November 14, 2008

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

Dear Ms. Walli:

Re: Union Gas Prefiled Evidence
(Board File No. - EB-2008-0106)

Please find attached Union's evidence for the EB-2008-0106 proceeding.

Should you have any questions on this submission please contact me at (519) 436-5476.

Sincerely,

[original signed by]

Chris Ripley
Manager, Regulatory Applications

cc: Crawford Smith, Torys
All EB-2008-0106 Intervenors

UNION GAS LIMITED

SUMMARY OF APPLICATION

On March 30, 2005 the Ontario Energy Board ("Board") issued its Policy Framework Report on the Natural Gas Forum (the "NGF Report"). As part of the NGF Report, the Board stated an interest in Ontario's natural gas utilities moving towards establishing consistent rate-setting practices for the regulated gas supply. In particular, the Board indicated that the Quarterly Rate Adjustment Mechanism ("QRAM") should be a "transparent benchmark that reflects market prices, and that the methodology for determining the reference prices should therefore be formulaic and consistent". The Board also said that the methodology for determining the Purchase Gas Variance Account ("PGVA") and for disposing the PGVA balances should be similarly formulaic and consistent.

In its conclusions, the Board also cited the merits of possible harmonization of load balancing policies of the gas utilities. Further, the Board stated that the regulated gas supply option should be structured in a way that facilitates competition, and that "further examination was required to determine whether the manner in which gas utilities currently allocate costs as between the delivery and gas supply functions raises concerns regarding cross-subsidization."

On July 31, 2008 the Board convened an Issues Day to consider the issues that would be considered in this proceeding. On August 8, 2008 the Board issued its Decision and

Order setting out those issues. The issues are organized under the following five main topics:

1) Commodity Pricing;
2) Load Balancing;
3) Cost Allocation;
4) Billing Terminology; and,
5) Implementation Issues

Evidence Overview

In the evidence that follows Union provides a description of its current and proposed processes under each topic. Union explains that in its view, most of Union's processes support the Board's stated objectives. In addition, Union responds directly to the questions raised by the Board in its final Issues List. Union notes that it has not addressed as part of the evidence any implications to the QRAM process or deferral accounts resulting from the move to International Financial Reporting Standards ("IFRS"). Implementation issues associated with IFRS are being addressed in a separate Board proceeding (EB-2008-0104).

In Union's view, it is important for all parties to have a common understanding of the perspective from which this filing was developed as it will provide context and linkages for the more detailed evidence that follows. For this reason, Union in conjunction with Enbridge Gas Distribution ("Enbridge") developed a table (Appendix A) which:

1. identifies the issues under review in this proceeding;

2. identifies the current methodology(s) or practice(s) specific to each issue for each utility;
3. identifies where a utility (s) proposes to change its current methodology(s) or practice(s) to create a standardized approach; and,
4. identifies where a utility does not propose a change from status quo due to cost and/or operational issues and constraints.

Appendix A shows that the existing QRAM processes are, for the most part, already standardized. The QRAM-related changes proposed by Enbridge and Union in Appendix A will result in processes that are virtually identical. For its part, Union is proposing to: i) eliminate the Intra-Period Weighted Average Cost of Gas ("WACOG") deferral account and; ii) revise its QRAM filing requirements. As described in greater detail later in this submission, these changes are expected to not only enhance Union's current QRAM process but achieve even greater alignment with Enbridge.

In terms of the remaining issues relevant to this proceeding, in recognition of the operational realities and potential cost concerns addressed later in this submission, Union is not proposing any changes to its current approach to load balancing, cost allocation or billing terminology.

With respect to load balancing, in RP-2003-0063 (Union's 2004 rate case) Union sought and received Board approval for changes to its standard balancing provisions in its Southern Operations area ("the South"). Union did not propose any changes to the

contract language associated with balancing direct purchase ("DP") customers in its Northern and Eastern Operations area ("the North"). Union's position was, and continues to be, that the balancing provisions in the North reflect the unique operational requirements in the North and different load balancing mechanisms are appropriate for each delivery area. The changes approved to the South's load balancing service in RP-2003-0063 recognized that Union is not the supplier of DP customers, but that a base level of forecasted balancing is provided as part of the bundled service. Costs related to incremental balancing activity required as a result of changes in consumption should be borne by the DP customer, not Union or other DP customers in the same rate class. Union's current load balancing mechanisms in the South and North provide DP customers with balancing flexibility while ensuring they pay for any seasonal balancing costs.

It is Union's view that its current methods for allocating costs associated with the administration of the regulated supply and DP supply options and load balancing costs are appropriate and reflect cost causation. Thus, in responding to the Board's issues specific to the allocation of costs in the regulated gas supply and DP options, as well as how costs are allocated to load balancing and delivery, Union is not proposing any changes to its Board approved cost allocation methods. Union believes that the structure of the regulated gas supply service in no way impedes the competitiveness of the DP activity. Union further believes that its current load balancing requirements treat the DP and sales service customer groups appropriately. Union is therefore not proposing any changes to how load balancing costs are allocated.

In July of 2006, Union introduced a new gas bill format in response to the Board's RP-2003-0063 decision which approved Union's proposal to display rate riders on the bill. Union's bill redesign features include summary information on the front of the bill and more detailed information and calculations on the back to provide customers with the information they require to understand the charges on the bill. Customer research indicates that Union's customers put a high degree of reliance on the energy information provided to them and the majority of Union's customers rate the effectiveness of Union's bill very high. Further, Union submits that consumers are not actively comparing the billing terminology between Union and Enbridge. Union is not proposing any changes to the bill terminology.

SECTION A - REVIEW OF QUARTERLY RATE ADJUSTMENT MECHANISM FOR NATURAL GAS DISTRIBUTORS:

Background

In the NGF Report, the Board, on pages 68-69, concluded that the appropriate pricing structure for regulated gas supply should reflect the following objectives:

- a balance between an accurate price signal and price stability for customers;
- transparency that results from QRAM prices that reflect market prices; and,
- reference prices and Purchase Gas Variance Account ("PGVA") calculations and disposition methodologies that are formulaic and consistent.

In the same report, the Board communicated two key concerns that it wished to address in a subsequent hearing, specifically:

- Is a 12-month price outlook appropriate as the basis for pricing the regulated gas supply option?
- Is the frequency of the price adjustment appropriate?

Further, the Board stated that to achieve the objective of market price transparency the utilities should consider similar methodologies for calculating the QRAM price.

Union supports the Board's objective to achieve greater consistency in QRAM pricing methodology and believes natural gas consumers in the Ontario competitive marketplace are well served by a QRAM that reflects the principles outlined by the Board in the NGF

Report. Those principles are supported by Union's current Board approved QRAM methodology.

In Union's 2007 rate case (EB-2005-0520), the Board on page 11 of its Decision with Reasons, stated that it has "determined that the reduction of volatility is a worthwhile measure of consumer protection, which is also one of the Board's statutory objectives. The Board has implemented the QRAM process because of the increased need to implement gas price changes regularly, and with more frequency, to better reflect marketplace conditions. The QRAM has the effect of smoothing prices and bills." The current Board approved QRAM methodology was designed to achieve this objective. Union believes that the existing QRAM methodology continues to achieve a balance between market price sensitivity and price stability.

Union's current QRAM methodology was also designed to be automatic, formulaic and mechanical. Each quarter Union gathers specific market data and performs routine calculations to derive a forward looking market price of gas and to prospectively recover/refund gas supply related deferral balances. Upon approval by the Board, rates are adjusted quarterly to reflect the current market conditions, regardless of how small or large they may be.

Finally, Union and Enbridge have maintained practices that in many instances are common. In designing the current methodologies, the utilities have individually considered each other's best practices and that effort resulted in similar QRAM

methodologies. Union acknowledges that further standardization and streamlining is possible and this evidence will propose some changes to that end.

Union's Current QRAM Methodology

Calculation of Gas Supply Reference Price

Union's quarterly gas supply reference price represents an average cost for gas at Empress (the Alberta Border Reference Price) for the next 12 months. Union determines this price by applying a forward Empress basis differential to the future 12-month NYMEX market prices, applying a foreign exchange rate and weighting these monthly prices by the volume Union plans to buy in each of the 12 months. The result is an average cost per gigajoule in Canadian dollars that represents the forward market price at Empress. The reference price is, therefore, essentially a rolling 12-month price that is updated quarterly. This 12-month average price is intended to smooth seasonal prices or cost anomalies that may be present in any of the individual months, so that customers see a more stable rate on their bills. Quarterly updates to this rate are intended to ensure that the reference price adequately reflects any changing market dynamics.

To set the gas supply commodity charge for both the North and South customers, Union adds compressor fuel and the gas supply administration charge to the Empress reference price specific to each delivery area.

Calculation of PGVA Deferred Balances

Union currently maintains separate PGVA's for the North and South. In the North, Union serves its sales service customers using Western Canadian supplies transported to the North on TransCanada Pipelines ("TCPL"). Accordingly, in the North, actual Empress gas costs are deferred against the Empress reference price each month and the cost variances accumulate in the North PGVA account for disposition to the sales service customers at the next QRAM period. The North transportation deferred costs are not included in the PGVA, but instead are accounted for in separate accounts. The separation is necessary because Union provides transportation services in the North to both sales service and DP customers and the deferred balances are disposed of to this combined group.

The South PGVA captures cost variances in both gas supply commodity and upstream transportation. This treatment is appropriate because DP customers in the South do not pay Union for either the gas supply commodity or upstream transportation. Accordingly, the South PGVA is entirely related to sales service activity and is recovered/refunded from only sales service customers. To calculate the South PGVA reference price Union adds the forward forecast of all gas supply and upstream transportation costs to determine the Ontario landed reference price. Actual gas supply and upstream transportation costs are added together (actual landed cost) and are deferred against this Ontario landed reference price to calculate the South PGVA deferral account balances.

Prospective Recovery of the PGVA Deferred Balances

Each quarter Union identifies the debits/credits that have accumulated in both PGVA accounts during the previous quarter and calculates commodity price adjustments (also referred to as rate riders) that recover/refund accumulated deferral account balances prospectively over the next 12 months. Union also includes in the rate rider any variances between the actual and forecast amounts recovered/refunded from the previous quarter as a result of actual consumption varying from planned consumption over the quarter.

Calculation of Transportation Reference Price and Disposition of Deferred Balances

For customers in the North, Union recovers the approved TCPL tolls for each delivery area as part of the gas supply transportation charge. Any variance between actual TCPL tolls and those approved in rates are deferred to the TCPL Tolls and Fuel deferral account. Like the PGVA accounts, disposition of the deferred balances in these accounts is accomplished through a 12-month price adjustment that is initiated in the subsequent quarter.

As indicated above, Union provides the transportation services to all bundled customers, both sales service and DP customers, in the North. The actual transportation costs, therefore, reflect services to both sales service and DP customers and transportation deferred balances are disposed of to both sales service and DP customers. The North PGVA balances are disposed only to sales service customers.

Under Union's approved QRAM process, gas supply transportation rates are adjusted once new TCPL tolls are approved by the National Energy Board.

