KT1.2

Documents from EB-2011-0210

Evidence

Exhibit A2 Tab 1 Schedule 1 pages 14, 15 c) TCPL Mainline Toll Application

Exhibit C1 Tab 3 Pages 9 -13 2/ Short-Term Transportation and Exchange Revenue Forecast

Transcripts

Volume 6 and 7 - Evidence of Panel 4 Ex- franchise revenue panel

- as it relates to treatment of upstream transportation optimization revenues for 2011, in the context of Union's existing IRM framework.

IR's

JC 4-3-1
JC 4-7-9
JC 4-7-10
JC 4-10-6
JC 4-10-8
JD 1-16-2
JD 1-16-4
JD 1-16-5
JD 14-16-14

Tech conference undertakings

JT 1.6
JT 2.13

Undertakings

J3.2	J6.5
J3.3	J7.1
J3.5	J7.3
J3.6	J7.6
J4.1	J7.8
J4.2	J7.9
J6.1	J7.10
J6.2	

Exhibits

K6.4 Union Direct Examination Compendium – Ex Franchise panel
K6.5 CME Compendium Ex-Franchise Revenue Witness panel
K7.1 updated table from EB-2012-0087 IR B7.7
K7.4 IR response from EB-2009-0101

UNION GAS LIMITED

INDEX

TAB 1

1. 2005 YEAR-END DEFERRAL ACCOUNT BALANCES

At the end of December 2005, the balances accumulated in Union's Board approved deferral accounts total a credit of $10.979 million. This amount is comprised of $16.943 million in credits in gas supply related deferral accounts (the majority of which is managed through the QRAM), $10.152 million in credits in Storage & Transportation related deferral accounts, and $16.116 million in debits in the other deferral accounts. Individual account balances are shown at Tab ~~2~~ 1, Schedule 1. Each account balance includes interest up to December 31, 2005. Interest is computed monthly on the opening balance of each account. The applicable interest rate used is the short-term debt rate of 4.15% approved by the Board in the RP-2003-0063 proceeding.

Deferral account balances have been categorized into three types: Gas Supply deferral accounts, S&T deferral accounts and Other deferral accounts. The balances for each account are discussed below.

GAS SUPPLY DEFERRAL ACCOUNTS

The balances recorded in the following gas supply related deferral accounts were examined in each of Union's four Quarterly Rate Adjustment Mechanism ("QRAM") applications in 2005.

179-105 North Purchased Gas Variance Account ("PGVA")

179-100 TCPL Tolls and fuel – Northern and Eastern Operations area

179-106 South PGVA

179-109 Inventory Revaluation

179-107 Spot Gas Variance Account

Union's Board-approved QRAM process establishes reference prices for selected gas supply-related deferral accounts and the prospective recovery, or refund, of the projected balances of these accounts including interest, over the following 12 month period. Variances between the forecast and actual prospective recovery amounts are tracked and included in the amounts prospectively recovered in future QRAM proceedings.

Under the QRAM process, the actual year-end deferral account balances are subject to the Board's final approval. This application seeks that approval. The Board approved all four of Union's QRAM applications in 2005.

The balances for the two other gas supply related deferral accounts were not prospectively recovered as part of the approved QRAM process. These accounts are as follows:

Account No. 179-108 Unabsorbed Demand Costs

Account No. 179-89 Heating Value

Account No. 179-108 Unabsorbed Demand Costs

The credit balance of $1.888 million in the Unabsorbed Demand Costs ("UDC") account is the difference between the actual unabsorbed demand costs incurred by Union and the amount of unabsorbed demand costs included in rates as approved by the Board. All credits are attributable to 2005 forecast UDC costs not incurred to serve customers in the Northern & Eastern Operations area.

Account No.179-89 Heating Value

The credit balance of $2.709 million in the Heating Value deferral account is the difference between the actual heat content of the gas purchased and the forecast energy content included in gas sales rates. The credit balance is the result of gas delivered to customers having a lower average energy content than what was reflected in delivery rates.

Storage and Transportation Deferral Accounts

Actual net revenues from storage and transportation services are deferred against the net revenues included in the rates approved by the Board in the RP-2003-0063 Rate Order. Balances in S&T deferral accounts are currently shared on a 75/25 basis between ratepayers and the shareholder. The current credit balance of $10.152 million represents the ratepayer portion in the following S&T deferral accounts.

Account No. 179-69 Transportation and Exchange Services

The balance in the Transportation and Exchange Services deferral account is the difference between actual net revenues for Transportation and Exchange Services including C1 Interruptible Transportation, Energy Exchanges, M12 Transportation Overrun, M12 and C1 Non-Loss-of-Critical-Unit Protected Firm Transportation, M12 Limited Firm/Interruptible Transportation and C1 Firm Short Term Transportation, and the net revenues forecast for these services as approved by the Board for ratemaking purposes.

The credit balance of $3.404 million is 75% of the variance between the Board approved forecast of $0.688 million and actual net revenues of $5.227 million. The total variance of $4.539 million is primarily attributable to M12 Overrun and C1 short-term interruptible service transportation.

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

The balance in the Short-Term Storage and Other Balancing Services deferral account is the difference between actual net revenues for Short-term Storage and Other Balancing Services (including C1 Off-Peak Storage, Gas Loans, Consumers' LBA, Supplemental Balancing Services, C1 Firm Peak Storage, C1 Firm Short-term Deliverability and M12 Interruptible Deliverability) and the net revenue forecast for these services as approved by the Board for ratemaking purposes.

The credit balance of $6.708 million is 75% of the variance between the Board approved forecast of $6.793 million and actual net revenues of $15.736 million. The total variance of $8.943 million is primarily the result of increased sales of C1 peak and off peak storage services.

Account No. 179-72 Long-Term Peak Storage Services

The balance in the Long- Term Peak Storage Service deferral account is the difference between actual net revenues for Long-Term Peak Storage Services including C1 Firm Peak Storage and the net revenues forecast for these services as approved by the Board for ratemaking purposes.

The debit balance of $1.135 million is 75% of the variance between the Board approved forecast of $17.965 million and actual net revenues of $16.451 million. The total variance of $1.514 million is attributable to lower sales of C1 long term peak storage than forecast.

Account No. 179-73 Other S&T Services

The balance in the Other S&T Services deferral account is the difference between actual net revenues for Other S&T Services including Off-system Capacity, Redirection/Name Changes, Ontario Production and Other S&T services and the net revenues forecast for these services as approved by the Board for ratemaking purposes.

The credit balance of $0.427 million is 75% of the variance between the Board approved forecast of $0.460 million and actual net revenues of $1.028 million.

Account No. 179-74 Other Direct Purchase Services

The credit balance of $0.749 million in the Other Direct Purchase Services deferral account is 75% of the actual net revenues earned for Supplemental Load Balancing (T1 and R1) and T1 Storage Inventory Demand Charges. There were no revenues forecast in 2005.

OTHER DEFERRAL ACCOUNTS

The other deferral account balances are discussed below.

Account No. 179-26 Deferred Customer Rebates/Charges

The Deferred Customer Rebates/Charges account has no balance. This account captures unclaimed cheques related to amounts refunded to customers that arose from the disposition of deferral balances as approved by the Board. Disposition of deferral accounts as approved by the Board in the EB 2005-0211 Rate Order were dealt with prospectively in rates from July 1 to December 31, 2005. As a result, no cheques were issued and none returned.

TAB 2

TransCanada

NewsRelease

TransCanada and Stakeholders Reach a Settlement for 2001 and 2002 Canadian Mainline System Services and Pricing

CALGARY, Alberta – February 22, 2001 – (TSE: TRP) (NYSE: TRP) – TransCanada PipeLines Limited today announced it has reached a settlement regarding 2001 and 2002 services and pricing on its Canadian Mainline natural gas transmission system that resolves all issues other than cost of capital. The parties agreed that the issue of cost of capital would be determined in a different forum. The settlement is the result of broad industry negotiations and represents a balance of interests among most of the negotiating parties.

"We are pleased to have reached this settlement, which will assist in meeting the needs of TransCanada's customers and shareholders," said Doug Baldwin, TransCanada's President and Chief Executive Officer. "The settlement provides the foundation for further discussions to ensure the Canadian Mainline System continues to compete effectively for market demand and natural gas supplies. It's also another example of what can be accomplished by working collaboratively with industry stakeholders."

Highlights of the Settlement

Revenue Requirement:
The settlement establishes the Canadian Mainline System's fixed operating, maintenance and administration; post employment benefits; and regulatory commission (OM&A) costs for the next two years. All other elements of the 2001 and 2002 revenue requirements will be treated on a flow through basis. OM&A variances between actual costs and those agreed to in the settlement will accrue to TransCanada's account.

OM&A costs for 2001, commencing January 1, 2001, are fixed at $223 million. Commencing January1, 2002, the OM&A costs for 2002 are fixed at $216.5 million. These amounts are subject to adjustments from the final 2000 Merger and Cost Benefit Agreement account.

Depreciation is based on a composite rate of 2.75 per cent in 2001, compared to 2.65 per cent in 2000. In 2002, the composite depreciation rate will increase to 2.90 per cent.

Contract Demand:
Contract demand will be estimated each year. Variance between forecast and actual contract demand will be deferred and recovered in the following test year.

Incentives:
The settlement includes various incentive programs to assist in balancing the cost incentive provided by the fixed OM&A agreement. Specific incentive programs include:

Fuel Gas and Power Incentive - to minimize total delivered costs. Details of this incentive are to be determined by April 30, 2001.

Foreign Exchange Program - to reduce foreign exchange costs on Interest and Transportation by Others in foreign currencies. Savings, to a benchmark, are shared equally between TransCanada and its shippers. This program will terminate December 31, 2002.

Interest Rate Management Program - to reduce interest costs by managing fix/floating rates. Savings are shared equally between TransCanada and shippers. This program will terminate December 31, 2002.

Revenue /Asset Management Mechanism:
Revenue/Asset Management Mechanism - a commission to TransCanada of varying percentages to provide an incentive to reduce asset costs and generate incremental revenue. Revenue to TransCanada from this mechanism is capped at $5 million.

Services:
Firm Service (FT) - will be provided with Make-up and Authorized Overrun Service (AOS) rights as described below:

FT Make-up - the Demand Charge associated with each FT shipper's unutilized FT Demand rights in each month will be credited towards that FT shipper's Interruptible Service (IT) invoice at the end of each month. This service will terminate December 31, 2002.

AOS - four per cent of each FT shipper's monthly contract demand charges will be credited to that shipper's IT invoice each month. This service will terminate December 31, 2002.

Short Term Firm Service (STFT) – there is no change to the existing STFT offering. STFT will remain as a biddable service with a floor price of 100 per cent of the FT toll.

IT – will remain as a biddable service. The price is based on a proxy for marginal fuel, plus commodity toll, plus a contribution to fixed costs. The floor price for IT can vary between 80 per cent of the FT toll and 120 per cent of the FT toll.

Future Business Model:
The parties acknowledged that a competitive pipeline system is in the interest of all stakeholders and will enable TransCanada to meet its needs and those of its customers, supporting the long-term viability of the TransCanada system. By the end of August 2001, TransCanada will work to present to the stakeholders, a specific business and regulatory model for the future that will allow it to compete effectively for market demand and gas supplies. Discussions with stakeholders regarding any new model, including a code of conduct, will be initiated on or before September 17, 2001 and completed by February 28, 2002.

This settlement will form the basis of a formal agreement between the parties. Once TransCanada and the parties have completed the agreement (anticipated by the end of this March), TransCanada will apply to the National Energy Board for approval of the agreement.

TransCanada is a leading North American energy company. It is focused on natural gas transmission, power, and gas marketing services, complemented by employees who are expert in these businesses. The company's network of approximately 38,000 kilometres of pipeline transports the majority of western Canada's natural gas production to the fastest growing markets in Canada and the United States. TransCanada's common shares trade under the symbol TRP on the Toronto and New York stock exchanges. Visit us on the internet at www.transcanada.com for more information.

Note: All dollar amounts are expressed in Canadian funds, unless otherwise indicated.

(For a complete version of the Settlement, please visit TransCanada's web site at www. transcanada.com and follow the links to this news release.)

