-	2,963	(15)	-	28,506	3.6259	28,506	3.6259	1,132	-	787,300	28,506	3.6207	
4	All over 250 m^3	10^3m^3	-	4,130	(21)	-	39,736	3.1337	39,736	3.1337	1,826	-	1,269,848	39,736	3.1292	
5	Total Delivery - M1		-	10,621	(425)	-	369,207	12.5600	369,207	12.5600	4,233	-	2,943,776	369,207	12.5420	0.1%
6	Storage	10^3m^3	-	-	(67)	-	21,805	0.7418			4,233	-	2,943,776	21,805	0.7407	0.5%
7	Total Rate M1		-	10,621	(491)	-	391,012	-			4,233	-	2,943,776	391,012	-	
	M2															
8	Monthly Charge	bills	-	-	(12)	-	5,690	$69.86	5,702	$70.00	-	-	81,451	5,702	$70.00	
	Monthly Delivery Commodity Charge															
9	First 1 000 m^3	10^3m^3	-	234	(1)	-	2,227	4.1978	2,225	4.1941	8,349	-	61,396	2,225	3.6238	
10	Next 6 000 m^3	10^3m^3	-	1,117	(6)	-	10,638	4.1209	10,629	4.1173	40,631	-	298,787	10,629	3.5574	
11	Next 13 000 m^3	10^3m^3	-	1,192	(7)	-	11,353	3.8919	11,353	3.8919	45,911	-	337,614	11,353	3.3626	
12	All over 20 000 m^3	10^3m^3	-	1,416	(8)	-	13,479	3.6170	13,479	3.6170	58,653	-	431,318	13,479	3.1251	
13	Total Delivery - M2		-	3,959	(35)	-	43,388	4.4474	43,388	4.4474	153,544	-	1,129,115	43,388	3.8426	-13.1%
14	Storage	10^3m^3	-	-	(23)	-	7,415	0.7601			153,544	-	1,129,115	7,415	0.6567	-13.0%
15	Total Rate M2		-	3,959	(58)	-	50,803	-			153,544	-	1,129,115	50,803	-	

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage	Current Approved Revenue ($000's)	Current Approved Rates (cents / m^3)	Adjustments to 2013 Base Rates: 2013 DSM ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	One-Time Adjustments Settlement Agreement ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (b+d+e+f+g)	(i)	(j)
	M4 Firm Commercial/Industrial Contract Rate											
	Monthly Demand Charge											
1	First 8 450 m^3	10^3m^3/d	12,905	6,017	46.6239	(686)	-	-	(7)	5,324	35	
2	Next 19 700 m^3	10^3m^3/d	7,864	1,644	20.9050	(188)	-	-	(2)	1,454	9	
3	All over 28 150 m^3	10^3m^3/d	4,507	792	17.5631	(90)	-	-	(1)	700	5	
	Monthly Delivery Commodity Charge											
4	First Block	10^3m^3	396,153	3,887	0.9813	(637)	-	-	(6)	3,244	21	
5	All remaining use	10^3m^3	8,525	38	0.4435	(6)	-	-	(0)	32	0	
6	Total Delivery - M4		404,678	12,378	3.0587	(1,607)	-	-	(16)	10,755	70	0.65%
7	Total Rate M4		404,678	12,378	-	(1,607)	-	-	(16)	10,755	70	0.65%
	M5A Interruptible Commercial/Industrial Contract Rate											
	Firm contracts											
8	Monthly Demand Charge	10^3m^3/d	626	179	28.6252	(30)	-	-	(2)	147	1	
9	Monthly Delivery Commodity Charge	10^3m^3	17,385	340	1.9563	(57)	-	-	(4)	278	2	
10	Total Delivery - Firm M5A		17,385	519	2.9863	(87)	-	-	(7)	425	3	0.65%
	Interruptible contracts											
11	Monthly Charge	bills	1,692	1,167	$690.00	-	-	-	(14)	1,153	7	
12	Delivery Commodity Charge (Avg Price)	10^3m^3	517,747	11,700	2.2599	(2,595)	-	-	(26)	9,079	59	
13	Total Delivery -Interruptible M5A		517,747	12,868	2.4854	(2,595)	-	-	(40)	10,233	67	0.65%
14	Total Rate M5A		535,132	13,387	-	(2,683)	-	-	(47)	10,658	69	0.65%

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Prior to MCC Change: Proposed Revenue ($000's)	Prior to MCC Change: Proposed Rates (cents / m^3)	MCC Change: Proposed Revenue ($000's)	MCC Change: Proposed Rates (cents / m^3)	Volume Adjustments: NAC Adjustment (10^3m^3)	Volume Adjustments: LRAM Adjustment (10^3m^3)	Proposed: Usage including NAC & LRAM	Proposed: Revenue ($000's)	Proposed: Rates (cents / m^3)	Rate Change (%)
			(k)	(l)	(m)	(n) = (-f)	(o) = (h+i+k+l+m+n)	(p) = (o / a)	(q)	(r) = (q / a)	(s)	(t)	(u) = (a + s + t)	(v)	(w) = (v / u)	(x)
	M4 Firm Commercial/Industrial Contract Rate															
	Monthly Demand Charge															
1	First 8 450 m^3	10^3m^3/d	-	698	(5)	-	6,050	46.8830			-	-	12,905	6,050	46.8830	
2	Next 19 700 m^3	10^3m^3/d	-	191	(1)	-	1,653	21.0212			-	-	7,864	1,653	21.0212	
3	All over 28 150 m^3	10^3m^3/d	-	92	(1)	-	796	17.6607			-	-	4,507	796	17.6607	
	Monthly Delivery Commodity Charge															
4	First Block	10^3m^3	-	647	(5)	-	3,907	0.9864			-	-	396,153	3,907	0.9864	
5	All remaining use	10^3m^3	-	6	(0)	-	38	0.4458			-	-	8,525	38	0.4458	
6	Total Delivery - M4		-	1,633	(13)	-	12,445	3.0753			-	-	404,678	12,445	3.0753	0.5%
7	Total Rate M4		-	1,633	(13)	-	12,445	-			-	-	404,678	12,445	-	
	M5A Interruptible Commercial/Industrial Contract Rate															
	Firm contracts															
8	Monthly Demand Charge	10^3m^3/d	-	31	(0)	-	178	28.4418			-	-	626	178	28.4418	
9	Monthly Delivery Commodity Charge	10^3m^3	-	58	(0)	-	338	1.9461			-	-	17,385	338	1.9461	
10	Total Delivery - Firm M5A		-	89	(0)	-	516	2.9695			-	-	17,385	516	2.9695	-0.6%
	Interruptible contracts															
11	Monthly Charge	bills	-	-	(2)	-	1,159	$684.76			-	-	1,692	1,159	$684.76	
12	Delivery Commodity Charge (Avg Price)	10^3m^3	-	2,638	(15)	-	11,761	2.2716			-	-	517,747	11,761	2.2716	
13	Total Delivery -Interruptible M5A		-	2,638	(17)	-	12,920	2.4954			-	-	517,747	12,920	2.4954	0.4%
14	Total Rate M5A		-	2,726	(17)	-	13,436	-			-	-	535,132	13,436	-	

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage (a)	Current Approved Revenue ($000's) (b)	Current Approved Rates (cents / m^3) (c)	Adjustments to 2013 Base Rates: 2013 DSM ($000's) (d)	2013 Capital Pass-Throughs ($000's) (e)	Upstream Transportation ($000's) (f)	One-Time Adjustments Settlement Agreement ($000's) (g)	Adjusted Revenue ($000's) (h) = (b+d+e+f+g)	Price Cap Index ($000's) (i)	Price Cap Index (%) (j)
	M7 Special Large Volume Contract Rate											
	Firm Contracts											
1	Monthly Demand Charge	$10^3m^3/d$	14,220	3,611	25.3924	(773)	-	-	(1)	2,836	18	
2	Monthly Delivery Commodity Charge	10^3m^3	142,488	485	0.3402	(104)	-	-	(0)	381	2	
3	Total Delivery - Firm M7		142,488	4,096	2.8743	(877)	-	-	(2)	3,217	21	0.65%
	Interruptible / Seasonal Contracts											
4	Monthly Delivery Commodity Charge	10^3m^3	4,655	60	1.2943	(29)	-	-	(1)	31	0	0.65%
5	Total Rate M7		147,143	4,156	-	(906)	-	-	(3)	3,248	21	0.65%
	M9 Large Wholesale Service											
6	Monthly Demand Charge	$10^3m^3/d$	3,993	606	15.1688	-	-	-	1	607	4	
7	Monthly Delivery Commodity Charge	10^3m^3	60,750	133	0.2196	-	-	-	0	134	1	
8	Total Rate M9		60,750	739	1.2165	-	-	-	1	740	5	0.65%
	M10 Small Wholesale Service											
9	Monthly Delivery Commodity Charge	10^3m^3	189	10	5.2035	-	-	-	(0)	9	0	0.65%
10	Total Rate M10		189	10	5.2035	-	-	-	(0)	9	0	0.65%

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							Prior to MCC Change		MCC Change		Volume Adjustments		Proposed			
Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	NAC Adjustment (10^3m^3)	LRAM Adjustment (10^3m^3)	Usage including NAC & LRAM	Revenue ($000's)	Rates (cents / m^3)	Rate Change (%)
			(k)	(l)	(m)	(n) = (-f)	(o) = (h+i+k+l+m+n)	(p) = (o / a)	(q)	(r) = (q / a)	(s)	(t)	(u) = (a + s + t)	(v)	(w) = (v / u)	(x)
	M7 Special Large Volume Contract Rate															
	Firm Contracts															
1	Monthly Demand Charge	10^3m^3/d	-	786	(4)	-	3,637	25.5751			-	-	14,220	3,637	25.5751	
2	Monthly Delivery Commodity Charge	10^3m^3	-	105	(0)	-	489	0.3430			-	-	142,488	489	0.3430	
3	Total Delivery - Firm M7		-	891	(4)	-	4,125	2.8953			-	-	142,488	4,125	2.8953	0.7%
	Interruptible / Seasonal Contracts															
4	Monthly Delivery Commodity Charge	10^3m^3	-	29	(0)	-	60	1.2819			-	-	4,655	60	1.2819	-1.0%
5	Total Rate M7		-	920	(4)	-	4,185	-			-	-	147,143	4,185	-	
	M9 Large Wholesale Service															
6	Monthly Demand Charge	10^3m^3/d	-	-	(0)	-	610	15.2850			-	-	3,993	610	15.2850	
7	Monthly Delivery Commodity Charge	10^3m^3	-	-	(0)	-	134	0.2213			-	-	60,750	134	0.2213	
8	Total Rate M9		-	-	(0)	-	745	1.2259			-	-	60,750	745	1.2259	0.8%
	M10 Small Wholesale Service															
9	Monthly Delivery Commodity Charge	10^3m^3	-	-	(0)	-	9	4.9767			-	-	189	9	4.9767	-4.4%
10	Total Rate M10		-	-	(0)	-	9	4.9767			-	-	189	9	4.9767	