The South sales service customer rate for transportation services is determined by comparing the average forecasted landed cost of the South portfolio to what the cost would have been had all the South supplies been purchased at Empress and transported on TCPL. This cost differential, referred to as the South Portfolio Cost Differential ("SPCD"), is added to or subtracted from the Eastern Zone TCPL toll to derive the South transportation rate. The result is sales service customers in the South are charged a rate for regulated gas supply service equivalent to the expected landed cost over the forward 12-month period.

As indicated above, in the South Union provides transportation services to sales service customers only. As a result, the South PGVA captures variances between the Ontario landed reference price and the actual landed cost as associated with serving sales service customers in the South. The balances in the South PGVA are disposed only to sales service customers.

Other Gas Supply-Related Deferral Accounts

In addition to the North PGVA, the TCPL Tolls and Fuel deferral account and the South PGVA, Union maintains the following gas supply related deferral accounts that are disposed of as part of the QRAM process:

- Inventory Revaluation Deferral Account – records the change of inventory value that results when the gas supply reference price is reset each quarter.
- Spot Gas Variance Account – records costs incurred to balance Union's operating system beyond what was forecast in rates.

Both accounts are disposed of prospectively over 12 months.

Distribution Rate Adjustments

Reference price changes driven by Union's QRAM process do not currently cause Union to update its revenue requirement and, as a result, its distribution rates. Union's delivery rate includes the costs associated with gas in inventory, compressor fuel and unaccounted for gas ("UFG"). These delivery-related costs of gas items are not currently updated through the QRAM process. Instead, the price variance between the cost of gas included in Board approved rates and the WACOG determined in the QRAM is captured in the Intra-Period WACOG deferral account. The Intra-Period WACOG deferral account is not disposed of as part of the QRAM process. This account is disposed of annually.

Rate Stability for Customers

It is Union's view that the QRAM provides customers with the appropriate balance between rate stability and market price sensitivity. Rate stability is achieved through Union's QRAM methodology because forecast costs are averaged over the forward 12 months and any past cost variances are also recovered/refunded over the forward 12

months. Changing the gas supply commodity charge quarterly is sufficiently responsive to changing market conditions.

Approximately 35 percent of customers are enrolled in the Equal Billing Plan to achieve further bill stability. In this program, Union averages anticipated monthly bill costs for each customer over a 12-month period starting in September. Customers pay the equal billing amount each month from September to July with a true-up amount in August. Union will adjust the equal billing amount through the year, if required, to accommodate any significant changes in either gas commodity charges or consumption.

At page 17 of the Board's EB-2007-0606/EB-2007-0615 Decision (dated July 31, 2008), the Board commented on the importance both the QRAM and the equal billing plan have on reducing price volatility and smoothing customer impacts. The Board concluded that:

> *"…in the event of price volatility customers are subject to the price impacts, but the use of the QRAM process and the equal billing plan have the effect of smoothing customer impacts generally in any event."*

Examination of Possible Alternatives to Price-Setting Forecast and Disposition Periods

To compare the attributes of Union's current QRAM methodology to other alternative methodologies that may be considered in this proceeding, Union prepared an analysis of what the Empress reference price and the price adjustment (rate rider) would have been under different price adjustment scenarios if these scenarios had been in place over the last four years.

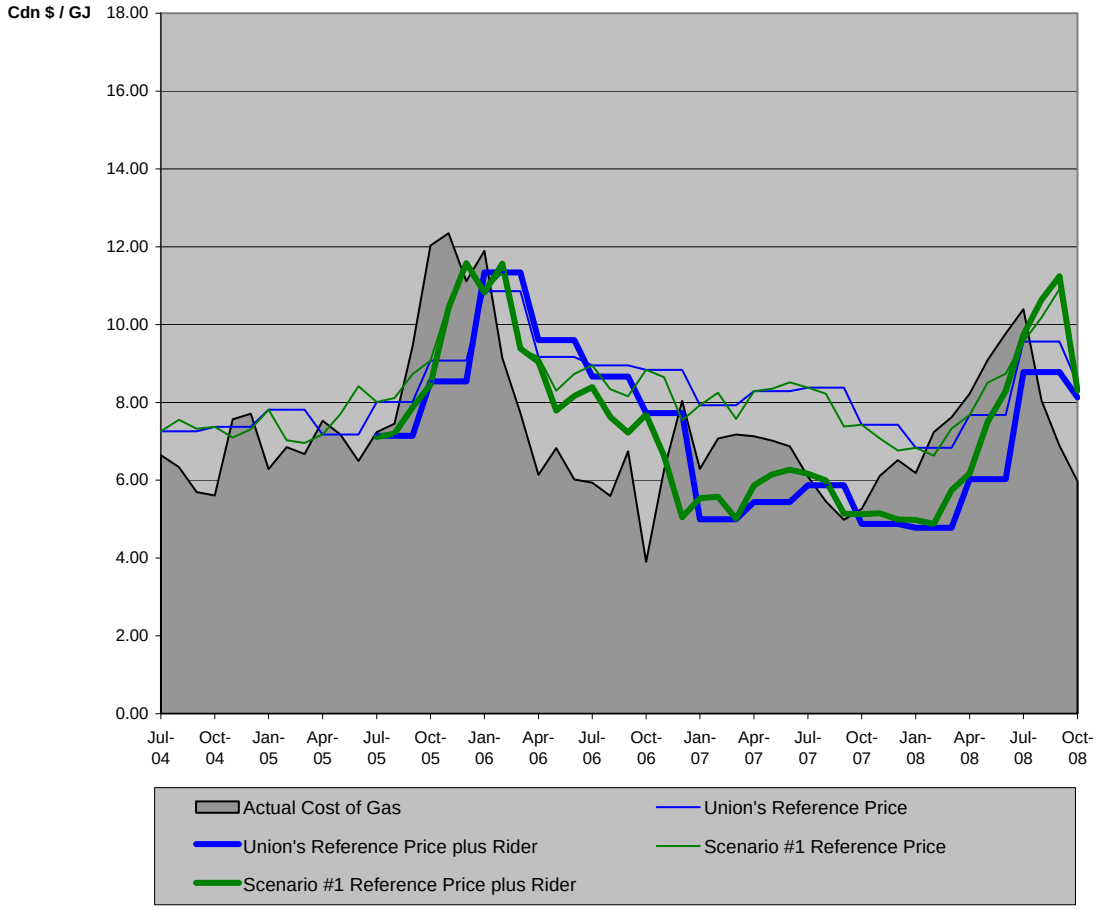
Specifically, Union considered three alternative QRAM scenarios and compared the results to Union's current QRAM process. The scenarios considered were:

1. Monthly Updates with a 12-month Outlook period and a 12-month Deferral Disposition Period.
2. Quarterly Updates with a 3-month Outlook period and a 3-month Deferral Disposition Period.
3. Monthly Updates with a 1-month Outlook period and a 1-month Deferral Disposition Period.

The purpose of this exercise was to determine whether or not, with the benefit of actual information, a better alternative to the current QRAM exists. A better alternative is defined as one that offers improved balance between price stability and market price sensitivity. Stability is measured through a volatility calculation, defined as the range in which prices occurred within one standard deviation of the mean, or 68 percent of the time. Market price sensitivity was measured by calculating the absolute difference between Union's actual cost of gas and the rate approved each quarter through the QRAM process. The actual cost of gas was intended to generally represent market prices. Ideally a preferred QRAM would have low volatility and a low variance to the actual cost of gas. Since these two attributes often move in different directions, it is necessary to strive for a reasonable balance between the two.

The following graphs show the results of the comparative analysis. Union concludes that the current QRAM methodology continues to offer the best balance of stability and price sensitivity.

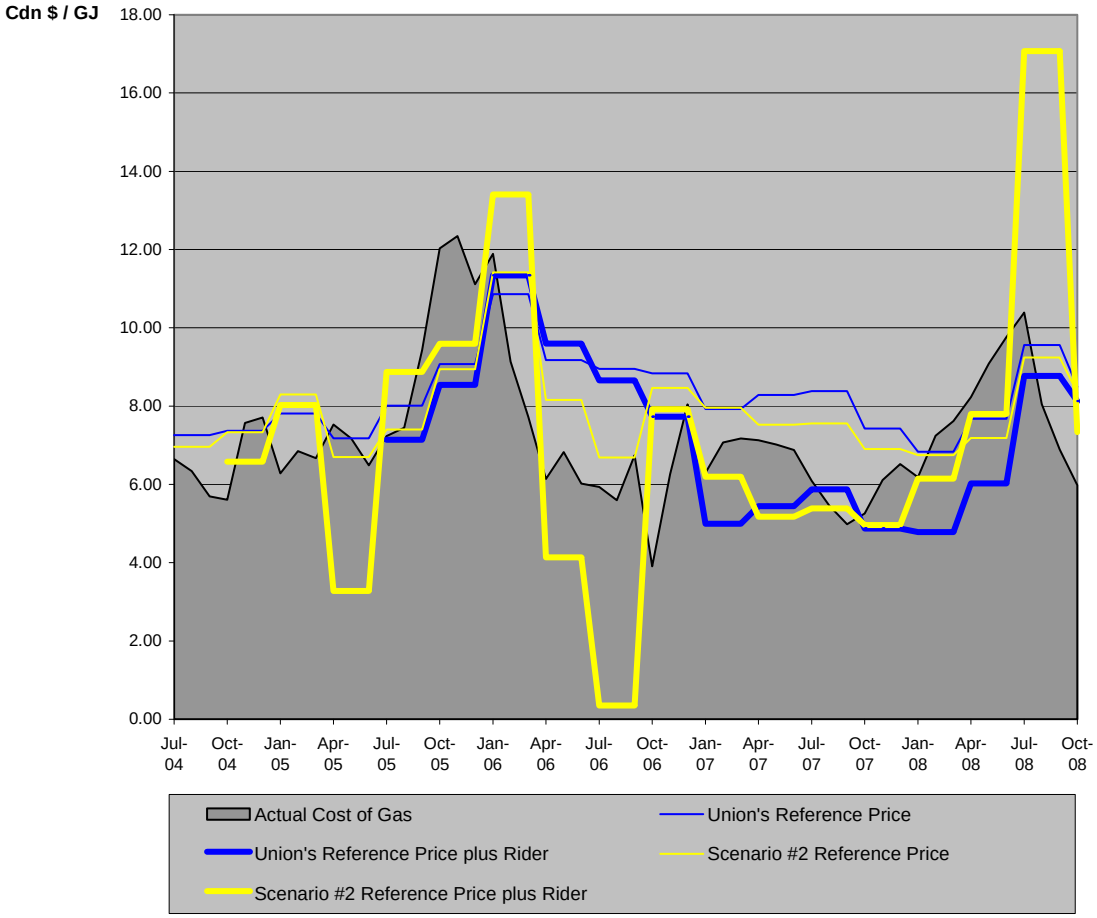
SCENARIO #1
Monthly Filing using 12 Month Outlook and 12 Month Disposition