– 30 –

Media Inquiries:	Glenn Herchak/Kurt Kadatz	(403) 267-3309
Analyst Inquiries:	David Moneta	(403) 267-8521

TAB 3

Ontario Energy Board
Commission de l'énergie de l'Ontario

Ontario

EB-2008-0106

METHODOLOGIES FOR COMMODITY PRICING, LOAD BALANCING AND COST ALLOCATION FOR NATURAL GAS DISTRIBUTORS

AMENDED DECISION AND ORDER

September 21, 2009

This page has been intentionally left blank

EB-2008-0106

IN THE MATTER OF a proceeding initiated by the Ontario Energy Board to determine methodologies for commodity pricing, load balancing and cost allocation for natural gas distributors.

BEFORE: Paul Sommerville
Presiding Member

Cathy Spoel
Member

AMENDED DECISION AND ORDER

September 21, 2009

This page has been intentionally left blank

TABLE OF CONTENTS

This page has been intentionally left blank

INTRODUCTION

BACKGROUND

In the fall of 2003, the Ontario Energy Board (the "Board") began a comprehensive sector review – the Natural Gas Forum – to examine ways to further improve the efficiency and effectiveness of natural gas regulation in Ontario. The outcome of the review was a Board report, released on March 30, 2005, entitled *Natural Gas Regulation in Ontario: A Renewed Policy Framework* (the "NGF Report").

In the NGF Report, the Board concluded that gas utilities should continue to provide a regulated gas supply option and that proper costing and pricing of the services within the regulated gas supply option were essential. The Board stated that the Quarterly Rate Adjustment Mechanism ("QRAM") should be a transparent benchmark that reflects market prices and should reflect an appropriate trade-off between market prices and price stability. The Board further noted that the method for determining the reference price should be formulaic and consistent across natural gas utilities, as should the methods for determining and disposing of Purchase Gas Variance Account ("PGVA") balances. The Board also indicated that the harmonization of load balancing policies and the manner in which natural gas utilities currently allocate costs between the delivery and gas supply functions were matters that merited examination.

THE PROCEEDING

On May 29, 2008, the Board commenced a proceeding on its own motion pursuant to sections 19 and 36 of the *Ontario Energy Board Act, 1998* to determine the methodology to be used by natural gas distributors for (i) gas commodity pricing, (ii) load balancing and (iii) cost allocation between the supply and delivery functions in relation to regulated gas supply.

On July 8, 2008, the Board issued Procedural Order No. 1 establishing the process by which the Board would determine the issues to be considered in this proceeding. On July 31, 2008 the Board convened an Issues Day to hear submissions on the proposed issues list. On August 8, 2008 the Board issued Procedural Order No. 2 which established the Issues List for this proceeding. In addition to the three areas noted above, the Board also included issues relating to the standardization of the billing terminologies and implementation matters stemming from the various proposals. The issues list is reproduced as Appendix A to this Decision. The Board also directed Union Gas Limited ("Union"), Enbridge Gas Distribution ("Enbridge" or "EGD") and Natural Gas Limited ("NRG") to file evidence.

The Procedural Order No. 2 also set out dates for filing evidence by gas utilities and intervenors, interrogatories, responses to interrogatories, a technical conference and the oral hearing.

Union, EGD and NRG filed their evidence on the set of issues by November 14, 2008. In addition to the evidence of the gas utilities, the Board also received evidence from the Gas Marketer Group ("GMG").[1] The Board held a Technical Conference on November 27th and 28th, 2008. The oral hearing was held on April 6, 13 and 16, 2009.

In addition to the arguments of Union, EGD, and NRG, the Board received final arguments in this proceeding from Board staff and the following parties: the GMG; the Vulnerable Energy Consumers Coalition ("VECC"); the Building Owners and Managers Association of the Greater Toronto Area ("BOMA"); the London Property Management Association ("LPMA"); the Federation of Rental-housing Providers of Ontario ("FRPO"); Canadian Manufacturers and Exporters ("CME"); the City of Kitchener ("Kitchener"); the Low Income Energy Network ("LIEN"); the Industrial Gas Users Association ("IGUA"); and the School Energy Coalition ("SEC"). A complete list of participants is provided at Appendix B.

ORGANIZATION OF THIS DECISION

This Decision is organized into five areas, which follow the Board's Issues list as previously referenced. Those areas are: review of QRAM for natural gas distributors, review of load balancing obligations for natural gas distributors, cost allocation, billing terminology and implementation matters and cost awards.

[1] Direct Energy Marketing Limited, Ontario Energy Savings L.P. and Superior Energy Management L.P

REVIEW OF QUARTERLY RATE ADJUSTMENT MECHANISM FOR NATURAL GAS DISTRIBUTORS

Following the determination of the issues in this proceeding, Union and EGD collaborated to propose a standardized quarterly rate adjustment methodology. For its part, Union proposed to streamline the regulatory review process and eliminate the Intra-WACOG[2] deferral account in favour of a quarterly adjustment to delivery rates within the QRAM process. EGD proposed to eliminate the trigger mechanisms, to adopt the rolling 12 month rate rider methodology for clearing PGVA balances, and to streamline the regulatory review process.

NRG's evidence focussed primarily on the issue of commodity pricing. NRG's quarterly rate adjustment methodology is similar to the standardized methodology proposed by Union and EGD. With the exception of certain changes to its filing requirements, NRG proposed no changes to its existing QRAM for many of the same reasons noted by Union and EGD. NRG's proposal is summarized in response to Board staff interrogatory no. 1.

The GMG's evidence focussed primarily on the review of the QRAM proposed by Union and EGD. While the GMG supported some of the changes to harmonize the different elements of the QRAM proposed by Union and EGD, it argued that the overall QRAM is not appropriate and should be rejected by the Board. The GMG submitted that the ideal rate setting methodology is one that involves monthly price setting, monthly forecasting and monthly dispositions of PGVA balances.[3] The GMG argued that the Board should adopt a monthly rate adjustment mechanism ("MRAM") modelled on the approach followed by regulated utilities in Alberta.

The review of the QRAM involved six sub-issues which are addressed below. The sub-issues follow the Board's Issues list. These sub-issues are:

- Trigger mechanism for changing the reference price or clearing the purchased gas variance account;
- Price adjustment frequency and forecast periods;

[2] Intra-Weighted Average Cost of Gas
[3] GMG Argument, Paragraph 8, p. 2

- Methodology for the calculation of the reference price;
- Deferral and variance accounts and disposition methodology;
- Effect of a change in the reference price on the revenue requirement;
- Filing requirements.

TRIGGER MECHANISM FOR CHANGING THE REFERENCE PRICE OR CLEARING THE PURCHASE GAS VARIANCE ACCOUNT

BACKGROUND

The section deals with issues 1.1 and 1.2 from the Board's issues list which are:

1.1- Should there be a trigger mechanism to prompt a change in the reference price or to clear the PGVA?

1.2 - If a trigger mechanism is desirable, what methodology or methodologies should be used by natural gas distributors for setting the trigger to prompt a change in the reference price or to clear the PGVA?

Union, EGD and NRG argued that there should be no trigger mechanism to prompt a change in the reference price or to clear the PGVA balance. Currently, neither Union's nor NRG's QRAMs have a trigger mechanism while EGD's current QRAM has two triggers. The first trigger is set at $0.005/m3, and is used to trigger a change in the reference price. The second trigger, which is also set at $0.005/m3, is used to determine if the PGVA balance will be cleared. In this proceeding, EGD is proposing to eliminate both triggers and to align its methodology with that of Union and NRG.

No party objected to the elimination of EGD's current trigger mechanisms.

CCC submitted that the trigger mechanism has proven to provide little benefit throughout the years and noted that there are no clear advantages or disadvantages to the utility or its customers arising from the elimination of the trigger mechanisms.

IGUA submitted that the elimination of the trigger mechanisms would make the QRAM more mechanical and certain, and would act to minimize balances in the PGVA.

BOARD FINDINGS

The Board approves EGD's request to eliminate the trigger mechanisms. The rationale for the triggers was to allow for regulatory efficiencies and some level of rate stability. However, since the implementation of the triggers in 2002, EGD has in effect operated as if there was no trigger in place.[4] EGD explained that since adopting the trigger mechanism in 2002, there have only been three instances where the trigger to effect a change in the reference price was not reached and five instances where the disposition of the PGVA was not triggered. In each of these instances, at least one of the triggers was exceeded, thereby requiring EGD to file an application for a rate change.

In the Board's view there is no requirement for a trigger mechanism either to clear PGVA balances or to prompt a change in the reference price. The elimination of the trigger mechanism will ensure that the reference price is periodically updated to reflect market prices, and will achieve further standardization of the rate adjustment methodologies across distributors.

Therefore, the Board orders that EGD shall eliminate the trigger mechanisms starting with the January 2010 QRAM application.

PRICE ADJUSTMENT FREQUENCY AND FORECAST PERIODS

BACKGROUND

This section of the Decision addresses the issues in relation to price adjustment frequency and forecast periods.

Union, EGD and NRG proposed no changes to the current quarterly price adjustment frequency or the current price forecast period. Under the current QRAM, the gas supply reference price is based on a rolling 12 month forecast period that is updated quarterly. The reference price represents an average cost for gas at Empress for the next 12 months determined over a 21-day strip. The quarterly updates to the reference price are intended to ensure that the reference price reflects any changing market dynamics.

The utilities argued that their gas supply purchases follow a 12 month cycle that encompasses the summer (storage injection) period and the winter (storage withdrawal)

[4] EGD pre-filed evidence, Exhibit E1, Paragraph 27, p. 7

period and that the 12 month price forecast utilized matches this pattern of gas supply purchases.

The GMG submitted that the current 12 month price forecast period and price adjustment frequency is not appropriate and proposed that the Board adopt a monthly rate adjustment mechanism modelled on the approach followed by regulated utilities in Alberta.

The GMG argued that the ideal rate setting methodology is one that involves monthly price setting, monthly forecasting and monthly dispositions of the PGVA balances.[5] The GMG also argued that pricing estimates should align themselves with a utility's buying protocol [6] and since Union and EGD purchase gas on a monthly basis, the reference price should change monthly. The GMG also argued that setting reference prices on a one month forward basis will produce more accurate gas price forecasts, will more closely match the cost and benefit of the regulated service, and reduce intergenerational mismatches.[7]

In response to interrogatories from the utilities, most intervenors and Board staff, the GMG revised its original proposal to reflect the manner in which gas utilities in Ontario use storage.[8] The GMG proposed that the monthly index during the summer would be a monthly default rate, while at the start of the winter season (November) the monthly price would include the cost of gas withdrawn from storage, leading to a "blended" WACOG (WACOG II). Alternately, storage balances would be re-priced monthly at prevailing prices, and customers would be either charged or credited for the difference.[9]

In its final submission the GMG submitted that the Board could also consider adopting a methodology that is a compromise between the MRAM and the QRAM. Under this approach the reference price would be reset on a monthly basis, but would still be based on a 12 month forecast. Similarly, the PGVA balances would be disposed over a 12 month period.

Union, EGD and NRG argued that the monthly price adjustment and the one month forward price forecast methodology is flawed and should be rejected by the Board.

---

[5] GMG Argument, Paragraph 8, p. 2
[6] Ex. K3.1, line A2, GMG pre-filed evidence, page 2
[7] GMG Argument, Paragraph 8, p. 2
[8] Transcript Vol. 3, page 48, lines 25 - 28
[9] GMG response to Union interrogatory no. 8 (a)

Union and EGD submitted that this approach does not take into consideration the manner in which EGD and gas utilities in Ontario procure gas supplies and use storage.

EGD explained that unlike gas utilities in Alberta, which are in close proximity to a major supply basin, it relies on long haul transportation at 100% load factor to move gas to the Province. As a result, while EGD purchases gas on a monthly basis, its gas purchases are based on a constant profile and are not intended to match the amount of gas customers will consume in any given month. When gas deliveries are in excess of consumption, such as in the summer months, the excess gas is stored and withdrawn in the winter season when gas consumption exceeds gas deliveries. This means that gas purchased in a particular month may not be consumed in the same month; however, over a twelve month period the quantity of gas purchased and sold is equal.[10]

Therefore, EGD argued, applying a 12 month price to varying monthly consumption will result in annual billings equal to annual purchases, assuming there is no variance between forecast and actual prices. In contrast, applying a varying monthly price to varying monthly consumption will result in a variance between annual billings and annual purchases, even if there is no variance between forecast and actual prices. This variance in annual billings and annual purchases will further add to the PGVA balances.