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage	Current Approved Revenue ($000's)	Current Approved Rates (cents / m³)	Adjustments to 2013 Base Rates: 2013 DSM ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	One-Time Adjustments Settlement Agreement ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (b+d+e+f+g)	(i)	(j)
	T1 Storage and Transportation											
	Storage ($/GJ's)											
	Demand:											
	Firm injection / withdrawal											
1	Union provides deliverability inventory	GJ/d/mo.	492,360	813	1.651	-	-	-	5	818	5	
2	Customer provides deliverability inventory	GJ/d/mo.	166,800	200	1.197	-	-	-	1	201	1	
3	Incremental firm injection right	GJ/d/mo.	-	-	1.197	-	-	-	-	-	-	
4	Interruptible	GJ/d/mo.	62,244	75	1.197	-	-	-	-	75	0	
5	Space	GJ/d/mo.	22,396,680	253	0.011	-	-	-	0	253	2	
6	Commodity (Customer Provides)	GJ	2,750,300	21	0.008	-	-	-	(0)	21	0	
7	Commodity (Union Provides)	GJ	-	-	0.031	-	-	-	-	-	-	
8	Customer supplied fuel	GJ	16,442	52	-	-	-	-	-	52	0	
	Transportation (cents/ m^3)											
	Demand											
9	First 28 150 m^3	10^3m^3/d/mo.	12,448	3,978	31.9554	(1,004)	-	-	(3)	2,972	19	
10	Next 112 720 m^3	10^3m^3/d/mo.	13,002	2,871	22.0775	(724)	-	-	(2)	2,144	14	
	Commodity											
	Firm											
11	All Volumes	10^3m^3	485,700	346	0.0712	-	-	-	(3)	343	2	
12	Interruptible	10^3m^3	63,286	781	1.2341	(73)	-	-	(3)	705	5	
13	Monthly Charges	Meter/mo.	528	1,022	$1,936.13	-	-	-	(6)	1,016	7	
14	Customer supplied fuel	10^3m^3	2,979	244	-	-	-	-	-	244	2	
15	Total Rate T1		548,986	10,655	1.9408	(1,801)	-	-	(10)	8,844	57	0.65%
	T2 Storage and Transportation											
	Storage ($/GJ's)											
	Demand:											
	Firm injection / withdrawal											
1	Union provides deliverability inventory	GJ/d/mo.	1,516,920	2,504	1.651	-	-	-	17	2,521	16	
2	Customer provides deliverability inventory	GJ/d/mo.	1,336,556	1,600	1.197	-	-	-	11	1,610	10	
3	Incremental firm injection right	GJ/d/mo.	-	-	1.197	-	-	-	-	-	-	
4	Interruptible	GJ/d/mo.	415,704	498	1.197	-	-	-	-	498	3	
5	Space	GJ/d/mo.	106,645,056	1,204	0.011	-	-	-	2	1,207	8	
6	Commodity (Customer Provides)	GJ	7,869,782	60	0.008	-	-	-	(1)	59	0	
7	Commodity (Union Provides)	GJ	-	-	0.031	-	-	-	-	-	-	
8	Customer supplied fuel	GJ	47,061	150	-	-	-	-	-	150	1	
	Transportation (cents/ m^3)											
	Demand											
9	First 140 870 m^3	10^3m^3/d/mo.	49,971	10,090	20.1911	(905)	-	-	15	9,200	60	
10	All Over 140 870 m^3	10^3m^3/d/mo.	167,088	17,845	10.6802	(1,600)	-	-	26	16,271	106	
	Commodity											
	Firm											
11	All Volumes	10^3m^3	4,521,813	353	0.0078	-	-	-	(4)	349	2	
12	Interruptible	10^3m^3	358,485	3,387	0.9447	(104)	-	-	(6)	3,277	21	
13	Monthly Charges	Meter/mo.	444	2,664	$6,000.00	-	-	-	(1)	2,663	17	
14	Customer supplied fuel	10^3m^3	23,922	1,854	-	-	-	-	-	1,854	12	
15	Total Rate T2		4,880,298	42,209	0.8649	(2,609)	-	-	59	39,659	258	0.65%

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Prior to MCC Change: Proposed Revenue ($000's)	Prior to MCC Change: Proposed Rates (cents / m^3)	MCC Change: Proposed Revenue ($000's)	MCC Change: Proposed Rates (cents / m^3)	Volume Adjustments: NAC Adjustment (10^3m^3)	Volume Adjustments: LRAM Adjustment (10^3m^3)	Proposed: Usage including NAC & LRAM	Proposed: Revenue ($000's)	Proposed: Rates (cents / m^3)	Rate Change (%)
			(k)	(l)	(m)	(n) = (-f)	(o) = (h+i+k+l+m+n)	(p) = (o / a)	(q)	(r) = (q / a)	(s)	(t)	(u) = (a + s + t)	(v)	(w) = (v / u)	(x)
	T1 Storage and Transportation															
	Storage ($/GJ's)															
	Demand:															
	Firm injection / withdrawal															
1	Union provides deliverability inventory	GJ/d/mo.	-	-	(1)	-	822	1.670			-	-	492,360	822	1.670	
2	Customer provides deliverability inventory	GJ/d/mo.	-	-	(0)	-	202	1.210			-	-	166,800	202	1.210	
3	Incremental firm injection right	GJ/d/mo.	-	-	-	-	-	1.210			-	-	-	-	1.210	
4	Interruptible	GJ/d/mo.	-	-	-	-	75	1.210			-	-	62,244	75	1.210	
5	Space	GJ/d/mo.	-	-	(1)	-	255	0.011			-	-	22,396,680	255	0.011	
6	Commodity (Customer Provides)	GJ	-	-	(0)	-	21	0.008			-	-	2,750,300	21	0.008	
7	Commodity (Union Provides)	GJ	-	-	-	-	-	0.031			-	-	-	-	0.031	
8	Customer supplied fuel	GJ	-	-	-	-	53	-			-	-	16,442	53	-	
	Transportation (cents/ m^3)															
	Demand															
9	First 28 150 m^3	10^3m^3/d/mo.	-	1,020	(3)	-	4,008	32.1954			-	-	12,448	4,008	32.1954	
10	Next 112 720 m^3	10^3m^3/d/mo.	-	736	(2)	-	2,892	22.2433			-	-	13,002	2,892	22.2433	
	Commodity															
	Firm															
11	All Volumes	10^3m^3	-	-	(0)	-	345	0.0710			-	-	485,700	345	0.0710	
12	Interruptible	10^3m^3	-	74	0	-	784	1.2390			-	-	63,286	784	1.2390	
13	Monthly Charges	Meter/mo.	-	-	(1)	-	1,022	$1,935.06			-	-	528	1,022	$1,935.06	
14	Customer supplied fuel	10^3m^3	-	-	-	-	246	-			-	-	2,979	246	-	
15	Total Rate T1		-	1,830	(9)	-	10,723	1.9533			-	-	548,986	10,723	1.9533	0.6%
	T2 Storage and Transportation															
	Storage ($/GJ's)															
	Demand:															
	Firm injection / withdrawal															
1	Union provides deliverability inventory	GJ/d/mo.	-	-	(5)	-	2,533	1.670			-	-	1,516,920	2,533	1.670	
2	Customer provides deliverability inventory	GJ/d/mo.	-	-	(3)	-	1,618	1.210			-	-	1,336,556	1,618	1.210	
3	Incremental firm injection right	GJ/d/mo.	-	-	-	-	-	1.210			-	-	-	-	1.210	
4	Interruptible	GJ/d/mo.	-	-	-	-	503	1.210			-	-	415,704	503	1.210	
5	Space	GJ/d/mo.	-	-	(3)	-	1,212	0.011			-	-	106,645,056	1,212	0.011	
6	Commodity (Customer Provides)	GJ	-	-	(0)	-	60	0.008			-	-	7,869,782	60	0.008	
7	Commodity (Union Provides)	GJ	-	-	-	-	-	0.031			-	-	-	-	0.031	
8	Customer supplied fuel	GJ	-	-	-	-	151	-			-	-	47,061	151	-	
	Transportation (cents/ m^3)															
	Demand															
9	First 140 870 m^3	10^3m^3/d/mo.	-	919	(2)	-	10,176	20.3645			-	-	49,971	10,176	20.3645	
10	All Over 140 870 m^3	10^3m^3/d/mo.	-	1,626	(4)	-	17,999	10.7719			-	-	167,088	17,999	10.7719	
	Commodity															
	Firm															
11	All Volumes	10^3m^3	-	-	(0)	-	352	0.0078			-	-	4,521,813	352	0.0078	
12	Interruptible	10^3m^3	-	105	(5)	-	3,399	0.9481			-	-	358,485	3,399	0.9481	
13	Monthly Charges	Meter/mo.	-	-	(10)	-	2,671	$6,015.52			-	-	444	2,671	$6,015.52	
14	Customer supplied fuel	10^3m^3	-	-	-	-	1,866	-			-	-	23,922	1,866	-	
15	Total Rate T2		-	2,651	(31)	-	42,538	0.8716			-	-	4,880,298	42,538	0.8716	0.8%

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage	Current Approved Revenue ($000's)	Current Approved Rates (cents / m^3)	Adjustments to 2013 Base Rates: 2013 DSM ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	One-Time Adjustments Settlement Agreement ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (b+d+e+f+g)	(i)	(j)
	T3											
	Storage ($/GJ's)											
	Demand											
	Firm injection / withdrawal											
1	Union provides deliverability inventory	GJ/d/mo.	-	-	1.651	-	-	-	-	-	-	
2	Customer provides deliverability inventory	GJ/d/mo.	679,320	813	1.197	-	-	-	7	820	5	
3	Incremental firm injection right	GJ/d/mo.	-	-	1.197	-	-	-	-	-	-	
4	Interruptible	GJ/d/mo.	-	-	1.197	-	-	-	-	-	-	
5	Space	GJ/d/mo.	36,614,256	414	0.011	-	-	-	1	414	3	
6	Commodity (Customer Provides)	GJ	4,459,672	34	0.008	-	-	-	(0)	34	0	
7	Commodity (Union Provides)	GJ	-	-	0.031	-	-	-	-	-	-	
8	Customer supplied fuel	GJ	26,668	85	-	-	-	-	-	85	1	
	Transportation (cents/ m^3)											
9	Demand	10^3m^3/d/mo.	28,200	2,639	9.3582	-	-	-	11	2,650	17	
10	Commodity	10^3m^3	272,712	29	0.0107	-	-	-	(0)	29	0	
11	Monthly Charges	Meter/mo.	12	244	$20,371.35	-	-	-	(1)	243	2	
12	Customer supplied fuel	10^3m^3	1,972	141	-	-	-	-	-	141	1	
13	Total Rate T3		272,712	4,400	1.6133	-	-	-	16	4,416	29	0.65%

