January 21, 2009

Via E-Mail and Courier

Kirsten Walli Board Secretary Ontario Energy Board PO Box 2319 2300 Yonge Street Suite 2700 Toronto, ON M4P 1E4

Re: Commodity Pricing, Load Balancing and Cost Allocation Methodologies for Natural Gas Distributors EB-2008-0106

Dear Ms. Walli,

On behalf of the Gas Marketer Group (Direct Energy Marketing Limited, Ontario Energy Savings L.P., and Superior Energy Management Gas L.P.) please find attached the evidence of the Gas Marketer Group in the above noted proceeding.

Should you have any questions or concerns, please contact the undersigned.

Yours faithfully

Ric Forster Director

Government & Regulatory Affairs

Cc:

Mr. Norm Ryckman, Enbridge Gas Distribution

Mr. Chris Ripley, Union Gas Limited

Mr. Mark Bristoll, Natural Resources Gas Limited

GAS MARKETER GROUP (GMG) (DIRECT ENERGY MARKETING LIMITED, ONTARIO ENERGY SAVINGS L.P., and SUPERIOR ENERGY MANAGEMENT GAS L.P.)

Evidence Submission re: Commodity Pricing, Load Balancing, and Cost Allocation Methodologies for Natural Gas Distributors

The following is the collective evidence of the Gas Marketer Group (GMG) comprised of Direct Energy Marketing Limited, Ontario Energy Savings L.P., and Superior Energy Management Gas L.P. While this submission is made on a collective basis, each company retains the right to comment separately or abstain from taking a position on any issue raised.

GMG companies have affiliates active in many jurisdictions across North America and have attempted to draw upon this multijurisdictional experience to offer best practices in utility rate setting for consideration by the OEB, recognizing any elements particular to the Ontario marketplace.

Evidence overview

The Direct Purchase segment of the natural gas market provides service to approximately 40% of natural gas customers within the Province and brings in approximately 60% of the load requirement. GMG believes that a fair, efficient and openly competitive market is the most desirable outcome for consumers and all market participants. As such, our responses to the QRAM questions posed by Board staff are shaped by our view of ideal market conditions pertaining to supply, pricing, transportation, storage, and distribution.

The following evidence will consist of background information provided on each of the 5 major sections of the Consultative (QRAM, Load Balancing, Cost Allocation, Reviews and Implementation Issues), followed by GMG responses to Board specific questions.

Section A: Review of Quarterly Rate Adjustment Mechanism for Natural Gas Distributors

A.1 Background

GMG approached this process with the view that the Ontario Energy Board's (OEB) mandate should provide the guiding principles for changes proposed by GMG, and the recommendations included in this submission were prepared accordingly. The Board's vision and three year business objectives for the Ontario energy market¹ are noted below,

Our Vision

The Board envisions a viable and efficient energy sector with informed consumers served by responsive regulatory processes that are effective, fair and transparent.

Our Objectives

The Board has identified six objectives for its three-year business plan:

- 1. to provide sound economic regulation that considers both the interests of consumers and the need for a financially viable and efficient energy sector;
- 2. to help meet Ontario's challenges for renewal of energy infrastructure and supply;
- 3. to facilitate energy conservation and demand management;
- 4. to monitor, report and improve on regulatory processes to ensure that they are effective, fair and transparent;
- 5. to enhance public confidence in the Board's regulation through audit and compliance programs; and
- 6. to provide clear and timely communications to enhance transparency with stakeholders and empower consumers.

In its review of the Ontario regulated natural gas supply, from the Ten-Year Market Review in 1996² to the publication of the Natural Gas Market Design Tasks Force Report in 2005,³ the OEB's goal for the development of regulated natural gas supply has been consistent. The Board has communicated that the regulated gas price should be viewed as the default supply by consumers, accurately reflect market prices, and that retroactive adjustments related to the PGVA should be kept at a minimum. The GMG acknowledges that the utilities and stakeholders have made progress in achieving some of these goals. An opportunity now exists to harmonize the gas supply rate setting methodologies between Enbridge, Union, and NRG; develop formulaic and transparent methodologies; and move towards a monthly setting of the regulated rate in order to more accurately reflect market prices.

The GMG experience is that open, effective, and competitive markets best evolve where there is a clear understanding of the areas where markets bring value, and those areas that should remain rightly under the scrutiny and oversight of the appropriate regulatory body. Accessing gas supply and moving it to the

Gas Marketer Group - January, 2009

Ontario Energy Board 2008-2011 Business Plan - Approved by the Minister of Energy on March 12, 2008

September 27, 1996: Report on the Ten-Year Market Review of natural gas Deregulation

Natural Gas Market Design Task Force – Report to the Ontario Energy Board June 16, 1998

distributor franchise area encompasses the area where marketers can offer varying pricing alternatives, as there are no natural monopoly elements or market failures that would necessitate monopoly provision of this service. The safe operation and reliable transportation of in-franchise supply to the burner tip should remain the monopoly service of the distributor, under the scrutiny of the regulator.

In addition, if consumers continue to be offered a default commodity service, either by the distributor or another entity, the Default Supply Provider (DSP) should calculate a default price that is reflective of real, short-term market prices. As the default option, pricing reflective of market rates allows consumers to make informed provider and consumption choices. This provides the appropriate balance between allowing consumers to remain on a commodity rate overseen by a regulator, with the need for that pricing to send appropriate signals about consumption levels and consumer choice. Provider choices are then determined by the consumer's tolerance for price risk, and their consumption choices are made given appropriate consideration of the actual cost associated with that consumption.

In previous years there has been a portfolio approach applied to hedging gas supply costs, where a combination of fixed and floating pricing structures have been employed. This does not explicitly give consumers an indicator of the market price to enable them to make effective provider or consumption choices in response to that "market price". A key component of conservation programs is to link price to a particular behaviour. Further to this, the current Board approved buying protocol is to purchase all supply on a monthly index basis. As such, the pricing estimates to be used in rate setting should be adjusted to align with the costs the utilities can reasonably expect to incur within the period. In doing so there is no risk to the default supply rate payer, as the utility will not be incurring additional costs on any negative outcomes of hedging practices made by the utility, and the likelihood of significant over or under collection from customers will be reduced. Risk exposure on the procurement of gas should be the purview of the private sector, in this case natural gas marketers, and those customers that value price surety over extended periods of time.

When determining the components of an ideal market structure it is important to define what the regulated rate is, and equally important to outline what the regulated rate is not. The clear and understandable delineation of alternative pricing schemes for customers is therefore fundamental. An important component of this is to communicate to consumers the wholesale market price for gas compared to the delivered price of the commodity. GMG recognizes that the retail energy delivery is comprised of many other services (load balancing, distribution, customer care etc.) but the key starting element is the need to compare the wholesale price as publicly reported and the commodity portion charged for gas service that appears on the bill. All costs incurred by the DSP should be included in the default rate and the supporting supply, transportation, and storage transactions should be reported in a transparent and understandable fashion.

A key determinant in defining the default rate should be the restriction of this rate to short term pricing exposure. This would be similar to the treatment of mortgages in the banking industry. Upon renewal of a mortgage, if a customer does not choose a fixed rate option, the mortgage is moved into an open, variable rate mortgage as the default product. This is done because it is the most neutral of all pricing options, since the customer can move to a fixed rate option at any time. To replicate this in the natural gas marketplace, the default supply would be a completely open, variable rate based on the market prices at that point in time. Specifically, system gas would be "all short term, all the time", based on current index pricing. This clearly delineates system supply from fixed price offerings. Should consumers choose the default rate, then they either hold the view that prices should go down over time (worth less tomorrow than today) that is, a "bearish" market view, or they are not concerned enough about the price of natural gas to take a market view (the "do nothing" scenario). For those consumers who are managing to differing needs or views of the market (bullish), the competitive energy marketers offer fixed price solutions. By providing distinct definition of the default rate, retailers can develop energy

products to address customer needs. Some examples might be a carbon neutral gas program, a fixed winter with floating summer plan, or a partially hedged year round plan.

The OEB should weigh the relative merits of the smoothing effect the current price setting methodology has on prices (although the GMG will show that this is not always the case), versus the negative impacts that this methodology necessarily yields. Inarguably, the current price setting protocols lead to an increased "mismatch" between the costs incurred by a specific set of customers and the customers that actually receive system service within a given period. This is due to the fact that rates are set at 3 month intervals, in which many customers can change gas suppliers. Also, the 12 month deferral recovery/ charge period further distorts the price signal to the customers served. Furthermore, the long lead time to calculate the QRAM, plus the 3 month nature of the price leads to an exaggerated need of deferral accounts, further distorting the price charged to system customers from the wholesale market price paid by utilities.

A.2 Issues with EGD/Union's Current QRAM Methodology

Lack of transparency in the "Effective Rate" formula

There are a number of issues not only with the method used by the distributors in setting rates, but also in the differences between distributors, and the lack of transparency in the calculations and inputs. It was clear from the numerous questions posed at the Technical Conference held on November 27, and 28, 2008 pursuant to Procedural Order No.2 in EB-2008-0106 in this proceeding that many market participants do not have insight into what elements, inputs, and calculations are used for rate setting by the distributors. While each distributor claims to have a "formulaic approach" to calculating rates, there is no standard formula that the natural gas marketplace can reference to ensure that an approved formula and process have been followed in order to set default supply rates.