Union and EGD also argued that a monthly price forecasting approach does not ensure that customers will necessarily receive the most accurate price signals. EGD explained that it regularly purchases spot gas to meet winter demand.[11] These additional purchases of spot gas are not priced at a monthly index price but rather at the spot price at the time of purchase. Given that these additional gas purchases are not priced at the monthly index price (settled in the previous month), variances would continue to accrue in the PGVA even if the gas supply price was set on a one-month forward basis.

With respect to the GMG's revised proposal, Union and EGD submitted that the blending of gas prices in the winter with the cost of gas taken out of storage will have the effect of muting price signals[12] which is one of the GMG's criticisms of the QRAM methodology.[13]

[10] EGD pre-filed evidence, Paragraph 31, p. 9
[11] Oral Hearing Transcript Vol. 2, p 35-37
[12] GMG response to Union's Interrogatory no. 8 (b)
[13] Transcript Vol. 3, page 50, lines 1 – 50

To test if a better alternative to the QRAM was available, Union conducted an examination of alternative rate adjustment mechanisms. A better alternative was defined as one that offers improved balance between price stability and market price sensitivity.

Union's analysis concluded that the QRAM provides the best balance between price stability and market price sensitivity compared to the other methods that were tested. Notably scenario 3, which represents a monthly rate adjustment methodology using a one month forecast period, was 98% less stable than the current QRAM and -7% less accurate than the current QRAM.[14] Based on its analysis Union argued that the existing 12 month forecast period provides customers with an appropriate balance between market price sensitivity and price stability. Union also submitted that changing the gas supply commodity charge quarterly is sufficiently responsive to changing market conditions.

Union and EGD also argued that a reference price based on a 12 month forecast period is better aligned with the multi-year offerings provided by the gas marketers, and that monthly rate changes would be confusing for system customers and costly to implement. The estimated cost of implementing the MRAM was in the range of $1.5 to $2.5 million annually.

EGD also noted that the Manitoba Public Utilities Board ("MPUB") had declined to follow the Alberta model, because it did not want to introduce additional regulatory costs and increase rate volatility by re-setting rates on a monthly basis. In arriving at its conclusion, the MPUB concurred with a similar conclusion reached by the British Columbia Utilities Commission.[15]

NRG submitted that a forecast period of less than twelve months would not be appropriate for its customer base. NRG submitted that its seasonal customers (e.g., farmers, grain dryers, etc.), who consume virtually all of their gas in the late summer and early fall, would experience significantly more volatility if the reference price would be set using a period shorter than 12 months. NRG also submitted that if the forecast period is less than twelve months, any gas cost variance in this period would be recovered or returned to a different set of consumers.[16]

[14] Union Pre-filed evidence, Ex E2, p. 19
[15] EGD Argument-in-Chief, Paragraph 10, p.3
[16] NRG Argument, Paragraph 11-12, p. 2

CCC argued that an MRAM approach would not bring greater transparency to the marketplace, would not provide better price signals to customers, and is not consistent with the way in which the LDCs purchase their gas. CCC further argued that a monthly price setting methodology will result in increased confusion and costs for customers.[17]

BOMA and LPMA submitted that matching a 12 month forecast for prices with the 12 month purchasing cycle is appropriate. BOMA and LPMA also supported a quarterly price adjustment frequency. They submitted that the GMG proposal fails to recognize the difference between consumption profiles and purchase profiles, and that "it would be fundamentally unjust to customers to adopt a rate adjustment mechanism that ignores the reality of gas purchasing and can result in some customers paying more than the actual cost of gas while others pay less than the actual cost".[18]

CME submitted that the GMG had failed to demonstrate whether any customer groups support monthly gas price changes over the current quarterly approach and if any material benefit will flow to customers by moving to a monthly approach. CME also submitted that the evidence supports the conclusion that the MRAM would increase rate volatility, increase administrative and regulatory burdens, and cause customer confusion.[19]

IGUA submitted that changing gas supply and related costs monthly would merely raise administrative costs without providing significantly more gas price transparency, and that comparing multi-year fixed price offers against a one month forward gas price forecast would be comparing "apples to oranges".[20] IGUA also submitted that a quarterly change to commodity rates provides an appropriate balance between market price reflectivity and rate stability.[21]

VECC submitted that the GMG's proposal would harm small-volume residential customers by increasing the volatility of overall utility sales rates and impairing the ability of these customers to make informed decisions about their gas supply. VECC also submitted that a reference price based on a rolling 12-month forecast period is an

[17] CCC Argument, Paragraph 15, p. 6
[18] BOMA & LPMA Argument, p. 4
[19] CME Argument, p. 3
[20] *Ibid.*, p.3
[21] IGUA Argument, p. 3 and p. 4

appropriate benchmark for customers to use in evaluating the reasonableness of fixed-price offerings.[22]

Kitchener submitted that its experience is that most customers prefer stable rates and that the GMG's proposal to have monthly rate adjustments would run counter to this preference.

LIEN submitted that the MRAM would likely result in greater volatility in rates than the QRAM and that the GMG had not demonstrated that the MRAM would have other consumer benefits that outweigh the disadvantage of the increased risk of volatility.[23]

Board staff submitted that the GMG's proposal may expose system supply consumers to higher price volatility, and may not be appropriate given the different operational characteristics of Ontario utilities, especially with respect to the use of storage. Further, Board staff noted that the benefits to customers do not appear to be commensurate with the incremental costs of implementing a MRAM.[24]

SEC argued that "a monthly adjustment system, if made sufficiently mechanistic, and if stripped of the kind of contentious issues that have dogged the process in the past, could be cost-effective and timely. This is particularly true if some or all of the methodology selected by the Board going forward is a true-up of historical actuals rather than a rolling forecast".[25]

BOARD FINDINGS

After considering the options put forward by all of the parties, the Board is of the view that a 12 month forecast period and a quarterly rate adjustment frequency remains appropriate. The Board's reasons for so finding are set out below.

In the Board's view, the 12 month forecast period takes into consideration the manner in which the natural gas utilities incur their gas supply costs. In contrast, establishing a reference price using a one-month forward basis would not be reflective of the manner in which gas utilities in Ontario procure gas supply and use storage. The Board notes that the analysis presented by LPMA and BOMA further illustrates that the GMG's proposal does not take into account the difference between consumption and gas

[22] VECC Argument, p. Paragraph 16, p. 4
[23] LIEN Argument, Paragraph 20, p. 5
[24] Board staff Submission, p. 5
[25] SEC Argument, Paragraph 10, p. 2

acquisition profiles, and could result in some customers paying more than the actual cost of gas while others pay less than the actual cost. NRG, which has significant seasonal load, raised similar concerns.

The Board does not accept the GMG's argument that the monthly forecasting method provides customers with more accurate price signals than the rolling 12 month method.

The Board notes that the GMG acknowledged that it's revised proposal, which blends the price of gas in the winter with the cost of gas taken out of storage, has the effect of muting price signals.[26] Given that one of the fundamental reasons advanced by the GMG for proposing a change to the current rolling 12 month forecast period is that it has the effect of distorting price signals, [27]the Board is not convinced that the GMG's proposals will provide system gas customers with improved price signals.

The Board also notes that the GMG's alternative with respect to dealing with storage would require utilities to revalue gas in storage on a monthly basis. In this regard, the Board notes that Union's witness explained that this approach "absolutely would not work" and will result in large rate riders through the summer months, when little consumption is occurring.[28]

The Board also considered the GMG's position that monthly gas cost changes would enhance gas consumers' ability to compare default supply options with competitive multi-year fixed price supply options.

In the Board's view, comparing multi-year fixed price offerings such as those provided by gas marketers with a monthly reference price is not an appropriate comparison and will not assist consumers in making informed decisions about their energy choices. The Board believes that the rolling 12-month forecast period removes the effects of seasonality and is a suitable benchmark for customers to use in evaluating the reasonableness of multi-year fixed-price offerings (which necessarily remove seasonality effects).

In its final arguments the GMG proposed that the Board could adopt a compromise between the QRAM and the MRAM. Under this approach, the reference price would be forecast on a rolling 12-month basis, and the prices would be set monthly.

---

[26] GMG response to Union's Interrogatory no. 8 (b)
[27] GMG Pre-filed evidence, p. 21
[28] Oral Hearing Transcript Vol. 1, p. 62, l.14-27

The Board notes that under the GMG's original and revised proposals, the utilities would be required to prepare and file a rate application with the Board every month, effect rate changes in the billing system, and communicate them to all customers. This change could result in incremental costs of about $2.45 million per year for Union [29]and about $1.5 million per year for EGD.[30] While these cost estimates are 'high level' estimates, the Board agrees with intervenors and Board staff that the benefits to customers do not appear to be commensurate with the incremental costs of implementing an MRAM. With respect to the price adjustment frequency, the Board agrees with the conclusion of the NGF Report which states that the current pricing process, whereby the price is set every three months on the basis of a 12-month price forecast, represents a balance between market-price signals and price stability.[31]

METHODOLOGY FOR THE CALCULATION OF THE REFERENCE PRICE

BACKGROUND

This section of the Decision addresses issues 3.1 to 3.4. The central question on this issue is whether or not a single Ontario-wide reference price should be used as the basis for the gas supply commodity charge.

Union noted that it and EGD use a common methodology to determine their respective gas supply reference price. The gas supply reference price is based on a forecast of market prices at Empress using a 21-day market strip over a 12 month period. To set the gas supply charge for sales service customers, the utilities add to the gas supply reference price: compressor fuel charges to transport the commodity to the delivery area(s), commodity related bad debt and working cash requirements, and the gas supply administrative fee. The result is a gas supply or commodity charge that varies somewhat between the utilities but reflects the respective costs of each utility.[32]

The utilities did not support the establishment of a single Ontario-wide reference price as the basis for the gas supply commodity charge. Given that natural gas distributors operate their distribution systems differently and use different purchasing strategies, Union, EGD and NRG argued that the average price for the commodity will also vary

[29] Undertaking J1.1
[30] EGD Pre-filed, Exhibit E1, Paragraph 208, p. 59
[31] NGF Report, p. 68
[32] Union pre-filed evidence, Ex E2, p.26

across distributors. Union, EGD and NRG submitted that the current methodology minimizes variances that would otherwise be accumulated in the PGVA and better reflects the market prices for each utility.

BOMA and LPMA submitted that each utility has a unique supply portfolio that meets its operational needs and reflects its geographic location, and as such the average price of the gas will also vary across distributors. Imposing a single Ontario-wide reference price would not match the respective costs of Union or EGD and would lead to higher PGVA balances and greater rate volatility. CME supported the position of BOMA and LPMA.

Kitchener supported the utilities' proposal that no change should be made to the current methodology.

VECC was also of the view that it is not necessary to provide for a single Ontario-wide reference price for the reasons outlined by the utilities in their evidence and arguments.

The GMG stated in their pre-filed evidence that a single Ontario-wide monthly reference price that reflects the cost of gas delivered to the reference point (e.g. Dawn or city-gate), would provide consumers with pricing which reflects supply/demand in the consuming area. The GMG also argued that this approach would be beneficial to customers as a published index will clearly show consumers how their bills are being calculated and will allow them to make conservation decisions on a fully informed basis. However, the GMG concluded by stating that it was unable to propose implementation of a single Ontario-wide reference price in the absence of unbundling of storage and transportation, which is not within the scope of this proceeding.[33]

BOARD FINDINGS

The Board agrees with the position of the utilities and most intervenors that establishing a single Ontario-wide monthly reference price would lead to higher variance account balances and greater rate volatility.

[33] Ex. E8, E14, E19, page 24

With respect to the position of the GMG that this approach would benefit customers, the Board notes that this argument was not supported by any market research or any intervenors representing customer groups.