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							Prior to MCC Change		MCC Change		Volume Adjustments		Proposed			
Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	Proposed Revenue ($000's)	Proposed Rates (cents / m^3)	NAC Adjustment (10^3m^3)	LRAM Adjustment (10^3m^3)	Usage including NAC & LRAM	Revenue ($000's)	Rates (cents / m^3)	Rate Change (%)
			(k)	(l)	(m)	(n) = (-f)	(o) = (h+i+k+l+m+n)	(p) = (o / a)	(q)	(r) = (q / a)	(s)	(t)	(u) = (a + s + t)	(v)	(w) = (v / u)	(x)
	T3															
	Storage ($/GJ's)															
	Demand															
	Firm injection / withdrawal															
1	Union provides deliverability inventory	GJ/d/mo.	-	-	-	-	-	1.670			-	-	-	-	1.670	
2	Customer provides deliverability inventory	GJ/d/mo.	-	-	(2)	-	822	1.210			-	-	679,320	822	1.210	
3	Incremental firm injection right	GJ/d/mo.	-	-	-		-	1.210			-	-	-	-	1.210	
4	Interruptible	GJ/d/mo.	-	-	-		-	1.210			-	-	-	-	1.210	
5	Space	GJ/d/mo.	-	-	(1)	-	416	0.011			-	-	36,614,256	416	0.011	
6	Commodity (Customer Provides)	GJ	-	-	(0)	-	34	0.008			-	-	4,459,672	34	0.008	
7	Commodity (Union Provides)	GJ	-	-	-	-	-	0.031			-	-	-	-	0.031	
8	Customer supplied fuel	GJ	-	-	-	-	85	-			-	-	26,668	85	-	
	Transportation (cents/ m^3)															
9	Demand	10^3m^3/d/mo.	-	-	3	-	2,670	9.4668			-	-	28,200	2,670	9.4668	
10	Commodity	10^3m^3	-	-	(0)	-	29	0.0107			-	-	272,712	29	0.0107	
11	Monthly Charges	Meter/mo.	-	-	(0)	-	245	$20,381.53			-	-	12	245	$20,381.53	
12	Customer supplied fuel	10^3m^3	-	-	-	-	142	-			-	-	1,972	142		
13	Total Rate T3		-	-	(0)	-	4,443	1.6293			-	-	272,712	4,443	1.6293	1.0%

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						Adjustments to 2013 Base Rates					
Line No.	Particulars	Billing Units	Current Approved Forecast Usage	Current Approved Revenue ($000's)	Current Approved Rates ($/ GJ)	One-Time Adjustments Settlement Agreement ($000's)	2013 Capital Pass-Throughs ($000's)	Upstream Transportation ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)
			(a)	(b)	(c)	(d)	(e)	(f)	(g) = (b+d+e+f)	(h)	(i)
	M12 Transportation Service										
	Demand:										
	Dawn to Kirkwall										
1	- 12 months	GJ/d/mo	419,318	11,312	2.011	56	-	-	11,368	74	
2	- 10 months	GJ/d/mo	304,563	6,124	2.011	31	-	-	6,154	40	
3	- 2 months	GJ/d/mo	18,365	74	2.011	0	-	-	74	0	
4	- F24-T - 12 months	GJ/d/mo	49,500	40	0.068	-	-	-	40	0	
	Dawn to Parkway										
5	- 12 months	GJ/d/mo	3,226,050	101,007	2.382	506	-	-	101,513	660	
6	- 10 months	GJ/d/mo	65,000	1,549	2.382	8	-	-	1,556	10	
7	- 3 months	GJ/d/mo	2,000	14	2.382	0	-	-	14	0	
8	- F24-T - 12 months	GJ/d/mo	307,000	319	0.068	-	-	-	319	2	
	M12-X Easterly (between Dawn, Kirkwall and Parkway)										
9	- 12 months	GJ/d/mo	391,011	11,179	2.382	56	-	-	11,235	73	
	M12-X Westerly (between Dawn, Kirkwall and Parkway)										
10	- 12 months	GJ/d/mo	391,011	2,717	0.579	14	-	-	2,731	18	
	Kirkwall to Parkway										
11	- 12 months	GJ/d/mo	88,497	395	0.372	2	-	-	397	3	
12	- 2 months	GJ/d/mo	174,752	130	0.372	1	-	-	131	1	
	Commodity:										
13	Easterly - Providing Own Fuel	GJ	705,499,899	22,625		-	-	-	22,625	147	
	Westerly - Providing Own Fuel	GJ									
14	Parkway to Kirkwall/Dawn		905,475	12		-	-	-	12	0	
15	Kirkwall to Dawn		5,031,274	37		-	-	-	37	0	
16	**Total Rate M12**		711,436,648	157,532		674	-	-	158,206	1,028	0.65%

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Proposed Revenue ($000's)	Proposed Rates ($/ GJ)	Billing Unit Adjustments: Demand Adjustment	Billing Unit Adjustments: LRAM Adjustment	2014 Forecast: Usage including Demand & LRAM	2014 Forecast: Revenue ($000's)	2014 Forecast: Rates ($/ GJ)	Rate Change (%)
			(j)	(k)	(l)	(m) = (-f)	(n) = (g+h+j+k+l+m)	(o) = (n / a)	(p)	(q)	(r) = (a + p + q)	(s)	(t) = (s / r)	(u)
	M12 Transportation Service													
	Demand:													
	Dawn to Kirkwall													
1	- 12 months	GJ/d/mo	-	-	53	-	11,495				419,318	11,495	2.043	
2	- 10 months	GJ/d/mo	-	-	28	-	6,223				304,563	6,223	2.043	
3	- 2 months	GJ/d/mo	-	-	0	-	75				18,365	75	2.043	
4	- F24-T - 12 months	GJ/d/mo	-	-	-	-	41				49,500	41	0.068	
	Dawn to Parkway				-									
5	- 12 months	GJ/d/mo	-	-	485	-	102,657				3,226,050	102,657	2.421	
6	- 10 months	GJ/d/mo	-	-	7	-	1,574				65,000	1,574	2.421	
7	- 3 months	GJ/d/mo	-	-	0	-	15				2,000	15	2.421	
8	- F24-T - 12 months	GJ/d/mo	-	-	-	-	321				307,000	321	0.068	
	M12-X Easterly (between Dawn, Kirkwall and Parkway)				-									
9	- 12 months	GJ/d/mo	-	-	54	-	11,361				391,011	11,361	2.421	
	M12-X Westerly (between Dawn, Kirkwall and Parkway)				-									
10	- 12 months	GJ/d/mo	-	-	15	-	2,764				391,011	2,764	0.589	
	Kirkwall to Parkway				-									
11	- 12 months	GJ/d/mo	-	-	2	-	402				88,497	402	0.378	
12	- 2 months	GJ/d/mo	-	-	1	-	132				174,752	132	0.378	
	Commodity:													
13	Easterly - Providing Own Fuel	GJ	-	-		-	22,772				705,499,899	22,772		
	Westerly - Providing Own Fuel	GJ												
14	Parkway to Kirkwall/Dawn						12				905,475	12		
15	Kirkwall to Dawn						37				5,031,274	37		
16	**Total Rate M12**		-	-	646	-	159,880	-	-	-	716,873,715	159,880		1.49%

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage (a)	Current Approved Revenue ($000's) (b)	Current Approved Rates ($ / GJ) (c)	Adjustments to 2013 Base Rates: One-Time Adjustments Settlement Agreement ($000's) (d)	Adjustments to 2013 Base Rates: 2013 Capital Pass-Throughs ($000's) (e)	Adjustments to 2013 Base Rates: Upstream Transportation ($000's) (f)	Adjusted Revenue ($000's) (g) = (b+d+e+f)	Price Cap Index ($000's) (h)	Price Cap Index (%) (i)
	M13 Transportation of Locally Produced Gas										
1	Monthly Fixed Charge	monthly	15	167	$926.60	-	-	-	167	1	
2	Transmission Commodity Charge	GJ	5,934,507	200	0.034	1	-	-	201	1	
3	Commodity	GJ	5,934,507	53	0.009	-	-	-	53	0	
4	**Total Rate M13**		5,934,507	421		1	-	-	422	3	0.65%
	M16 Transportation Service										
5	Monthly Fixed Charge	monthly	4	71	$1,474.12	-	-	-	71	0	
6	Transmission Commodity Charge	GJ	6,236,394	211	0.034	1	-	-	212	1	
	Charges West of Dawn:										
7	Firm Demand Charge	GJ/d	17,846	227	1.059	0	-	-	227	1	
8	Fuel & UFG to Dawn	GJ	4,098,775	37	0.009	-	-	-	37	0	
9	Fuel & UFG to Pool	GJ	4,098,775	107	0.026	-	-	-	107	1	
	Charges East of Dawn:										
10	Firm Demand Charge	GJ/d	9,067	81	0.741	-	-	-	81	1	
11	Fuel & UFG to Dawn	GJ	2,137,619	19	0.009	-	-	-	19	0	
12	Fuel & UFG to Pool	GJ	2,137,619	19	0.009	-	-	-	19	0	
13	**Total Rate M16**		12,472,788	771		1	-	-	772	5	0.65%

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's) (j)	2014 DSM ($000's) (k)	2014 Capital Pass-Throughs ($000's) (l)	Add Back Upstream Transportation ($000's) (m) = (-f)	Proposed Revenue ($000's) (n) = (g+h+j+k+l+m)	Proposed Rates ($/ GJ) (o) = (n / a)	Billing Unit Adjustments: Demand Adjustment (p)	Billing Unit Adjustments: LRAM Adjustment (q)	2014 Forecast: Usage including Demand & LRAM (r) = (a + p + q)	2014 Forecast: Revenue ($000's) (s)	2014 Forecast: Rates ($/ GJ) (t) = (s / r)	Rate Change (%) (u)
	M13 Transportation of Locally Produced Gas													
1	Monthly Fixed Charge	monthly	-	-	-		168				15	168	$932.62	
2	Transmission Commodity Charge	GJ	-	-	(0)		202				5,934,507	203	0.034	
3	Commodity	GJ	-	-	-		54				5,934,507	54	0.009	
4	**Total Rate M13**		-	-	(0)	-	424	-	-	-	5,934,507	424		0.87%
	M16 Transportation Service													
5	Monthly Fixed Charge	monthly	-	-	-		71				4	71	$1,483.70	
6	Transmission Commodity Charge	GJ	-	-	(0)		213				6,236,394	213	0.034	
	Charges West of Dawn:													
7	Firm Demand Charge	GJ/d	-	-	(0)		228				17,846	228	1.066	
8	Fuel & UFG to Dawn	GJ	-	-	-		37				4,098,775	37	0.009	
9	Fuel & UFG to Pool	GJ	-	-	-		107				4,098,775	107	0.026	
	Charges East of Dawn:													
10	Firm Demand Charge	GJ/d	-	-	-		82				9,067	82	0.753	
11	Fuel & UFG to Dawn	GJ	-	-	-		19				2,137,619	19	0.009	
12	Fuel & UFG to Pool	GJ	-	-	-		19				2,137,619	19	0.009	
13	**Total Rate M16**		-	-	(0)	-	777	-	-	-	12,472,788	777		0.88%