Comparison to Current Pricing Methodology including Rate Rider Impacts ($/GJ)
Period - July 2005 to Oct 2008

Filing Period over Outlook Period	STABILITY			ACCURACY		
	Volatility (1 Standard Deviation)	Stability Comparison to Current Pricing Methodology		Average Variance to Actual Cost of Gas	Accuracy Comparison to Current Pricing Methodology	
UNION (Q over Y)	$2.00			$1.98		
S#1 (M over Y)	$2.04	2%	Less Stable	$1.55	21%	More Accurate

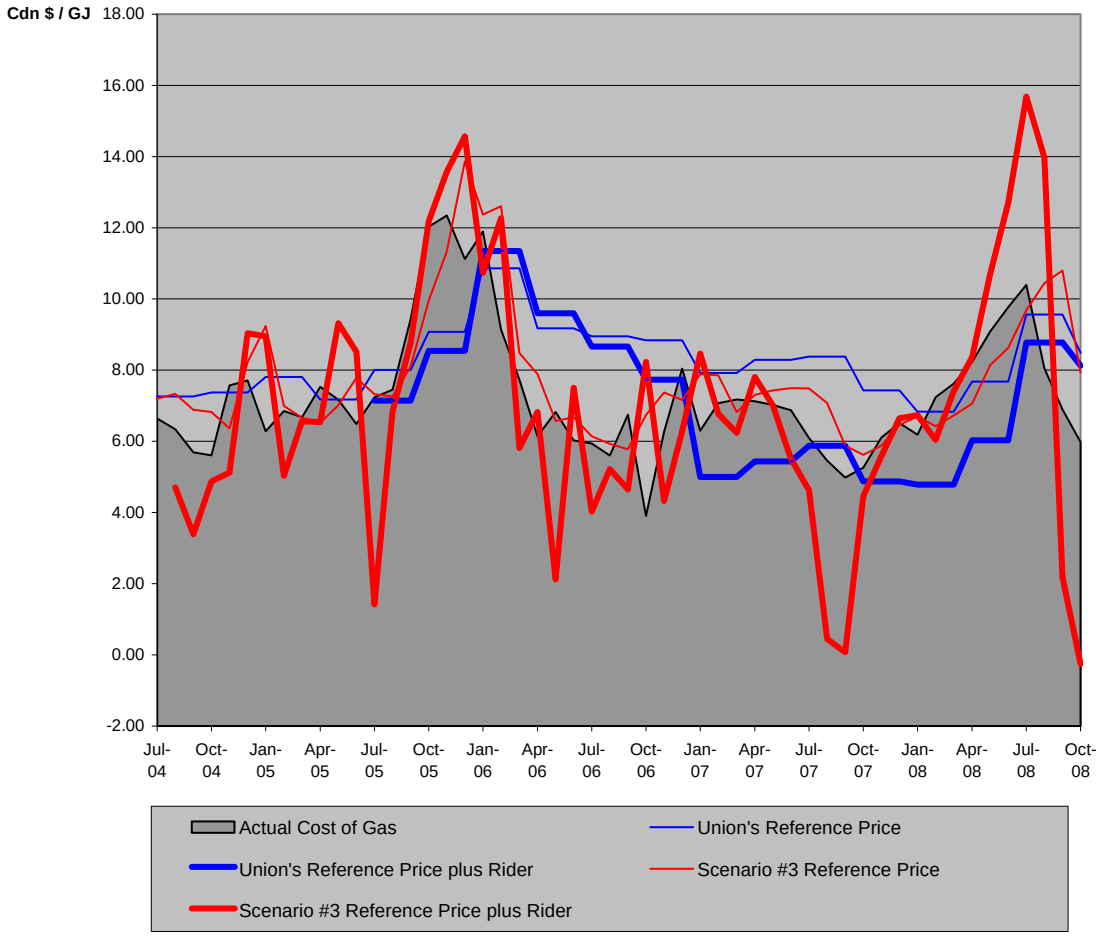
SCENARIO #2
Quarterly Filing using 3 Month Outlook and 3 Month Disposition



Comparison to Current Pricing Methodology including Rate Rider Impacts ($/GJ)
Period - July 2005 to Oct 2008

Filing Period over Outlook Period	STABILITY			ACCURACY		
	Volatility (1 Standard Deviation)	Stability Comparison to Current Pricing Methodology		Average Variance to Actual Cost of Gas	Accuracy Comparison to Current Pricing Methodology	
UNION (Q over Y)	$2.00			$1.98		
S#2 (Q over Q)	$4.07	103%	Less Stable	$2.41	-22%	Less Accurate

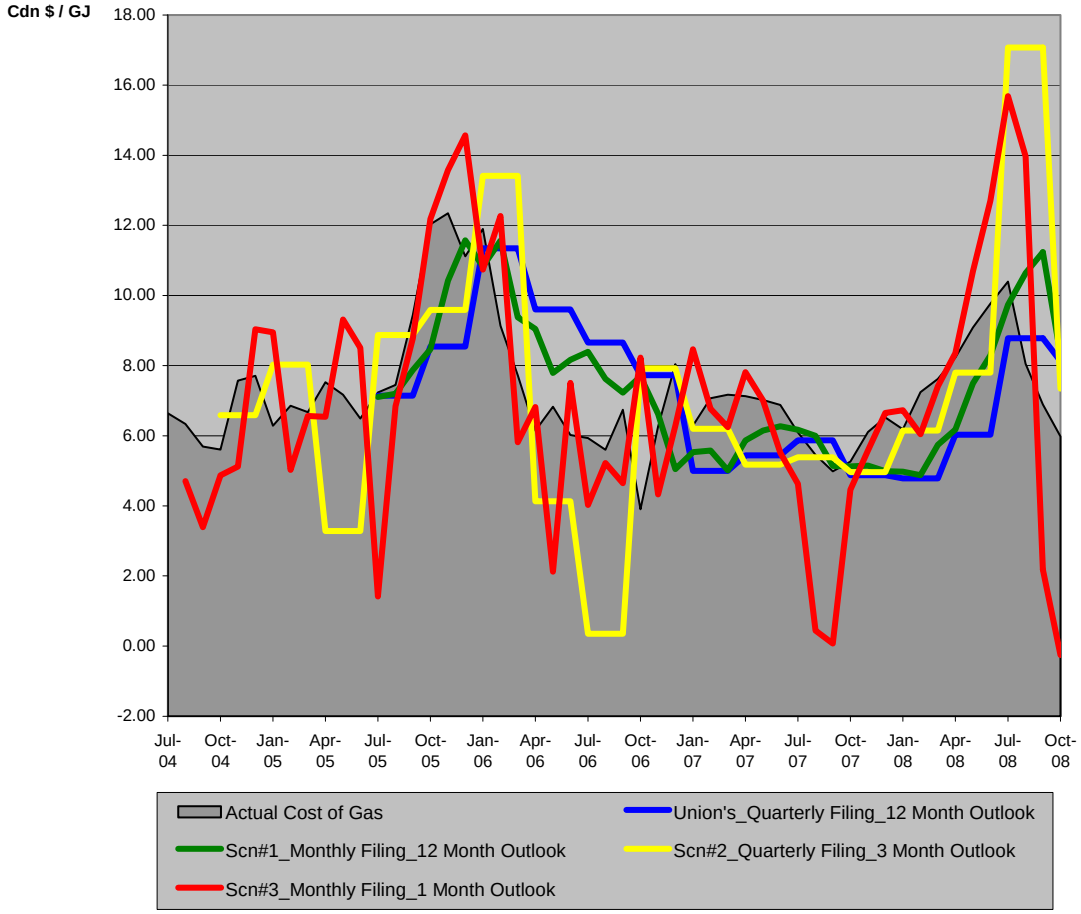
SCENARIO #3
Monthly Filing using 1 Month Outlook and 1 Month Disposition



Comparison to Current Pricing Methodology including Rate Rider Impacts ($/GJ)
Period - July 2005 to Oct 2008

Filing Period over Outlook Period	STABILITY			ACCURACY		
	Volatility (1 Standard Deviation)	Stability Comparison to Current Pricing Methodology		Average Variance to Actual Cost of Gas	Accuracy Comparison to Current Pricing Methodology	
UNION (Q over Y)	$2.00			$1.98		
S#3 (M over M)	$3.97	98%	Less Stable	$2.11	-7%	Less Accurate

SUMMARY COMPARISON
Reference Prices Including Rate Rider Impacts



Comparison to Current Pricing Methodology including Rate Rider Impacts ($/GJ)
Period - July 2005 to Oct 2008

Filing Period over Outlook Period	STABILITY			ACCURACY		
	Volatility (1 Standard Deviation)	Stability Comparison to Current Pricing Methodology		Average Variance to Actual Cost of Gas	Accuracy Comparison to Current Pricing Methodology	
UNION (Q over Y)	$2.00			$1.98		
S#1 (M over Y)	$2.04	2%	Less Stable	$1.55	21%	More Accurate
S#2 (Q over Q)	$4.07	103%	Less Stable	$2.41	-22%	Less Accurate
S#3 (M over M)	$3.97	98%	Less Stable	$2.11	-7%	Less Accurate

Scenario #1 - Shows the result of monthly rate updates with a 12-month outlook period and a 12-month deferral disposition period. This scenario results in slightly less stable rates (volatility of $2.04/GJ) but more accuracy to the actual cost of gas (average variance of $1.55) when compared to the current QRAM methodology. This scenario, however, would, require Union to adjust its gas supply commodity charges and reference amounts on a monthly basis.

Scenario #2 - Shows the result of quarterly rate updates with a 3-month outlook period and a 3-month deferral disposition period. This scenario results in significantly less stable rates (volatility of $4.07/GJ) and less accuracy to the actual cost of gas (average variance of $2.41) when compared to the current QRAM methodology.

Scenario #3 - Shows the result of monthly rate updates with a 1-month outlook period and a 1-month deferral disposition period. This scenario results in significantly less stable rates (volatility of $3.97/GJ) and also reduced accuracy to the actual cost of gas (average variance of $2.11) when compared to the current QRAM methodology. This scenario would also require Union to file its rate application 12 times per year for regulatory review and approval and would therefore result in significantly more administration than a quarterly update.

The current QRAM methodology has resulted in a volatility level of $2.00/GJ, meaning that the range of customer rates, including both the reference price and the rate rider, occurred within $2.00 of the mean rate 68 percent of the time. A review of the accuracy

showed that the current QRAM rates were, on average, $1.98/GJ different than the monthly actual cost of gas.

Conclusion: Examination of Possible Alternatives

As indicated above, Scenario #1 results in rates that are slightly less stable but more accurate than the current QRAM process. If the Board is prepared to accept Scenario #1 as a better alternative on the basis that it is more accurate, it must also accept the increased regulatory burden, administrative costs, communication costs and customer confusion. In Union's view the current quarterly process is known and understood by customers and provides the appropriate balance of stability and market price sensitivity. Further, the cost implication and negative customer reaction outweigh any perceived benefit from a more accurate commodity rate. Accordingly, Union does not support moving to a more frequent process for setting gas supply commodity charges.

