Ontario Energy Board

Commission de l’énergie de l’Ontario

Ontario

EB-2008-0106

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

DECISION AND ORDER

September 18, 2009

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EB-2008-0106

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

BEFORE: Paul Sommerville
Presiding Member

Cathy Spoel
Member

DECISION AND ORDER

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INTRODUCTION

BACKGROUND

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

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

THE PROCEEDING

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

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

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

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

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

ORGANIZATION OF THIS DECISION

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

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

REVIEW OF QUARTERLY RATE ADJUSTMENT MECHANISM FOR NATURAL GAS DISTRIBUTORS

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

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

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

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

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

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

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

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

BACKGROUND

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

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

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

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

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

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

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

BOARD FINDINGS

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

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

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

PRICE ADJUSTMENT FREQUENCY AND FORECAST PERIODS

BACKGROUND

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

BOARD FINDINGS

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

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

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

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

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

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

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

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

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

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

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

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

METHODOLOGY FOR THE CALCULATION OF THE REFERENCE PRICE

BACKGROUND

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

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

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

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

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

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

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

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

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

BOARD FINDINGS

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

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

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

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

DEFERRAL AND VARIANCE ACCOUNT AND DISPOSITION METHODOLOGY

BACKGROUND

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

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

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

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

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

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

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

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

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

NRG did not propose any changes to its disposition methodology.

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

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

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

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

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

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

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

BOARD FINDINGS

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

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

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

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

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

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

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

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

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

BACKGROUND

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

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

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

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

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

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

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

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

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

BOARD FINDINGS

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

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

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

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

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

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

FILING REQUIREMENTS

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

<u>QRAM Review Process:</u>

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

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

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

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

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

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

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

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

BOARD FINDINGS

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

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

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

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

The Board directs NRG to file a QRAM application with the Board within 8 calendar days from the close of the 10 day strip. NRG shall serve the application on all intervenors in NRG's last rates case. Intervenors and Board staff will have 5 calendar days to file comments. NRG will have 3 calendar days to file responses to any

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

comments received. Thereafter the Board will issue its decision by the 25th of the month to allow NRG to implement the rate changes.

Standardized Filing Requirements:

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

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

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

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

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

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

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

BOARD FINDINGS

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

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

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

REVIEW OF LOAD BALANCING OBLIGATIONS FOR NATURAL GAS DISTRIBUTORS

The section deals with issues 8.1 to 8.4 from the Board's issues list. The main issues in this proceeding with respect to load balancing obligations for natural gas distributors were as follows:

- Should there be standardized load balancing mechanisms for Union and Enbridge?
- What mechanism(s) for load balancing should be used by natural gas distributors?
- Should the Mean Daily Volume ("MDV")/Daily Contract Quantity ("DCQ") re-establishment process be standardized, including in relation to the weather normalization of MDV/DCQ volumes?

LOAD BALANCING MECHANISM

BACKGROUND

Union currently has a checkpoint balancing mechanism for Bundled-T ("BT") service customers in the South. Under that mechanism, BT customers are responsible for maintaining a Banked Gas Account ("BGA") balance at or above the Fall checkpoint amount and at or above the Winter checkpoint value. At each contract renewal the customer must have a BGA balance of zero (within the maximum allowable variances outlined within the contract). BT customers have access to a suite of transactional services that are used by T1/T3 and Unbundled customers to manage their supply. These include incremental/suspension of supply, assignment/diversion of DCQ, ex-franchise/in-franchise transfers, loans and short term storage. The checkpoint mechanism supports the principle of cost causality by placing the responsibility for balancing costs with BT customers.

To the extent that a BT customer fails to meet the Fall checkpoint, the quantity in excess of the checkpoint amount is subject to unauthorized space overrun charges. Any imbalances above the maximum positive variance at contract year-end will be subject to the same charges. Similarly, to the extent that a BT customer fails to meet the Winter checkpoint, the quantity below the checkpoint is billed the higher of the daily spot gas at Dawn in the month or the month following the occurrence. Any imbalances below the maximum negative variance at contract year-end are subject to the same charges.