The Board finds that the current methodology used to establish the reference price shall continue.

DEFERRAL AND VARIANCE ACCOUNT AND DISPOSITION METHODOLOGY

BACKGROUND

This section of the Decision addresses issues 4.1 to 4.5. The Board has grouped these issues under three broad issues which are:

- What deferral and variance accounts should gas utilities use to capture variances in commodity, transportation, load balancing and inventory revaluations?
- What methodology should be used to dispose of the account balances?
- Should there be a final adjustment to re-allocate the PGVA balances?

Currently, Union uses separate commodity accounts in the North and in the South. The balances in these accounts are disposed by means of a rate rider over a rolling 12-month period.

The North PGVA only captures commodity price variances. The variances in the North PGVA are allocated to sales service customers. In the North, Union provides transportation services to all bundled customers including sales and direct purchase ("DP") customers. The transportation tolls in the North are captured in the TCPL Tolls and Fuel deferral account and the variances in transportation costs are allocated to both sales service and DP customers.

The South PGVA captures variances in both gas supply commodity and upstream transportation costs. This is because DP customers do not pay Union for either the gas supply commodity or upstream transportation costs. Accordingly, the balances in the South PGVA are allocated to sales service customers.

In addition to the North PGVA, the TCPL Tolls and Fuel deferral account and the South PGVA, Union also disposes of the Spot Gas Variance account and the Inventory Revaluation deferral account as part of the QRAM process. Union automatically clears the balances in these accounts by means of rate riders over a rolling 12 month period.

In comparison, EGD's PGVA account captures variances attributable to commodity, transportation and load balancing. The projected year-end PGVA balance for each quarter is cleared by means of a rate rider. The rate rider is derived by dividing the projected year-end PGVA balance by the budgeted sales volumes for the remaining months of the fiscal year. EDG assumes that the price variances captured in the PGVA are solely attributable to the commodity and therefore the rate rider applies to sales service customers only. At the end of the fiscal year, EGD performs a true-up whereby the year-end PGVA balance is separated into variances attributable to commodity, transportation and load balancing. These variances are allocated to the appropriate customer groups based on cost causality.

The Board reviews NRG's Purchased Gas Commodity Variance Account ("PGCVA") as part of the QRAM. Similar to Union's methodology, NRG clears the balances in this account over a rolling 12 month period.

Union, EGD and NRG proposed no changes to the existing accounts or the manner in which the balances are recorded in these accounts. With respect to the different disposition methodologies, EGD proposed to adopt Union's methodology to determine the PGVA balances and the manner in which the rate rider is derived. Further, EGD proposed to identify the PGVA balances attributable to commodity, transportation and load balancing as part of the QRAM. Based on this breakdown, individual rate riders would be calculated and would apply to sales service, western bundled transportation service ("T-service"), and Ontario T-service customers. This approach would eliminate the need for the existing one-time true-up mechanism at year-end.[34] EGD estimated a one-time implementation cost of $100,000 to cover the incremental costs of printing, design and communication.

NRG did not propose any changes to its disposition methodology.

With the exception of the GMG, all intervenors supported the changes proposed by EGD.

[34] Exhibit E1, Paragraph 53, p. 18

No party objected to Union and NRG's proposal to continue its existing accounts or the manner in which the accounts are cleared.

BOMA and LPMA submitted that the deferral and variance accounts used by both Union and EGD are appropriate and that no change is required to these accounts. BOMA and LPMA further added that EGD's current disposition methodology was "inferior to the 12 month methodology used by Union".[35] They added that EGD's current methodology can result in significant rate volatility and can result in cross subsidization among customers."

IGUA noted that the use of a 12 month rolling disposition methodology would lower rate impacts, remove EGD's discretion in respect of the disposition period and better facilitate recovery of the variances from all customers in an equitable manner.[36]

SEC submitted that the Union's approach is to be preferred. SEC further added that the fact that Enbridge has in the past extended the recovery period beyond the rate year because of inappropriate bill impacts suggests that it is not a good approach.[37]

The GMG submitted that the disposition methodology to clear PGVA balances should match the price forecast period and the price adjustment frequency. Because gas prices are adjusted every month, the GMG proposed the balances in the PGVA should also be cleared over one month as opposed to 12-months, proposed by the gas utilities. The GMG submitted that the advantage of a monthly disposition is that it provides customers with more accurate price signals and will better match the recovery of the PGVA balances from customers who cause them.

BOARD FINDINGS

The Board finds that the existing deferral and variance accounts used by Union, EGD and NRG remain appropriate and that no change is required to these accounts. The Board also finds that disposing of the account balances on a rolling 12-month basis is an appropriate methodology.

The Board agrees with EGD and other parties that the 12-month rolling approach will reduce the volatility of the rate riders, especially during the third and last quarters where

[35] BOMA and LPMA Argument, p. 6
[36] IGUA Argument, Paragraph 2, p. 2
[37] SEC Argument, Paragraph 14, p. 3

the volumes over which the balances are spread out are considerably smaller. The Board sees merit in disposing of previous PGVA balances as opposed to a year-end forecast balance. The Board also notes that disposing of the balances over a 12-month basis would contribute to the elimination of a year-end true up.

The Board does not accept the arguments of the GMG that clearing PGVA balances monthly will lead to improved price signals. The Board agrees with EGD and other parties that a monthly deferral account disposition methodology has the potential to exacerbate the underlying volatility in natural gas commodity prices, thereby exposing customers to an effective price that can be significantly different from the actual price of the commodity. EGD further explained that for example, were spot gas purchases to occur in the month of March, the PGVA variance would be cleared in April, when volumes are generally much lower, resulting in a sizable rate rider in April.

The Board also does not accept the GMG's argument that the monthly clearing of PGVA balances will better match the recovery of the PGVA balances from customers who cause them. The utilities provided adequate evidence that gas purchases in any month are not necessarily made to be consumed in that same month and disposing of PGVA balances over a 12 month period is consistent with that approach. Further, the clearance of account balances over a shorter time period creates the potential for cross subsidization across customers. Union's evidence at pages 30 and 31 of Exhibit E2 provides examples of such potential cross subsidization.

The Board approves EGD's proposal to adopt the rolling 12-month disposition methodology for clearing the PGVA balance and orders that EGD shall implement this change starting with its January 2010 QRAM application. Going forward, in each quarter, EGD shall identify and support, as part of its QRAM application, the elements of its PGVA attributable to commodity, transportation and load balancing costs. Based on this breakdown, individual riders shall be determined and applied where applicable to sales service, western bundled T-service, and Ontario T-service customers based on the existing Board approved cost allocation methodology.

The Board orders EGD to record the costs of implementing this change in a deferral account for review and disposition in a subsequent proceeding.

EFFECT OF A CHANGE IN THE REFERENCE PRICE ON THE REVENUE REQUIREMENT

BACKGROUND

This section of the Decision relates to issues 5.1 and 5.2.

A change in the gas reference price also affects the carrying costs of gas in inventory, working cash allowance, capital taxes, and unaccounted for gas ("UFG"). These changes impact the revenue requirement and are reflected in delivery rates.

Currently EGD and Union follow different approaches on how changes to the revenue requirement are treated.

EGD updates its delivery rates every quarter to account for changes in the revenue requirement due to these delivery–related costs. A summary of these changes is provided at Exhibit E1, page 21. Union uses the Intra-Period WACOG deferral account to record the change in the carrying costs of gas in inventory, compressor fuel and UFG. This account is reviewed and cleared annually.

A change in the reference price currently has no impact on NRG's revenue requirement. This is because NRG does not have any gas in inventory and consequently incurs no inventory carrying costs or compressor fuel costs.

Union proposed to adopt EGD's approach with respect to these costs. Specifically, Union proposed to eliminate the Intra-Period WACOG deferral account and adjust delivery rates quarterly to account for changes in the carrying costs of gas in inventory, compressor fuel and UFG. Union proposed to implement these changes in its next QRAM application following the issuance of this decision.

With the exception of SEC, all intervenors and Board staff supported Union's proposal to eliminate the Intra-WACOG deferral account.

SEC argued that distributors should not be held harmless with respect to commodity-related operational costs. In SEC's view, these costs should be managed to a budgeted level like any other distribution cost. SEC also submitted that load balancing costs, including gas inventory, upstream transportation and storage costs should be treated like any other cost of the distribution business, and should be forecast and not adjusted during the year. SEC also supported an annual update to delivery rates, noting that quarterly changes to delivery rates can complicate the QRAM process.

Union submitted that SEC's argument is beyond the scope of this proceeding and should be rejected by the Board. Union argued that it has not filed any evidence which addresses SEC's argument nor did SEC ask any relevant interrogatories or conduct cross-examination on the issue. Union also noted that the issue raised by SEC was previously decided by the Board in RP-1999-0017, where the Board concluded that Union should not be at the risk for the recovery of such costs since gas prices are largely beyond management's control. Union also noted that since the Board's Decision in RP-1999-0017, Union's approach has received Board approval in each of Union's subsequent cost of service and deferral account disposition proceedings.

BOARD FINDINGS

The Board disagrees with Union and EGD that the issue raised by SEC is not in scope in this proceeding. The Board finds that SEC's issue falls within Issue 5.2 of the Board's issues list.

However, the Board is not persuaded by SEC's argument. The Board believes that SEC's proposed treatment of load balancing costs, upstream transportation and storage costs would be inappropriate as it would effectively make distributors' responsible for costs that are beyond their control. This would constitute a fundamental change to the regulatory compact that would alter the risk profile of the distributors. In addition, the manner in which costs are recovered in rates (e.g. through the gas supply charge or load balancing/delivery charge) should not be confused with the nature of these costs. For example, load balancing costs are incurred on behalf of all bundled service customers and while the costs are tied to fluctuations in gas prices, they cannot be recovered through the gas supply charge as this charge is only applicable to sales service customers.

Finally, Board sees no compelling reasons to deviate from the Board's Decision in RP-1999-0017 which stated that:

> The Board is prepared to accept adjustments to reflect changes to gas prices and thereby reduce this risk to which the Company would otherwise be exposed. The Board deals with the methodology for the treatment of unaccounted-for gas volumes separately below in Section 2.5.7. With respect to inventory carrying costs and compressor fuel the Board accepts Union's

> proposal that these be dealt with annually through the customer review process on a forecast basis. The Board believes that it is appropriate for Union to be at risk for volume variances in these items, at least a year at a time as they have proposed. However, since the Board believes that gas prices are largely beyond management's control it directs that price variances be tracked and dealt with annually through the customer review process.

The Board finds that the standardization proposal of Union is appropriate and directs Union to close the Intra-Period WACOG deferral account as of December 31, 2009. Any balance accumulated in the Intra-Period WACOG Deferral account prior to delivery rates being adjusted shall be disposed as part of the annual deferral account disposition proceeding. Starting with its January 2010 QRAM application Union shall adjust delivery rates quarterly to account for changes in the carrying costs of gas in inventory, compressor fuel and UFG.

FILING REQUIREMENTS

With regard to filing requirements, there are two issues before the Board. The first deals with the request from Union and EGD to further streamline the QRAM review process and the second is in relation to establishing standardized filing requirements.

QRAM Review Process:

In the current QRAM process the determination of the gas supply reference price is based on a 21-day strip of market prices that ends 45 calendar days prior to the start of each quarter. This 45 calendar day period is used to prepare the application, receive Board approval, prepare notices of rate changes for customers, and to implement the rate changes. Union and EGD have proposed to shorten this 45 calendar day review period to a 30 calendar day review period. Union and EGD submitted that this change would provide a better price signal and could reduce variances in the PGVA.

IGUA stated that the Board should change Union's QRAM process to the process used by EGD (i.e. no notice of proceeding or procedural order) in order to provide regularity and predictability to Union's QRAM process timing.

Board staff submitted that the review process currently followed by EGD is more efficient than Union's as the application is automatically forwarded to all parties and the dates for comments and replies are pre-determined. Board staff further submitted that adopting the EGD process for all distributors would eliminate the need for the issuance of a notice and procedural order and would further standardize the regulatory review process.