Union's Responses to the Board's Specific Questions:

I) TRIGGER MECHANISM FOR CHANGING THE REFERENCE PRICE OF CLEARING THE PURCHASED GAS VARIANCE ACCOUNT ("PGVA")

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

No, there should not be a trigger mechanism to prompt a change in the reference price or to clear the PGVA's. Union's current practice does not involve the use of a trigger mechanism for changing either the reference price or clearing the PGVA's and other gas cost deferral accounts.

It is Union's experience that trigger mechanisms do not result in any less work for the utility since each quarter it is necessary to calculate the reference prices and deferral account impacts to determine if, in fact, the trigger has been exceeded. Further, the trigger mechanism reduces predictability of price changes and potentially introduces judgement into the QRAM. A trigger mechanism does not ensure the timely disposition of deferral account balances and may produce an unnecessary lag between when costs are incurred and when those costs are recovered.

Prior to 2004, Union's QRAM included a trigger mechanism. Since 2004, there have been approximately 20 QRAM applications using Union's existing process. Over that time Union's QRAM process has gained the acceptance of customers, intervenors and the Board primarily due to its mechanical, automatic and formulaic approach.

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?

Please refer to Union's response to Issue 1.1.

II) PRICE ADJUSTMENT FREQUENCY AND FORECAST PERIODS

2.1 Is a price adjustment based on a 12 month price forecast appropriate for the regulated gas supply option?

Yes, a 12-month price forecast is the appropriate term for calculating the gas supply rate for sales service customers. It provides greater price stability than a seasonal or monthly term, and is more aligned to other DP supply options available to customers. A 12-month outlook reduces price volatility for consumers by smoothing out seasonal or monthly volatility in market prices. The current QRAM practice continues to meet its original goal of reducing volatility for customers, while ensuring rates reflect market pricing through the quarterly update.

Further, calculating the gas commodity charge using the 12-month price forecast allows customers to make more appropriate cost comparisons when considering alternative supply options. When considering the various supply options available in the market, customers predominantly consider price. A utility price based on a 12-month outlook provides a more appropriate comparator to the fixed-price direct purchase offerings that are generally either a 3-year or 5-year price. A utility 3-month price or a 1-month price would provide an inappropriate price comparator to the 3 to 5-year annual prices.

2.2 If not, what alternative forecast period or periods should be used by natural gas distributors?

Please refer to Union's response to Issue 2.1.

2.3 Is a quarterly price adjustment appropriate for the regulated gas supply option?

Yes, the current quarterly adjustments are preferable to either a less frequent or more frequent schedule. As noted earlier in this submission, the quarterly schedule continues to provide an appropriate balance of price stability, market sensitivity and administrative efficiency.

2.4 If not, what alternative frequency or frequencies should be used by natural gas distributors?

Please refer to Union's response to Issue 2.3.

In Union's view, more frequent price adjustments (monthly) are not appropriate for the following reasons.

1. Although the current QRAM process is mechanical, it is a significant undertaking to calculate the reference price, calculate the deferral balances and associated rate riders and prepare an application and implement the rate change once approved by the Board. Additional resources may be required if Union was required to change to monthly commodity rate changes.

2. As indicated above more frequent commodity rate changes would result in increased price volatility for sales service customers. Increased price volatility is clearly counter to the Board's desire to balance price stability with market price sensitivity.
3. Due to cycle billing, if the gas sales rate changed every month Union would have to prorate the charges on almost all of its customers' bills each month. For example, if a customer's meter was read on December 15, Union would prorate the consumption from November 15 (the last meter read date) to December 15 using heating degree days. The prorated consumption for each period, November 15 to November 30 and December 1 to December 15 would be invoiced at different rates adding multiple lines for each charge item on the bill. This would result in a bill that on an ongoing basis would be cluttered and confusing to customers.
4. DP service offerings from gas marketers are fixed price offerings that are generally a 3-year or 5-year price.
5. To Union's knowledge customers have not expressed an interest in a monthly gas commodity charge.

III) METHODOLOGY FOR THE CALCULATION OF THE REFERENCE PRICE

3.1 Should a single Ontario-wide reference price be used as the basis for the gas supply commodity charge?

No, the most appropriate gas supply reference price for each utility is one that best reflects the supply portfolio of each utility. Given that each utility has a unique supply plan that meets its operational needs, the average price for the gas costs also varies between the utilities. Therefore, Union suggests that the best reference price is one that reflects these cost differences and is not common across Ontario.

Union notes the utilities however do use a common method to determine their respective gas supply reference prices. Each utility uses a common practice to forecast Empress market prices for the 12 months in the QRAM period. Each utility then calculates a WACOG after considering the volumes to be purchased in each month of the forward 12 months. To set the gas commodity charge for customers, the utility then adds to the reference price compressor fuel charges to transport the commodity to the various delivery areas in its service area and the utility-specific gas supply administrative fee. The result is a gas commodity charge that varies somewhat between the utilities, but reflects the respective costs of each utility.

Finally, even if utilities had a single Ontario-wide reference price customers would still pay the same effective gas commodity charge as they do today through the disposition of deferral accounts.

The benefits of the current methodology, compared to a single common reference price for all utilities, are smaller deferral account balances and reference price rates that better match the market prices for each utility.

3.2 If a single Ontario-wide reference price is implemented, how and by whom should it be determined?

Please refer to Union's response to Issue 3.1.

3.3 If not, what supply inputs, pricing point data and method or methods should be used to determine the reference price?

The current practice of using the Alberta Border Market Price (Empress market price) as the basis for the reference price continues to be appropriate given that the majority of Union's supply continues to be purchased from the Western Canadian Sedimentary Basin ("WCSB"). As described above, other supply costs particular to each utility are then added to/subtracted from this Alberta price to determine the weighted average 12 month gas commodity charge for customers. In Union's view, this practice has worked well.

3.4 What role, if any, should the Board take in relation to the determination of the inputs and/or data to be used in calculating the reference price?

Union does not see the Board as having a role in the determination of inputs and/or data to be used in the calculation of the reference price. In Union's view, the role of the Board should remain as it is currently (i.e. ensure the timely approval of rate changes brought

forward as part of the QRAM process). Reference prices are calculated by the utilities using publicly available information.

IV) DEFERRAL AND VARIANCE ACCOUNTS AND DISPOSITION METHODOLOGY

4.1 What should be the deferral/variance accounts to capture variances in commodity, transportation and load balancing and inventory revaluations?

Union currently maintains separate deferral accounts to capture variances in gas supply commodity prices, TCPL tolls and fuel, inventory revaluation and spot gas/load balancing. Union's current approved gas cost deferral accounts were established to:

1. Provide transparency of deferral account balances;
2. Eliminate the need for allocations between the North and South / sales service and DP;
3. Recognize the operational and rate design differences between the North and South; and
4. Recognize the differences between North and South DP offerings.

Union defers both commodity price and transportation price variances into the South PGVA. The North PGVA only captures commodity price variances. Variances in transportation tolls in the North are captured in the TCPL Tolls and Fuel deferral account. This deferral account structure is consistent with how Union recovers the cost of commodity and upstream transportation costs in its Board approved rates.

In the South, Union recovers gas supply commodity costs and upstream transportation costs from sales service customers only. Consistent with this recovery, Union only requires a single deferral account since both gas supply commodity cost-related deferral account balances and upstream transportation-related variances commodity are recovered from the same group of customers. In the South, DP customers do not pay Union's costs related to gas supply commodity or upstream transportation.

In the North, gas supply commodity costs are recovered from sales service customers only while upstream transportation costs included in the gas supply transportation rate are recovered from both sales service and DP customers. Accordingly, Union maintains separate deferral accounts in the North for gas supply commodity and transportation so that on disposition Union can direct the recovery easily and transparently to the appropriate group of customers.

The inventory revaluation deferral account applies to sales service customers in both the North and the South. Union does not maintain a separate inventory for each delivery area and as a result separate deferral accounts are not required.

4.2 What methodology or methodologies should be used by natural gas distributors to determine the deferral/variance account balances to be disposed of?

Deferral account balances should be determined by comparing the actual price of the gas supply commodity and upstream transportation to the appropriate approved reference prices for each deferral account.

4.3 What methodology or methodologies should be used by natural gas distributors to dispose of the deferral/variance account balances? How frequently should the account be cleared?

The disposition of projected gas cost deferral account balances should continue to occur on a quarterly basis with balances being recovered/refunded prospectively over a rolling 12-month period.

Disposing of projected gas cost deferral account balances prospectively over a rolling 12-month period eliminates the possibility of large out of period adjustments and volatility associated with annual deferral account disposition. This approach also ensures the appropriate market price signals are provided to customers by avoiding unnecessary volatility in price adjustments (i.e. rate riders) that are utilized to dispose of deferral account balances.

Further, if the recovery/refund of projected gas supply deferral accounts was done over a shorter time period the potential exists for inappropriate cross subsidization. For example, deferral account balances created in the January to March timeframe should not be recovered over a 3-month timeframe from July to September. This approach would not match the recovery of deferral account balances with the customers that caused them since deferral account balances would potentially be recovered from customers with large summer loads (e.g. asphalt, cement, grain dryers, etc.) that were not responsible for a winter-related gas cost variance. Likewise, recovering deferral account balances over three months would distort the price adjustment (i.e. rate rider) required for recovery,

providing an inappropriate signal of market prices and creating rate instability. A rolling 12-month recovery period (capturing all customer consumption) better aligns cost recovery with cost incurrence, reducing the possibility of inappropriate market signals and provides increased rate stability to customers.

Union's current approach of disposing deferral account balances over a rolling 12-month period on a quarterly basis, concurrent with reference price updates, best balances the Board's goals of market price sensitivity, rate stability and transparency.

4.4 Should there be a final adjustment to re-allocate the PGVA? What methodology or methodologies should be used for that purpose by natural gas distributors?

Please refer to Union's response to Issue 4.3.

4.5 What are the implications of the different methodologies considered in light of seasonal consumption patterns?

Please refer to Union's response to Issue 4.3.

Union's current practice allows costs to be recovered from the appropriate customers, including those customers with seasonal consumption patterns.

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

5.1 What methodology or methodologies should be used by natural gas distributors for recovering the carrying cost of gas in inventory and related costs?

As indicated above, Union does not currently update its delivery related cost of gas items (i.e. gas in inventory, compressor fuel and UFG) for changes in the commodity cost as part of the QRAM process. Currently, variances between Union WACOG approved through the QRAM and the WACOG approved in delivery rates are captured in the Intra-Period WACOG deferral account. The Intra-Period WACOG deferral account balances are recovered as part of Union's annual deferral account disposition by way of a one-time adjustment to contract rate classes and prospective recovery in General Service rate classes.

As part of this proceeding, Union proposes to:

1. Change its current practice of recovering variances in these gas costs annually through the Intra-Period WACOG deferral account in favour of a quarterly resetting of distribution rates to update these costs with the QRAM reference price; and,
2. Eliminate the Intra-Period WACOG deferral account after a final disposition of the account balance.