In the North, Union uses a year-end balancing mechanism.

NRG is subject to the load balancing obligations required by Union under the M9 service contract.

EGD's current methodology is similar to Union's in the North as the only obligation to balance delivery and consumption within a given tolerance is at the expiry date of the contract. Any volume of gas in the BGA exceeding the tolerance of +/- 20 times the MDV is automatically purchased or sold at a price set to induce customers to stay within the tolerance band.

EGD explained that the tools offered to its DP customers to manage BGA imbalances are similar to those offered by Union; the difference is one of availability.

The availability of BGA management tools is different between Union and EGD. Union offers tools year-round on an interruptible basis, whereas EGD's tools are firm but are restricted during peak winter months (limited suspensions) and late in the storage injection season (limited make-ups). This difference is due to the geographical location of each utility and because EGD does not have a trading hub within its franchise area.

Union argued that its customers have not expressed any concerns with the existing methodology and proposed no changes to the current methodology. Similarly EGD did not propose any changes to its load balancing mechanism. Given the operational differences between the two utilities, Union and EGD argued that it was not appropriate to have identical load balancing mechanisms.

EGD further argued that implementing a mechanism similar to Union would mean that EGD would have to increase the availability of BGA management tools throughout the year so that customers have the ability to meet the checkpoint requirements. EGD maintained that it could not guarantee the availability of such management tools on a firm basis as this could place system supply at risk during peak system constraint periods. EGD explained that it would have to offer these tools on an interruptible basis (as does Union) which could expose customers to the risk of not being able to make alternative arrangements.

While EGD is not proposing to implement checkpoint balancing, it estimated that the costs of this initiative would be about $4.8 million.

FRPO disagreed with EGD's position regarding the checkpoint balancing. FRPO submitted that EGD had failed to make the distinction between daily and seasonal load balancing. In FRPO's view, the pipelines constraints cited by EGD are in reference to daily load balancing. FRPO argued that if checkpoint balancing is included for seasonal balancing, then customers could use EGD's enhanced title transfer at Dawn to increase storage levels on a firm basis prior to the checkpoint. FRPO submitted that checkpoint balancing would be in the interest of customers since it would place the responsibility for balancing costs with the DP customer and therefore enhance cost causality. FPRO further estimated that the cost of un-forecasted purchase for load balancing incurred by EGD would be about $50 to $60 million per year, and expressed the view that the benefits of the checkpoint balancing could outweigh the costs possibly in the first year.

BOMA and LPMA agreed with EGD that the mechanisms used for load balancing should reflect the physical location and constraints of the utility. BOMA and LPMA argued that while EGD's concerns are legitimate with respect to peak day balancing and the constraints on EGD, it is unclear that these concerns would be the same in regard to seasonal load balancing. As a result, BOMA and LPMA suggested that EGD address this issue in its reply argument.

SEC supported FRPO's submission on this issue.

VECC supported the utilities' position with respect to this issue.

CME argued that until there is evidence that ratepayers would receive an appreciable benefit from the checkpoint balancing mechanism that would justify an expenditure of $4.8 million, EGD should continue to operate under the existing model.

The GMG submitted that Union's current practices are acceptable. With respect to EGD, the GMG expressed the view that in order to provide an ideal degree of flexibility in the market, weather normalized MDV and multi-point balancing should both be implemented. However, the GMG submitted that the multi-point balancing should not be considered at the expense of the MDV re-establishment implementation.[42]

CCC supported EGD's arguments that the cost of implementing a change to the load balancing mechanisms will not produce any meaningful benefit for customers.[43]

In its reply argument, EGD indicated that the need to adjust discretionary purchases to balance supply and demand due to variations in weather would continue to exist even if EGD were to implement a checkpoint balancing mechanism. The return of loaned gas by DP customers at a time earlier than the end of the contract year would not diminish EGD's need to provide load balancing for the system as a whole on a daily basis. In conclusion, EGD argued that the implementation of a BGA checkpoint mechanism would not offer any benefits to customers or the system as a whole. EGD further argued that in comparison to the existing mechanism, DP customers would be subject to additional responsibility and administration and potential penalty charges, while continuing to share the load balancing costs in the PGVA.