In addition, BOMA, LPMA, CCC, CME, Kitchener and VECC supported the proposal of the distributors to streamline the review process.

With respect to the regulatory review process, EGD follows a process where once the QRAM application is filed with the Board, copies are e-mailed to all parties in EGD's most recent rates proceeding for review and comment. The Board does not issue a notice of proceeding or procedural order as the timing for the process is pre-established. Intervenors are allotted 7 calendar days to file comments. EGD files its reply with the Board and serves intervenors within 7 calendar days. The Board issues its decision within a week from the date reply comments are filed.

From the time EGD's application is filed with the Board to the date a decision is issued typically takes about 21 calendar days. In order to meet the 30 calendar day review period, EGD proposed to shorten the time for comments to 5 calendar days, (previously 7 calendar days) and the time for EGD's reply comments to 2 calendar days (previously 7 calendar days).

The Board follows a slightly different process for Union's QRAM applications. The Board issues a Notice of Written Hearing and Procedural Order ("Notice") once the application is filed. The Notice is not published but is served to all intervenors in Union's last rate case. The Notice provides time for comments on the nature of the hearing, intervenor comments and Union's reply following which the Board issues its decision. From the time that Union files its QRAM application to the date the Board issues its decision takes 21 calendar days. Union is proposing to shorten this period to about 14 calendar days. *In order to meet these timelines, Union proposed to expedite the timing* of their application to five business days, and reduce the intervenor comment period from 12 to 7 days.

The Board's regulatory review process for NRG's QRAM application is the same as the approach followed by the Board in Union's case. NRG is proposing no changes to the regulatory review process.

BOARD FINDINGS

The Board directs EGD and Union to move the close of the 21-day strip to 31 calendar days before the effective date of the rate change. The Board directs NRG to move the close of 10 day strip to 31 calendar days before the effective date of the rate change. This change would provide a better price signal by virtue of shortening the time between the forecast end date and the QRAM effective date. Further, this could reduce variances in the PGVA.

The Board also concludes that there are merits to establishing a consistent regulatory review process for Union, EGD and NRG. Consequently, the Board considers it appropriate to establish the following review process for Union, EGD and NRG, and directs the natural gas distributors to implement these changes starting in their respective January 2010 QRAM application. The revised regulatory process is below.

The Board directs EGD to file a QRAM application with the Board within 12 calendar days from the close of the 21-day strip.[38] EGD shall serve the application and evidence to all intervenors in this case and in EGD's most recent rates proceeding, for review and comment. Intervenors and Board staff will have 5 calendar days to file comments. EGD will have 2 calendar days to respond to any comments. Thereafter the Board will issue its decision and order by the 25th of the month to allow EGD to implement the rate changes.[39]

The Board directs Union to file a QRAM application with the Board within 6 calendar days from the close of the 21 day strip.[40] Union shall serve the application and evidence to all intervenors in this case and in Union's most recent rates proceeding, for review and comment. Intervenors and Board staff will have 5 calendar days to file comments. Union will have 2 calendar days to file responses to any comments received. Thereafter the Board will issue its decision and order by the 19th of the month to allow Union to implement the rate changes.

The Board directs NRG to file a QRAM application with the Board within 8 calendar days from the close of the 10 day strip. NRG shall serve the application on all intervenors in NRG's last rates case. Intervenors and Board staff will have 5 calendar

[38] Exhibit E1, Paragraph 95, p. 30, Table Y - EGD explained that it requires 12 calendar days to prepare and file a QRAM application.
[39] EGD Pre-filed evidence, Ex E1, Paragraph 94, p. 30
[40] Exhibit E2, p. 38 - Union indicated that it requires 5 business days to prepare and file a QRAM application and 8 days to prepare the communications package.

days to file comments. NRG will have 3 calendar days to file responses to any comments received. Thereafter the Board will issue its decision by the 25th of the month to allow NRG to implement the rate changes.

Standardized Filing Requirements:

Union and EGD supported the development of standard filing requirements consisting of common summary schedules in order to facilitate an effective and efficient regulatory review process. To this effect, the distributors proposed to consult with stakeholders to develop a consistent approach to the presentation of the information.

Union and EGD submitted that due to operational differences between the two distributors, it would not be possible to have identical (i.e., with identical inputs, format, number of lines or pages, etc.) filing requirements. In EGD's view, having identical filing requirements would not provide any incremental benefit to ratepayers.

NRG proposed to eliminate schedules 5, 10 and 11. NRG argued that schedules 10 and 11 relate to the Purchased Gas Transportation Variance Account ("PGTVA"), which is not cleared as part of the QRAM process, and schedule 5 deals with the trigger mechanism and is no longer required.

VECC stated that: "Enbridge provides more detail on supply volumes and unit prices by supply point than Union, and accordingly VECC submits that Union should provide similar detail".[41]

BOMA, LPMA, CCC, CME, IGUA, Kitchener and Board staff supported the proposal of the distributors to standardize the filing requirements to the extent possible. No party objected to NRG's request to eliminate schedules 5, 10 and 11 from its QRAM filing.

The GMG supported establishing standardized filing requirements and a streamlined review process. Specifically, with respect to the MRAM, the GMG proposed that the Board adopt the MRAM filing requirements and the regulatory review process followed by the Alberta Utilities Commission. The proposed filing requirements are found at Appendix A of the GMG's pre-filed evidence.

[41] VECC Argument, Paragraph 49, p. 13

BOARD FINDINGS

Given the operational differences between the two utilities, the Board is of the view that it is not appropriate to require Union and EGD to have identical filing requirements; however, the Board agrees that establishing some level of standardization in the QRAM applications will facilitate an effective and efficient regulatory review process. Therefore the Board orders that at minimum, future QRAM applications of Union, EGD and NRG should contain the schedules that are filed as part of their current QRAM application. In the case of Union and EGD, these include schedules relating to gas commodity price forecast calculations and determination of the QRAM reference price, gas cost deferral amounts and disposition, bill impacts and working papers relating to delivery rate changes, derivation of the rider(s), change in annualized revenue requirement, derivation of rates, changes to the approved rates, rate schedules, customer rate notices, and other non-routine changes such as approved TCPL toll changes. Appendices to the QRAM rate order shall include (i) changes to the approved rates, (ii) approved rate schedules, (iii) customer notices.

The Board also directs Union and EGD to jointly work with intervenors in this proceeding to determine how the above information shall be presented by the utilities in their QRAM applications. The changes to the filings should be implemented in the January 2010 QRAM.

The Board also approves NRG's request to remove schedules 5, 10 and 11 from its QRAM application. The Board directs NRG to implement this change in its January 2010 QRAM application.

TAB 4

d. Permanent demand destruction, offsetting the contract revenue increases described above, of $3.0 million is a direct result of significant additional plant closures in Union's large infranchise contract markets.

2008 General Service Revenues

The actual total general service delivery revenue in 2008 was $574.9 million (Appendix A, Schedule 9, Column (r), line 6), prior to adjustments, compared to the 2007 Board approved forecast of $565.2 million (Appendix A, Schedule 9, Column (f), line 6). The primary contributors to the variance of $9.7 million were colder than normal weather in 2008 ($3.6 million) and rate class migration from contract rate classes to general service rate classes ($2.1 million). The remaining variance of $4.0 million was due to variances in the forecast level of customer additions, demand price elasticity related normalized average consumption ("NAC") variances, non demand side management ("DSM") related energy conservation, the Average Use ("AU") factor and the unbilled revenue accrual.

TRANSPORTATION REVENUE

Revenue from exfranchise transportation services increased by $37.7 million in 2008 relative to 2007 Board approved levels. This was primarily driven by increases in short-term transportation and exchange revenue of $23.3 million. Increases in long-term transportation revenue of $14.5 million as a result of the expansion of Union's Dawn Trafalgar transmission system, offset by increases in depreciation and cost of capital identified below, also contributed to the increased transportation revenue in 2008. The increase in short-term transportation and exchange revenue is explained in more detail below.

Short-Term Transportation and Exchange Revenue

As noted above, short-term transportation and exchange revenues accounted for $23.3 million of the $37.7 million increase in exfranchise transportation revenue in 2008 over 2007 Board approved levels. The increased revenue was a result of increased customer activity and service values due to colder than normal weather late in the year and new market opportunities. In addition, Union put a greater focus on the gas supply transportation portfolio optimization starting in 2007. This focus continued through 2008. Union also invested in incremental sales staff to capture the incremental revenue opportunities and deliver these services to customers. Union's approach to the marketing of transactional services and the financial results for 2008 were the direct result of the IR framework and the elimination of the transportation deferral accounts.

Union notes that Board approved distribution rates in 2008 include $6.9 million in short-term transportation and exchange margin. To achieve the total net margin of $6.9 million as embedded in the 2008 distribution rates, Union must achieve gross transactional revenue (before deduction of costs) of approximately $10 to $12 million.

TAB 5

UNION GAS LIMITED

Answer to Interrogatory from
Board Staff

Ref: Exhibit A, page 26

Question:

Union forecasted short-term transportation and exchange revenues of $18 million in 2009. This is a $5 million reduction from 2008 actual revenue. Union stated, "*The 2009 forecast reflects Union's continued focus and proactive approach to optimization of transportation assets by selling services early in 2008, prior to the precipitous decline in the markets and commodity prices. Those contracts will sustain higher revenues into the 2009 winter season*".

a) Please explain how Union's proactive approach to the optimization of transportation assets would result in a reduction of 2009 short-term transportation and exchange revenues.

Response:

The evidence at the above-noted reference explains that while the 2009 transportation and exchange revenues are projected to be lower than the 2008 actuals, had Union not been proactive in its approach, the 2009 revenues would have been lower than forecast. Specifically, given that Union proactively sold transport and exchange services in 2008 for terms that extended into 2009 prior to a deterioration of the economy and commodity prices, 2009 revenues will reflect these higher market values.

TAB 6

EB-2009-0101

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 amending or varying the rate or rates charged to customers as of July 1, 2009 in connection with the sharing of 2008 earnings under the incentive rate mechanism approved by the Ontario Energy Board on January 17, 2008

SETTLEMENT AGREEMENT

June 4, 2009

This Settlement Agreement ("Agreement") is for the consideration of the Ontario Energy Board ("the Board") in its determination, under Docket No. EB-2009-0101, of the disposition of Calendar 2008 earnings sharing under a settlement agreement approved by the Board on January 17, 2008 in EB-2007-0606 (the "IR Settlement Agreement") for Union Gas Limited ("Union"). By Procedural Order No.1 dated April 28, 2009, the Board scheduled a Settlement Conference to commence May 27, 2009. The Settlement Conference was duly convened, in accordance with Procedural Order No. 1, with Mr. George Dominy as facilitator. The Settlement Conference proceeded until May 28, 2009.

The settlement presented in this Agreement is comprehensive in that the agreement that has been reached settles all issues in this proceeding.

The Agreement is supported by the evidence filed in the EB-2009-0101 proceeding.

The purpose of this proceeding was:

(a) to provide Union's calculation of its 2008 utility earnings for the purposes of earnings sharing pursuant to Section 10.1 of the IR Settlement Agreement. Section 10.1 of the IR Settlement Agreement provides:

> *"If in any calendar year Union's actual utility return on equity is more than 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such excess earnings will be shared 50/50 between Union and its customers. 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 reducing 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."*

(b) to consider Union's application pursuant to section 9.1 of the IR Settlement Agreement. Section 9.1 provides:

> *"The parties agree that if there is a 300 basis point or greater variance in weather normalized utility earnings above or below the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, Union will file an application to the Board, with appropriate supporting evidence, for a review of the price cap mechanism. During the course of that review, the Board may be asked to determine whether it is appropriate to continue the price cap mechanism for future years and, if so, with or without modifications. All parties including Union will be free to take such positions as they consider appropriate with respect to that application, including without limitation; a) proposing that a component of the IR Plan, including the X factor, be adjusted, b) proposing that IR plan be terminated, and c) taking any other positions as the party may consider relevant and the Board agrees to hear. Union shall file such application as soon as reasonably possible in the year following the year in which the over earnings threshold is met, unless all parties to this Agreement agree otherwise at that time."*

It is acknowledged and agreed that none of the provisions of this Agreement is severable. If the Board does not, prior to the commencement of the hearing of the evidence in EB-2009-0101, accept the Agreement in its entirety, there is no Agreement (unless the parties to the Agreement agree that any portion of the Agreement the Board does accept may continue as a valid agreement).