Standardization of an effective rate formula coupled with the transparency of the elemental inputs will allow any consumer regardless of their geographic location in Ontario to recreate and verify the reference price put forth by each distributor in its Rate Adjustment Application. While the inputs to the calculation may vary slightly based on geography, the formula used to calculate the effective rate based on those inputs should be the same across the rate class. Using a standardized formula could also reduce the regulatory approvals process as then only input variances would need to be accounted for each distributor.

Forecasting and frequency of rate setting

Each of the distributors uses a 21 (business) day strip of forward pricing over the upcoming 12 month period, concluding approximately 45 days prior to the beginning of the next quarterly rate period. As Enbridge has indicated at the Technical Conference in this proceeding on page 64, lines 18-28,(in which they discuss changing TCPL tolls close to the rate setting date which do not get incorporated into the current rate), there are issues with setting the reference price so much earlier than the implementation date of those rates. Forecasting methodologies used by the distributors do not provide a view of current market price and therefore do not facilitate provider choice and influence informed energy consumption. Furthermore if the long term forecast is for higher prices, but market conditions change such that prices actually decrease, then utilities may have purchased gas for injection and storage at higher prices than prevailing market rates. This can be seen in the difference between the July 2008 twelve month outlook and the December 2008 twelve month outlook. The GMG submits that quarterly rate setting in conjunction with twelve month forecasting leads to the distortion of pricing signals.

In the graph below, NYMEX is used to show the disconnection between a 12 month average price (taken mid-month) and the actual NYMEX monthly settles. NYMEX is used as a proxy for the Reference Price.

The graph below clearly shows the differences between an average price as a proxy for the quarterly Reference Price versus the actual WACOG for the gas procured in the quarter. This demonstrates how large PGVA's should be expected from this pricing method. The ovals represent the quarterly price and the rectangles represent the estimated WACOG for the quarter based on actual NYMEX settles (the red dotted line).

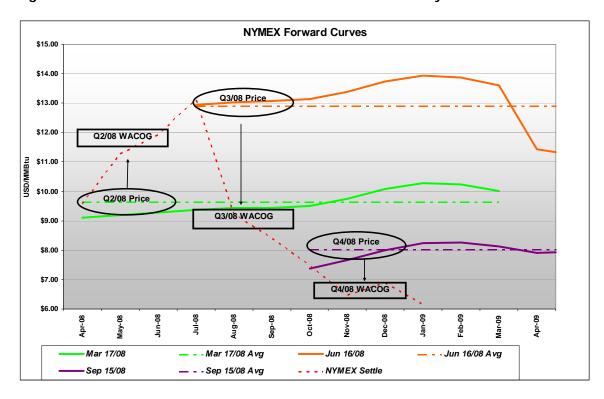


Figure 1: NYMEX Forward Curves versus actual NYMEX monthly settles

Source: The dates in the legend that do not include "Avg" are 12 month forward NYMEX curve settles as at the dates indicated in the legend ("mid-month"). The dates in the legend that include "Avg" are the simple average of the same 12 month forward curve (which replicates the method used in the current QRAM process). The dotted red line (denoted "NYMEX" in the legend) tracks the historical last day NYMEX settles for each monthly contract.

Any price setting procedure should attempt to report to the regulators and customers the best estimate of the actual costs that will be incurred for the time period in question. The existing methodology that Enbridge and Union Gas employ using 12 month forecasting would be a rational and sound perspective if the utilities were purchasing 12 month fixed price strips and hence "locking in" the commodity cost for the consumer. The GMG understands that in years past, much of the supply portfolio was purchased on a fixed price basis, and as such, this was a fair and reasonable approach, because the supply procurement protocol aligned with the rate setting mechanism.

However, as the Ontario market place has evolved, both Union and Enbridge have explicitly stated that the current Board-approved buying protocol is to purchase all supply on a monthly index basis. As such, the pricing estimates to be used in rate setting should be adjusted to align with the costs the utilities can reasonably expect to incur within the period. Purchasing on a monthly basis also removes the risk of hedging on supply for system gas customers. As discussed earlier, long term hedging supply risks should

not be unfairly borne by system supply customers that have not chosen such a risk. Hedging risks should be borne by the agents of those customers that have chosen long term natural gas contracts in the pursuit of price surety.

As noted in Union's Exhibit E2, Page 23, Lines 14-21, the notion that the use of the 12 month strip aids gas consumers in understanding competitive retail fixed price offerings in relation to the default supply offering is fundamentally flawed. The default supplier should, instead, put forward a price that reflects the best estimate as to what the costs incurred for securing supply will actually be. By using a 12 month strip, the utilities are reporting prices for gas that they will not be exposed to for months 4 through 12 (if using a QRAM example). The natural shape of the forward gas market in North America includes a premium for winter delivery. For example, the current summer 2009 vs. winter 2009-10 premium is approximately \$1.25 US\$/MMBtu. As such, under the current QRAM protocol, in the fall, the utilities typically underestimate the cost of the winter supply by including the lower summer cost. This distorts the actual winter price down during periods of peak demand. Likewise, the summer reported price is distorted up by including winter prices that will not be incurred by the utility. This price distortion (or not market prices) results in a misalignment between the actual costs incurred by the utility and the prices charged to consumers. This leads to exaggerated over and under recoveries each quarter that must be disposed of through the deferral accounts, and does not support the QRAM principle of fairness and equity among all customer groups.

The summer-winter spread, as shown by NYMEX (or any liquid hub), is the notional premium put on winter supply due to heating demand. This "value" spread is typically a reflection of the notional (or expected) cost of the gas storage service plus an appropriate carrying cost. Another way to look at this is that an end user should only expect to "pay" the winter premium if they do NOT have access to (or have not purchased) gas storage services. The current practice is to include the storage and balancing costs as a distribution charge.

NYMEX Natural Gas (US \$/MMBtu) \$10.00 under estimating Winter \$9.00 \$8.00 \$7.00 \$6.00 over estimating summer \$5.00 \$4.00 Aug 13 Febria Aug. 14 Feb.12 'Feb.15 Aug'11 Aug feb au Aug Feb Au Aug Feb A Aug Feb Au Aug Feb Au

- prompt 💶 12 month mean

Figure 2: Example of price distortion caused by the use of the 12 Month Average Forward Price

Source: NYMEX forward curve as at January 14, 2008.

⁴ As of the end of business January 7, 2009

The GMG submits that a price forecast that aligns with the effective period produces a more market reflective rate that will allow consumers to make more informed provider and consumption choices. The mandate to purchase all supply on a monthly index basis should also allow utilities to report the prices that the wholesale market is transacting at, namely index, in a more timely manner. Reporting these market sensitive prices necessitates forecasting in the most accurate way.

Gas indices are typically set during "Bid Week", which is the 5 business days prior to the NYMEX gas prompt month contract expiration (which is the 3rd last business day). All fixed price deals executed for a particular trading hub (e.g. Dawn, Chicago) for the prompt month are reported to various reporting bodies (Gas Daily, Inside FERC, CGPR). The weighted average price is then published as the monthly index for the point and month in question. If the utilities were to file to the OEB 5 business days prior to the flow month, a much closer estimate of the monthly index could be used as the utility procurement groups could use the first 3 days of bid week as a proxy for the actual cost of gas that the utility will incur. Ideally this would be done on a monthly basis to ensure a true reflection of the bid week prices.

Note the Alberta Monthly index is set using a slightly different methodology. It is calculated by the weighted average of all fixed price deals done on NGX the month prior to flow. This price could likewise be estimated 5 business days prior to the end of the month resulting in a much closer estimate of actual costs to be incurred. The figure below shows the negligible difference between the forecast estimated 5 days prior and the actual month end result.

Table 1: Difference between Alberta Forecast Monthly Index, and Actual Monthly Index

	F	orecast	Actual	Dif	ference
Jan-07	\$	7.140	\$ 6.916	\$	(0.224)
Feb-07	\$	6.696	\$ 6.862	\$	0.166
Mar-07	\$	7.428	\$ 7.424	\$	(0.004)
Apr-07	\$	6.971	\$ 7.021	\$	0.050
May-07	\$	7.119	\$ 7.088	\$	(0.031)
Jun-07	\$	6.944	\$ 6.856	\$	(0.089)
Jul-07	\$	6.372	\$ 6.139	\$	(0.233)
Aug-07	\$	5.154	\$ 5.052	\$	(0.102)
Sep-07	\$	4.981	\$ 4.756	\$	(0.224)
Oct-07	\$	4.960	\$ 4.982	\$	0.022
Nov-07	\$	5.771	\$ 5.823	\$	0.051
Dec-07	\$	6.299	\$ 6.257	\$	(0.043)
Jan-08	\$	6.148	\$ 6.101	\$	(0.047)
Feb-08	\$	6.829	\$ 6.876	\$	0.047
Mar-08	\$	7.157	\$ 7.299	\$	0.142
Apr-08	\$	8.008	\$ 8.091	\$	0.083
May-08	\$	8.727	\$ 8.918	\$	0.191
Jun-08	\$	9.547	\$ 9.578	\$	0.031
Jul-08	\$	10.623	\$10.800	\$	0.177
Aug-08	\$	9.273	\$ 8.442	\$	(0.831)
Sep-08	\$	7.214	\$ 7.048	\$	(0.166)
Oct-08	\$	6.072	\$ 5.911	\$	(0.161)
Nov-08	\$	6.573	\$ 6.557	\$	(0.016)
Dec-08	\$	6.861	\$ 6.830	\$	(0.031)

Source: Actual AECO Monthly Index as reported by NGX versus month to date reported AECO Monthly Index sourced from NGX as filed in the Gas Cost Flow through Rate Filing by Direct Energy Regulated Services.