Union is making this proposal to reduce the need for potentially large out of period adjustments and standardize the treatment of delivery related gas supply costs between Union and Enbridge.

Union acknowledges that changing delivery rates on a quarterly basis will require that it file additional supporting schedules, including both infranchise and exfranchise rates schedules. It is Union's view however that changing delivery rates will not increase the complexity of Union's QRAM process materially as Union delivery rate adjustments will be mechanical and formulaic.

5.2 Should the revenue requirement (other than gas costs) change as a result of a change in the reference price?

If so:

i. What component of the revenue requirement should be adjusted?

ii. What methodology or methodologies should be used by natural gas distributors for the purpose of allocating the change in the revenue requirement to the various customer rate classes?

Please refer to Union's response to Issue 5.1.

The components of the revenue requirement to be adjusted with each change in the QRAM reference price are the carrying cost of gas in inventory, compressor fuel and UFG. Union proposes to allocate changes in its delivery related cost of gas items to rate classes in the same manner as these costs are included with 2007 approved delivery rates. This allocation to rate classes is the same as that currently used to allocate the Intra-Period WACOG deferral account on disposition.

VI) IMPLICATIONS/COSTS OF STANDARDIZING PRICING MECHANISMS ACROSS ALL NATURAL GAS DISTRIBUTORS.

6.1 Should there be standardized pricing mechanisms for all natural gas distributors? What are the costs, benefits and implications for ratepayers, gas marketers and natural gas distributors of standardizing the pricing mechanisms across all natural gas distributors?

With the changes proposed by Enbridge and Union (see Appendix A), the QRAM processes are, for the most part, aligned. Union believes its current QRAM process, in conjunction with the proposed changes, is an appropriate pricing structure for regulated gas supply and is aligned with the Board's stated goals on QRAMs.

VII) FILING REQUIREMENTS

7.1 Should there be standard filing requirements for QRAM applications? If so, what should the filing requirements be?

Union supports standard filing requirements for QRAM applications and a common framework of schedules and tabs for all natural gas utilities. At the same time, Union also recognizes there are unique features of the filing requirements arising from the rate designs and service options for each utility.

The common framework of QRAM schedules should, at a minimum, include:

Schedule 1: Gas commodity price forecast calculations,

Schedule 2: Gas cost deferral amounts and disposition, and

Schedule 3: General Service bill impacts

Working Papers: delivery rate changes, other non-routine changes such as approved TCPL toll changes

Appendices to the QRAM rate order should, at a minimum, include

(i) changes to approved rates,

(ii) approved rate schedules,

(iii) customer notices

Unique Features by Utility and Operating Areas

Unique operating areas, rate designs and service options, will continue to require schedule differences between natural gas utilities. Gas costs must reflect utility specific purchases by month for each operating area.

For example, in the North, TCPL compressor fuel ratios and fuel deferrals will continue to reflect differences in the TCPL delivery zones. In addition, there are distinct transportation portfolios serving each operating area and different heat value assumptions between utilities.

While Union's current approach allows for utility specific differences in the schedule calculations, Union supports the development of standard filing requirements consisting of common summary schedules. Standard filing requirements will help facilitate an

effective and efficient regulatory review. It will also allow for a ready comparison of changes among Ontario utilities.

Proposed QRAM Process Timeline

To calculate the gas supply reference price each quarter, Union employs a 21-day strip of market prices. Specifically Union calculates the 12-month forward market price by averaging the market prices at the relevant supply locations for 21 subsequent business days. This average 21-day strip ends 45 calendar days prior to the start of each quarter. The 45 days prior to the effective date of the QRAM is then used to prepare Union's rate application, receive Board approval and implement the rate change. Any market price changes that occur during that 45 days is not captured in the new reference price. This creates the potential for the gas commodity charge to be marginally out-of-date relative to market conditions when the rate becomes effective.

Union believes that the QRAM process timeline can be adjusted to provide a more timely market price for each QRAM.

Union's current QRAM process is very mechanical. Union however believes the application and approval process can be improved such that it is completely mechanical. Since Union changed its QRAM process following RP-2003-0063, Union has received limited interrogatories from intervenors. Since 2005 Union has only received a total of three interrogatories in 12 QRAM proceedings. Of the three received, two were not related to the commodity or gas cost deferral accounts. Union acknowledges that it holds

informal discussions with the Industrial Gas Users Association ("IGUA") and the Canadian Manufacturers and Exporters ("CME"). Union has found these discussions to be helpful and efficient. Following each discussion, IGUA and CME have filed letters with the Board supporting Union's QRAM application.

Given the apparent level of comfort with the current QRAM process, the Board may be able to reduce the QRAM application review period to allow the utility to incorporate more recent/current NYMEX pricing data.

Union believes that with improved efficiencies in the application process and the elimination of written interrogatories, the close of the 21-day strip could be moved closer to the QRAM effective date making it more reflective of current market conditions.

For example, if Union is applying for a gas commodity charge change on October 1st, 2008 Union submits it would be possible to file an application with the Board using a 21-day strip that closes 14 days later than the current process.

The table below identifies the specifics of the QRAM review process as well as the associated timeline, both current and potential:

Table - QRAM Steps and Timelines

October 1, 2008 QRAM Steps	**Current Completion**	**Potential Completion**
Close of 21 day-strip	August 15	August 29
Commodity and Rate Calculations Filed with Board	August 30	September 5
Intervenor Comments on Hearing Structure	September 9	N/A
Intervenor Comments on Evidence	September 11	September 12
Board Decision	September 18	September 19
Communications package prepared	September 28	September 28

Union requires five business days to prepare and file the QRAM application. Following Board approval, Union requires eight business days to prepare and print the customer bill inserts.

SECTION B - REVIEW OF LOAD BALANCING OBLIGATIONS FOR NATURAL GAS DISTRIBUTORS

Overview

The purpose of this overview is to:

1. Review the history and operational requirements that underpin the current load balancing mechanisms;
2. Review Union's current load balancing mechanisms in both the South and North; and,
3. Make a recommendation on standardization between Union and the Ontario LDCs.

Union currently uses the seasonal checkpoint mechanism in the South while, in the North, Union uses an end-of-year balancing mechanism.

History of Seasonal Checkpoint Mechanism for Union South

The Board's directive with respect to load balancing originated in E.B.R.O 493/494.

Paragraph 11.7.13 of the E.B.R.O. 494 Decision with Reasons states:

> *"The Board also directs Union to conduct a cost allocation study and propose a rate structure similar to that of Centra where the forecast cost of short-term supplies are included in the delivery charge. In that way all customers, such as ABC customers who cause load balancing costs to be incurred will pay those costs"*

Union responded to this directive in E.B.R.O. 493-04/494-06 (Gas Cost Hearing, October 1997) at which time it proposed the creation of a "level playing field" among sales

service, Buy/Sell service and Bundled-T ("BT") service so as not to create a bias for one service over another. In the E.B.R.O. 493-04/494-06 proceeding, Union proposed to include in delivery rates applicable to both sales service and DP customers, costs associated with load balancing.

Load Balancing costs were incurred by Union, on behalf of both sales service and DP customers. At the time, DP customers had the option, but not the obligation, to supply any incremental consumption above forecast in the same time period during which the consumption exceeded forecast. Few customers chose to supply incremental gas in the winter. Union, therefore, held the default position of manager of all consumption variances in excess of forecast throughout the contract year. Union was required to purchase incremental spot gas in the winter, as needed, to maintain system integrity and storage deliverability. The costs were calculated as the difference between summer and winter gas prices, multiplied by the volume of incremental spot gas purchased in the winter.

The Board accepted Union's proposal as the best alternative then available. The Board however directed Union to develop a method that better tracked and attributed the load balancing costs to those that caused them. The specific issues the Board wanted Union to consider were addressed on pages 27 and 28 of the E.B.R.O. 493-04/494-06 Decision (dated February 10, 1998):

> *"The Board considered other possible allocation methods such as direct allocation and direct charging based on cost causality by type of service, which is consistent with Union's current practice in charging system supply*

customers the gas supply administration charge. At this time the Board concluded that the administrative problems that may be encountered in implementing such different proposals in a timely manner may outweigh any advantages such proposals may have." (para. 4.2.22)

"A possible model might include the following features:

- *preparation of a monthly supply/demand/inventory forecast for each type of service;*
- *calculation of monthly differences in the supply/demand balance;*
- *comparison of monthly actual results to forecast amounts to isolate variances by type of service at the end of the forecast period; and*
- *a "true-up" mechanism." (para. 4.2.24)*

Union subsequently addressed this issue in the E.B.R.O. 499 Decision, with a further Board directive being issued at paragraph 3.1.59:

"The Board finds that although there are good reasons to continue the current methodology for the test year, the Board's approval is a temporary measure. The Board expects that a new load balancing service will be brought forward as soon as the company has completed its work on the unbundling of its services. The Company is directed to report to the Board as soon as it is in a position to present a new load balancing proposal."

Due to colder than normal winters in 2001/2002 and 2002/2003, Union was required to make significant load balancing ("spot winter gas") purchases to balance incremental consumption by both sales service and BT customers. These additional load balancing purchases resulted in significant deferral account debits.

As a result of the significant load balancing costs, BT customers in the South questioned why Union continued to purchase gas supplies on their behalf when they had clearly elected a marketer to manage that activity. In addition, a number of BT customers asserted that they had taken action to ensure their BT contract was balanced throughout

the colder than normal winter, yet were still subject to additional load balancing costs as a result of rate class disposition of costs.

In response to this customer feedback and to the Board directive issued in E.B.R.O. 499, Union, in consultation with customers, developed the current checkpoint balancing mechanism for BT customers in the South. Union sought and received Board approval for this mechanism as part of the RP-2003-0063 proceeding.

In developing the checkpoint mechanism approved in RP-2003-0063, Union was guided by a number of business principles. These principles (filed in RP-2003-0063 at Exhibit H1, Tab 4, pgs. 7 and 8) are as follows:

- The solution should be based on fair and equitable treatment of all customers.
- The solution should not prevent or cause undue switching between service options.
- Union should not make gas purchase decisions that impact direct purchase customers' supply costs.
- Union has a responsibility to provide a base level of load balancing to all bundled direct purchase customers as part of its delivery service (i.e. for normal weather).
- The solution needs to limit the need for retroactive adjustments.
- The solution needs to recognize that supply imbalances outside of the forecast should be attributable to a specific contract, not a rate class.
- The solution needs to be administratively simple for both Union and the customer.