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Line No.	Particulars	Billing Units	Current Approved Forecast Usage	Current Approved Revenue ($000's)	Current Approved Rates (cents / m³)	Adjustments to 2013 Base Rates: One-Time Adjustments Settlement Agreement ($000's)	Adjustments to 2013 Base Rates: 2013 Capital Pass-Throughs ($000's)	Adjustments to 2013 Base Rates: Upstream Transportation ($000's)	Adjusted Revenue ($000's)	Price Cap Index ($000's)	Price Cap Index (%)
			(a)	(b)	(c)	(d)	(e)	(f)	(g) = (b+d+e+f)	(h)	(i)
	C1 Cross Franchise Transportation Service										
	Storage Service:										
1	Peak Storage(Short-term)	GJ	22,489,337	7,883		17	-	-	7,900		
	Commodity										
2	Off Peak Storage/ Balancing /Loans	GJ	-	2,500		-	-	-	2,500		
	Transportation Service:										
	Demand:										
	St.Clair & Dawn, Ojibway & Dawn										
3	- 12 months	GJ/mo	85,460	3,197	1.059	3	-	-	3,200	21	
	Parkway to Dawn/Kirkwall										
4	- 12 months	GJ/mo	347,371	2,414	0.579	12	-	-	2,426	16	
5	- 3 months	GJ/mo	54,357	94	0.579	0	-	-	95	1	
6	Kirkwall to Dawn	GJ/mo	-	-	1.021	-	-	-	-	-	
	Dawn to Parkway										
7	- 12 months	GJ/mo	7,065	413	2.382	-	-	-	413	3	
8	Kirkwall to Parkway	GJ/mo	-		0.372	-	-	-	-	-	
	Dawn to Dawn Vector					-	-	-			
9	- 12 months	GJ/mo	92,845	32	0.029	-	-	-	32	0	
	Dawn to Dawn TCPL					-	-				
10	- 12 months	GJ/mo	500,000	805	0.134	-	-	-	805	5	
	Firm Commodity										
	Easterly										
	Union Providing Fuel										
11	Dawn to Parkway (TCPL)	GJ	2,423,295	104		-	-	-	104	1	
	Providing Own Fuel										
12	Dawn to Dawn TCPL	GJ	5,000,000	82		-	-	-	82	1	
13	Dawn to Dawn Vector	GJ	18,280,703	243		-	-	-	243	2	
14	Ojibway to Dawn	GJ	9,968,577	164		-	-	-	164	1	
	Westerly - Providing Own Fuel										
15	Parkway to Kirkwall	GJ	0								
16	Parkway to Dawn	GJ	3,990,264	51		-	-	-	51	0	
17	Short-term Transportation	GJ	177,529,686	11,067		(6)	-	-	11,061		
18	Exchanges			14,918		-	-	-	14,918		
19	Other Transactional			1,067		-	-	-	1,067		
20	**Total Rate C1**		217,192,525	45,034		28	-	-	45,062	49	
21	**Total Ex-Franchise**			203,758		703	-	-	204,461	1,086	

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Line No.	Particulars	Billing Units	2014 Z-Factor Adjustments ($000's)	2014 DSM ($000's)	2014 Capital Pass-Throughs ($000's)	Add Back Upstream Transportation ($000's)	Proposed Revenue ($000's)	Proposed Rates ($/ GJ)	Billing Unit Adjustments Demand Adjustment	LRAM Adjustment	2014 Forecast Usage including Demand & LRAM	Revenue ($000's)	Rates ($/ GJ)	Rate Change (%)
			(j)	(k)	(l)	(m) = (-f)	(n) = (g+h+j+k+l+m)	(o) = (n / a)	(p)	(q)	(r) = (a + p + q)	(s)	(t) = (s / r)	(u)
	C1 Cross Franchise Transportation Service													
	Storage Service:													
1	Peak Storage(Short-term)	GJ	-	-	(9)	-	7,891				22,489,337	7,891		
	Commodity													
2	Off Peak Storage/ Balancing /Loans	GJ	-	-	-	-	2,500					2,500		
	Transportation Service:													
	Demand:													
	St.Clair & Dawn, Ojibway & Dawn													
3	- 12 months	GJ/mo	-	-	-	-	3,221				85,460	3,221	1.066	
	Parkway to Dawn/Kirkwall													
4	- 12 months	GJ/mo	-	-	14	-	2,455				347,371	2,455	0.589	
5	- 3 months	GJ/mo	-	-	1	-	96				54,357	96	0.589	
6	Kirkwall to Dawn	GJ/mo	-	-	-	-	-				-	-	1.039	
	Dawn to Parkway													
7	- 12 months	GJ/mo	-	-	-	-	415				7,065	415	2.421	
8	Kirkwall to Parkway	GJ/mo	-	-	-	-	-				-	-		
	Dawn to Dawn Vector		-	-	-	-								
9	- 12 months	GJ/mo	-	-	-	-	32				92,845	32	0.029	
	Dawn to Dawn TCPL		-	-	-	-								
10	- 12 months	GJ/mo	-	-	-	-	810				500,000	810	0.135	
	Firm Commodity													
	Easterly													
	Union Providing Fuel													
11	Dawn to Parkway (TCPL)	GJ	-	-	-	-	104				2,423,295	104		
	Providing Own Fuel													
12	Dawn to Dawn TCPL	GJ	-	-	-	-	83				5,000,000	83		
13	Dawn to Dawn Vector	GJ	-	-	-	-	245				18,280,703	245		
14	Ojibway to Dawn	GJ	-	-	-	-	165				9,968,577	165		
	Westerly - Providing Own Fuel													
15	Parkway to Kirkwall	GJ												
16	Parkway to Dawn	GJ	-	-	-	-	51				3,990,264	51		
17	Short-term Transportation	GJ	-	-	(1)	-	11,060				177,529,686	11,060		
18	Exchanges		-	-	-	-	14,918					14,918		
19	Other Transactional		-	-	-	-	1,067					1,067		
20	**Total Rate C1**		-	-	4	-	45,115	-	-	-	240,768,960	45,115		0.18%
21	**Total Ex-Franchise**		-	-	650	-	206,197	-	-	-		206,197		

UNION GAS LIMITED
2014 IR Forecast - Rate Impact Continuity
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Line No.	Particulars		2013 Current Approved Revenue	One-Time Adjustments Settlement Agreement	Application of Price Cap Index	2014 DSM	2014 Capital Pass Throughs	Total Excluding Volume Adjustments	Volume Adjustments	Total Including Volume Adjustments
			(a)	(b)	(c)	(d)	(e)	(f) = sum (a to e)	(g)	(h) = (f + g)
	In-Franchise North Delivery									
1	R01	Revenue ($000's)	161,653	(839)	1,009	61	(234)	161,649		161,649
2		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	50,219	934,640
3		Average rate (cents / m^3)	18.2778	(0.0949)	0.1141	0.0069	(0.0265)	18.2774	(0.9821)	17.2953
4		Average rate change (1)		-0.5%	0.6%	0.0%	-0.1%	0.0%	-5.4%	-5.4%
5	R10	Revenue ($000's)	20,100	(59)	119	19	(30)	20,150		20,150
6		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	23,054	345,941
7		Average rate (cents / m^3)	6.2251	(0.0181)	0.0370	0.0060	(0.0094)	6.2405	(0.4159)	5.8246
8		Average rate change (1)		-0.3%	0.6%	0.1%	-0.2%	0.2%	-6.7%	-6.4%
9	R20	Revenue ($000's)	13,537	(47)	80	16	(23)	13,563		13,563
10		Volumes (10^3m^3)	629,802	629,802	629,802	629,802	629,802	629,802	-	629,802
11		Average rate (cents / m^3)	2.1494	(0.0074)	0.0128	0.0025	(0.0037)	2.1536	-	2.1536
12		Average rate change (1)		-0.3%	0.6%	0.1%	-0.2%	0.2%	0.0%	0.2%
13	R25	Revenue ($000's)	4,473	(18)	29	-	(7)	4,476		4,476
14		Volumes (10^3m^3)	159,555	159,555	159,555	159,555	159,555	159,555	-	159,555
15		Average rate (cents / m^3)	2.8033	(0.0116)	0.0181	-	(0.0044)	2.8055	-	2.8055
16		Average rate change (1)		-0.4%	0.6%	0.0%	-0.2%	0.1%	0.0%	0.1%
17	R100	Revenue ($000's)	15,483	(51)	89	29	(19)	15,531		15,531
18		Volumes (10^3m^3)	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	1,895,488	-	1,895,488
19		Average rate (cents / m^3)	0.8168	(0.0027)	0.0047	0.0015	(0.0010)	0.8194	-	0.8194
20		Average rate change (1)		-0.3%	0.6%	0.2%	-0.1%	0.3%	0.0%	0.3%
	In-franchise South Delivery and Storage									
21	M1 - Delivery	Revenue ($000's)	368,258	(1,115)	2,318	170	(425)	369,207		369,207
22		Volumes (10^3m^3)	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	4,233	2,943,776
23		Average rate (cents / m^3)	12.5277	(0.0379)	0.0789	0.0058	(0.0144)	12.5600	(0.0181)	12.5420
24	M1 - Storage	Revenue ($000's)	21,660	71	141	-	(67)	21,805		21,805
25		Volumes (10^3m^3)	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	2,939,543	4,233	2,943,776
26		Average rate (cents / m^3)	0.7368	0.0024	0.0048	-	(0.0023)	0.7418	(0.0011)	0.7407
27	M1	Total Revenue ($000's)	389,918	(1,045)	2,460	170	(491)	391,012		391,012
28		Total Average rate (cents / m^3)	13.2646	(0.0355)	0.0837	0.0058	(0.0167)	13.3018	(0.0191)	13.2827
29		Average rate change (1)		-0.3%	0.6%	0.0%	-0.1%	0.3%	-0.1%	0.1%
30	M2 - Delivery	Revenue ($000's)	43,127	(23)	255	63	(35)	43,388		43,388
31		Volumes (10^3m^3)	975,571	975,571	975,571	975,571	975,571	975,571	153,544	1,129,115
32		Average rate (cents / m^3)	4.4207	(0.0024)	0.0261	0.0065	(0.0036)	4.4474	(0.6048)	3.8426
33	M2 - Storage	Revenue ($000's)	7,366	24	48	-	(23)	7,415		7,415
34		Volumes (10^3m^3)	975,571	975,571	975,571	975,571	975,571	975,571	153,544	1,129,115
35		Average rate (cents / m^3)	0.7550	0.0025	0.0049	-	(0.0023)	0.7601	(0.1034)	0.6567
36	M2	Total Revenue ($000's)	50,493	1	303	63	(58)	50,803		50,803
37		Total Average rate (cents / m^3)	5.1758	0.0001	0.0310	0.0065	(0.0059)	5.2075	(0.7081)	4.4994
38		Average rate change (1)		0.0%	0.6%	0.1%	-0.1%	0.6%	-13.7%	-13.1%
39	M4	Revenue ($000's)	12,378	(16)	70	26	(13)	12,445		12,445
40		Volumes (10^3m^3)	404,678	404,678	404,678	404,678	404,678	404,678	-	404,678
41		Average rate (cents / m^3)	3.0587	(0.0040)	0.0173	0.0065	(0.0031)	3.0753	-	3.0753
42		Average rate change (1)		-0.1%	0.6%	0.2%	-0.1%	0.5%	0.0%	0.5%
43	M5	Revenue ($000's)	13,387	(47)	69	44	(17)	13,436		13,436
44		Volumes (10^3m^3)	535,132	535,132	535,132	535,132	535,132	535,132	-	535,132
45		Average rate (cents / m^3)	2.5016	(0.0088)	0.0129	0.0082	(0.0032)	2.5108	-	2.5108
46		Average rate change (1)		-0.4%	0.5%	0.3%	-0.1%	0.4%	0.0%	0.4%

Notes:
(1) Average rate change is compared to column (a).