Impacts of forecasting on PGVA balances and subsequent clearing

Balances within the PGVA accounts are directly related to the accuracy of, and the method used, in forecasting. The size of the resultant rider is dependent on the variance within the deferral account and the mechanisms used to dispose of such riders, including the length of time for disposition, the existence of any triggers or thresholds, and any discretion allowed by the utilities in the process. These items combined have caused significant divergence between the effective rate and market prices, sending incorrect price signals to customers. Further to this, large rate riders have been applied in many quarters, indicating that either the customer or the utility has had increased carrying costs for the period. The issues with the current forecasting, and clearing of deferral accounts can best be reviewed by examining forecasted PGVA balances and the corresponding riders over the past 3 years. In order to do so, GMG is relying on the evidence provided by Enbridge in their response to GMG IR#3, along with the QRAM fillings for Enbridge over the past 3 years.

As can be viewed by the data below, Enbridge continually over-collected from customers in 11 out of 12 quarters in the past 3 years as a result of the forecasted reference price being higher than the cost of gas purchased within each month. It should be noted that the reference price was calculated using the 21 day strip/ 12 month forward forecast methodology continuing to be proposed by each utility in this proceeding. The over-collection resulted in significant Sales Service Credit Riders in most quarters obscuring the true cost of natural gas at the time. In some cases it could have given customers the perception that natural gas prices were in decline, when in fact they were on the rise. Further to this, customers have been paying the carrying costs of the less accurate forecasting methodologies currently employed by the utilities on each bill in 11 of the last 12 quarters by paying higher rates than necessary. Whether interest is paid back to customers by the utilities for the use of ratepayer monies as a result of over collection should be considered.

Table 2: Forecasted/estimated PGVA balances with corresponding Rider

Period	Forecasted YTD PGVA Balance at End of Period per January QRAM Filing of Each Year	Estimated Year End PGVA Balance per QRAM Application for the Period	Sales Service Rider for Rate 1 Customers as per QRAM Application.
2006 Q1	\$22.373M CR	\$91.81M CR	1.9301 cents/m ³ CR
2006 Q2	\$139.518M CR	\$41.58M CR	1.6354 cents/m³ CR
2006 Q3	\$242.484M CR	\$98.784M CR	6.2430 cents/ m ³ CR
2006 Q4	\$349.038M CR	\$140.701M CR	11.5645 cents/ m³ CR
2007 Q1	\$24.973M CR	\$46.26M CR	0.8735 cents/ m ³ CR
2007 Q2	\$94.034 M CR	\$97.212M CR	3.8645 cents/ m ³ CR
2007 Q3	\$223.119M CR	\$101.982M CR	6.6333 cents/ m ³ CR
2007 Q4	\$289.360M CR	\$109.168M CR	3.0868 cents/ m ³ CR
2008 Q1	\$41.746M	\$108.435M CR	2.2612 cents/ m ³ CR
2008 Q2	\$116.395M	\$96.673M CR	3.9604 cents/m ³ CR
2008 Q3	\$49.270M	\$12.797M CR	0.8578 cents/ m ³ CR

Period	Forecasted YTD PGVA Balance at End of Period per January QRAM Filing of Each Year	Estimated Year End PGVA Balance per QRAM Application for the Period	Sales Service Rider for Rate 1 Customers as per QRAM Application.
2008 Q4	\$37.944M CR	\$59.689M	1.7008 cents/ m ³

Source: Enbridge response to GMG IR#3, EGDI QRAM Applications

In Union Exhibit IR 23.2, Union noted: "Since 2006, the forward 12 month price tended to be higher than the actual cost for gas in those months. Riders were, therefore, generally credits." This speaks to the fact that a 12 month forward look does not accurately reflect market index prices, and as can be seen in the chart above, produce significant credit riders. It should be noted that Enbridge received approval to spread the 2008 Q4 rider over 6 months as opposed to within the last quarter of the year. Had the rider been spread only over the remaining 3 months of 2008, the rider would have been 5.0557 cents/m3. In its submission to the OEB in the Q4 2008 QRAM filing, Enbridge stated "that a three month clearing period would not align with current market conditions of decreasing natural gas prices and would cause consumer confusion". Enbridge argued that extending the clearing period to six months, "yields an effective gas supply charge that reflects the current decreasing price trend in North American natural gas prices". GMG recognizes that by spreading out this particular rider over a six month period, the Enbridge Effective Rate will be more reflective of declining market prices. However, this rationale has not been applied consistently over the past 3 years and hence becomes discretionary on the part of Enbridge as to when Applications will be made for a 6 month disposition as opposed to a 3 month disposition. It is the position of the GMG that all discretion in the clearing mechanism should be removed.

The GMG believes that a formulaic approach to default gas acquisition, rate setting and deferral disposition should be the preferred process for all stakeholders.

A.3 Proposed structure for rate setting

In developing its position on changes to the current QRAM process the GMG has not only adhered to the principles behind the current rate setting mechanism, but enhanced them. The GMG believes that the following proposed rate setting structure better reflects the principles as outlined in Enbridge QRAM Applications, as originally approved in RP-2000-0040 and subsequently modified in RP-2002-0133 and RP-2003-0203.

"The QRAM process is intended to achieve or accommodate the following eight principles:

- More reflective of market prices on an ongoing basis;
- Enhanced price transparency;
- Regular quarterly review process;
- Customer awareness, customer acceptance, and less confusion in the marketplace;
- Mitigation of large adjustments of customer bills:
- Fairness and equity among all customer groups;
- Implementation in a cost effective manner: and
- Reduced regulatory burden relative to the former "trigger methodology" and the related rate adjustment mechanism, for Enbridge's PGVA".

The rate setting mechanism of utilities should match, as much as is practicable, the methodology used to procure supply. That is, if the utilities are buying Monthly index-based supply, the appropriate monthly index estimate should be reported as the input or reference price as close to flow date as is practicable. As mentioned earlier in this submission using the "bid week" monthly index eliminates the inherent pricing distortion that accompanies 12 month forecasting alongside monthly procurement and quarterly rate setting.

The rationale for using a "bid week" number is to try to arrive at a price that most closely reflects the "cash" price of what the physical supply/demand fundamentals should yield. By using a public source, it removes any discretion from the utility (or regulator) regarding the prudency of the reported commodity price. All of this could allow for utility reporting of prices to the regulator much closer to the actual time that the commodity will flow to the customer and the actual costs incurred by the utility – 3-5 business days prior to delivery period. Additionally other supply points (AECO, Chicago) that offer liquid, reported transactions could likewise be used which would more closely mimic the actual costs incurred by the utility.

Once the reference price is set using the approved index source, these index estimates would then have to be adjusted by the appropriate transportation costs estimates to get a fair approximation of the delivered commodity cost for the utility customers. Following this, any intra-month PGVA balances along with any pre-approved costs and deferral account balances would be added to the reference price to determine the Effective Rate for customers by rate class.

At a high level, the calculation of the Effective Rate would be similar to that submitted in Union's IR8.1(b) Attachment 1:

Reference Price + Fuel Charges + Gas Supply Admin Charge + Intra-Month PGVA Balance + Other Deferral Account Balances = Effective Rate.

In the approach laid out above, the forecasting is matched to the procurement practice, which should then be matched to the rate setting frequency and subsequently to the disposition frequency of deferral accounts.

Impacts of rate setting methodologies

Given the movement in gas prices over recent years it is important to understand the impact of different rate setting methodologies under different markets. It is of greater importance to implement a rate setting methodology that will be robust enough to reflect various market conditions. Rate setting methodology is not as important in a "Range Bound" market where prices are flat; however, when prices are rising rapidly in a "Break Out" market, the rate setting methodology is very important. A shorter time frame for price setting minimizes price distortion by minimizing deferral impacts. That is, the default rate is more reflective and representative of the wholesale market place especially if the buying protocols are mandating index only buying by utilities.

A market is described as "Range Bound" when the price moves up and down between predictable upper and lower limits. For example, in the time frame shown in the graph below, the price moves up and down between \$4.80 and \$6.10.