BOARD FINDINGS

The Board finds that the current load balancing mechanisms of Union and EGD are appropriate. The Board's reasons for so finding are noted below.

The Board agrees that the operational differences between EGD and Union South are such that the application of a standardized approach could expose DP customers to the risk of not being able to make alternative arrangements. The Board views this risk as a detriment to DP customers.

The Board also agrees with EGD that the return of loaned gas by DP customers at a time earlier than the end of the contract year would not diminish EGD's need to provide load balancing for the system as a whole on a daily basis, and that consequently, DP customers would continue to share the costs of load balancing. This is also the case for Union's BT customers in the South.

The Board is also of the view that FRPO's comparison of the estimated implementation costs of the checkpoint balancing mechanism with FRPO's estimate of EGD's un-forecasted annual load balancing costs is without merit. Given EGD's weather sensitive

[42] GMG Argument, p. 6
[43] CCC Argument, Paragraph 22, p. 8

customer base, the need for additional discretionary purchases to balance supply and demand would not go away if DP customers were to assume that responsibility instead of EGD. In other words, if a DP customer were to assume that responsibility, the costs would then be borne by that customer. Therefore, the Board does not see the relevance of that comparison.

MDV/DCQ RE-ESTABLISHMENT PROCESS

BACKGROUND

Currently Union and EGD have different approaches to determining the DCQ/MDV.

Union is proposing no changes to its existing DCQ methodology and argues that DCQ's should continue to be determined using weather normalized consumption. Further, under Union's approach, if a customer's BT contract experiences material changes during the contract term, the DCQ is reviewed and recalculated to minimize imbalances at contract end. Union currently uses a materiality threshold of 4 GJ/d as the net impact for account additions and removals during the term of the contract.

In comparison, EGD uses the most recent 12 months of actual consumption, unadjusted for weather to determine the MDV. The MDV once determined is "locked" and does not change for the duration of the pool term.

EGD is proposing to adopt Union's approach and is proposing to establish the MDV on a weather normalized basis and allow for re-establishment of MDV during the contract pool term. The preliminary cost estimate to develop a weather normalized MDV establishment and MDV re-establishment (without the "check point" function) is $3.7million.[44] A high level breakdown of the costs was provided in EGD's response to Board staff interrogatory no. 9. At the technical conference EGD also noted that it had yet to establish the details of the new MDV mechanism, especially with respect to establishing an appropriate materiality threshold to trigger the re-establishment of MDV.[45] EGD also indicated that it needed about 18 months to implement these changes.[46]

[44] EGD Pre-filed Evidence, paragraph 127, p. 38
[45] Technical Conference Transcript, p. 123, l. 7 - 12
[46] EGD Argument in Chief, p. 10

CCC submitted that it is concerned that the costs could significantly exceed EGD’s estimate of $3.7 million and potentially outweigh any benefits to EGD’s customers. CCC submitted that the Board should direct EGD to provide, in its next rate proceeding, a detailed cost break-down of the change and a proposal as to how those costs would be allocated to its customers. Based on this information, the Board could reassess the reasonableness of the proposal.

FRPO supported EGD’s proposal. FRPO submitted that establishment of the MDV on a weather normalized basis and the re-establishment of the MDV will assist DP customers in the management of their BGA while ensuring that the utility maintains the control necessary to support cost effective load balancing on behalf of all customers.

The GMG supported EGD’s proposal to adopt a weather normalized MDV re-establishment and submitted that these changes should be implemented as soon as possible to address customer mobility and delivery issues as a result of recent GDAR changes.