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2014 IR Forecast - Rate Impact Continuity
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Line No.	Particulars		2013 Current Approved Revenue	One-Time Adjustments Settlement Agreement	Application of Price Cap Index	2014 DSM	2014 Capital Pass Throughs	Total Excluding Volume Adjustments	Volume Adjustments	Total Including Volume Adjustments
			(a)	(b)	(c)	(d)	(e)	(f) = sum (a to e)	(g)	(h) = (f + g)
	In-franchise South Delivery and Storage (Con't)									
1	M7	Revenue ($000's)	4,156	(3)	21	15	(4)	4,185		4,185
2		Volumes (10^3m^3)	147,143	147,143	147,143	147,143	147,143	147,143	-	147,143
3		Average rate (cents / m^3)	2.8243	(0.0018)	0.0143	0.0100	(0.0026)	2.8443	-	2.8443
4		Average rate change (1)		-0.1%	0.5%	0.4%	-0.1%	0.7%	0.0%	0.7%
5	M9	Revenue ($000's)	739	1	5	-	(0)	745		745
6		Volumes (10^3m^3)	60,750	60,750	60,750	60,750	60,750	60,750	-	60,750
7		Average rate (cents / m^3)	1.2165	0.0019	0.0079	-	(0.0004)	1.2259	-	1.2259
8		Average rate change (1)		0.2%	0.7%	0.0%	0.0%	0.8%	0.0%	0.8%
9	M10	Revenue ($000's)	10	(0)	0	-	(0)	9		9
10		Volumes (10^3m^3)	189	189	189	189	189	189	-	189
11		Average rate (cents / m^3)	5.2035	(0.2472)	0.0322	-	(0.0118)	5.0032	-	5.0032
12		Average rate change (1)		-4.8%	0.6%	0.0%	-0.2%	-3.9%	0.0%	-3.9%
13	T1	Revenue ($000's)	10,655	(10)	57	29	(9)	10,722		10,722
14		Volumes (10^3m^3)	548,986	548,986	548,986	548,986	548,986	548,986	-	548,986
15		Average rate (cents / m^3)	1.9408	(0.0018)	0.0105	0.0053	(0.0016)	1.9530	-	1.9530
16		Average rate change (1)		-0.1%	0.5%	0.3%	-0.1%	0.6%	0.0%	0.6%
17	T2	Revenue ($000's)	42,209	59	258	43	(31)	42,535		42,535
18		Volumes (10^3m^3)	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	4,880,298	-	4,880,298
19		Average rate (cents / m^3)	0.8649	0.0012	0.0053	0.0009	(0.0006)	0.8716	-	0.8716
20		Average rate change (1)		0.1%	0.6%	0.1%	-0.1%	0.8%	0.0%	0.8%
21	T3	Revenue ($000's)	4,400	16	29	-	(0)	4,444		4,444
22		Volumes (10^3m^3)	272,712	272,712	272,712	272,712	272,712	272,712	-	272,712
23		Average rate (cents / m^3)	1.6133	0.0060	0.0105	-	(0.0001)	1.6296	-	1.6296
24		Average rate change (1)		0.4%	0.7%	0.0%	0.0%	1.0%	0.0%	1.0%
	Northern Transportation and Storage									
25	R01	Revenue ($000's)	94,442	42	99	-	10	94,593		94,593
26		Volumes (10^3m^3)	884,421	884,421	884,421	884,421	884,421	884,421	50,219	934,640
27		Average rate (cents / m^3)	10.6784	0.0048	0.0112	-	0.0012	10.6955	(0.5747)	10.1208
28		Average rate change (1)		0.0%	0.1%	0.0%	0.0%	0.2%	-5.4%	-5.2%
29	R10	Revenue ($000's)	30,338	12	26	-	1	30,378		30,378
30		Volumes (10^3m^3)	322,887	322,887	322,887	322,887	322,887	322,887	23,054	345,941
31		Average rate (cents / m^3)	9.3957	0.0038	0.0082	-	0.0004	9.4082	(0.6270)	8.7812
32		Average rate change (1)		0.0%	0.1%	0.0%	0.0%	0.1%	-6.7%	-6.5%
33	R20	Revenue ($000's)	10,055	(2)	8	-	0	10,061		10,061
34		Volumes (10^3m^3)	121,935	121,935	121,935	121,935	121,935	121,935	-	121,935
35		Average rate (cents / m^3)	8.2463	(0.0018)	0.0062	-	0.0002	8.2510	-	8.2510
36		Average rate change (1)		0.0%	0.1%	0.0%	0.0%	0.1%	0.0%	0.1%
37	R25	Revenue ($000's)	2,010	(3)	0	-	(0)	2,007		2,007
38		Volumes (10^3m^3)	42,913	42,913	42,913	42,913	42,913	42,913	-	42,913
39		Average rate (cents / m^3)	4.6844	(0.0068)	0.0003	-	(0.0001)	4.6778	-	4.6778
40		Average rate change (1)		-0.1%	0.0%	0.0%	0.0%	-0.1%	0.0%	-0.1%
41	R100	Revenue ($000's)	166	(2)	1	-	0	165		165
42		Change (1)		-1.0%	0.4%	0.0%	0.0%	-0.6%	0.0%	-0.6%
	Ex-franchise - Cost Based									
43	M12	Revenue ($000's)	157,532	674	1,028	-	646	159,880		159,880
44		Change (1)		0.4%	0.7%	0.0%	0.4%	1.5%	0.0%	1.5%
45	M13	Revenue ($000's)	421	1	3	-	(0)	424		424
46		Change (1)		0.3%	0.7%	0.0%	-0.1%	0.8%	0.0%	0.8%
47	M16	Revenue ($000's)	771	1	5	-	(0)	777		777
48		Change (1)		0.1%	0.7%	0.0%	0.0%	0.8%	0.0%	0.8%
49	C1	Revenue ($000's)	45,034	28	49	-	4	45,115		45,115
50		Change (1)		0.1%	0.1%	0.0%	0.0%	0.2%	0.0%	0.2%

Notes:
(1) Average rate change is compared to column (a).

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UNION GAS LIMITED
Union North
Percentage Change in Average Unit Price
Effective January 1, 2014

Line No.	Particulars (cents/m^3)	Rate Classification	Current Approved Rates (1) (cents / m^3)	Rate Change	Proposed Rates (2) (cents / m^3)	Percent Change (3) (%)
			(a)	(b) = (c - a)	(c)	(d) = (b / a)
	Small Volume General Service	01				
1	Delivery		18.2778	(0.9825)	17.2953	-5.4%
2	Gas Supply Transportation		7.5030	(0.4042)	7.0988	-5.4%
3	Storage		3.1754	(0.1534)	3.0220	-4.8%
4	Total		28.9562	(1.5401)	27.4161	-5.3%
	Large Volume General Service	10				
5	Delivery		6.2251	(0.4005)	5.8246	-6.4%
6	Gas Supply Transportation		7.0872	(0.4730)	6.6142	-6.7%
7	Storage		2.3085	(0.1415)	2.1670	-6.1%
8	Total		15.6208	(1.0150)	14.6058	-6.5%
	Medium Volume Firm Service	20				
9	Delivery		2.1494	0.0042	2.1536	0.2%
10	Gas Supply Transportation		8.2463	0.0046	8.2510	0.1%
11	Total		10.3957	0.0088	10.4046	0.1%
	Large Volume High Load Factor	100				
12	Delivery		0.8168	0.0025	0.8194	0.3%
	Large Volume Interruptible	25				
13	Delivery		2.8033	0.0022	2.8055	0.1%

Notes:
(1) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 4, column (c).
(2) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 4, column (w).
(3) Excludes Gas Supply Commodity related costs.

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UNION GAS LIMITED
Union South
Percentage Change in Average Unit Price
Effective January 1, 2014

Line No.	Particulars (cents/m^3)	Rate Classification	Current Approved Rates (1) (cents / m^3) (a)	Rate Change (b) = (c - a)	Proposed Rates (2) (cents / m^3) (c)	Percent Change (3) (%) (d) = (b / a)
	General Service	M1				
1	Delivery		12.5277	0.0142	12.5420	0.1%
2	Storage		0.7368	0.0039	0.7407	0.5%
3	Total		13.2646	0.0181	13.2827	0.1%
	General Service	M2				
4	Delivery		4.4207	(0.5781)	3.8426	-13.1%
5	Storage		0.7550	(0.0983)	0.6567	-13.0%
6	Total		5.1758	(0.6764)	4.4993	-13.1%
	Firm Contract Commercial / Industrial	M4				
7	Delivery		3.0587	0.0166	3.0753	0.5%
	Firm Contract Commercial / Industrial	M5 (F)				
8	Delivery		2.9863	(0.0168)	2.9695	-0.6%
	Interruptible Contract Commercial / Industrial	M5 (I)				
9	Delivery		2.4854	0.0100	2.4954	0.4%
	Firm Special Large Volume Contract	M7 (F)				
10	Delivery		2.8743	0.0210	2.8953	0.7%
	Interruptible Special Large Volume Contract	M7 (I)				
11	Delivery		1.2943	(0.0124)	1.2819	-1.0%
	Large Wholesale Service	M9				
12	Delivery		1.2165	0.0094	1.2259	0.8%
	Small Wholesale Service	M10				
13	Delivery		5.2035	(0.2268)	4.9767	-4.4%
	Storage and Transportation	T1 (F/I)				
14	Delivery		1.9408	0.0125	1.9533	0.6%
15	Delivery excluding fuel		1.8868	0.0122	1.8990	0.6%
	Storage and Transportation	T2 (F/I)				
16	Delivery		0.8649	0.0068	0.8716	0.8%
17	Delivery excluding fuel		0.8238	0.0065	0.8303	0.8%
18	Storage and Transportation Distributor	T3	1.6133	0.0160	1.6293	1.0%

Notes:
(1) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 4, column (c).
(2) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 4, column (w).
(3) Excludes Gas Supply Commodity related costs.