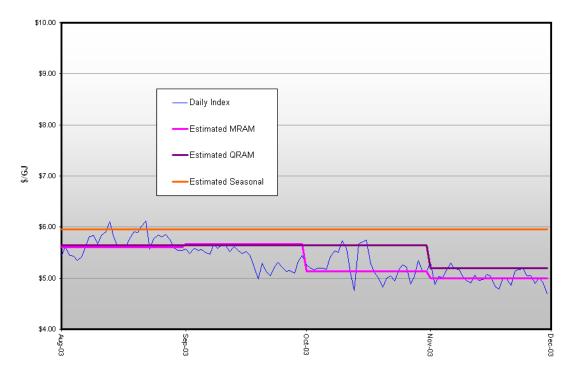


Figure 3: Rate setting methodology in a "Range Bound" market

Source: Estimated MRAM, QRAM and Seasonal price based off of historical AECO daily and monthly index prices. Daily Index prices are historical numbers as reported by NGX. Estimated over and under collections based on average daily index within the period, compared to the MRAM, QRAM or Seasonal price in the same time period. See monthly detail below.

Table 3: Historical Monthly Index with Estimated Reference prices

	AECO MI	N	4RAM	QRAM		Se	asonal
Aug-03	\$5.5227	\$	5.600	\$	5.640	\$	5.960
Sep-03	\$5.8635	\$	5.670	\$	5.640	\$	5.960
Oct-03	\$5.4221	\$	5.130	\$	5.640	\$	5.960
Nov-03	\$5.1938	\$	5.000	\$	5.200	\$	5.960

In this example, the prices are fairly similar across the different methodologies as the market price is essentially flat. An estimate, given this lack of volatility, is therefore less likely to be substantially different as the majority of the trading occurs between \$5/GJ to \$6/GJ. Deferrals will also be minimal as a result. However, as shown below, under different market conditions and particularly where there is greater volatility, the impact of the rate setting methodology becomes clear. It is therefore important to develop a rate setting methodology that is as accurate as possible, that is, as close as possible to reflecting market movements, even in periods of great volatility.

A market is described as "Break Out" when there is a one way upward price movement. For example, in the time frame shown in the graph below, the price moves up from the \$5.50/GJ range to the \$9.50/GJ range. This occurred in the first half of 2008.

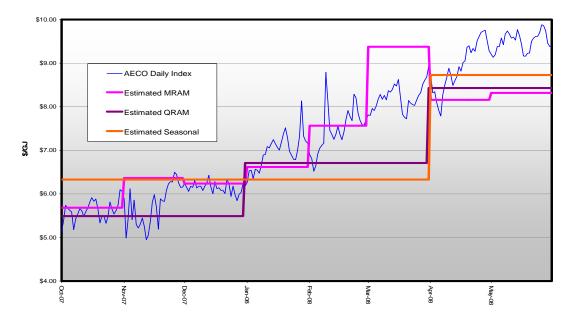


Figure 4: Rate setting methodology in a "Break Out" market

Source: Estimated MRAM and QRAM and Seasonal price based off of historical AECO daily and monthly index prices. Daily Index prices are historical numbers as reported by NGX. Estimated over and under collections based on average daily index within the period, compared to the MRAM, QRAM or Seasonal price in the same time period. See monthly detail below.

Table 4: Historical Monthly	Index with	Estimated	Reference prices

	AECO MI	II MRAM QRAM)RAM	Se	easonal
Oct-07	\$4.9824	\$	5.684	\$	5.490	\$	6.330
Nov-07	\$5.8228	\$	6.365	\$	5.490	\$	6.330
Dec-07	\$6.2567	\$	6.238	\$	6.710	\$	6.330
Jan-08	\$6.1011	\$	6.238	\$	6.710	\$	6.330
Feb-08	\$6.8759	\$	7.565	\$	6.710	\$	6.330
Mar-08	\$7.2992	\$	9.376	\$	8.430	\$	6.330
Apr-08	\$8.0905	\$	8.158	\$	8.430	\$	8.730
May-08	\$8.9182	\$	8.316	\$	8.430	\$	8.730

The benefit of the estimated MRAM price for customers is that the price charged by the utility more accurately reflects the cost of the commodity at that time. The QRAM prices do not match as closely and the utility is persistently either over or under collecting, charging consumers more or less than market rates in the next quarter. This same result would be seen with a Seasonal Rate Adjustment Mechanism (SRAM) as the forward curve does not anticipate a breakout market. The curve simply shifts over time, but the full effect of the change takes time and is not captured in a 21 day average forward curve calculation. The only way to capture this movement is to more regularly reset the price, as in a MRAM scenario.

In order to enable the competitive marketplace, and not place unnecessary risk on the rate payer, the clear distinction between what the default provider is offering versus what competitive retailers are offering is a crucial message. The default provider is offering market prices monthly (variable rate) and

the competitive retailers are offering a fixed price contract, with the associated hedging risk. Consumers who desire price surety should be finding a fixed price contract that meets their needs.

Forecasting periods and Rate setting frequency

One of the fundamental principles in rate setting is to ensure price transparency and that rates set by the utilities are reflective of the market price on an ongoing basis. To further demonstrate the importance of the correlation between forecasting periods and rate setting frequency an examination of the methods employed should be completed to understand the impacts each method has on the variances between the reference price used for rate setting, and the market index for the month. This variance is a key determinant in the over or under-collection from customers, and the severity of riders.

The following is a copy of the table submitted by Union Gas in IR8.7, which indicates the results of 12 month forecasting in a QRAM setting when compared to the market index for a given month. It can be seen in the data below that a 12 month forward forecast coupled with a quarterly rate setting mechanism results in relatively large variances between the Alberta Border Reference price used in Union's QRAM, and the Monthly Index price at Empress. Within the 60 month period noted below, Union's forecasted reference price was greater than the Empress price 70% of the time. A variance of greater than (+/-) \$1.00 per GJ occurred in no less than 39 months or 65% of the time. A variance of greater than (+/-) \$2.00 per GJ occurred 17 times or 28% of the time, and a variance of greater than (+/-) \$3.00 per GJ occurred no less than 9 months or 15% of the time.

Table 5: Union Gas QRAM Comparison to Monthly Index

Exhibit IR8.7 Attachment

Quarterly Rate Adjustment Mechanism (QRAM) Comparison

		Alberta Border	EMPRESS	VARIANCE
		Reference Price (Cdn\$/GJ)	Monthly Index CGPR (Cdn\$GJ)	
QRAM	Docket #	` ' '		
Jan-04	EB-2003-0287	\$ 5.480	\$ 6.651	\$ (1.171)
Feb-04		\$ 5.480	\$ 6.638	\$ (1.158)
Mar-04	ED 2004 0240	\$ 5.480	\$ 6.016	\$ (0.536)
Apr-04	EB-2004-0210	\$ 6.320	\$ 6.071	\$ 0.249
May-04 Jun-04		\$ 6.320 \$ 6.320	\$ 6.533 \$ 7.219	\$ (0.213) \$ (0.899)
Jul-04 Jul-04	EB-2004-0267	\$ 6.320 \$ 7.260	\$ 6.785	\$ 0.475
Aug-04	EB-2004-0207	\$ 7.260	\$ 6.700	\$ 0.560
Sep-04		\$ 7.260	\$ 5.956	\$ 1.305
Oct-04	EB-2004-0416	\$ 7.373	\$ 5.501	\$ 1.873
Nov-04		\$ 7.373	\$ 7.738	\$ (0.365)
Dec04		\$ 7.373	\$ 7.332	\$ 0.041
Jan-05	EB-2004-0499	\$ 7.812	\$ 6.751	\$ 1.061
Feb-05		\$ 7.812	\$ 6.318	\$ 1.494
Mar-05		\$ 7.812	\$ 6.412	\$ 1.400
Apr-05	EB-2005-0232	\$ 7.177	\$ 7.223	\$ (0.046)
May-05		\$ 7.177	\$ 7.411	\$ (0.234)
Jun-05		\$ 7.177	\$ 6.739	\$ 0.438
Jul-05	EB-2005-0290	\$ 8.009	\$ 7.142 \$ 7.322	\$ 0.867 \$ 0.687
Aug-05		\$ 8.009 \$ 8.009	\$ 7.322 \$ 9.203	
Sep-05 Oct-05	EB-2005-0462	\$ 8.009 \$ 9.075	\$ 11.091	\$ (1.194) \$ (2.016)
Nov-05	EB-2005-0402	\$ 9.075	\$ 11.091	\$ (2.016)
Dec-05		\$ 9.075	\$ 10.364	\$ (1.289)
Jan-06	EB-200-0531	\$ 10.859	\$ 11.625	\$ (0.766)
Feb-06	22 200 0001	\$ 10.859	\$ 8.130	\$ 2.729
Mar-06		\$ 10.859	\$ 6.985	\$ 3.874
Apr-06	EB-2006-0033	\$ 9.173	\$ 6.417	\$ 2.756
May-06		\$ 9.173	\$ 6.345	\$ 2.828
Jun-06		\$ 9.173	\$ 5.406	\$ 3.767
Jul-06	EB-2006-0106	\$ 8.954	\$ 5.607	\$ 3.347
Aug-06		\$ 8.954	\$ 5.953	\$ 3.001
Sep-06	ED 2007 0700	\$ 8.954	\$ 5.934	\$ 3.020
Oct-06 Nov-06	EB-2006-0500	\$ 8.837 \$ 8.837	\$ 4.318 \$ 6.464	\$ 4.519 \$ 2.373
Dec-06		\$ 8.837	\$ 7.621	\$ 2.373
Jan-07	EB-2006-0502	\$ 7.926	\$ 7.027	\$ 0.899
Feb-07	EB-2000-0502	\$ 7.926	\$ 6.977	\$ 0.949
Mar-07		\$ 7.926	\$ 7.537	\$ 0.389
Apr-07	EB-2007-0053	\$ 8.288	\$ 7.126	\$ 1.162
May-07		\$ 8.288	\$ 7.196	\$ 1.092
Jun-07		\$ 8.288	\$ 6.966	\$ 1.322
Jul-07	EB-2007-0634	\$ 8.379	\$ 6.252	\$ 2.127
Aug-07		\$ 8.379	\$ 5.161	\$ 3.218
Sep-07		\$ 8.379	\$ 4.868	\$ 3.511
Oct-07	EB-2007-0720	\$ 7.426	\$ 5.087	\$ 2.339
Nov-07 Dec-07		\$ 7.426 \$ 7.426	\$ 5.929 \$ 6.359	\$ 1.497 \$ 1.067
Jan-08	EB-2007-0918	\$ 6.834	\$ 6.212	\$ 0.622
Feb-08	EB-2007-0518	\$ 6.834	\$ 6.985	\$ (0.571)
Mar-08		\$ 6.834	\$ 7.409	\$ (0.575)
Apr-08	EB-2008-0033	\$ 7.677	\$ 8.193	\$ (0.516)
May-08		\$ 7.677	\$ 9.018	\$ (1.341)
Jun-08		\$ 7.677	\$ 9.679	\$ (2.002)
Jul-08	EB-2008-0109	\$ 9.562	\$ 10.904	\$ (1.342)
Aug-08		\$ 9.562	\$ 8.543	\$ 1.019
Sep-08		\$ 9.562	\$ 7.140	\$ 2.422
Oct-08	EB-2008-0281	\$ 8.489	\$ 6.008	\$ 2.481
Nov-08		\$ 8.489	\$ 6.634 \$ 6.920	\$ 1.855 \$ 1.569
Dec-08		\$ 8.489	\$ 6.920	\$ 1.569