These principles remain valid today and are consistent with the Board's findings issued in its RP-2003-0063 Decision with Reasons (dated March 18, 2004):

> *"… The notable virtue of the Applicant's proposal is that it places the responsibility for balancing costs with the direct purchase customers. The proposal is also consistent with the Direct Purchase customers acting as managers of their respective gas supply requirements. It is appropriate and equitable for them to have an enhanced and better informed opportunity to track and manage their position at the two critical periods in the year. To date they have been dependent on the Utility for the management of divergences from forecast. Having chosen Direct Purchase gas supply, it is predictable that direct purchasers would prefer an informed opportunity to manage any divergences from forecast that have arisen at February and September. Finally the Board considers the proposal to be an enhancement of security of supply for the system as a whole …" (pages 119 and 120)*

Physical Operations underpinning Checkpoint Balancing Mechanism in Union's South

The South features an integrated system anchored with Dawn storage and Dawn to Parkway transmission that enables customers to manage their own supply/demand imbalances using storage and other transactional upstream services. The South is supplied externally by multiple pipeline interconnections enabling customers to source gas from varied North American supply basins.

BT Service

The BT contracting process is driven by customers' annual consumption forecast. The forecast is used to define the obligated Daily Contract Quantity ("DCQ") and the Banked Gas Account ("BGA") curve (accumulating the difference between gas deliveries to Union and forecast consumption throughout the year). This produces end of September (Fall) and end of February (Winter) checkpoints.

The BT customer is responsible for maintaining a BGA balance at or below the Fall checkpoint amount (within forecasted allocated storage levels) and, at or above the Winter checkpoint value (within the forecasted draft position). At each contract renewal the customer must also have a BGA balance of zero (within the maximum allowable variances outlined within the contract). BT customers have access to the full suite of transactional services that are used by T1/T3 and Unbundled Customers to manage supply. These include Incremental/Suspension of Supply; Assignment/ Diversion of DCQ; ex-franchise/in-franchise Transfers; Loans and Short Term Storage.

To the extent that a customer fails to meet the Fall checkpoint, the quantity in excess of the checkpoint is subject to unauthorized storage space overrun charges. Any imbalance above the maximum positive variance at contract year-end, will be subject to the same charges.

To the extent that a customer fails to meet the Winter checkpoint, the quantity below the checkpoint will be billed the higher of the daily spot gas at Dawn in the month or the month following the occurrence. Any imbalance below the maximum negative variance at contract year-end, will be subject to the same charges.

The checkpoint mechanism supports the principle of cost causality in that it clearly places more of the responsibility for balancing costs with BT customers. The Board supported this concept as noted at page 120 of its RP-2003-0063 Decision with Reasons.

> *"Currently, costs related to balancing the system are imposed on all in-franchise customers without regard to their respective out-of-balance status. The adoption of the proposal places responsibility for over-and-under supply where it belongs, on those direct purchase customers who are out of balance at the stipulated Winter and Fall checkpoints."*

Load Balancing Costs

Union provides a base level of load balancing to all BT customers as part of its distribution service. In Union's view, the base level of load balancing to be provided from the utility should be derived from the weather normalized (as appropriate) demand and supply forecast established at the beginning of the BT contract year, as this aligns with the operating plan to which Union manages. The nature and allocation of the asset costs used to provide the base level of load balancing are discussed later in this evidence. Any unforecasted balancing activity and costs related to the Winter and Fall checkpoints, are the responsibility of each BT customer.

These costs could result from the need for incremental winter supply to meet the Winter checkpoint if winter consumption is greater than forecast, and/or supply mitigation costs to meet Fall checkpoint if fall consumption is less than forecast.

Load Balancing Costs Not Included in Rates

Under normal weather conditions, it is unlikely Union would incur any costs associated with balancing BT customers. Union will only incur costs if it must take action outside of the checkpoints on behalf of BT customers.

If Union is forced to take action and by doing so incurs load balancing costs, Union will seek recovery of these costs as part of the disposition of deferral accounts. Since the checkpoint mechanism was implemented, Union has not incurred any incremental load balancing costs on behalf of BT customers.

Example: Post September 30th (Fall checkpoint)

If Union experiences or forecasts continued warm weather through the peak net injection period (October – early December), costs may be incurred to mitigate lower than normal in-franchise consumption by both sales service and BT customers as gas in storage is greater than forecast for these customers. While a BT customer may have met the contractual obligation of the Fall checkpoint, mitigation costs may be incurred on their behalf after the Fall checkpoint in the late injection season.

Example: Post February 28th (Winter checkpoint)

If Union experiences or forecasts colder than normal weather past the Winter checkpoint, with a subsequent increase in anticipated in-franchise sales service and BT demands during the remaining withdrawal period (March through April), Union may incur costs to manage late season withdrawals and demands on behalf of both system and DP customers.

If costs are incurred on behalf of BT customers after the checkpoints, they will be deferred into the Spot Gas Variance deferral account.

Benefits of the Checkpoint Mechanism

The current checkpoint mechanism reflects the business principles that guided its development and provides several benefits to customers and Union. The mechanism:

1. Recognizes that Union plans and manages its portfolio and gas acquisitions based on the aggregation of forecast demands and supplies on its system and based on normal weather.
2. Recognizes cost causality. Customers incur their own balancing costs if they are consuming gas in excess of forecast or under consuming compared to forecast.
3. Provides customers with flexibility given the increased availability of diversions in winter months, recognizing the increased certainty Union has with the winter balancing checkpoint.
4. Aligns with the current design and physical operation of the South system.

Physical Operations Underpinning Annual Balancing Mechanism – North

Union's operations in the North differ from the South in two key respects. First, the North's system consists of various pipeline laterals that connect communities and customers to the TCPL mainline. Second, with the exception of Union's LNG peaking facility located at Hagar, physical storage does not exist within the Northern delivery zone. Accordingly, Union's approach to load balancing in the North must be different than that used in the South.

Customers in the North are served through a combination of Union storage and transportation capacity. TCPL FT and STS capacity and delivered gas supply result in a

complex system operation. All assets held by Union for the purposes of serving the North are operated in an integrated manner to optimize the system and to attain the highest load factor at the lowest cost possible.

From a transportation perspective, there are six separate TCPL delivery areas with separate TCPL capacity contracted to each area. These six TCPL delivery areas are: Manitoba, Western, Northern, Sault Ste. Marie, Central and Eastern. In addition to firm TCPL FT capacity to each area, other assets consisting of storage, Storage Transportation Service (STS), STS pooling rights, Dawn to Parkway capacity and other third party assets such as exchange contracts and other transportation capacity are used to provide the integrated service to all customers across all delivery areas in the North and East. In general, the firm transportation capacity and other assets are used to transport Alberta supply to the market area. All other services listed above are used to transport volumes from Dawn (supplies from storage) to the market areas and to transport volumes from the market areas to Dawn (storage) depending on seasonal or market conditions.

Union currently manages all the transportation assets in the North on an integrated basis. Union is able to manage market demand swings through the capacity to nominate daily firm capacity, diversions, STS services and injections and withdrawals into and out of Dawn storage.

BT Service

Consistent with the South, the customer's consumption forecast is used to define the DCQ and the BGA curve. BT customers in the North are required to balance to zero at the contract year end. This can be done through physical or financial means.

Physical Balancing: To help ensure customers in the North balance to zero, Union monitors the customers' BGA balance to determine if balancing activity is required. If Union determines the contract is under-consuming and supply needs to be reduced to bring the BGA to zero by the contract year-end, Union will consult with the customer. If no proactive action is taken by the customer, Union will ratchet back the DCQ during the remainder of the contract year.

As mentioned above, the ratcheting of the DCQ is used because all BT gas receipts in the North take place at Empress and are transported via Union Gas upstream transportation capacity. As Union reduces the customer obligation to deliver the DCQ, Union assumes responsibility to manage the pipeline capacity.

Customers in the North have access to many of the transactional balancing services that are available to customers in the South. Customers have the option, but not the obligation, to use these services to meet their annual balancing requirements. To date, customers continue to rely on the ratcheting of the DCQ to reduce supply in times where consumption is less than forecast. The financial settlement process (outlined below) addresses any remaining imbalances at contract renewal.

Financial Balancing**:** If a zero balance is not achieved, a financial reconciliation will take place. If the customer has a positive balance (due to consumption being less than deliveries) then the excess gas will be sold to Union. If the BGA balance is negative (consumption greater than deliveries), then the customer will purchase the shortfall from Union. The rate in both cases is the Alberta Border Reference price plus an adjustment for compressor fuel to the applicable delivery areas.

Load Balancing Costs

In the North, the costs associated with providing a base level of load balancing are included in the gas supply transportation rates applicable to all sales service and BT customers.

Unforecasted balancing activity and related costs for each BT customer are addressed through the financial reconciliation at the end of each contract year, and through the disposition of the transportation deferral account balances.

Load Balancing Costs Not Included in Rates

Under normal weather conditions, it is unlikely Union would incur any costs associated with balancing BT customers. Union will only incur costs if it must take action on behalf of BT customers.

If Union is forced to take action and by doing so incurs load balancing costs, these will be deferred into the Spot Gas Variance deferral account.

Seasonal Load Balancing – Fall: Union will proactively ratchet back the DCQ during the contract year if Union determines the contract is under-consuming and supply needs to be reduced to bring the BGA to zero by the contract end. BT customers may still experience deferral account impacts if Union's actions to mitigate late season storage injection by reducing DCQ's is not sufficient and incremental measures are required.

Seasonal Load Balancing – late Winter**:** If Union experiences or forecasts colder than normal weather, with a subsequent increase in anticipated sales service and BT demands during late season withdrawals period, Union may be required to incur and defer costs to manage these demands.

Benefits of Current Mechanism - North

The current mechanism reflects the business principles that have guided its administration and provides the following benefits to customers and Union:

1. The most significant benefit is the simplicity for the customer and the marketer given the complex nature of managing the North. Customers benefit from having Union manage daily and seasonal balancing utilizing the system and asset diversity Union has while at the same time providing customers access to optional load balancing services to help them manage their annual balancing requirement.
2. By having all BT DCQ deliveries at Empress and a suite of transportation and storage services to manage all customers throughout the various TCPL areas it serves, Union can efficiently and cost effectively provide the daily and seasonal load balancing needs for the North BT customers.

3. The mechanism recognizes cost causality for both sales service and DP customers.
4. Aligns with the design and physical operation of the North System.

Conclusion

The load balancing mechanisms in both the South and North have evolved over time to meet the needs of customers and reflect the design and physical and design operation of each operating area. Additional supplemental transactional services have been developed to provide customers options to assist them in meeting their balancing obligations. There has been no feedback of any issues with the current methodologies by customers or gas marketers either in the South or North. Union believes no changes to its load balancing mechanisms are warranted at this time.

MDV/DCQ Establishment

The purpose of this evidence is to address Union's methodology for setting the DCQ. Specifically, this evidence addresses:

- Weather normalization in the setting of DCQ;
- Resetting DCQ during the term of the contract.

Weather Normalization

Union plans its operational requirements on the basis of normal weather. Because of its sensitivity to weather, general service consumption is weather normalized in determining

Union's revenue forecasts as well as its upstream capacity, storage, and load balancing needs.