While IGUA endorsed EGD’s proposal, it noted that the details of the MDV mechanism have yet to be put forward. IGUA submitted that the Board should direct EGD to file the details of its proposed mechanism, the quantum of the costs incurred to implement the proposal, and the appropriate mechanism for recovery of those costs for review and approval in EGD's 2010 rate case.

VECC supported EGD’s proposal.

BOARD FINDINGS

The Board finds that Union’s existing approach to establishing DCQ on a weather normalized basis and the re-establishment of DCQ when a customer’s BT contract experiences material changes during the contract term is appropriate, since it acts to minimize imbalances in the BGAs.

Similarly, the Board finds EGD’s proposal to adopt Union’s approach and establish the MDV on a weather-normalized basis, and re-establish it during the contract term to be appropriate.

The Board orders EGD to file the details of its MDV proposal at its earliest convenience for the Board’s review and approval. The changes to the MDV shall be implemented in

2011. With respect to the costs of implementing the changes to the MDV, the Board directs EGD to record these costs in a deferral account, the prudence and disposition of which will be decided in a subsequent proceeding.

COST ALLOCATION

METHODOLOGY FOR SETTING ADMINISTRATION CHARGES

BACKGROUND

EGD and Union proposed to maintain their existing cost allocation methodology with respect to the setting of the gas supply administration fee and the direct purchase administration charge ("DPAC"). Both the gas supply administration fee and the DPAC currently recover the incremental costs associated with administering each supply offering.

Union and EGD argued that an incremental costing approach is appropriate since it keeps them financially neutral with respect to customers' ability to elect to buy their gas from a distributor or from a gas marketer. It also eliminates the need for exit fees and promotes customer mobility. The gas supply administration fee recovers the incremental costs of employees engaged in the functions of gas acquisition, contract management, nominations, invoicing and payment processing, and reporting. The DPAC recovers the incremental costs associated with contract administration, gas management, billing and reporting.

NRG currently uses a fully allocated costing approach to set its system gas fee. NRG submitted that it will move to incremental costing for system gas fee as part of its next cost of service application.[47] NRG submitted that an incremental costing approach would more appropriately reflect the costs associated with system gas and would be consistent with the approach of Union and EGD.

BOARD FINDINGS

No party raised any objections to the continuation of the existing incremental costing approach followed by EGD and Union, nor took issue with the activities included in these administration charges.

The Board agrees that the continuation of an incremental costing approach for setting the gas supply administration fee and DPAC is appropriate as it facilitates customer

[47] NRG's Response to Board staff interrogatory no. 1

mobility and competition in the sale of gas by allowing the distributors to be financially indifferent to customers who elect to buy their gas from a distributor or a gas marketer.

The Board directs NRG to file a proposal to move to incremental costing for system gas fee as part of its next cost of service application.

ALLOCATION OF LOAD BALANCING AND DELIVERY COSTS

BACKGROUND

EGD allocates load balancing and delivery related costs to both sales service and DP customers as these costs are incurred on behalf of all customers. Similarly, Union does not distinguish between sales service and DP customers in the allocation of base load balancing and delivery related costs. There was agreement amongst the parties that this approach was appropriate.

FRPO raised concerns about the allocation of incentives for DP customers to manage imbalances within a preset tolerance level. FRPO argued that based on cost causality principles, the net proceeds from the penalties should offset the load balancing component of the PGVA rather than the commodity component of the PGVA in order to mitigate the costs the utility may have incurred to balance deliveries and consumption. To remedy this, FRPO suggested that EGD "move the commodity cost to the system gas pool at the AECO price embedded in the PGVA and to allow the remaining economic value, after paying for UDC incurred, to accrue to the Load Balancing account".[48] This approach was supported by CME and SEC.

In its reply argument, EGD explained that the remedy offered by FRPO is the practice currently followed by EGD. EGD also explained that its objective is to encourage DP customers to manage their BGAs appropriately.