As can be seen from the above data, large, frequent variances between the Quarterly Reference Price used by the utility and the monthly market price have helped to distort price signals over the last 5 years. In comparison, the table below shows the resulting rates when monthly forecasting is used for a monthly rate adjustment mechanism. The calculation of the Alberta default supply price or Gas Cost Flow-through Rate (GCFR) as done by Direct Energy Regulated Services (DERS) is shown below.

The GCFR calculation involves a six-step process.

- 1. Volumes for the forecast month are determined on the basis of normal temperatures. Normal temperatures for each day of the forecast month are the average of the last 20 years' temperatures for that day as determined by Environment Canada data. Natural gas consumption for residential and commercial customers in Alberta is highly dependent on weather.
- 2. On the 5th last working day of the month prior to the forecast month, referred to as the current month, the current market view of natural gas prices for the forecast month from the Natural Gas Exchange, or NGX. NGX prices represent the most public and widely accepted market view of natural gas prices, and form the basis for the AECO Monthly Index and Daily Index prices used to settle the vast majority of natural gas transactions in Alberta.
- 3. The cost of the forecast month natural gas requirements are then determined by multiplying the forecast volumes determined in Step 1 by the forecast month pricing obtained in Step 2.
- 4. Alberta regulation requires that the gas charged be calculated on a flow-through basis and pay the actual costs of natural gas supply. Because volumes and prices are forecasts in the determination of its gas costs for the month the rates are being set for, a mechanism has been established to capture the differences between these forecasts and actuals. These differences result in the DSP paying suppliers more or less than what is recovered from customers through the GCFR, this difference is accumulated in a Deferral Account. The Deferral Account transactions and balances are reviewed by the AUC and consumer groups on a monthly basis.
- 5. The current month cumulative balance of this Deferral Account identified in Step 4 is added to the cost of the forecast month natural gas requirements determined in Step 3 to arrive at the forecast month aggregate natural gas supply cost.
- 6. This aggregate natural gas supply cost is then divided by the forecast month volume forecast determined in Step 1. The result is the forecast month GCFR filed by all DSPs on the 5th last business day of the current month.

With this methodology, the reference price more closely matches the monthly index price, allowing customers to make informed decisions with respect to consumption and service provider. Within the 60 month period noted below, DERS forecasted reference price was greater than the AECO price only 55% of the time in the North delivery point and 53% in the South delivery point; compared to 70% in the Union example. A variance greater than \$1.00 per GJ occurred in only 16 months for the North delivery point and 18 months for the South; or 27% and 30% respectively; compared to the Union example of 65%. A variance of greater than \$2.00 per GJ occurred in only 4 months for the North delivery point and 10 months for the South; or 7% and 17% respectively; compared to the Union example of 28%. And finally a variance of greater than \$3.00 per GJ occurred in only 2 months for the North delivery point and 4 months for the South; or 3% and 7% respectively; compared to the Union example of 15%.

Table 6: DERS Gas Cost Flow-through Rate Comparison to Monthly Index

Date	Cost of G	as (GCFR)	AECO	Variance	Variance
	North	South	MI	North	South
Jan-04	\$7.5840	\$7.5900	\$6.4793	\$ 1.1047	1.1107
Feb-04	\$6.6400	\$6.9810	\$6.4644	\$ 0.1756	0.5166
Mar-04	\$5.6320	\$5.7370	\$5.8461	\$ (0.2141)	(0.1091)
Apr-04	\$5.5440	\$5.5680	\$5.9287	\$ (0.3847)	(0.3607)
May-04	\$5.5430	\$5.3810	\$6.3683	\$ (0.8253)	(0.9873)
Jun-04	\$8.2570	\$8.3130	\$7.0502	\$ 1.2068	1.2628
Jul-04	\$5.8940	\$6.4030	\$6.6132	\$ (0.7192)	(0.2102)
Aug-04	\$6.6110	\$6.7920	\$6.5278	\$ 0.0832	0.2642
Sep-04	\$6.5270	\$5.9270	\$5.8044	\$ 0.7226	0.1226
Oct-04	\$5.1060	\$5.1930	\$5.3886	\$ (0.2826)	(0.1956)
Nov-04	\$7.9090	\$8.2830	\$7.5870	\$ 0.3220	0.6960
Dec-04	\$7.0530	\$7.0060	\$7.1717	\$ (0.1187)	(0.1657)
Jan-05	\$7.1940	\$7.3120	\$6.5874	\$ 0.6066	0.7246
Feb-05	\$5.9840	\$5.9970	\$6.1644	\$ (0.1804)	(0.1674)
Mar-05	\$6.7650	\$6.0570	\$6.2672	\$ 0.4978	(0.2102)
Apr-05	\$6.2530	\$6.9320	\$7.0903	\$ (0.8373)	(0.1583)
May-05	\$5.3520	\$5.7900	\$7.2777	\$ (1.9257)	(1.4877)
Jun-05	\$5.3200	\$6.8250	\$6.6087	\$ (1.2887)	0.2163
Jul-05	\$8.0850	\$9.0420	\$7.0164	\$ 1.0686	2.0256
Aug-05	\$6.1990	\$7.5180	\$7.1769	\$ (0.9779)	0.3411
Sep-05	\$9.6360	\$9.9830	\$9.0489	\$ 0.5871	0.9341
Oct-05	\$11.8050	\$12.2620	\$10.9373	\$ 0.8677	1.3247
Nov-05	\$12.7430	\$12.1820	\$12.0770	\$ 0.6660	0.1050
Dec-05	\$9.2170	\$8.7320	\$10.2158	\$ (0.9988)	(1.4838)
Jan-06	\$15.0370	\$15.5990	\$11.4813	\$ 3.5557	4.1177
Feb-06	\$6.6820	\$5.6160	\$8.0225	\$ (1.3405)	(2.4065)
Mar-06	\$6.2030	\$5.0980	\$6.8651	\$ (0.6621)	(1.7671)
Apr-06	\$7.0480	\$5.9710	\$6.3089	\$ 0.7391	(0.3379)
May-06	\$6.4810	\$5.9190	\$6.2260	\$ 0.2550	(0.3070)
Jun-06	\$3.5610	\$2.6760	\$5.3007	\$ (1.7397)	(2.6247)
Jul-06	\$5.8940	\$5.8820	\$5.4923	\$ 0.4017	0.3897
Aug-06	\$4.1540	\$5.3040	\$5.8385	\$ (1.6845)	(0.5345)
Sep-06	\$6.7020	\$7.8280	\$5.8245	\$ 0.8775	2.0035
Oct-06	\$4.1020	\$3.7200	\$4.2155	\$ (0.1135) \$ 0.5827	(0.4955)
Nov-06	\$6.9470	\$6.7750	\$6.3643	·	0.4107
Dec-06 Jan-07	\$8.2780 \$7.4640	\$8.2310 \$7.3760	\$7.5189 \$6.9162	\$ 0.7591 \$ 0.5478	0.7121 0.4598
Feb-07	\$5.8930	\$6.6970	\$6.8624	\$ (0.9694)	(0.1654)
Mar-07	\$9.1490	\$9.1710	\$7.4241	\$ 1.7249	1.7469
Apr-07	\$7.5560	\$7.6340	\$7.0207	\$ 0.5353	0.6133
May-07	\$4.5110	\$4.4560	\$7.0875	\$ (2.5765)	(2.6315)
Jun-07	\$6.7620	\$6.6070	\$6.8557	\$ (0.0937)	(0.2487)
Jul-07	\$5.5500	\$4.8970	\$6.1388	\$ (0.5888)	(1.2418)
Aug-07	\$5.7570	\$5.7020	\$5.0518	\$ 0.7052	0.6502
Sep-07	\$4.5650	\$4.0500	\$4.7563	\$ (0.1913)	(0.7063)
Oct-07	\$5.1200	\$5.3860	\$4.9824	\$ 0.1376	0.4036
Nov-07	\$5.4490	\$5.1810	\$5.8228	\$ (0.3738)	(0.6418)
Dec-07	\$6.3260	\$6.1500	\$6.2567	\$ 0.0693	(0.1067)
Jan-08	\$6.6560	\$6.5780	\$6.1011	\$ 0.5549	0.4769
Feb-08	\$7.4093	\$7.7212	\$6.8759	\$ 0.5334	0.8453
Mar-08	\$9.0437	\$9.7074	\$7.2992	\$ 1.7445	2.4082
Apr-08	\$8.5337	\$7.7813	\$8.0905	\$ 0.4432	(0.3092)
May-08	\$7.6219	\$9.0092	\$8.9182	\$ (1.2963)	0.0910
Jun-08	\$13.0414	\$13.5169	\$9.5781	\$ 3.4633	3.9388
Jul-08	\$10.0081	\$6.1168	\$10.7996	\$ (0.7915)	(4.6828)
Aug-08	\$11.2299	\$12.6922	\$8.4424	\$ 2.7875	4.2498
Sep-08	\$5.1236	\$7.0550	\$7.0475	\$ (1.9239)	0.0075
Oct-08	\$5.3096	\$5.8896	\$5.9105	\$ (0.6009)	(0.0209)
Nov-08	\$7.1680	\$6.8840	\$6.5568	\$ 0.6112	0.3272
Dec-08	\$7.2100	\$7.2240	\$6.8300	\$ 0.3800	0.3940