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UNION GAS LIMITED
Union South
General Service Customer Bill Impacts

		Rate M1 - Residential (Annual Consumption of 2,200 m³)					Rate M2 - Commercial (Annual Consumption of 73,000 m³)				
Line No.		EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1)		EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1)		Impact ($)	EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1)		EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1)		Impact ($)
		(a)		(b)		(c) = (b) - (a)	(d)		(e)		(f) = (e) - (d)
	Delivery Charges										
1	Monthly Charge	252.00		252.00		-	840.00		840.00		-
2	Delivery Commodity Charge	79.23		79.90		0.67	2,955.03		2,569.98		(385.05)
3	Prospective Recovery - Delivery	11.01	(2)	11.01	(2)	-	576.89	(2)	576.89	(2)	-
4	Storage Services	16.23		16.28		0.05	551.18		479.39		(71.79)
5	Total Delivery Charge	358.47		359.19		0.72	4,923.10		4,466.26		(456.84)
	Supply Charges										
6	Transportation to Union	103.27		103.27		-	3,426.61		3,426.61		-
7	Commodity & Fuel	311.40		311.38		(0.02)	10,332.76		10,331.96		(0.80)
8	Prospective Recovery - Commodity & Fuel	(50.76)	(3)	(50.76)	(3)	-	(1,684.11)	(3)	(1,684.11)	(3)	-
9	Subtotal	260.64		260.62		(0.02)	8,648.65		8,647.85		(0.80)
10	Total Gas Supply Charge	363.91		363.89		(0.02)	12,075.26		12,074.46		(0.80)
11	Total Bill	722.38		723.08		0.70	16,998.36		16,540.72		(457.64)
12	Impacts for Customer Notices - Sales (line 11)					0.70					(457.64)
13	Impacts for Customer Notices - Direct Purchase (line 5)					0.72					(456.84)

Notes:
(1) Includes temporary charges/(credits).
(2) Prospective recovery charge of 0.0002 cents/m³ for 12 months.
(3) Prospective recovery credit of (0.4799) cents/m³ for 12 months.

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UNION GAS LIMITED
Union North
General Service Customer Bill Impacts

		(Fort Frances) Rate 01 - Residential (Annual Consumption of 2,200 m³)			(Western) Rate 01 - Residential (Annual Consumption of 2,200 m³)		
Line No.		EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1)	EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1)	Impact ($)	EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1)	EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1)	Impact ($)
		(a)	(b)	(c) = (b) - (a)	(d)	(e)	(f) = (e) - (d)
	Delivery Charges						
1	Monthly Charge	252.00	252.00	-	252.00	252.00	-
2	Delivery Commodity Charge	208.51	196.85	(11.66)	208.51	196.85	(11.66)
3	Total Delivery Charge	460.51	448.85	(11.66)	460.51	448.85	(11.66)
	Supply Charges						
4	Transportation to Union	108.65	102.80	(5.85)	121.88	115.31	(6.57)
5	Prospective Recovery - Transportation	4.05 (2)	4.05 (2)	-	4.05 (2)	4.05 (2)	-
6	Storage Services	47.32	45.05	(2.27)	52.60	50.06	(2.54)
7	Prospective Recovery - Storage	-	-	-	-	-	-
8	Subtotal	160.02	151.90	(8.12)	178.53	169.42	(9.11)
9	Commodity & Fuel	305.94	305.92	(0.02)	307.55	307.53	(0.02)
10	Prospective Recovery - Commodity & Fuel	(15.21) (3)	(15.21) (3)	-	(15.21) (3)	(15.21) (3)	-
11	Subtotal	290.73	290.71	(0.02)	292.34	292.32	(0.02)
12	Total Gas Supply Charge	450.75	442.61	(8.14)	470.87	461.74	(9.13)
13	Total Bill	911.26	891.46	(19.80)	931.38	910.59	(20.79)
14	Impacts for Customer Notices - Sales (line 13)			(19.80)			(20.79)
15	Impacts for Customer Notices - Direct Purchase (line 3 + line 8)			(19.78)			(20.77)

Notes:
(1) Excludes temporary charges/(credits).
(2) Prospective recovery charge of 0.1841 cents/m³ for 12 months.
(3) Prospective recovery credit of (0.6911) cents/m³ for 12 months.

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UNION GAS LIMITED
Union North
General Service Customer Bill Impacts

Line No.		(Northern) Rate 01 - Residential (Annual Consumption of 2,200 m³) EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1) (a)	(Northern) EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1) (b)	(Northern) Impact ($) (c) = (b) - (a)	(Eastern) Rate 01 - Residential (Annual Consumption of 2,200 m³) EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1) (d)	(Eastern) EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1) (e)	(Eastern) Impact ($) (f) = (e) - (d)
	Delivery Charges						
1	Monthly Charge	252.00	252.00	-	252.00	252.00	-
2	Delivery Commodity Charge	208.45	196.77	(11.68)	208.14	196.53	(11.61)
3	Total Delivery Charge	460.45	448.77	(11.68)	460.14	448.53	(11.61)
	Supply Charges						
4	Transportation to Union	167.80	158.79	(9.01)	187.35	177.24	(10.11)
5	Prospective Recovery - Transportation	4.05 (2)	4.05 (3)	-	4.05 (2)	4.05 (3)	-
6	Storage Services	70.97	67.52	(3.45)	78.75	74.96	(3.79)
7	Prospective Recovery - Storage	-	-	-	-	-	-
8	Subtotal	242.82	230.36	(12.46)	270.15	256.25	(13.90)
9	Commodity & Fuel	309.59	309.57	(0.02)	311.40	311.37	(0.02)
10	Prospective Recovery - Commodity & Fuel	(15.22) (3)	(15.22) (3)	-	(15.21) (3)	(15.21) (3)	-
11	Subtotal	294.37	294.35	(0.02)	296.19	296.16	(0.02)
12	Total Gas Supply Charge	537.19	524.71	(12.48)	566.34	552.41	(13.92)
13	Total Bill	997.64	973.48	(24.16)	1,026.48	1,000.94	(25.53)
14	Impacts for Customer Notices - Sales (line 13)			(24.16)			(25.53)
15	Impacts for Customer Notices - Direct Purchase (line 3 + line 8)			(24.14)			(25.51)

Notes:
(1) Excludes temporary charges/(credits).
(2) Prospective recovery charge of 0.1841 cents/m³ for 12 months.
(3) Prospective recovery credit of (0.6911) cents/m³ for 12 months.

UNION GAS LIMITED
Union North
General Service Customer Bill Impacts

Line No.		(Fort Frances) Rate 10 - Commercial / Industrial (Annual Consumption of 93,000 m³) EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1) (a)	EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1) (b)	Impact ($) (c) = (b) - (a)	(Western) Rate 10 - Commercial / Industrial (Annual Consumption of 93,000 m³) EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1) (d)	EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1) (e)	Impact ($) (f) = (e) - (d)
	Delivery Charges						
1	Monthly Charge	840.00	840.00	-	840.00	840.00	-
2	Delivery Commodity Charge	5,962.03	5,576.19	(385.84)	5,962.03	5,576.19	(385.84)
3	Total Delivery Charge	6,802.03	6,416.19	(385.84)	6,802.03	6,416.19	(385.84)
	Supply Charges						
4	Transportation to Union	4,014.77	3,746.84	(267.93)	4,574.11	4,268.85	(305.26)
5	Prospective Recovery - Transportation	171.02 (2)	171.02 (3)	-	171.02 (2)	171.02 (3)	-
6	Storage Services	1,117.39	1,048.89	(68.50)	1,340.88	1,258.67	(82.21)
7	Prospective Recovery - Storage	-	-	-	-	-	-
8	Subtotal	5,303.18	4,966.75	(336.43)	6,086.01	5,698.54	(387.47)
9	Commodity & Fuel	12,933.00	12,931.99	(1.01)	13,000.99	12,999.98	(1.01)
10	Prospective Recovery - Commodity & Fuel	(642.72) (4)	(642.72) (5)	-	(642.72) (4)	(642.72) (5)	-
11	Subtotal	12,290.28	12,289.27	(1.01)	12,358.27	12,357.26	(1.01)
12	Total Gas Supply Charge	17,593.46	17,256.02	(337.44)	18,444.28	18,055.80	(388.48)
13	Total Bill	24,395.49	23,672.21	(723.28)	25,246.31	24,471.99	(774.32)
14	Impacts for Customer Notices - Sales (line 13)			(723.28)			(774.32)
15	Impacts for Customer Notices - Direct Purchase (line 3 + line 8)			(722.27)			(773.31)

Notes:
(1) Excludes temporary charges/(credits).
(2) Prospective recovery charge of 0.1839 cents/m³ for 12 months.
(3) Prospective recovery credit of (0.6911) cents/m³ for 12 months.

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UNION GAS LIMITED
Union North
General Service Customer Bill Impacts

Line No.		(Northern) Rate 10 - Commercial / Industrial (Annual Consumption of 93,000 m³) EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1) (a)	EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1) (b)	Impact ($) (c) = (b) - (a)	(Eastern) Rate 10 - Commercial / Industrial (Annual Consumption of 93,000 m³) EB-2013-0215 Approved 01-Jul-13 Total Bill ($) (1) (d)	EB-2013-0202 Proposed 01-Jan-14 Total Bill ($) (1) (e)	Impact ($) (f) = (e) - (d)
	Delivery Charges						
1	Monthly Charge	840.00	840.00	-	840.00	840.00	-
2	Delivery Commodity Charge	5,956.46	5,571.04	(385.42)	5,970.80	5,584.31	(386.49)
3	Total Delivery Charge	6,796.46	6,411.04	(385.42)	6,810.80	6,424.31	(386.49)
	Supply Charges						
4	Transportation to Union	6,515.40	6,080.53	(434.87)	7,340.99	6,851.05	(489.94)
5	Prospective Recovery - Transportation	171.04 (2)	171.04 (3)	-	171.03 (2)	171.03 (3)	-
6	Storage Services	2,116.67	1,986.93	(129.74)	2,446.53	2,296.56	(149.97)
7	Prospective Recovery - Storage	-	-	-	-	-	-
8	Subtotal	8,803.11	8,238.50	(564.61)	9,958.55	9,318.64	(639.91)
9	Commodity & Fuel	13,087.39	13,086.38	(1.01)	13,163.65	13,162.64	(1.01)
10	Prospective Recovery - Commodity & Fuel	(642.72) (4)	(642.72) (5)	-	(642.73) (4)	(642.73) (5)	-
11	Subtotal	12,444.67	12,443.66	(1.01)	12,520.92	12,519.91	(1.01)
12	Total Gas Supply Charge	21,247.78	20,682.16	(565.62)	22,479.47	21,838.55	(640.92)
13	Total Bill	28,044.24	27,093.20	(951.04)	29,290.27	28,262.86	(1,027.41)
14	Impacts for Customer Notices - Sales (line 13)			(951.04)			(1,027.41)
15	Impacts for Customer Notices - Direct Purchase (line 3 + line 8)			(950.03)			(1,026.40)

Notes:
(1) Excludes temporary charges/(credits).
(2) Prospective recovery charge of 0.1839 cents/m³ for 12 months.
(3) Prospective recovery credit of (0.6911) cents/m³ for 12 months.