BOARD FINDINGS

The Board is satisfied with the manner in which EGD allocates the penalties stemming from the management of the BGA. The Board also notes that EGD explained that the remedy offered by FRPO is the practice currently followed by EGD.

[48] FRPO Argument p. 12

BILLING TERMINOLOGY

BACKGROUND

This section of the Decision addresses issue 10.1 - *Should natural gas distributors be required to use standard billing terminology? If so what should the terminology be?*

Union, EGD and NRG argued that the billing terminologies currently in use by the three distributors are similar and do not need to be further standardized. Union submitted that as recently as 2006, it undertook a full redesign of its bill and introduced a new bill format in response to the Board's Decision in RP-2003-0063. Similarly, EGD noted that it launched a redesigned bill for mass market customers in 2008 and proposes to update the bills of large volume customers once the update to its legacy billing system is completed.[49] At that time, EGD also proposes to unbundle the transportation charge component on the bill, consistent with Union's bill format.

BOMA/LPMA, CME, FRPO, CME, Kitchener and VECC submitted that the bill presentment of Union and EGD is already very similar and there is no reason for either utility to incur additional costs associated with bill harmonization. Such costs, as argued by CME, are "simply unnecessary".[50] FRPO submitted that the utilities have demonstrated that the existing bill presentment is based on rigorous customer research and incorporates customer feedback.

The GMG supported the billing format and terminologies employed by Union and argued that harmonized terminology across utilities is critical for consumers. The GMG submitted that the lack of consistency in the terminology used by the two utilities can be seen from the fact that both utilities preferred the use of their own terminology over the others.[51]

[49] EGD bills its customers on a monthly basis in three different formats: mass market residential and small commercial accounts, monthly statements (a consolidated bill of individual mass market accounts) and large volume accounts.
[50] CME Argument, p. 5
[51] Transcript Vol. 2, p. 185, l. 12-22.

BOARD FINDINGS

At the oral hearing both Union and EGD filed a sample of their general service customer bill.[52] In the Board's view, the format and layout of Union and EGD's bills are already very similar and further standardization is not required. The Board notes that both bills include a summary page, detailed commodity page and in the case of EGD, a third page which contains services from other energy companies. Consistent with Union's bill format, EGD's bill also includes a graph of consumption usage, definitions, pertinent phone numbers and various bill messages. One area where differences exist is in the level of unbundling provided in the Union bill. EGD advised that once the update to its legacy billing system is completed, it too will unbundle the transportation component of its bill, consistent with Union's approach.

With respect to specific billing terminologies, the GMG argued that the difference in nomenclature makes it difficult for natural gas consumers to interpret and compare services and rates offered by the two utilities, and the terminologies should be harmonized.

The Board notes that while differences exist in the billing terminologies used by the two utilities, these differences are not significant to warrant another bill redesign. First, the Board notes there is no evidence that customers have attempted the comparison of one bill to another and have been frustrated in those attempts by the differences in terminology. The Board also notes that customers which may have accounts with more than one distributor are likely large volume customers who are sophisticated enough to understand the different terminologies used. Second, the Board notes that there is consistency in certain specific terminologies, in that both Union and EGD use similar terms to identify the various charges. For example, EGD refers to the monthly customer charge as “Customer Charge”, while Union refers to this charge as “Monthly Charge”. With respect to the terminology used to refer to the monthly cost to deliver gas, EGD refers to this charge as “Delivery Charge” while Union refers to this charge as “Delivery”. Lastly, the terminology used to refer to the cost of the commodity, EGD uses the term “Gas Supply Charge” while Union uses the term “Gas Used”. The Board also notes the different terminologies used are defined on the bill.

In summary, the Board is of the view that the evidence does not support the need for harmonized billing terminologies.

[52] Union Sample bill, Exhibit K 2.2 and EGD Sample bill, Undertaking J 2.1

IMPLEMENTATION MATTERS AND COST AWARDS

The Board Orders that:

1. EGD, Union and NRG shall continue the current quarterly rate adjustment frequency and the 12 month forecast period for determining the reference price.