Table 7: Comparison between Union QRAM and DERS GCFR in relation to Monthly Index

	Union QRAM vs.	DERS GCFR vs. A	ECO Monthly Index
Reference Price (RP)	Empress Monthly Index	North	South
Reference Price > Index	70% of Time	55% of Time	53% of Time
RP Variance > \$1.00/ GJ	65% of Time	27% of Time	30% of Time
RP Variance > \$2.00/ GJ	28% of Time	7% of Time	17% of Time
RP Variance > \$2.00/ GJ	15% of Time	3% of Time	7% of Time

As outlined, accuracy and transparency are both improved when the rate setting mechanism of utilities align with the methodology used to procure supply. As the utilities are buying Monthly index based supply, the appropriate monthly index estimate should be reported as the input or reference price as close to flow date as is practicable. This will allow rates to be more reflective of the costs to procure gas, and subsequently reduce the over collection from customers that has occurred consistently over the last three years. Union Gas supports this logic in comments made in Exhibit IR7.4:

"Union is proposing to shorten the time between the close of the 21-day strip and the effective date of the rate updates. Such a change would increase the market sensitivity of Union's rates and reduce the size of the out-of-period adjustments that are disposed through rate riders."

Furthermore in Union Gas Exhibit IR8.12, page 2, b) Union comments that:

"Generally, gas price forecasts made closer to the effective supply dates would tend to be more accurate than price forecasts made earlier."

This logic can be extended to justify the benefits of a market index price being used to support monthly forecasting and rate setting. To demonstrate this, a recalculation of Union's Ontario Landed Reference price was completed using monthly index pricing.

Using the Q1/09 Union QRAM (EB-2008-0371 Tab 1, Schedule 1 and Schedule 3 Page 4 of 6), the Ontario Landed Reference Price was recalculated using the prompt month only NYMEX settle on the fifth last business day of the current month instead of the 12 month average price curve which is currently used in the QRAM. The monthly prices for 2008 were recalculated in order to determine how much smaller the "Unit Rate Difference" would have been based on a monthly price setting mechanism. The following graph shows the absolute value of the differences between the "MRAM" Ontario Reference Price and the "QRAM" Ontario Landed Reference Price in relation to the actual WACOG for the month as reported in Schedule 3 Page 4 of 6.

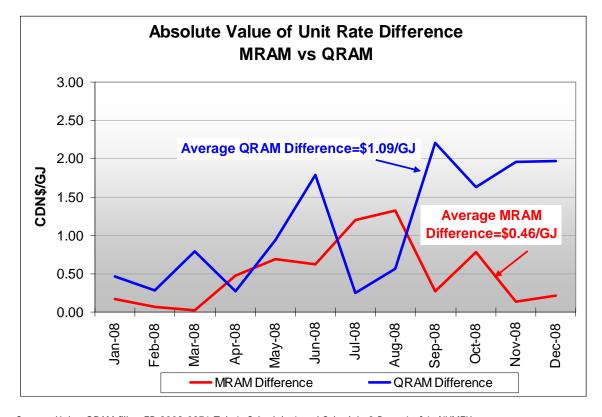


Figure 5: Comparison of forecasting and rate setting methodologies on reference price

Source: Union QRAM filing EB-2008-0371 Tab 1, Schedule 1 and Schedule 3 Page 4 of 6; NYMEX

The "Unit Rate Difference" is significantly smaller for the backcast MRAM versus the actual QRAM "Unit Rate Difference". In fact, the difference is smaller in 9 out of 12 months, which would mean a smaller PGVA to clear and a much truer reflection of market prices.

In order to put this into perspective at the customer level, the "Unit Rate Difference" calculated above was applied to the average monthly consumption for a residential customer in Ontario. The results in the table below illustrate that the Reference Price set by QRAM was inflated by an estimated \$36.92 CDN for 2008. In contrast, the MRAM only inflated the Reference Price by \$5.65 CDN. This is an example of the overestimation of the Reference Price produced by the QRAM versus the MRAM. It also helps explain why persistent over collection can occur under the current regulated rate setting mechanism in Ontario.

Table 8: Customer impacts of forecasting and rate setting methodologies on reference price

																Estimated				
		Referen	ce l	Price		Actual		Referen	ce l	Price	Actual Unit Price Difference			Difference	Residential		Impact of Unit Difference			
	N	/IRAM		QRAM	W	/ACOG	N	/IRAM	(QRAM	W	/ACOG	П	MRAM	QRAM	Consumption	1	MRAM		QRAM
			CI	DN\$/GJ							1D0	√\$/m³				m ³		CD	N\$	
		(a)		(b)		(c)		(p)		(e)		(f)	(9)=(d)-(f)	(h)=(e)-(f)	(1)	(j):	=(g) x (i)	(k))=(h) x (i)
Jan-08	\$	7.634	\$	8.183	\$	7.720	\$	0.288	\$	0.308	\$	0.291	\$	(0.003)	\$ 0.017	466	\$	(1.518)	\$	8.132
Feb-08	\$	8.361	\$	8.183	\$	8.462	\$	0.315	\$	0.308	\$	0.319	\$	(0.004)	\$ (0.011)	530	\$	(2.025)	\$	(5.573)
Mar-08	\$	9.009	\$	8.183	\$	8.980	\$	0.340	\$	0.308	\$	0.338	\$	0.001	\$ (0.030)	500	\$	0.540	\$	(15.019)
Apr-08	\$	9.800	\$	9.119	\$	9.392	\$	0.369	\$	0.344	\$	0.354	\$	0.015	\$ (0.010)	157	\$	2.417	\$	(1.615)
May-08	\$	10.668	\$	9.119	\$	10.052	\$	0.402	\$	0.344	\$	0.379	\$	0.023	\$ (0.035)	140	\$	3.249	\$	(4.923)
Jun-08	\$	11.325	\$	9.119	\$	10.911	\$	0.427	\$	0.344	\$	0.411	\$	0.016	\$ (0.068)	34	\$	0.530	\$	(2.296)
Jul-08	\$	12.828	\$	11.372	\$	11.619	\$	0.483	\$	0.429	\$	0.438	\$	0.046	\$ (0.009)	58	\$	2.642	\$	(0.540)
Aug-08	\$	10.635	\$	11.372	\$	11.939	\$	0.401	\$	0.429	\$	0.450	\$	(0.049)	\$ (0.021)	58	\$	(2.850)	\$	(1.239)
Sep-08	\$	8.931	\$	11.372	\$	9.162	\$	0.337	\$	0.429	\$	0.345	\$	(0.009)	\$ 0.083	58	\$	(0.505)	\$	4.831
Oct-08	\$	7.844	\$	10.224	\$	8.594	\$	0.296	\$	0.385	\$	0.324	\$	(0.028)	\$ 0.061	79	\$	(2.234)	\$	4.853
Nov-08	\$	8.404	\$	10.224	\$	8.260	\$	0.317	\$	0.385	\$	0.311	\$	0.005	\$ 0.074	279	\$	1.517	\$	20.652
Dec-08	\$	8.515	\$	10.224	\$	8.257	\$	0.321	\$	0.385	\$	0.311	\$	0.010	\$ 0.074	400	\$	3.887	\$	29.654
								HV=		0.03769	GJ	/m3			Total	2,759	\$	5.651	\$	36.916

Source: Using the Q1/09 Union QRAM (EB-2008-0371 Tab 1, Schedule 1 and Schedule 3 Page 4 of 6), the Ontario Landed Reference Price was recalculated using the prompt month only NYMEX settle on the fifth last business day of the current month for each month of 2008 and denoted "MRAM". The "Unit Rate Difference" is multiplied by the "Estimated Residential Consumption" to calculate an estimated impact of using the QRAM rate setting methodology instead of the MRAM rate setting methodology. Please note that the "Unit Price Difference" was calculated so that a positive difference indicated an estimated over collection from a customer.