Normal weather is the key demand forecast variable for the general service market segments as variation in weather affects demand. On page 23 of the Board's RP-2003-0063 Decision, the Board allowed Union, for 2004, to use a blend of the 30-year average and 20-year trend "…to test the suitability of changing the normalization methodology and in consideration of the principle of minimizing rate shock". Further, the Board also said it would "consider 5% declines and inclines to the weighting of the 30 year and 20 year methodology respectively until such time as a 50:50 weighting is in place". As described in Union's evidence filed in EB-2005-0520 (2007 rate case), the 2007 normal weather was set by the blended 55:45 (30-year average/20-year trend) normal weather methodology in accordance with the Board's RP-2003-0063 Decision. In the EB-2005-0520 Settlement Agreement, parties accepted Union's proposal to "establish the test year weather normalization on the basis of a blend of 55% of the 30 year average and 45% of the 20 year declining trend estimate in accordance with the RP-2003-0063 Decision with Reasons and that the forecast revenue consequences of this proposal are reasonable."

As end use customers move from sales service to DP, the allocation of upstream capacity, storage, and load balancing responsibilities moves with the customer. It is consistent to set DP contract parameters, including DCQ and checkpoint values (where applicable), on a similar basis.

The use of non-weather normalized consumption from the previous 12 months for a future contract period assumes that weather experienced in that period will be repeated. To the extent that a forecast of weather is included in the setting of contract parameters, Union's operations and/or other customers may be at risk. Likewise, forecasting weather over the term of the contract parameters results in similar concerns. The use of weather normalized consumption reduces these risks.

Union's approach to the use of normal weather is consistent with its operations and ensures fair and consistent treatment of customers (regardless of whether they are sales service or DP). Further, customers/gas marketers have not voiced a concern with Union's approach.

Resetting DCQ during the Contract Term

When a DP contract is initially established or renewed, the contract's DCQ is set to match forecast consumption for the contract term. All other things being equal, this will result in a zero balance at the end of the contract term. The basis for the forecast consumption is the most recent 12 months actual consumption (weather normalized where applicable) for the accounts underlying the contract.

In the non-general service market, where account additions and deletions to a DP contract are very rare and/or have an insignificant impact on the contract's overall DCQ, the DCQ is not typically adjusted during the term of the contract. However, in the general service market, gas marketers have the ability to add or remove accounts from a DP contract

during the term of the contract. These additions and deletions may result from movement between sales service and DP, between contracts held by a gas marketer, or between contracts held by different gas marketers. Changes to the DCQ for the remaining term of the affected contracts are considered to ensure that the DCQ follows the customer. This in turn, ensures that the underlying service follow the customer and maintains an appropriate allocation of assets between Union and DP contracts. At the same time the contract's DCQ is adjusted for account additions and removals, changes in normalized consumption for the accounts remaining on the contract and changes in checkpoint values (where appropriate) are also reflected.

The change in DCQ is based on 12 months of consumption regardless of when, during the term of the contract, the contract is amended to reflect the change. Customers have the ability to balance during the term of the contract by using the transactional services available (subject to Union's operational ability to accommodate).

This approach currently uses a materiality threshold of 4 GJ/d as the net impact for account additions and removals during the term of the contract. The use of a threshold provides a fair balance between tracking the DCQ and resetting balancing parameters with the administration (by Union and customer) associated with processing contract amendments. Union periodically reviews the need to alter this threshold.

Union believes DCQ's should be determined using weather normalized consumption values. Further, if the customers BT contract experiences a material change during the

contract term, the DCQ should be reviewed and recalculated to minimize the balancing at contract end.

Union's Responses to Board's Specific Questions:

8.1 Should there be standardized load balancing mechanisms for Union and Enbridge? What are the costs and benefits to ratepayers, gas marketers and natural gas distributors of the current load balancing mechanisms used by each of Union and Enbridge? What are the costs, benefits and implications to ratepayers, gas marketers and natural gas distributors of standardizing the load balancing mechanisms for Union and Enbridge?

Load balancing mechanism(s) should be driven by the operational characteristics of each utility. Issues such as upstream pipeline/supply diversity, proximity to storage and liquid trading points, system infrastructure, asset and customer base are different from one utility to the next.

There are sufficient differences not only between Union and Enbridge but between Union's South and North systems such that consistent load balancing approaches would be neither practical nor cost effective.

There are many reasons why the checkpoint mechanism is practical for Union South BT customers and why the end-of-year balancing mechanism is practical for the Union North BT customer. These reasons have been outlined in this evidence.

8.2 What mechanism(s) for load balancing should be used by natural gas distributors?

Union supports a mechanism(s) for load balancing that supports the principle that those customers who cause the costs ought to bear them. Union's current load balancing mechanism in both the South and North operation areas is consistent with this principle.

8.3 What are the implications of different balancing mechanism(s) in relation to the issue of drafting?

Union understands this question to debate what are the implications of utilities having different load balancing mechanisms for DP customers. Union believes that a load balancing mechanism should be utility specific to match the design and physical operations of the utility's system.

8.4 Should the MDV/DCQ reestablishment process be standardized, including in relation to the weather normalization of MDV/DCQ volumes?

Union does not believe the MDV/DCQ process needs to be standardized. Union believes DCQ's should be determined using weather normalized consumption values. Further, if customers' BT contracts experience material changes during the contract terms, the DCQs should be reviewed and recalculated to minimize the balancing at contract ends.

Union's approach to setting and adjusting DCQ is fair in that it ensures that DCQ follows the underlying accounts without creating excess administration.

SECTION C - COST ALLOCATION

This evidence addresses the allocation of costs associated with the administration of the regulated gas supply and DP options. It also addresses the allocation of asset costs to load balancing and delivery and between regulated gas supply and DP customers.

Gas Supply Administration and Direct Purchase Administration Charges

Gas customers within Ontario have the option to choose between the utility and energy marketers as their commodity supplier. Customers that elect Union as their supplier (sales service customers) pay a gas supply administration fee in respect of that service. The gas supply administration fee is included in the commodity line of the bill for sales service customers. Customers that contract with a gas marketer for their gas supply do not pay Union's gas commodity charge and therefore do not pay the gas supply administration fee. The gas marketer, however, pays Union the Direct Purchase Administration Charge ("DPAC") in recognition of the costs related to administering the DP contract. It is Union's view that the administration and cost structure of the regulated gas supply service in no way impedes the competitiveness of the DP activity or distorts market price signals. Gas customers within Ontario have the option to choose between the utility and energy marketers as the commodity supplier.

Union includes the incremental costs associated with administering each supply offering when determining the gas supply administration fee and the DPAC. The gas supply administration fee recovers costs such as the direct salaries and benefits of Union

employees actually engaged in the purchase and administration of system supply (i.e. gas acquisition, nominations, invoicing and payment processing, reporting); the investment carrying costs on gas purchase working capital; plus, an allowance for bad debt.

The DPAC recovers costs associated with contract administration, gas management and billing and reporting. Neither the gas supply administration fee nor the DPAC includes the costs associated with load balancing. Union recovers the forecasted load balancing costs for sales service and DP customers in delivery rates in the South and in the gas supply transportation rate in the North.

Union has taken an incremental approach to calculating the gas supply administration fee and the DPAC for the following reasons:

- The costs related to both services vary directly with sales service or DP activity. In other words, if Union no longer provided a sales service option, Union would no longer incur the costs associated with the purchase and administration of system supply. The same would be true if Union no longer facilitated DP (i.e. the associated costs would no longer be incurred);
- Neither the provision of the gas supply service to sales service customers nor the services related to facilitating DP are considered part of Union's core business. Union's primary business is to provide distribution, transmission and storage services to in-franchise and ex-franchise customers including base level load balancing for in-franchise customers;

- It is appropriate to treat the fees associated with system supply and the facilitation of DP in a consistent manner; and
- If Union determined the costs related to the gas supply administration fee on a fully allocated basis Union would be at risk of non recovery of the difference between the incremental and fully allocated costs should system sales activity levels decrease. By taking an incremental approach, Union eliminates the incentive to actively market the system supply option so as to maintain the recovery of the fully allocated cost.

As indicated above, the fees associated with providing gas supply service and facilitating DP are designed to recover the incremental costs of each service. The fees take into account the differences in:

- The customer or party whom the service is being provided;
- The underlying nature of the cost drivers for each service.

Union recovers the incremental costs related to providing the gas supply from the sales service customer. The fee itself is included in the commodity and fuel portion of the total gas supply commodity charge. The fee is calculated by dividing the total costs associated with administering the regulated gas supply service by total sales service volumes. This rate treatment is appropriate because it aligns the recovery of the costs related to purchasing the gas supply to the driver of the costs i.e. the supply itself. The current gas supply administration fee is 0.3138 cents/m^3.

In the case of DP, Union recovers the costs related to service from the DP contract holder, rather than the end use customer. As such the recovery reflects the fact that it is the contract holder's actions that drive the costs and not the end use consumption. The DPAC rate structure has two components:

- A fixed charge per contract per month (currently $75); and
- A fixed charge per customer per month (currently $0.19).

This rate structure recognizes the cost drivers in the case of DP are primarily associated with contract administration and are independent of end use consumption.

The above rates for the DPAC were proposed by Union as part of RP-2003-0063. As noted on page 11 of the RP-2003-0063 Settlement Agreement (dated September 19, 2003) parties came to a complete settlement on these DPAC rates. In Union's 2007 rate case (EB-2005-0520), parties also settled to keep these rates and not use Union's proposed amounts.

Union's Responses to the Board's Specific Questions:

9.1 What activities and underlying costs should be incorporated into the regulated gas supply and direct purchase options?

Gas Supply Administration-Related Costs

The gas supply administration fee recovers the incremental costs related to providing gas supply purchase services to sales service customers. It includes the direct salaries and benefits of Union employees actually engaged in the purchase and administration of

system supply (gas acquisition, nominations, invoicing and payment processing, reporting), the investment carrying costs on gas purchase working capital, and an allowance for bad debt.

The gas acquisition function includes the identification of potential suppliers, tendering of supply, negotiating contracts, and purchasing system gas. The nomination function is the actual nominating of the amount of gas to be delivered and is required to ensure that gas is available when and as needed. The invoicing and payment processing function includes receiving invoices, verifying accuracy and processing payments. The reporting function is related to the establishment of reference prices, quarterly adjustment mechanisms and following Board directed practices.

Investment carrying costs on gas purchase working capital and an allocation of bad debt are included in charges to system gas customers since these costs are directly related to the supply of commodity. Gas supply-related revenue is variable with volume and bad debt is a write-off of uncollectible revenues. This allocation ensures that all customers pay a proportionate share of the forecast bad debt.

Direct Purchase Administration-Related Costs

To provide DP gas to end-use customers, gas marketers rely on Union for forecasted balancing and distribution services. Union provides these services to gas marketers under transportation services agreements and at rates approved by the Board.

Union's charges for facilitating DP are designed to recover the incremental costs of facilitating DP gas supply. It is charged to the gas marketers and not the DP customers themselves.

The incremental costs associated with administering DP arrangements for the general service market (i.e., rate classes M1, M2, R01, R10) can be separated into three main functional areas: contract administration, gas management, and billing & reporting.