2. EGD and Union shall jointly work with intervenors to develop standardized QRAM filing requirements prior to the filing of their January 2010 QRAM applications.

3. EGD shall present the details of the MDV proposal for the Board's review and approval at the Company's earliest convenience. The changes to the MDV shall be implemented in 2011.

4. EGD shall record the costs of implementing the 12-month disposition methodology and the changes to the MDV in a deferral account. The prudence of the implementation costs and disposition of those costs shall be decided in a subsequent proceeding.

5. NRG shall file a proposal to move to incremental costing for system gas fee as part of its next cost of service application.

6. Starting in the January 2010 QRAM application:

   a). EGD, Union and NRG shall move the close of the 21-day strip to 31 calendar days before the effective date of the quarterly rate change and adopt the revised quarterly regulatory review process.

   b). EGD shall eliminate its trigger mechanism, and shall implement the 12-month rolling disposition methodology for PGVA balances. In every QRAM application EGD shall identify and support the elements of its PGVA attributable to commodity, transportation and load balancing costs. Based on this breakdown, individual riders should be determined and applied to sales service, western bundled T-service and Ontario T-service customers, where applicable.

c). Union shall close the Intra-WACOG deferral account as of December 31, 2009 and shall adjust delivery rates quarterly to account for changes in the carrying costs of gas in inventory, compressor fuel and UFG. Any balance accumulated in the Intra-Period WACOG deferral account prior to delivery rates being adjusted shall be disposed as part of the annual deferral account disposition proceeding.

d). NRG shall eliminate schedules 5, 10 and 11.

COST AWARDS

7. Parties eligible for costs shall submit their claims on or before **October 2, 2009**. The cost claim must be filed with the Board and one copy is to be served on Union, EGD and NRG. The cost claims must conform to the Board's Practice Direction on Cost Awards.

8. Union, EGD and NRG should review the cost claims. Objections must be filed with the Board and one copy must be served on the party against whose claim the objection is made, by **October 16, 2009**.

9. The party whose cost claim was objected to shall have until **October 23, 2009** to respond. Again, a copy of the submission must be filed with the Board and one copy is to be served on Union, EGD and NRG.

10. Union, EGD and NRG shall pay the Board's costs upon receipt of the Board's invoice.

DATED at Toronto September 18, 2009

ONTARIO ENERGY BOARD

Original signed by

____

Paul Sommerville
Presiding Member

Original signed by

____

Cathy Spoel
Member

APPENDIX A

Issues List

A. REVIEW OF QUARTERLY RATE ADJUSTMENT MECHANISM ("QRAM") FOR NATURAL GAS DISTRIBUTORS

1. Trigger mechanism for changing the reference price or clearing the purchased gas variance account ("PGVA")

Issues:

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

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

2. Price adjustment frequency and forecast periods

Issues:

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

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

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

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

3. Methodology for the calculation of the reference price

Issues:

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

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

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

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?

4. Deferral and variance accounts and disposition methodology

Issues:

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

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

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 accounts be cleared?

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?

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

5. Effect of a change in the reference price on the revenue requirement

Issues:

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?

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(s) 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?

6. Implications/costs of standardizing pricing mechanisms across all natural gas distributors

Issue:

6.1. What are the costs and implications for ratepayers, gas marketers and natural gas distributors of standardizing the pricing mechanisms across all natural gas distributors?

7. Filing requirements

Issue:

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

B. REVIEW OF LOAD BALANCING OBLIGATIONS FOR NATURAL GAS DISTRIBUTORS

Issues:

8.1 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?

8.2 Should there be standardized load balancing mechanisms for Union and Enbridge?

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

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

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

C. COST ALLOCATION

Issues:

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

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?

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?

D. BILLING TERMINOLOGY

Issue:

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

E. IMPLEMENTATION ISSUES

Issues:

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

11.2 Who should bear those costs?

11.3 How and when should any such changes be implemented?

APPENDIX B

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

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