Removal of Triggers and Clearing of PGVA's

As part of ensuring greater accuracy and transparency of rate setting, PGVA balances should be cleared automatically, regardless of amount, as part of the rate setting mechanism. Further to this, the clearing of the PGVA should match the rate setting timeline (for example, if rates are set monthly, then balances are cleared monthly, if quarterly rates than cleared quarterly), and must match the forecasting period to assist in avoiding large rate riders. The benefits of such a process include:

- A formulaic approach leads to better price transparency for consumers and market participants
- o Potentially reduced carrying costs for utilities or customers.
- Decreased regulatory review
- Better matching of the costs/ benefits incurred in the PGVA to those customers that consumed gas during the period.
- o Reduction of intergenerational riders.

MRAM preparation and Regulatory Approvals Process

A good example of how MRAM preparation and approval can be expedited is the approval process used in conjunction with the Alberta GCFR. An overview of the calculation of the GCFR has been provided earlier. This calculation is in accordance with the mechanical process approved in April 2002 by the Alberta Energy and Utilities Board (EUB), now the Alberta Utilities Commission, for use by all regulated natural gas default supply providers in Alberta. It is therefore not a product of subjective judgment or market speculation by default supply providers.

As outlined in the six-step process previously noted above, DSPs submit the monthly rate on the 5th last business day of the current month. The rate is acknowledged by the AUC by the last business day of the

month and the rate is updated in the billing system. The Commission acknowledges that the filings submitted by the DSPs are calculated in accordance with the rate setting methodology previously approved by the Commission. The Commission also allows for a 30 day review period for any party to raise concerns with the Gas Cost Recovery Rate (GCRR), price and volume forecasts, and prior period reconciliations used by the DSP.

This process is repeated on a monthly basis, and is followed by all regulated natural gas retailers in Alberta. Since the process is formulaic and provides excellent transparency to the AUC and interested parties, the filing is efficient and routine. The entire rate filing takes approximately 8 business days from when the upcoming volume forecast is prepared to the DSP receiving AUC acknowledgement, and hence the incremental amount of work to submit this monthly is not onerous. In an attempt to provide more clarity to the AUC, one DSP (DERS) voluntarily include graphs as an appendix, which help explain the current and prior month market activity and assists in the understanding of the month the monthly deferral balances.

For further assistance to the Board and Interested Parties, a copy of the DERS monthly GCFR filing is provided in Appendix A, and the voluntary supplemental information provided by DERS in the monthly GCFR filing to the AUC is provided in Appendix B.

To demonstrate the amount of effort required for the monthly filing of the GCFR in Alberta, the following work effort for the process is provided below:

Table 9: DERS GCFR Monthly Rate Filing Effort

Preparation			
Process Steps	Headcount	# of	People
	Requirement	Days	Days
Month Ahead Price Reporting	1	0.10	0.10
Supply Forecast Analysis	1	0.50	0.50
Deferral Update	1	1.00	1.00
Schedule & Evidence Prep	2	0.25	0.50
Cost Forecast Analysis	1	0.50	0.50
			2.60
Rates & Pricing			
	Headcount	# of	People
Process Steps	Requirement	days	Days
Model Updates	1	0.50	0.50
Schedule & Working Paper Prep	2	1.50	3.00
Evidence Prep	3	0.75	2.25
Bill Impacts	1	0.25	0.25
Rate Schedules & Appendices	1	0.10	0.10
Public Relations News Release	1	0.25	0.25
Contact Centre/District Support Q&A	1	1.60	1.60
			7.95
Total			10.55

A.4 Summary of GMG Proposed Structuring for Rate Setting

In summation, the Gas Marketer Group is proposing the following structure for Rate Setting:

- a) Rate setting on a monthly basis (MRAM).
- b) Monthly Forecasting based on the bid week prior to the prompt month NYMEX (or like) contract expiry to arrive at the Reference Price
- c) A standard formula for the calculation of the Effective Rate for each utility, based on the reference price derived in b) above.
- d) Automatic clearing of any intra-month PGVA balance over the following month.
- e) Forecasting and disposition periods must match the rate setting frequency (I.e. if MRAM then Monthly, if QRAM then quarterly).

The benefits of the above approach align with the vision and objectives outlined by the Board and allow for transparency in the setting of the "Effective Rates" of each distributor, as well as a more timely, accurate view of current market pricing for customers. By removing the triggers and utility discretion for PGVA clearing as well as automating the clearing over the coming period, it will assist in eliminating large rate riders over extended periods of time. The above methodology coupled with the utilities' continued monthly index procurement practice will continue to eliminate hedging risk for default supply customers as well as reduce the over collection from these customers that has occurred consistently over the past three years. In returning to the principles behind the current rate setting mechanism, the above noted rate setting structure better reflects the principles outlined in the Enbridge QRAM application in the following ways:

More reflective of market prices on an ongoing basis: Current Board-approved buying protocol is to purchase all supply on a monthly index basis, yet the current QRAM process allows for 12 month forward pricing. The 12 month deferral recovery/charge period further distorts the price signal to the customers served. Furthermore, the long lead time to calculate the QRAM, plus the 3 month nature of the price leads to an exaggerated need of deferral accounts, further distorting the price charged to system customers from the wholesale market price paid by utilities.

The pricing estimates to be used in rate setting should be adjusted to align with the costs the utilities can reasonably expect to incur within the period. Monthly rate setting using monthly index forecasting, along with the automatic clearing of deferral accounts within the rate setting frequency will allow default supply rates to be more reflective of current market prices.

<u>Enhanced price transparency</u>: Standardization of an effective rate formula coupled with the transparency of the elemental inputs into such a formula will allow consumers, regardless of their location or service provider, to recreate and verify the reference price and rates put forth by each distributor in its Rate Adjustment Application. While the inputs to the calculation may vary slightly based on geography, the formula used to calculate the effective rate based on those inputs should be the same across the rate class. Further to this, the use of a widely reported monthly prompt for the purposes of rate setting removes any discretion from the utility (or regulator) regarding the prudency of the reported commodity price.

<u>Regular quarterly review process</u>: Current Board-approved buying protocol is to purchase all supply on a monthly index basis. As such, the pricing estimates to be used in rate setting should be adjusted to align with the costs the utilities can reasonably expect to incur within the period. A regular monthly review process would allow for more frequent updates reflecting market conditions, and the incorporation of such conditions into current rates. The use of a widely reported monthly prompt for the purposes of rate

setting could allow for utility reporting of prices to the regulator much closer to the actual time that the commodity will flow to the customer.

<u>Customer awareness</u>, <u>customer acceptance</u>, <u>and less confusion in the marketplace</u>: The current QRAM process does not support customer awareness and acceptance of true market prices reflective of current market conditions. As noted in Union's Exhibit E2, Page 23, Lines 14-21, the notion that the use of the 12 month strip aids gas consumers in understanding competitive retail fixed price offerings in relation to the default supply offering is fundamentally flawed. By using a 12 month strip, the utilities are reporting prices for gas that they will not be exposed to for months 4 through 12 (if using a QRAM example). In doing so, the customer is not able to make informed consumption and provider choices.

Further to this, large rate riders may give customers the impression that natural gas prices are lower than current market rates. As can be seen in Table 2 in the attached evidence, Enbridge has continually over-collected from customers in 11 of the past 12 quarters. It is questionable as to whether customers are aware of this fact, and if so, would they be accepting of a continual over charging of rates that is returned to them months later without the benefit of interest?

More reflective market prices created by the alignment of forecasting, rate setting, and disposition periods with the utilities' procurement practices will help to minimize the over and under collection from customers produced by large PGVA balances. This should assist in reducing confusion for customers with respect to pricing signals and increase customer awareness and acceptance that the default rate put forth is a price that reflects the best estimate as to what the costs incurred for securing supply will actually be.

<u>Mitigation of large adjustments of customer bills</u>: Balances within the PGVA accounts are directly related to the accuracy of, and the method used, in forecasting. The size of the resultant rider is dependent on the variance within the deferral account and the mechanisms used to dispose of such riders, including the length of time for disposition, the existence of any triggers or thresholds, and any discretion allowed by the utilities in the process. These items combined have caused significant divergence between the effective rate and market prices, sending incorrect price signals to customers. Further to this, large rate riders have been applied in many quarters, indicating that either the customer or the utility has had increased carrying costs for the period.