UNION GAS LIMITED
Summary of Approved 2013 Revenue Changes

Line No.	Particulars ($000's)	Approved 2013 Revenue per EB-2011-0210 (1)	Revenue change per EB-2011-0210 (2)	Revenue change per EB-2013-0033 (3)	Revenue change per EB-2013-0215 (4)	2013 Revenue per EB-2013-0202 (5)
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)
	In-Franchise North Delivery					
1	R01	160,467	782	(91)	495	161,653
2	R10	19,743	235	(28)	149	20,100
3	R20	13,417	79	(9)	50	13,537
4	R25	4,473	-	-	-	4,473
5	R100	15,478	2	(0)	2	15,482
6	Total In-Franchise North Delivery	213,579	1,099	(129)	696	215,245
	In-franchise South Delivery and Storage					
7	M1	387,717	1,451	(170)	920	389,918
8	M2	49,752	488	(57)	310	50,493
9	M4	12,149	151	(18)	95	12,378
10	M5	13,096	192	(22)	122	13,387
11	M7	4,071	56	(7)	35	4,156
12	M9	702	24	(3)	15	739
13	M10	10	0	(0)	0	10
14	T1	10,614	28	(5)	18	10,655
15	T2	42,082	87	(14)	54	42,209
16	T3	4,400	-	-	-	4,400
17	Total In-Franchise South Delivery and Storage	524,592	2,477	(295)	1,570	528,343
18	Total In-franchise Delivery	738,171	3,576	(424)	2,266	743,588

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 13, column (f).
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 24. Update to January 2013 QRAM WACOG (EB-2012-0437).
(3) EB-2013-0033, Tab 2, Schedule 4.
(4) EB-2013-0215, Tab 2, Schedule 4.
(5) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 3, column (a).

UNION GAS LIMITED
Summary of Approved 2013 Revenue Changes

Line No.	Particulars ($000's)	Approved 2013 Revenue per EB-2011-0210 (1)	Revenue change per EB-2011-0210 (2)	Revenue change per EB-2013-0033 (3)	Revenue change per EB-2013-0215 (4)	2013 Revenue per EB-2013-0202 (5)
		(a)	(b)	(c)	(d)	(e) = (a+b+c+d)
	Northern Transportation and Storage					
1	R01	94,442	-	-	-	94,442
2	R10	30,338	-	-	-	30,338
3	R20	10,055	-	-	-	10,055
4	R25	2,010	-	-	-	2,010
5	R100	166	-	-	-	166
6	Total Northern Transportation and Storage	137,011	-	-	-	137,011
7	Gas Supply Admin Charge	6,830	-	-	-	6,830
8	Total In-franchise	882,011	3,576	(424)	2,266	887,429
	Ex-franchise - Cost Based					
9	M12	157,532	-	-	-	157,532
10	M13	411	7	(1)	4	421
11	M16	736	23	(4)	14	771
12	C1	45,015	13	(2)	8	45,034
13	Total Ex-franchise	203,695	43	(7)	27	203,758
14	Total Union Gas	1,085,705	3,618	(431)	2,293	1,091,186

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 13, column (f).
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 24. Update to January 2013 QRAM WACOG (EB-2012-0437).
(3) EB-2013-0033, Tab 2, Schedule 4.
(4) EB-2013-0215, Tab 2, Schedule 4.
(5) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 3, column (a).

UNION GAS LIMITED
Allocation of 2014 One-time Adjustments

Line No.	Particulars ($000's)	Deferred Tax Drawdown: 2013 Approved Allocation (1)	Deferred Tax Drawdown: Adjustment (2)	Administrative & General O&M Expense: 2013 Approved Allocation (3)	Administrative & General O&M Expense: Adjustment (4)	Total Adjustment
		(a)	(b)	(c)	(d)	(e) = (b + d)
	Union North In-Franchise					
1	R01	(478)	99	18,086	(904)	(804)
2	R10	(125)	26	1,524	(74)	(48)
3	R20	(33)	7	1,206	(56)	(49)
4	R100	(2)	0	1,092	(53)	(52)
5	R25	-	-	480	(22)	(22)
6	Total Union North In-Franchise	(639)	133	22,387	(1,108)	(976)
	Union South In-Franchise					
7	Rate M1	(5,973)	1,242	46,272	(2,311)	(1,069)
8	Rate M2	(995)	207	4,279	(210)	(3)
9	Rate M4	(268)	56	1,482	(72)	(16)
10	Rate M5	(151)	31	1,627	(79)	(47)
11	Rate M7	(96)	20	450	(23)	(3)
12	Rate M9	(20)	4	59	(3)	1
13	Rate M10	(1)	0	13	(1)	(0)
14	Rate T1	(215)	45	1,118	(55)	(11)
15	Rate T2	(1,067)	222	3,239	(163)	59
16	Rate T3	(167)	35	364	(18)	16
17	Total Union South In-Franchise	(8,952)	1,861	58,904	(2,934)	(1,073)
	Ex-Franchise					
18	Excess Utility Space	(172)	36	363	(18)	17
19	Rate C1	(32)	7	182	(9)	(3)
20	Rate M12	(5,365)	1,115	8,447	(429)	686
21	Rate M13	(3)	1	0	(0)	1
22	Rate M16	(6)	1	12	(1)	1
23	Total Ex-franchise	(5,578)	1,160	9,004	(457)	703
24	Grand Total (line 6 + 17 + 23)	(15,169)	3,154	90,295	(4,500)	(1,346)

Notes:

(1) EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, Updated for the EB-2011-0210 Board Decision (2013 Board-approved allocation of the Deferred Tax Drawdown).
(2) Allocated using column (a).
(3) EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, Updated for the EB-2011-0210 Board Decision (2013 Board-approved allocation of Administrative O&M expenses).
(4) Allocated using column (c).

UNION GAS LIMITED
Summary of 2014 Capital Pass Through Adjustments

Line No.	Particulars ($000's)	2014 Capital Pass Through Adjustments
		(a)
	Union North In-Franchise	
1	Rate 01	(224)
2	Rate 10	(29)
3	Rate 20	(23)
4	Rate 25	(7)
5	Rate 100	(19)
6	Total Union North In-Franchise	(302)
	Union South In-Franchise	
7	Rate M1	(492)
8	Rate M2	(58)
9	Rate M4	(13)
10	Rate M5A	(17)
11	Rate M7	(4)
12	Rate M9	(0)
13	Rate M10	(0)
14	Rate T1	(9)
15	Rate T2	(31)
16	Rate T3	(0)
17	Total Union South In-Franchise	(624)
	Ex-Franchise	
18	Excess Utility Space	(9)
19	Rate M12	660
20	Rate M13	(0)
21	Rate M16	0
22	Rate C1	(1)
23	Total Ex-Franchise	650
24	Grand Total (line 6 + 17 + 23)	(277)

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EB-2013-0202
Settlement Agreement
Working Papers
Schedule 11

UNION GAS LIMITED
Calculation of 2014 DSM Budget
Allocation by Rate Class

Line No.	Particulars ($000's)	2013 Approved DSM Budget (1)	2014 DSM Program Budget	Low Income Program Budget	Inflation Factor (2)	Inflation Factor	DSM Budget (3)
		(a)	(b)	(c)	(d)	(e) = (b+c) x (d)	(f) = (b+c+e)
	Union North						
1	Rate 01	3,732	1,998	1,734	1.63%	61	3,792
2	Rate 10	1,186	890	296	1.63%	19	1,206
3	Rate 20	974	883	92	1.63%	16	990
4	Rate 100	1,798	1,607	191	1.63%	29	1,827
5	Total Union North	7,690	5,378	2,312		125	7,816
	Union South						
6	Rate M1	10,451	6,228	4,223	1.63%	170	10,621
7	Rate M2	3,896	3,321	575	1.63%	63	3,959
8	Rate M4	1,607	1,464	143	1.63%	26	1,633
9	Rate M5A	2,683	2,582	101	1.63%	44	2,726
10	Rate M7	906	836	69	1.63%	15	920
11	Rate T1	1,801	1,697	104	1.63%	29	1,830
12	Rate T2	2,609	2,053	555	1.63%	43	2,651
13	Total Union South	23,951	18,181	5,770		390	24,341
14	Total Union (line 5 + line 13)	31,641	23,559	8,082		516	32,157

Notes:
(1) Per EB-2011-0210 Board approved Cost Study.
(2) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 1, line 6, column (c).
(3) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 3, column (k).

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EB-2013-0202

UNION GAS LIMITED
Calculation of 2014 NAC Target Percentage Change
to General Service Rate Classes

Line No.	Particulars (m^3)	2012 Actual NAC (1)	2013 Forecast NAC (1)	NAC Variance	2014 NAC Target % Change
		(a)	(b)	(c) = (a - b)	(d) = (c / b)
1	Rate 01	2,922	2,765	157	5.7%
2	Rate 10	168,618	157,381	11,237	7.1%
3	Rate M1	2,782	2,778	4	0.1%
4	Rate M2	166,510	143,867	22,643	15.7%

Notes:
(1) NAC based on 2013 Board-approved 50/50 weather methodology.