The contract administration process relates to establishing, maintaining and renewing DP contracts. Once a DP contract is established or renewed, gas marketers nominate their daily deliveries to Union for each underlying DP contract. Union's gas management group receives these nominations for each delivery point and in turn places nominations on all upstream pipelines (e.g., TCPL) on behalf of gas marketers. For some contracts, Union also manages upstream transportation arrangements on behalf of DP customers.

For each DP contract, the billing & reporting function involves producing monthly financial statements consisting of the invoice and the DP status report. The invoice includes items such as upstream transportation charges (for Western bundled transportation arrangements) and DP Administration fees. The costs associated with the Distributor Consolidated Billing ("DCB") service are not included in the DPAC because they are recovered via the DCB fee.

The DP status report shows the current and forecasted imbalance between deliveries and

consumption for each DP contract. In addition to the financial statements, the billing & reporting function reconciles receipt and consumption data, manages arrears, and responds to gas marketer queries and issues.

Unlike system gas, no additional amounts are allocated or charged to DP customers by Union for bad debt expenses or return on working capital. These costs are directly related to the supply of commodity and are, therefore, not incurred by Union for DP customers. Gas marketers bear these costs, although they typically contract with the utility for DCB service, which covers their bad debt cost exposure. (The DCB service is a service provided through agreements entered into between Union and gas marketers to have Union provide the billing, credit, and collection functions for the gas marketer.)

Union's DPAC only applies to administering DP services for the general service market (i.e., rate classes M1, M2, R01, R10). Costs to support DP for the large commercial and industrial rate classes are included in the respective delivery rate because the vast majority of large commercial and industrial customers are on DP arrangements.

Allocation of Asset Costs Between Load Balancing and Delivery and Regulated Gas Supply and DP Offerings

With respect to how asset costs are allocated to load balancing and delivery and how these costs are allocated between sales service and DP customers, it is Union's view that the allocation and recovery of base level load balancing costs is appropriate. Union does not differentiate between BT and sales service customers in its Board approved cost

allocation study. This consistent treatment allows for a common base level of load balancing costs in rates supporting one common rate for both.

Further, the annual balancing mechanism applicable to DP customers in the North and the checkpoint mechanism in the South appropriately ensure that the sales service customers do not incur costs associated with balancing DP customers beyond that included in base rates. This was recognized by the Board as noted on pages 119 and 120 of its RP-2003-0063 Decision with Reasons.

> *"The notable virtue of the Applicant's proposal is that it places the responsibility for balancing costs with the direct purchase customers. The proposal is also consistent with the Direct Purchase customers acting as managers of their respective gas supply requirements. It is appropriate and equitable for them to have an enhanced and better informed opportunity to track and manage their position at the two critical periods in the year. To date they have been dependent on the Utility for the management of divergences from forecast. Having chosen Direct Purchase gas supply, it is predictable that direct purchasers would prefer an informed opportunity to manage any divergences from forecast that have arisen at February and September."*

As indicated above, Union implemented its current load balancing structure as part of the RP-2003-0063 proceeding. In its evidence at Exhibit H1, Tab 4, pages 5-6, Union defined load balancing and the assets Union uses to provide a base level of load balancing. See relevant excerpt below:

> *"Load balancing is defined as the service of matching supply and demand. Load balancing is required when customers deliver more or less gas than they physically consume on a given day and throughout the season. Union uses its available resources to manage the resulting imbalance."*

Though this definition is mostly referring to DP customers it also holds true for system customers whereby Union purchases some of the gas to be burned in the winter during the summer months.

The evidence at H1 Tab 4 continues to define the assets used to provide load balancing. As noted below:

- *"Storage space and deliverability – Storage space is used to store gas on days (and between seasons) when demand is less than supply. The stored gas is then withdrawn when demand is greater than supply. Injection and withdrawal deliverability is required to move the gas in and out of storage. Load balancing costs related to storage space, injection and withdrawal (to meet normal weather demands) are currently recovered in delivery rates based on each rate class's forecast use of those assets.*
- *Balancing gas inventory – This is inventory owned by Union that enables Union to manage the forecast seasonal variances between the supply and demands of Bundled-T customers. Union's provision of balancing gas inventory enables Bundled-T customers to consume gas on a forecast basis at one time of the year, draft the system, and subsequently replace the supply in another period. Union holds 29.5 PJs of balancing inventory to manage the forecast imbalance between the supply and demand of all Bundled-T contracts. During the winter months Union essentially "loans" out the load balancing gas to Bundled-T customers who return it during the summer. The associated costs are treated in a manner similar to Union's working inventory and allocated to all rate classes."*

Similar to balancing gas inventory for DP customers, Union also uses gas in storage as an asset for load balancing for sales service customers.

The costs associated with the assets described above are allocated to all rate classes in proportion to each rate class demands for the underlying assets. Further, these costs are recovered through delivery rates in the South and the gas supply transportation rates in the North. Union does not distinguish in its Board approved cost allocation or rate design

between load balancing costs for sales service and DP customers. This approach recognizes that the load balancing requirements of customers are driven by factors other than the source of commodity (i.e. load and load profile). Further, it ensures that sales service and DP offerings are unbiased from a delivery rate perspective and supports customer choice.

Union is not proposing any changes to the allocation or recovery of load balancing costs.

9.2 What asset-related costs should be allocated to load balancing and delivery and how should the costs of these services be allocated between system/regulated supply and direct purchase customers?

Load balancing costs include costs associated with the use of Union's storage assets, gas inventory and balancing gas inventory. As indicated above, Union recovers load balancing costs in delivery rates in the South and in the gas supply transportation rates in the North.

Union's delivery rates and gas supply transportation rates are applicable to both sales service and DP customers. Union does not distinguish between sales service and DP customers in the allocation or recovery of base load balancing costs.

9.3 Under what circumstances should natural gas distributors be permitted to change cost allocation principles, percentages, or amounts as between distribution, load balancing, and commodity?

Changes to cost allocation methods require Board approval. It is Union's view that the cost allocation methods, to the extent Union is proposing changes, should be reviewed at the time of rebasing. During Incentive Regulation ("IR") delivery rates are determined using the price cap formula. Union does not produce a cost study annually as part of the rate setting process during the IR term.

SECTION D - BILLING TERMINOLOGY

Union's Responses to the Board's Specific Questions:

10.1 Should natural gas distributors be required to use standard billing terminology? If so what should the terminology be?

Union conducts customer research on an annual basis to review and confirm the quality of service that it provides to customers. It is clear from this research that Union's customers put a high degree of reliance on the energy information provided to them by Union. To be specific, 2008 year-to-date research data (based on a random sample of 821 who personally see bills issued by Union) indicates that 75% of Union's residential customers provide Union with a rating of 8 or above on a 10-point scale (with 10 being excellent) for its overall bill format and information provided on the bill. This data reveals that Union's current bill format is well received by its customers.

Bill Redesign

Union's most recent bill redesign initiative occurred in 2005 following a decision issued by the Board in Union's 2004 rate case (RP-2003-0063) which ordered Union to include rate riders on the bill. These four new rate rider lines include:

1. gas commodity
2. delivery
3. gas transportation
4. storage

The inclusion of the four riders allows for timely implementation and is seen as an integral part to Union's QRAM process. However, at the same time it created challenges with respect to bill presentment. Specifically, the added lines were viewed as creating an additional level of complexity on the bill that customers did not approve. In response to this feedback, Union undertook a major bill redesign. Focus groups were conducted at Union for customers to test alternative formats of the bill. The revised bill format, which is still in existence today, was introduced in July, 2006. The current design features summary information on the front of the bill and more detailed information and calculations on the back should customers wish to view this level of detail.

Although Union was able to manage the cost of this re-design within the $3.8 million budget approved by the Board in RP-2003-0063 for rate rider implementation, Union submits the investment to complete a major bill re-design, from a time, resource and dollar perspective, is significant.

Conclusion

Given that the majority of Union's customers rate the effectiveness of Union's bill very high, Union is not proposing any change to its bill presentment (including terminology) at this time. There is also no research or evidence to suggest Union's customers are comparing the bills they receive from Union to bills issued by other utilities (i.e. Enbridge).

SECTION E - IMPLEMENTATION ISSUES

Union's Responses to the Board's Specific Questions:

11.1. What are the costs of implementing changes to methodologies currently used by natural gas distributors?

Union does not anticipate any material cost impacts for Union and/or its ratepayers as a result its proposals in this proceeding.

11.2 Who should bear those costs?

As indicated above, Union does not anticipate any material implementation costs associated this proceeding. In the event that there are implementation costs, Union will allocate the costs to ratepayers in a manner consistent with Board approved cost allocation methods and seek recovery.

11.3 How and when should any such changes be implemented?

Union's only proposed changes are the elimination of the Intra-Period WACOG deferral account and the revision to the filing requirements. If Union's proposal with respect to the elimination of the Intra-Period WACOG deferral account is accepted, Union proposes to adjust delivery rates in the first QRAM immediately following the Board's decision. Any balance accumulated in the Intra-Period WACOG Deferral account prior to delivery

rates being adjusted will be disposed as part of the annual deferral account disposition proceeding.

		Current Process		Proposal
A	**REVIEW OF QRAM FOR GAS LDCs**	**Enbridge**	**Union**	
1	**Trigger Mechanism**	$0.005/m3 trigger for utility price and rider	No trigger	Enbridge to adopt "No Trigger" Mechanism
2	**Price adjustment frequency and forecast period**	Quarterly price and rate adjustments Forecast period = 12 months	12 month Forecast	No Change
3	**Calculation of reference price**	Common methodology to determine reference price. Reference price calculated by utility reflects utility specific gas supply mix.	Common methodology to determine reference price. Reference price calculated by utility reflects utility specific gas supply mix.	No Change
4	**Deferral and variance A/C disposition**	Rider C cleared to achieve zero balance in PGVA at end of year. True up for all PGVA components at year end.	Recovery of balances using 12 month rolling rate rider	Enbridge to adopt 12 month rolling rider methodology
5	**Impact on Revenue Requirement (re. reference price)**	Quarterly changes to gas costs and carrying cost of gas in storage and working cash requirement	Carrying costs recovered through annual deferral disposition	Union to eliminate Intra-Period WACOG deferral account and adjust delivery rates with QRAMs
6	**Implications/costs of standardizing pricing mechanisms**			No Change
7	**Filing requirements**			Utilities propose streamlined QRAM information filings and timeline efficiency
B	**LOAD BALANCING (LB)**	a) Single BGA management checkpoint (at account anniversary) b) MDV re-established at contract anniversary	a) Checkpoint balancing (February 28 and September 30) in Union South and Annual balancing in Union North b) Re-establishment of DCQ based on weather normalized consumption	a) Utilities to keep their existing BGA checkpoint systems b) Enbridge to adopt MDV reestablishment mechanism
C	**COST ALLOCATION**	Incremental costing for system gas and direct purchase management	Incremental costing for system gas and direct purchase management	No Change
D	**BILLING TERMINOLOGY**	Established based on customer / market research	Established based on customer / market research	No Change
E	**IMPLEMENTATION ISSUES**			Recovery of implementation costs