It is further acknowledged and agreed that parties to the Agreement 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.

The participants in the Settlement Conference agree that all positions, negotiations and discussion of any kind whatsoever which took place during the Settlement Conference and all documents exchanged during the conference which were prepared to facilitate settlement discussions are strictly confidential and 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 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".

The evidence supporting the Agreement is set out in the Agreement. Abbreviations will be used when identifying exhibit references. For example, Exhibit B1, Tab 4, Schedule 1, Page 1 will be referred to as B1/T4/S1/p1. There are Appendices to the Agreement which provide further evidentiary support. The structure and presentation of the settled issues is consistent with settlement agreements which have been accepted by the Board in prior cases. The parties agree that this Agreement and the Appendices form part of the record in the proceeding.

In Procedural Order No. 1 in this proceeding, the Board granted intervenor status to all intervenors of record in EB-2007-0606 and EB-2008-0220. The following entities participated in the Settlement Conference:

Building Owners and Managers Association of the Greater Toronto Area ("BOMA")
Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Industrial Gas Users Association ("IGUA")
City of Kitchener ("Kitchener")
London Property Management Association ("LPMA")
School Energy Coalition ("SEC")
The City of Timmins ("Timmins")
Union Gas Limited ("Union")
Vulnerable Energy Consumers Coalition ("VECC")
Wholesale Gas Services Purchasers Group ("WGSPG")
Energy Probe ("EP")
Federation of Rental-housing Providers of Ontario ("FRPO")

The parties to this Agreement include all of the above noted entities except IGUA (the "parties"). The parties to this Agreement represent major stakeholders and constituencies with an interest in Union's rates.

The parties to this settlement encourage the Board to accept this Agreement in its entirety. The parties to this Agreement also support finalization of the rate order in these proceedings to enable implementation of this Agreement in Union's July 1 QRAM.

1. Earnings Sharing Calculation and Off Ramp Amendments

(Complete Settlement)

The parties agree that, upon approval of this Agreement by the Board, the IR Settlement Agreement shall, for the entire IR term, 2008 to 2012, be amended as follows (for the assistance of parties and the Board, the agreed upon amendments to the IR Settlement Agreement are blacklined below):

> 9.1 [Section 9.1 of the IR Settlement Agreement shall be deleted in its entirety.]
>
> 10.1 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 200 basis points <u>but not more than 300 basis points</u> over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such excess earnings will be shared 50/50 between Union and its customers. <u>In addition to the above, if in any calendar year Union's actual utility return on equity is more than 300 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such earnings in excess of 300 basis points will be shared 90/10 between customers and Union (i.e., customers will be credited 90% and Union will be credited 10%).</u> 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 reducing 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. For greater clarity, Union's one time accounting adjustment in 2008 to true up an unbilled revenue accrual to reflect Union's current rate structure and billing cycles, in the amount of $3.6 million, is an adjustment that is excluded from the calculation of actual utility earnings, whereas the use of actual unaccounted for gas volume is an expense that would be recorded in the calculation of actual utility earnings.

The parties believe that these amendments to the Board-approved IR Settlement Agreement are in the public interest. The amendments are intended to modify the IR formula so as to in produce rates which are just and reasonable during the IR term. The Agreement:

1. clarifies possible ambiguities in the calculation of earning sharing in section 10.1 of the IR Settlement Agreement arising from the relationship between the use of actual utility earnings and the *proviso* in section 10.1 restricting any adjustments in the calculation of actual utility earnings to those adjustments to actual earnings that would be made in a cost of service filing. Intervenors took the position, for example, that none of the adjustments proposed by Union in the calculation of 2008 actual utility earnings were appropriate. Union took the position that all of its proposed adjustments were in accordance with the IR Settlement Agreement. This Agreement avoids the cost and uncertainty of litigation over these disputes, now and in the future, by resolving which adjustments to the calculation of actual utility earnings, for the purposes of earnings sharing, are appropriate;

2. provides additional potential benefits to customers during the term of the IR plan, 2008 to 2012, in circumstances where Union's actual utility income exceeds the amount

calculated by the application of the Board's ROE formula in any year of the IR plan by over 300 basis points, by crediting 90% of such earnings to customers.[1] The consumer protection afforded by the "off ramp" provision for review in section 9.1 of the IR Settlement Agreement has been replaced with crediting 90% of earnings over the 300 basis point threshold to customers, i.e., Union will have a modest incentive to pursue even greater productivity initiatives and customer bills will go down, all else equal, to the extent Union delivers earnings in excess of the 300 basis point threshold. The parties acknowledge that the elimination of the "off ramp" review in section 9.1 is without prejudice to all rights afforded under section 6.1 (Z Factors) of the IR Settlement Agreement;

3. provides greater certainty and incentive for Union to explore and make investments in productivity improvements during the term of the 2008 to 2012 IR plan;

4. continues to provide for annual reviews during the term of the IR plan during which intervenors will be able to carefully review the reasons and calculation of sharing for all earnings in excess of 200 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan.

5. avoids complex, lengthy and highly controversial and contested disputes over the potential for termination of the IR plan and the need for a new full cost of service proceeding. In this case, intervenors took the position, for example, that the proper calculation of weather normalized utility earnings in 2008 was materially in excess of the 300 basis point threshold which gave intervenors the right to seek a review of the IR plan, the consideration of adjustments to the components of the IR plan, including base rates, and the termination of the IR plan and a return to cost of service rates, just as Union would have had the right to take the same position had the company under-earned by an equivalent amount. Union took the position that the IR plan was working as contemplated and producing significant benefits for customers and that the termination of

---

1 Union does not currently forecast exceeding the 300 basis point threshold in 2009 or 2010.

incentive regulation after the first year of the five year plan was premature and inappropriate. Union will be applying in 2012 for 2013 cost of service rebasing in any event; and

6. avoids complex, lengthy and highly controversial and contested disputes over 2007 base rates and the potential for further adjustments to those base rates during the IR plan. For example, intervenors took the position that Union's 2007 normalized utility earnings were materially higher than the forecast available during the period in which the IR Settlement Agreement was negotiated and that adjustments to the IR plan, such as altering the size of the earnings sharing deadband, altering the level of earnings sharing, and adjustments to 2008 earnings sharing and/or to base rates during the IR term could be made to take account of this positive variance. Union took the position that such variances were not relevant to 2008 earnings sharing and that no adjustments to the IR plan or to base rates during the IR term, except those, such as Z factors, expressly contemplated by the IR Settlement Agreement, should be made. This issue involved a number of potentially controversial disputes, including disputes over the appropriate calculation methodology, the extent to which the likelihood of favourable variances, and the extent of those variances, was, or ought to have been, known to all parties when the IR Settlement Agreement was negotiated and whether base rate adjustments of this kind are appropriate during the IR term.

The financial consequences of this Agreement for the calculation of 2008 earnings sharing under the IR Settlement Agreement are set out in Appendix A attached to this Agreement. The adjustments in the Agreement to Union's original proposal are the result of compromise by the agreeing parties of their respective positions on the matters listed above. In all of the circumstances, the parties have agreed to increase the customer share of Union's 2008 earnings from the proposed \$15.2 million to \$34.2 million, as outlined in Appendix A.

Consistent with past practice, the customer portion of the amount calculated in Appendix A shall be allocated to rate classes in proportion to Board approved return on equity as set out in the allocation schedule in Appendix B attached to this Agreement. Of the \$34.2 million customer share of earnings for 2008, approximately $19.6 million will be allocated to small volume general service customers and approximately $3.2 million will be allocated to large volume general service customers. Approximately $4.7 million will be allocated to the large volume contract customers and approximately $6.7 million to M12 shippers such as Enbridge Gas Distribution Inc. ("EGD"), Gaz Métropolitain inc. ("GMi"), and TransCanada PipeLines Limited ("TCPL"). Approving the settlement reflected in the Agreement, therefore, will benefit all customers but, in particular, will provide benefits to small volume general service customers.

Evidence References:

1. A/p.9-20, A/p.27-29, A/App. B/S.1, A/App. B/S.2, A/App. B/S.3, A/App. D/S.1, A/ App. D/S.2
2. Technical Conference, pp. 19-28, 33-34
3. B/T1/S6, B/T2/S1, B/T2/S3, B/T4/S7, B/T4/S8, B/T5/S3
4. J1.1

UNION GAS LIMITED
Earnings Sharing Calculation
Year Ended December 31, 2008

Line No.	Particulars ($000's)	2008 (a)	Non-Utility Storage (b)	Adjustments (c)		2008 Utility (d)=(a)-(b)+(c)
	Operating Revenues:					
1	Operating revenue	$ 1,869,283	$ -	$ (3,654)	i	1,865,629
2	Storage & Transportation	243,317	78,230	-		165,087
3	Other	33,818	-	(7,530)	ii	26,288
4		2,146,418	78,230	(11,184)		2,057,004
	Operating Expenses:					
5	Cost of gas	1,171,320	8,082	-		1,163,238
6	Operating and maintenance expenses	335,115	12,028	(516)	iii	322,571
7	Depreciation	185,219	4,966	-		180,253
8	Other financing	-	-	535	iv	535
9	Property and capital taxes	65,895	953	-		64,942
10		1,757,549	26,029	19		1,731,539
11	Earning Before Interest and Taxes	$ 388,869	$ 52,201	$ (11,203)		$ 325,465
	Financial Expenses:					
12	Long-term debt					143,546
13	Unfunded short-term debt					2,805
14						146,351
15	Utility income before income taxes					179,114
16	Income taxes					31,300
17	Preferred dividend requirements					5,088
18	Utility earnings					142,726
19	Long term storage premium subsidy (after tax)					10,676
20	Short term storage premium subsidy (after tax)					7,484
21						18,160
22	Earnings subject to sharing					$ 160,886
23	Common equity					1,206,196
24	Return on equity (line22 / line 23)					13.35%
25	Benchmark return on equity					10.81%
26	50% Earnings sharing %					1.00%
27	90% Earnings sharing to ratepayer % (line 24 - line 25 - line 26)					1.54%
28	50% Earnings sharing $ (line 26 x line 23 x 50%)					6,026
29	90% Earnings sharing to ratepayer $ (line 27 x line 23 x 90%)					16,697
30	Total earnings sharing $ (line 28 + line 29)					22,723
31	Pre-tax earnings sharing (line 30 / (1 minus tax rate))					$ 34,170

Notes:

i) Accounting adjustment

ii) Shared Savings Mechanism

iii) Donations (394)
EB-2008-0304 costs (122)
(516)

iv) Customer deposit interest

UNION GAS LIMITED
Allocation of 2008 Earning Sharing to Rate Classes

Line No.	Particulars	Rate Class	C2007 Return on Equity Allocation (1) ($000's) (a)	2008 Earning Sharing ($000's) (b)
	Northern & Eastern Operations Area			
1	Small Volume General Firm Service	01	44,549	(5,867)
2	Large Volume General Firm Service	10	8,234	(1,084)
3	Medium Volume Firm Service	20	4,263	(561)
4	Large Volume High Load Factor Firm Service	100	5,641	(743)
5	Large Volume Interruptible Service	25	1,913	(252)
6	Wholesale Transportation Service	77	8	(1)
7	Total Northern & Eastern Operations Area		64,608	(8,509)
	Southern Operations Area			
8	Small Volume General Service Rate	M1	104,130	(13,715)
9	Large Volume General Service Rate	M2	15,828	(2,085)
10	Firm Industrial and Commercial Contract Rate	M4	4,220	(556)
11	Interruptible Industrial & Commercial Contract Rate	M5A	2,587	(341)
12	Special Large Volume Industrial & Commercial Contract Rate	M7	2,617	(345)
13	Large Wholesale Service Rate	M9	219	(29)
14	Small Wholesale Service Rate	M10	10	(1)
15	S & T Rates for Contract Carriage Customers	T1	12,835	(1,691)
16	S & T Rates for Contract Carriage Customers	T3	1,546	(204)
	Storage and Transportation			
17	Cross Franchise Transportation Rates	C1	186	(24)
18	Storage & Transportation Rates	M12	50,557	(6,659)
19	Transportation of Locally Produced Gas	M13	39	(5)
20	Storage & Transportation Services - Transportation Charges	M16	55	(7)
21	Total Southern Operations Area		194,830	(25,661)
22	Total		259,438	(34,170) (2)

Notes:
(1) Allocated costs per 2007 Decision in EB-2005-0520
(2) Earning Sharing balance for Disposition as per EB-2009-0101, Settlement Agreement, Appendix A

TAB 7

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	EB-2008-0101	
VOLUME:	1	
DATE:	June 8, 2009	
BEFORE:	Gordon Kaiser	Presiding Member and Vice-Chair
	Paul Vlahos	Member
	Paul Sommerville	Member

MR. KAISER: He who has the compendium goes first, a long-standing rule. Mr. Thompson.