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EB-2013-0202

UNION GAS LIMITED
Calculation of 2014 NAC Target Percentage Change
Volumetric Adjustments to Union North General Service Rate Classes

Line No.	Particulars (10^3m^3)	2013 Billing Units (1)	2014 NAC Target % Change (2)	Change in Billing Units	2014 Billing Units
		(a)	(b)	(c) = (a x b)	(d) = (a + c)
	Rate 01 Delivery				
1	First 100 m^3	260,791	5.7%	14,808	275,599
2	Next 200 m^3	296,122	5.7%	16,814	312,936
3	Next 200 m^3	129,180	5.7%	7,335	136,515
4	Next 500 m^3	88,231	5.7%	5,010	93,241
5	All Over 100 m^3	110,097	5.7%	6,251	116,349
6	Total Rate 01 Delivery	884,421		50,219	934,640
	Rate 01 Transportation & Storage				
7	Fort Frances Zone	12,297	5.7%	698	12,995
8	Western Zone	171,280	5.7%	9,725	181,005
9	Northern Zone	384,941	5.7%	21,857	406,799
10	Eastern Zone	315,903	5.7%	17,937	333,841
11	Total Rate 01 Transportation & Storage	884,421		50,219	934,640
	Rate 10 Delivery				
12	First 1,000 m^3	23,682	7.1%	1,691	25,373
13	Next 9,000 m^3	127,854	7.1%	9,129	136,983
14	Next 20,000 m^3	81,326	7.1%	5,807	87,132
15	Next 70,000 m^3	61,664	7.1%	4,403	66,066
16	All Over 100,000 m^3	28,362	7.1%	2,025	30,387
17	Total Rate 10	322,887		23,054	345,941
	Rate 10 Transportation & Storage				
18	Fort Frances Zone	2,654	7.1%	190	2,844
19	Western Zone	45,232	7.1%	3,230	48,462
20	Northern Zone	130,990	7.1%	9,353	140,342
21	Eastern Zone	144,011	7.1%	10,282	154,293
22	Total Rate 10 Transportation & Storage	322,887		23,054	345,941

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (a).
(2) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 12, Page 1, column (d).

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EB-2013-0202

UNION GAS LIMITED
Calculation of 2014 NAC Target Percentage Change
Volumetric Adjustments to Union South General Service Rate Classes

Line No.	Particulars (10^3m^3)	2013 Billing Units (1)	2014 NAC Target % Change (2)	Change in Billing Units	2014 Billing Units
		(a)	(b)	(c) = (a x b)	(d) = (a + c)
	Rate M1 Delivery				
1	First 100 m^3	885,353	0.1%	1,275	886,627
2	Next 150 m^3	786,168	0.1%	1,132	787,300
3	All Over 250 m^3	1,268,023	0.1%	1,826	1,269,848
4	Total Rate M1 Delivery	2,939,543		4,233	2,943,776
5	Rate M1 Storage	2,939,543	0.1%	4,233	2,943,776
	Rate M2 Delivery				
6	First 1,000 m^3	53,047	15.7%	8,349	61,396
7	Next 6,000 m^3	258,156	15.7%	40,631	298,787
8	Next 13,000 m^3	291,703	15.7%	45,911	337,614
9	All Over 20,000 m^3	372,665	15.7%	58,653	431,318
10	Total Rate M2 Delivery	975,571		153,544	1,129,115
11	Rate M2 Storage	975,571	15.7%	153,544	1,129,115

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (a).
(2) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 12, Page 1, column (d).

UNION GAS LIMITED
Summary of S&T Transactional Margin Included In 2014 In-Franchise Rates

Line No.	Particulars ($ 000's)	Total Revenue (1)	Allocated Cost (2)	Total Margin	Shareholder Portion of Margin	Margin Included in 2013 In-Franchise Rates	Margin Included in 2014 In-Franchise Rates	Variance
		(a)	(b)	(c) = (a - b)	(d) = (c) * 10%	(e) = (c - d)	(f)	(g) = (f - e)
	Long-Term Transportation							
1	M12 Long-term Transportation	120,604	125,384	(4,781)				
2	M12-X	13,896	11,623	2,272				
3	F24-T	359	359	0				
4	M12 Fuel	22,674	22,673	1				
5	C1 Long-term Transportation	6,954	1,669	5,286				
6	C1 Fuel	626	632	(6)				
7	M13	411	211	200				
8	M16	736	451	286				
9	Heritage Pool M16 Transmission Charge (3)			56				
10	Total Long-Term Transportation	166,260	163,002	3,314	-	3,314	3,314	-
	Short-Term Transportation							
11	Short-term Transportation	11,067	5,843	5,224				
12	Other Transactional	1,067	-	1,067				
13	Total Short-Term Transportation	12,134	5,843	6,291	-	6,291	6,291	-
	Short-term Storage and Other Balancing Services Acct. 179-70							
14	Short Term Peak Storage Services	7,883	5,626	2,257				
15	Less: Non-utility System Integrity Costs (4)	-	(300)	300				
16	Off Peak Storage/Balancing/Loans Services	2,500	-	2,500				
17	Total Short-term Storage and Other Balancing Services	10,383	5,327	5,056	506	4,551	4,551	-
18	Total S&T Transactional Margin Included in Rates	188,777	174,171	14,661	506	14,156	14,156	-

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, Page 9 - 11, column (g).
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 14, Page 9 - 11, column (e).
(3) EB-2011-0210, Rate Order, Working Papers, Schedule 39, line 4.
(4) Excludes the non-utility portion of system integrity costs of $0.300 million as per Board Decision.

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EB-2013-0202

UNION GAS LIMITED
Summary of Gas Supply Optimization Margin Included In 2014 Gas Supply Transportation Rates

Line No.	Particulars ($ 000's)	Total Revenue (1)	Allocated Cost	Total Margin	Shareholder Portion of Margin	Margin Included in 2013 Gas Supply Transportation Rates	Margin Included in 2014 Gas Supply Transportation Rates	Variance
		(a)	(b)	(c) = (a - b)	(d) = (c) * 10%	(e) = (c - d)	(f)	(g) = (f - e)
	Exchanges (2)							
1	Base Exchanges	9,118	-	9,118	912	8,206	8,206	-
2	FT-RAM Related Exchanges	5,800	-	5,800	580	5,220	5,220	-
3	Total Exchanges Revenue	14,918	-	14,918	1,492	13,426	13,426	-

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, Page 11, Line 18, column (g).
(2) EB-2011-0210, Board Decision, page 40.

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EB-2013-0202

UNION GAS LIMITED
Total Upstream Transportation Costs in Union North Rates
Effective July 1, 2013

Line No.	Particulars ($000's)	Upstream Transportation Costs (1)	Gas Supply Optimization Credit Included in Rates (2)	Upstream Transportation Costs per EB-2013-0202 (3)
		(a)	(b)	(c) = (a+b)
1	Rate 01	85,031	(3,920)	81,111
2	Rate 10	28,119	(1,342)	26,778
3	Rate 20	9,495	(477)	9,018
4	Rate 25	2,105	(117)	1,988
5	Rate 100	73	-	73
6	Total Union North	124,823	(5,856)	118,967

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 46, column (b).
Excludes FT Transportation fuel of $1.463 million and Black Creek Storage of $0.042 million.
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 44, Page 1, column (e), lines 1-6.
(3) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 3, column (e).

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EB-2013-0202

UNION GAS LIMITED
Calculation of 2014 Gas Supply Admin Charge

				2014 Adjustments		
Line No.	Particulars	EB-2011-0210 2013 Board Approved		One-Time Adjustments Settlement Agreement (3)	2014 Capital Pass Throughs (4)	EB-2013-0202 2014 Proposed
		(a)		(b)	(c)	(d) = (a+b+c)
1	Costs ($000's)	6,830	(1)	(38)	(1)	6,791
2	2013 Approved Sales Volumes (10^3m^3)	3,533,863	(2)			3,533,863
3	Gas Supply Admin Unit Rate (cents/m^3)	0.1933				0.1922

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (g).
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 14, column (a).
(3) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 3, Page 2, line 25, column (f).
(4) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 3, Page 2, line 25, column (l).

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EB-2013-0202

UNION GAS LIMITED
Southern Operations Area
Unbundled Delivery Rate Detail
Effective January 1, 2014

Line No.	Particulars	Billing Units	2014 Forecast Usage (1)	SSS & SPS ($000's)		Gas Supply Balancing Costs ($000's)	Gas in Storage Inventory Carrying Costs ($000's)		Unbundled Storage Revenue ($000's)	Unbundled Storage Rates (cents/m^3)	Unbundled Delivery Rates (6) (cents/m^3)
		(a)	(b)	(c)		(d)	(e)		(f) = (c+d+e)	(g) = (f / b) *100	(h)
	Rate M1										
	Monthly delivery commodity charge:										
1	First 100 m^3	10^3m^3	886,627	4,371		-	2,196		6,567	0.7407	3.8486
2	Next 150 m^3	10^3m^3	787,300	3,882		-	1,950		5,832	0.7407	3.6207
3	All over 250 m^3	10^3m^3	1,269,848	6,261		-	3,145		9,406	0.7407	3.1292
4	Total		2,943,776	14,513	(2)	-	7,291	(3)	21,805		
	Rate M2										
	Monthly delivery commodity charge:										
5	First 1,000 m^3	10^3m^3	61,396	268		-	135		403	0.6567	3.6238
6	Next 6,000 m^3	10^3m^3	298,787	1,303		-	659		1,962	0.6567	3.5574
7	Next 13,000 m^3	10^3m^3	337,614	1,473		-	745		2,217	0.6567	3.3626
8	All over 20,000 m^3	10^3m^3	431,318	1,881		-	951		2,833	0.6567	3.1251
9	Total		1,129,115	4,925	(4)	-	2,490	(5)	7,415		

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 14, Page 5, column (a).
(2) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 17, Page 2, line 6, column (a).
(3) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 17, Page 2, line 10, column (a).
(4) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 17, Page 2, line 6, column (b).
(5) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 18, Page 2, line 10, column (b).
(6) EB-2013-0202, Settlement Agreement, Working Papers, Schedule 4, Page 10, column (w).

UNION GAS LIMITED
Southern Operations Area
Unbundled Delivery Cost Detail
Effective January 1, 2014

Line No.	Particulars ($000's)	Rate M1 (a)	Rate M2 (b)
	SSS/ SPS		
1	Storage Dehydrator (1)	177	60
2	Storage Ex. Dehydrator (2)	9,767	3,305
3	Storage Space (3)	11,861	4,051
4	Storage	21,805	7,415
5	Less: ICC on Gas in Storage (4)	7,291	2,490
6	Total SSS/SPS	14,513	4,925
	Gas Supply Balancing		
7	Total Gas Supply Balancing	-	-
	Gas In Storage Inventory Carrying Costs		
8	Gas in Storage (5)	89,246	30,481
9	ICC %	8.2%	8.2%
10	Gas in Storage Inventory Carrying Costs	7,291	2,490

Notes:
(1) EB-2011-0210, Rate Order, Working Papers, Schedule 18, Page 2, line 1, updated for 2014 One-time Adjustments, PCI and Capital Pass Throughs per EB-2013-0202.
(2) EB-2011-0210, Rate Order, Working Papers, Schedule 18, Page 2, line 2, updated for 2014 One-time Adjustments, PCI and Capital Pass Throughs per EB-2013-0202.
(3) EB-2011-0210, Rate Order, Working Papers, Schedule 18, Page 2, line 3, updated for 2014 One-time Adjustments, PCI and Capital Pass Throughs per EB-2013-0202.
(4) Per line 10.
(5) EB-2011-0210, Exhibit G3, Tab 5, Schedule 9, page 16 of 40, updated for EB-2011-0210 Board Decision.