SUBMISSIONS BY MR. THOMPSON:

MR. THOMPSON: Thank you, Mr. Chairman, Members of the Board. You have the compendium which I will be referring to. It does duplicate some of the materials that Mr. Penny has already referenced.

There are other documents that I will refer to. Unfortunately, I don't have copies, and I couldn't circulate them last night. I am technically inept to do this electronically, but I did provide an e-mail notice of what I would be referring to, and one was excerpts from the Board's decision in EB-2008-0304.

That's your decision, Mr. Kaiser, in November of 2008 dealing with Union's restructuring application. I will make a couple of references to that. I don't think you will need copies.

The second item that I will refer to is Rule 43 of the Rules of Procedure, and, again, I can just read that when I come to that point. It's not terribly long.

CME strongly supports the settlement and urges you to approve it. Why? Because it resolves contentious earnings sharing adjustment calculation issues for 2008 which are issues of substance. It resolves those issues now and for future years, and it resolves them on a basis that is favourable to ratepayers.

Mr. Penny had addressed this perhaps in a slightly different way, and I will provide the ratepayer rationale, CME's rationale, for this aspect of the agreement.

It is spelled out in paragraph 1 of the settlement agreement. You will find the settlement agreement at tab 1 of my belief. And when I say paragraph 1, I mean paragraph 1 of the rationale. That is at page 5. Mr. Penny has already read that into the record.

The resolution of the matter is on the basis that the historic presentation of actual utility earnings in a cost of service filing does not include normalized UFG. The normalized UFG calculation is only included in the forecasted statement of income expenses which are presented in a cost of service filing for a prospective test year.

So the parties have agreed that the meaning to be ascribed to this section of their agreement is that the cost consequences of the actual historical test year filing are to be reflected in the calculation of actual utility earnings.

As Mr. Penny has indicated, this adjustment brings the sharing from about $15 million to about $23 million, and the additional $11 million comes from the resolution of the other item of the agreement that he addressed in his submissions.

This outcome on the earnings sharing calculation issue is favourable to ratepayers, and there is nothing in the questions circulated by Board Staff or in the IGUA letter that should prompt you to question this feature of the settlement proposal.

Turning to the second feature of the settlement proposal, which is essentially the adjustment to the sharing -- the over-earnings sharing percentages specified in the original settlement agreement for the years 2008 to 2012, inclusive, as well as the removal of the -- I call them "off-ramp" provisions of the agreement in article 10.1.

The settlement of both issues was linked, but I will address this issue in my submissions separately.

Now, the starting point for CME's submissions on this point are the provisions of the agreement describing the parties' rights, and you will find those in the settlement agreement. They are reproduced at page 2 of the document that is under tab 1.

I think it's useful to look at this clause as to what the rights of the parties were when the over 300 basis points earnings variance occurred, or, for that matter, when 300 basis points under the Board-approved occurs.

First of all, Union must file -- it says "will file an application to the Board for review". So the review is mandatory. It's not discretionary, in terms of the filing of it. And:

> "During the course of that review, the Board may be asked to determine whether it is appropriate to continue the price cap mechanism for future years, and, if so, with or without modifications. All parties, including Union, will be free to take such positions as they consider appropriate with respect to that application, including,

without limitation: A, proposing that a component of the IR plan including the X factor be adjusted; B, proposing that the IR plan be terminated; and C, taking any other positions as the party may consider relevant and the Board agrees to hear."

So the point is this is a very broad rights clause for both Union and the ratepayers. And it includes the right to request that any component of the IR plan be adjusted as well as a right to request that the plan be terminated.

So there is nothing in this agreement, in my submission, that suggests that we should be turning a blind eye to over-earnings in year 1 of a five-year plan. The prematurity issue that the Board raises in question one clearly is something that is incompatible with the provisions of this agreement.

When under-earnings occur or over-earnings occur more than 300 basis points from the Board's approved return, a review is mandatory, and I submit that in that review, the matters to be examined are the causes for the variance and ascertain whether an adjustment or adjustments to any planned component or termination of the plan are called for.

That's exactly what the parties did in this case.

Let me turn to the level of over-earnings we are talking about in this case. Just to put it in a basis points context, you can see from the appendix A to the agreement at Tab 1, that the return on equity that flows from the adjustment being made to eliminate the UFG deduction that Union had included there at line 24 is 13.35 percent. That's versus the Board approved of 8.81 percent. So we are talking here in this particular year, 2008, of a 454 basis points overage.

Now, on the weathered-normalized aspect of this, you can get a ballpark for this number from the calculation that Mr. Penny mentioned in his submissions with respect to the company's response to CME interrogatory number 1, and you will find that at page 71 of Mr. Penny's compendium.

If you go over to page 73, what the company is showing there is the -- a modified off-ramp calculation as per CME question 1. What we had asked in that question was for the -- all adjustments to be removed except the DSM adjustment which appeared at line 3. But what you do have in this calculation is the normalizing adjustment in column 1 -- sorry, line 1 of column C. You will see there that the return on equity at line 24 normalized, weather-normalized is 13.17 percent. Now this is a little high because the accounting adjustment has also been taken out. But we make it that the number, after adjusting for that accounting item, would be in excess of 13.0 percent. So we are dealing with a weather-normalized actual earnings for 2008 that exceeds 400 basis points. It's 419 if you take 13 as the estimate. But it exceeds 400 basis points.

What do these levels of over-earning mean in terms of the reasonableness of Union's revenue requirement and rates for 2008? Well, Union indicated to us that 100 basis points grossed up for taxes is -- 100 basis points on equity is $18 million. So at 454 basis points, looking at this from a cost of service rebasing perspective, Union's rates are some $82 million higher than they would be had they just come in at the Board-approved 8.81 percent. At 400 basis points, they would be about $72 million.

So we are dealing here with some very material amounts, and in terms of what would the Board do if this goes to hearing, would it turn a blind eye to these amounts? We don't think so. And in reaching that conclusion, we suggest the Board would unlikely turn a blind eye to a request by Union for adjustments to the plan following a $72 million under-earnings in the first year of the operation of the plan.

So we say there is a real issue here in terms of the ratepayer rights.

In the context, as well, of what off-ramp relief is all about and in that context, I have provided at tab 2 of the brief, excerpts from the Board's July 21, 2001, decision in Union's first PBR, performance regulation case, and the subject of off-ramps was discussed in section 2.7.6.

I won't read this, but at page 155 in the Board's findings, these findings make it clear that the off-ramp relief is designed to remedy a situation super-normal profits or a situation of under earnings which creates a threat to the integrity of the utility. What we have here, in my submission, is a case of super-normal earnings in year one of the IR plan.

Now, what are the causes of this situation? One of them is the UFG is lower than expected by $15.6 million, that would be about 87 basis points.

Another major reason which wasn't addressed by Mr. Penny in his submissions, but it was important to intervenors, is that the level of 2007 base rates turned out to be $34.1 million. This is normalized actual, 2007 base rates, $34.1 million higher than Board-approved ROE. You can see this at Tab 6 of our brief in the second page of that tab there is an exhibit that Union provided as provided showing the normalized actual over-earnings of 2007 of $34.1 million; that's in the final column.

Now was that what we were aware of when the initial agreement was negotiated? The answer to that is no. What we were aware of is shown on the previous page, which was normalized at actual over-earnings it's shown there of $19,227,000 but you need to add the tax -- sorry, you need to add the weather-normalization and tax in the amount of $3.4 million which comes up to $22.6 million which is shown on the first page under Tab 6.

As a result -- and we didn't learn this until I think it's in January of 2009, when the Board actually ordered Union to provide its 2007 normalized actual results, Union had not been -- that order was made in the context of the Board's approval of Union's 2009 rates.

Union was taking the position that it did not need to produce that information to intervenors under the terms of the Board-approved plan.

So we learn in January of 2009 that a significant factor pertaining to the negotiation of the initial agreement was not $22.6 million. It was more than 150 percent more, $34.1 million.

That raises this entire issue of disclosure and the kinds of discussions that were held and the rulings the Board made in the decision I mentioned earlier about the restructuring application.

We take the position -- at least CME takes the position that this is a live issue in this case that was up for resolution, that a 150 percent deviation from estimate is a misrepresentation. Whether it's innocent or not innocent, it gives rise to equitable remedies, and that's what this review clause is all about, in my respectful submission.

One outcome might be an adjustment to base rates of $11 million, and, if one looked at that, that would be, over five years, an amount of some $57.5 million. The actual difference between the 22.6 and the 34.1 is 11-1/2-million dollars.

Other possible outcomes would be an adjustment to the dead band. Would we have agreed to a 200 basis point dead band if we had known normalized actual earnings for 2007 were $11.5 million more than what was represented?

Another outcome would be a variance of the sharing ratio over 200, and that's really the route that we took in this for the purposes of reaching a settlement.

All of these possible outcomes would in issue if this settlement is not approved, and this is in addition to the ambiguity in the agreement with respect to sharing over 300, to which Mr. Penny has referred.

So what have the parties done to resolve these issues? As Mr. Penny has outlined, they have agreed to adjust the earnings sharing component of the IR plan for the years 2008 to 2012, inclusive, and increase the ratepayer's share to 90 percent over 300 basis points.

Ratepayers have agreed, except for IGUA, who has essentially abstained here, that we will get 90 percent of everything over 300, and, in exchange, we can eliminate the trigger from the agreement.

The financial implications of the settlement Mr. Penny has pointed out, but it might be useful to just give you the math here in terms of some basis points scenarios.

At 300 basis points, under the initial agreement, Union would get 250 of it and the ratepayers would get 50. Three hundred basis points would be $52 million, so Union's shareholder gets 45 and ratepayers get 9.

At 400 basis points, you would have 72 million of earnings. Under the original agreement, the shareholder would get 54; ratepayers get 18. Now the shareholder gets 46.8, the ratepayer gets 25.2. You can go do the math for higher basis rates scenarios, as well.

The point is that this settlement, as far as CME is concerned, is favourable to ratepayers.

We also suggest that the settlement is more beneficial to ratepayers than the Board's 3GIRM trigger mechanism is to electric utility ratepayers. I have attached the 3GIRM report segment dealing with off-ramps at tab 4.

In that plan or that -- that's not an agreed plan. That's an imposed arrangement. There is no earnings sharing mechanism, and there is a trigger at 300 basis points. So the utility gets everything up to 300 and everything over 300, unless the Board makes some order in the review proceeding that is triggered in that case.

In Union's situation, as a result of the deal that we made, Union gets 250 basis points for earnings up to $300, and then to get to 300 it would actually have to earn over 800 basis points, because it only gets 10 basis points of every 100 over 300.

So the scenario of Union having a licence to earn over 300 basis points, in my respectful submission, is not terribly realistic, because to achieve over 300 for its shareholder they would actually have to earn in excess of 800 basis points above the Board-approved ROE.

Does the agreement eliminate -- the agreement to eliminate the automatic review at 300 basis points dilute ratepayer protection when they get 90 percent of everything over 300? We submit, no.

First, as Mr. Penny has pointed out, the reviews of over-earnings are not eliminated. They take place over-earnings over 200, and all causes can be explored in the context of that process.

Second, the agreement doesn't give Union the licence to earn more than 300 basis points for shareholders, I have already mentioned.

Third, what is the likelihood of anything over 300 occurring in future years? Because if it doesn't occur, we have given up nothing under either agreement.

Now, in its evidence filing, you don't need to turn this up, but Union has forecast its ROE for 2010. I think it's at 10.37 percent. This is not in my brief, unfortunately. This is at - I will just give you the reference - Exhibit A, appendix C, schedule 2, page 1.

And based on the assumptions that are built into that forecast, that's slightly less than 200 basis points above the ROE that's assumed. In 2010, they are forecasting 8.94 percent ROE, which, again, would be less than the 300 basis points, and I think less than the 200 basis points.

So if we give their forecasts credence - and that can be sometimes risky - they are not going to get there, but even if their forecasts are off when we get 90 percent of everything over and above 300, in my submission, substantively what you have is a cost of service type offering.

Finally, when you ask yourself what are you giving up when you let this trigger go in exchange for the 90 percent of everything over 300, you have to consider what are the probabilities of a review being conducted as we approach the end of the five-year IR plan.

These reviews only take place after a year has been completed. So a 2011 review would come up if it occurred sometime in 2012. A 2012 review would come up in 2013. And we know that Union's rebasing application is going to be filed either at the end of 2011 or early 2012 for 2013.

So CME thinks it's highly unlikely there would be any full-scale plan or review undertaken either with respect to 2011 or 2012.

So when you put all this together, we are not really giving up much of anything as far as CME is concerned and we think that we've replaced it with what might be termed a more defined situation than that that existed in the initial agreement.

So with that, let me just turn to the Board Staff questions and the matters raised in those questions.

Dealing with the first point: Is the settlement premature? We submit clearly not premature. It's timely. The facts giving rise to this 2008 review are on the table and they give rise to very substantive issues that the parties have been able to resolve. So nothing premature about it at all.

Secondly, Staff questions whether there is a need for a full hearing. I agree with Mr. Penny. The whole purpose of settlement agreements is to avoid the need for a full hearing. That was the purpose of the initial five-year deal and if a five-year deal can be approved without a full hearing, certainly a four-year adjustment to the five-year deal should be capable of being approved without a full hearing. The case Mr. Penny cites certainly supports that proposition.

But then you go on to ask yourself: What is there to hear? As Mr. Penny says nobody is proposing there be an outcome more beneficial to ratepayers than the settlement proposal, so there is really nothing to hear, in our respectful submission.

The third question of Staff related to risks associated with eliminating the trigger mechanism, and it's risks to the parties, really, because the Board is not bound by what the parties do. And in Rule 43 of your Rules of Practice and Procedure, it states:

> "The Board may at any time indicate its intention to review all or part of any order or decision and may confirm, vary, suspend or cancel the order or decision serving a letter on all parties to the proceedings."

So even if some very strange and unexpected circumstances did materialize which called into question the continued appropriateness of this deal, the Board itself can do what is necessary to initiate the review.

Whatever risks there are, and CME doesn't see any, the parties have accepted them in this arrangement. We don't see any dilution of either ratepayer or utility protection. In fact, we submit there is some added ratepayer benefit in that it defines in advance what ratepayers get over the 300 basis points. The fact that we allow Union to keep 10 of it, in my respectful submission, maintains an incentive for Union to do better. The major incentives of this particular five-year deal are with the 200 basis points dead band and the 50/50 sharing over 200.

So we don't see that very much has been given up and it's arguable that the agreement has been strengthened in terms of ratepayer protection, not weakened.

On the issue of no retroactive ratemaking, we agree with Mr. Penny this does not involve retroactive rate making. There is this ambiguity of sharing over 300. What we have addressed in the settlement is an as yet unresolved item with respect to 2008 earnings sharing, as well as matters pertaining to the automatic 2008 review and reviews beyond 2008. The resolution of these two items is linked in the settlement, but that's the way settlements work and there is no reason, in our submission, why you would -- or why you should find that linkage as inappropriate.

There are these major benefits to ratepayers in the agreement.

At the last schedule, the last page -- this is under Tab 1 of our brief. You will see the allocation of the amounts to ratepayer classes, and by and large the beneficiaries of this settlement are the smaller ratepayers, and that's referenced in the settlement agreement itself at page 7, it's under Tab 1 at page 7, the second last paragraph -- full paragraph on the page.

The financial consequences of this agreement for the calculation of 2008 earnings sharing under the RSM are set out in Appendix A attached to this agreement. The adjustments in the agreement to Union's original proposal are the result of compromise by the agreeing parties of their respective positions on matters listed above. In all of the circumstances, the parties have agreed to increase the customer share of 2008 earnings from the proposed $15 million to $24.2 million.

And then starting at the bottom:

"Of the $34.2 million customer share of earnings, approximately 19.6 will be allocated to small volume general service customers and approximately 3.2 million will be allocated to large volume general service customers. Approximately 4.7 will be allocated to large volume contract customers, and approximately 6.7 to M-12 shippers."

It goes on and says:

"Those benefits will flow back to the customers of the M-12 shippers."

So it's a settlement that is favourable to all customers. If it's not approved, the customers that will suffer the most are the smaller customers.

The settlement agreements, we submit, are in the public interest. This particular agreement is in the interest of ratepayers and the shareholder. It resolves a potentially protracted hearing process and does not dilute the incentive effect of the initial agreement.

CME submits that the Board should not hesitate to approve the deal as fair and reasonable for ratepayers and for Union shareholders. Those are my submissions.

MR. KAISER: Thank you, Mr. Thompson.

TAB 8

Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2008-0101

VOLUME: 1

DATE: June 8, 2009

BEFORE:	Gordon Kaiser	Presiding Member and Vice-Chair
	Paul Vlahos	Member
	Paul Sommerville	Member

come back in 15 minutes.

--- Recess taken at 12:16 p.m.

--- Upon resuming at 12:29 p.m.

DECISION:

MR. KAISER: The Board heard submissions this morning regarding an application Union Gas filed with the Board on April 2nd of this year under section 36 of the Ontario Energy Board Act. That application sought orders to vary rates effective July 1st, 2009, in connection with the sharing of 2008 earnings under the incentive rate mechanism approved by this Board on January 17th, 2008 in EB-2007-0606. That incentive plan covers the period 2008 to 2012. We are now dealing with the first year under that plan, namely the 2008 year.

At the end of the day, what is at issue in this proceeding is two paragraphs in the original agreement. The first is Paragraph 10.1 at page 22 of that agreement. That paragraph states:

"The parties agree that there will be an earning sharing mechanism based on actual utility earnings. If in any calendar year, Union's actual utility return on equity is more than 200 basis points over the amount calculated annually by application of the Board's ROE formula in any year of the IR plan, then such excess earnings shall be shared 50/50 between Union and its customers."

The other issue concerns paragraph 9.1 of the original settlement agreement. That's at page 21 of the original agreement. That covenant read:

"The parties agree that if there is a 300-basis point or greater variance in weather-normalized utility earnings above or below the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, Union will file an application with the Board with appropriate supporting evidence for a review of the price cap mechanism."

The section goes on to outline the procedure regarding that application. This is known as the off-ramp.

On June 4th 2009, the parties in this proceeding filed a new settlement agreement with the Board. The relevant provisions are in paragraph 1 at page 4 of that agreement. Paragraph 1 provides, first of all, that Section 9.1 of the original IR settlement shall be deleted in its entirety. That was the section that provided for the so-called off-ramp

Paragraph 10.1 of the original agreement is also revised in the new agreement. The new agreement provides that:

"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 revenue return on equity is more than 200-basis point but not more than 300 basis points over the amount calculated annually by application of the Boards ROE formula in any year of the IR plan, then such excess earnings shall be shared 50/50 between Union and its customer."

This is followed by a new provision:

"In addition to the above, if in any calendar year, Union's actual utility return on equity is more than 300 basis points over the amount calculated annually by the application of the Board's ROE formula in any year of the IR plan, then such earnings in excess of 300-basis points will be shared 90/10 between customers and Union, (i.e., customers will be credited 90 percent and Union will be credited 10 percent.)"

A wide range of customer interests were represented in this proceeding. All agree to the settlement except one, which I will come to in a moment.

The evidence before us indicated that under the original settlement plan with the 50/50 split, some $15.2 million would be made available to the customers. That amount has increased by reason of certain adjustments in the calculations as well as the new 90/10 split. The amount is now $34.17 million. Those amounts are set out in Appendix A of the Settlement Agreement which is attached to this decision as Schedule 'A'. The original agreement is attached as Schedule 'B'.

Appendix B of the new Settlement Agreement shows the allocation of the $34.17 million between different customer classes. It has been pointed out that the main beneficiaries are the small-volume general service customers. In the Southern Operations Area, they receive 13.7 million of that 34 million. In the Northern and Eastern Operations Area it's almost 6 million.

The one conclusion no one disputes is that there will be a substantial reduction in rates under the new settlement agreement, all of which is clearly set out in the agreement.

The one objection to the settlement is made by IGUA. IGUA filed a letter on June 5th with the Board. The relevant paragraph of that letter reads as follows:

> "IGUA recognizes that the settlement proposes a greater share for ratepayers of any over-earnings above 300 basis which affords ratepayers some protection. However, IGUA remains concerned that the removal of the trigger mechanism, in effect, provides Union with a 'licence' to continue to over-earn in excess of 300 basis points under the IRM plan without review of the reasons therefore and the reasonableness of the continuing with the plan as set."

As I indicated, IGUA is the only party opposing this settlement Agreement, and it is on that basis.

The Board would note, and this has been argued by counsel, that even if the contractual right of the parties to review the plan disappears when the trigger mechanism disappears, the Board still has inherent jurisdiction to review situations it regards as unfair or unreasonable.

Mr. Thompson referred to Rule 43 of the Board's rules.

Various parties also disputed IGUA's claim that Union will have a 'licence' to continue to over-earn in excess of 300 basis points. The Board agrees. After all, 90 percent of any "over-earnings" go to the customers.

Mr. Penny, in his submissions, referred to the Natural Gas Forum Report this Board issued in 2005. It is useful to remember why we are all here, what the purpose of these settlement agreements is, and in particular what the purpose of IRM is.

Mr. Penny referred at page 25 of his document brief to the message from the Chair, in the introduction to that Report:

> "First, we believe that all stakeholders will benefit from a more predictable and longer term treatment of rates. Utilities will benefit because they can make longer term decisions and customer will benefit through downward pressure on rates. The Board's report identifies the specific components of the incentive regulation plan the Board believes will lead to these results."

The amendment to the original settlement agreement, in the new proposed settlement agreement, meets those goals and the Board's objectives. It will not only reduce the regulatory cost but will allow greater certainty for all parties going forward. We heard that there were a number of disputes regarding the ambiguity of the language in the existing agreement. Two days of settlement discussions on May 25th and 26th were taken up debating those issues. They have largely been resolved through this agreement. The new Agreement is more than a revision of the revenue split. It is a much clearer agreement. That is in the interest of all the parties.

As to the downward pressure on rates, the evidence is set out in Appendix A and B of the agreement. There is a substantial reduction in rates and that, too, is in the interests of the parties.

We recognize Mr. Mondrow's concern on behalf of his client but as mentioned, the Board does have inherent jurisdiction to deal with situations contrary to the public interest. If a clear unfairness arises, the Board has the capacity to deal with it. And, there will continue to be a review of the over-earning amount every year.

For these reasons, the Board approves the Settlement Agreement as drafted. We will ask the applicant to file a rate order giving effect to this decision and allow the parties three days to respond to the draft order. It is in the interest of all parties to ensure that these rate reductions become effective on July 1st as planned. Any questions?

MR. PENNY: No, thank you, Mr. Chairman.

MR. THOMPSON: Mr. Chair, can I just record my client's request for reasonably-incurred costs in connection with this matter, thank you.

MR. KAISER: Yes. Mr. Warren, same?

MR. WARREN: Please, sir.

MR. KAISER: It sounds like Charles Dickens. Anyone else?

MR. WARREN: It is Charles Dickens ...

MR. KAISER: Thank you, gentlemen.

--- Whereupon the conference concluded at 12:40 p.m.