In the GMG proposed rate structure pricing estimates to be used in rate setting would align with the costs the utilities can reasonably expect to incur within the period. By setting rates monthly, using monthly index forecasting, along with the automatic clearing of deferral accounts within the rate setting frequency should reduce the likelihood of significant over or under collection from customers.

<u>Fairness and equity among all customer groups</u>: Under the current QRAM protocol, in the fall, the utilities typically underestimate the cost of the winter supply by including the lower summer cost. This distorts the actual winter price down during periods of peak demand. Likewise, the summer reported price is distorted up by including winter prices that will not be incurred by the utility. This price distortion (or not market prices) results in a misalignment between the actual costs incurred by the utility and the prices charged to consumers. This leads to exaggerated over and under recoveries each quarter that must be disposed of through the deferral accounts.

Monthly forecasting, rate setting and disposition will more closely align the costs and benefits of gas procurement with those that consume gas in the period. This will eliminate the "mismatch" between the costs incurred by a specific set of customers and the customers that actually receive system service within a given period. Furthermore, the distortion on seasonal pricing created by a 12 month forecast will also be eliminated.

Implementation in a cost effective manner: The GMG believes that by using the Alberta model, there is an opportunity to implement a revised rate setting methodology in a cost effective manner. As noted above, only 10.5 people days are required for the current monthly filing in Alberta compared to the 14.5 people days for QRAM filings by Union Gas as noted in Exhibit 8.5 Attachment 1. This process is repeated on a monthly basis, and is followed by all regulated natural gas default suppliers in Alberta. Since the process is formulaic and provides excellent transparency to the AUC and interested parties, the filing is efficient and routine taking only 8 business days from start to finish.

Reduced regulatory burden relative to the former "trigger methodology" and the related rate adjustment mechanism, for Enbridge's PGVA: A standardized formula for Effective Rate setting along with a publicly reported reference price and automatic, standardized clearing of deferral accounts increases rate setting transparency, reduces intervention, and expedites the regulatory approvals process. A mandate to purchase all supply on a monthly index basis should also allow utilities to report wholesale market prices in a more timely manner. By using a public source, it removes any discretion from the utility (or regulator) regarding the prudency of the reported commodity price. All of this could allow for utility reporting of prices to the regulator much closer to the actual time that the commodity will flow to the customer and the actual costs incurred by the utility – 3-5 business days prior to delivery period.

Clearing PGVA balances automatically, regardless of amount, while matching the disposition to the forecasting and rate setting frequency provides greater accuracy and transparency in rate setting, and will assist in avoiding large rate riders. This also has the potential to reduce carrying costs for customers or utilities and intergenerational riders.

- A.5 GMG'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?

PGVA balances should be cleared automatically, regardless of amount, as part of the rate setting mechanism. No trigger mechanism should be used.

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?

An arbitrary means for setting a trigger to prompt changes in the reference price or to clear the PGVA is not appropriate. The reference price should be established as per the findings of this proceeding, and the PGVA should be cleared automatically within the next rate period.

- 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?

The price forecast should be reflective of the price adjustment period. If the rate setting frequency is monthly than a one month index price should be utilized in the calculation of the gas rate. If QRAM, than

a three month strip utilized in the calculation of the gas rate would be appropriate. Considering that there is no long term hedging for utilities, a 12-month forward view is not appropriate as it does not accurately reflect current short term pricing.

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

Forecast periods should relate to the length of the rate adjustment mechanism as it would more closely represent the cost of gas for the period in which the rates are set and recovered. GMG supports moving to MRAM based on monthly forecasting and monthly clearing of deferral accounts.

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

The monthly setting of rates is favourable to the current quarterly price adjustment, and therefore the QRAM is not appropriate for the regulated supply option, based on the evidence submitted above.

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

An MRAM should be used by the natural gas distributors, as it is more reflective of the current price index, providing greater price transparency. Intra-month volatility would be captured in the PGVA account and cleared in next month's rates. This would in turn reduce the lag time between consumption and the actual cost/benefit of gas for those customers that actually consumed gas during the period, as opposed to recovering these costs over a 12 month period as is done now by Union Gas, and proposed by Enbridge. Carrying costs of balances in deferral accounts will be reduced for natural gas distributors or customers in using this approach. Eliminating the need for triggers, and allowing for automated timely clearing of deferral accounts would create a mechanistic, transparent approach to rate setting, which should in turn reduce regulatory burden. It would also assist in eliminating multi-generational riders.

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?

Yes. 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. It is the most accurate signal in order to drive consumption behaviour. In addition, it could better reflect the increasingly diverse sources of potential diverse supply sources such as LNG and Arctic gas.

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

The GMG was not able to propose implementation of a single Ontario-wide reference price in the absence of unbundling of storage and transportation, which had been removed from the scope of this proceeding.

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

As noted in the submission above, the reference price should be based on a transparent monthly marker price for the forward month.

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?

As part of this proceeding, the Board should determine a standardized methodology to be implemented by the distributors for the transparent calculation of the reference price. This reference price should be transparent enough to allow for any market participant or Board Staff member to recreate and verify the reference price put forth by each distributor in its Rate Adjustment Application.

- 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?

Deferral accounts for the purposes of commodity rate setting should be split into commodity, transportation, and storage & load balancing.

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/variance accounts should be automatically cleared with the same frequency as the rate setting, and forecasting. Therefore, if rates are forecasted and set on a monthly basis, then the clearing of deferral/variance accounts should also be cleared on a monthly basis. No threshold should apply.

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?

A Province-wide standardized formulaic methodology should be applied to the disposition of deferral accounts. As noted previously, deferral/variance accounts should be cleared in conjunction with the rate setting and forecasting mechanism. With greater clearing frequency there should be reduced rider variances, therefore providing the customer with a more accurate indication of market prices.

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?

If the PGVA accounts are cleared on monthly or quarterly basis as proposed, there should be no need for final adjustments. Should the Board choose to change the methodology by which PGVA accounts are cleared, a one-time adjustment may be required at the time of implementation,

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

MRAM and automatic monthly clearing of PGVA accounts more closely reflects market price at time of consumption. This ties rate benefits/ costs more closely to the consuming customers and removes the risk of multi-generational riders.

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?

Carrying costs of gas in inventory, and related costs should be recovered through a distribution (or storage) rate rider on legacy assets. This rider should be applied to all consumers, regardless of supplier or supply type. However, such carrying costs should be reviewed for prudency, and the following questions should be asked:

- ➤ Operational prudency: For the past two storage cycles EGD ended the storage season (March 31) with approx. 18 Bcf of working gas in their accounts with a start of season inventory of up to 74 Bcf. It should be reviewed if that much storage is required. If so, how should this be calculated?
- ➤ Financial prudency: Given that there is no risk of recovery on gas in inventory, should the blended return of 9.36% be reviewed or risk adjusted?
- > Carrying cost requirement on working capital recovery: Is it reasonable for a utility to earn a return on the working capital already recovered for under the gross return?
- 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?

The GMG supports changes in the Board pre-approved revenue requirement components that are associated with a change in the reference price. Further to this, the allocation of the revenue requirement change should be based on the supply and load balancing requirements by rate class.

- 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?

To allow for the further development of the retail market in Ontario, and to align regulated gas prices more accurately with market rates, transparent regulated rates that are set on a monthly rather than quarterly basis would help to prevent the significant swings that can occur from quarter to quarter. Customers would also be equipped with the proper price signals that would allow them to manage their consumption and conservation efforts accordingly.

Standardization of pricing mechanisms and the use of a widely reported monthly index price as the reference price input will allow the appropriate transparency so that any customer, market participant, or Board Staff member can recreate and verify the reference price and the Effective Rate put forth by each distributor in its Rate Adjustment Application.

VII) Filing Requirements

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

The creation of a transparent, mechanistic, and formulaic MRAM or QRAM standard application should allow for an expedited regulatory process. This could be submitted as close to a week prior to the upcoming period, and could be approved by the OEB prior to the start of the period, provided the distributors are able to make system updates accordingly.

The Gas Marketer Group supports Enbridge's approach in paragraph 88 of their pre-filed submission to allow the Board and stakeholders to determine which information and in what order should be presented by the utilities in their rate adjustment application.

Section B: Review of Load Balancing Obligations for Natural Gas Distributors

B.1 Background

As stated in the Gas Marketer Group Issues submission, GDAR mobility issues contribute to a position of excess supply and inventory owing to the fluctuation of delivery requirements due to reductions or additions of customers. Currently, the methodology for setting the daily delivery volumes for Union, NRG and Enbridge differ. Union reviews changes in expected consumption to account for customer attrition and changes due to weather or customer consumption profiles. Union then adjusts the customers DCQ whenever the Pool's delivery requirements change by a minimum of +/- 4 GJ/day. The DCQ volumes on Union are also weather-normalized. Enbridge establishes the MDV for its customers thirty days prior to the start of a Direct Purchase contract (Pool) using all enrol requests for that Pool. Enbridge determines the consumption based on the prior year's historical usage for the customers included in the Pool and this MDV becomes the delivery requirement for the contract term, which is, typically one year. Currently, the MDV is only adjusted on the Pool's anniversary or termination date. Enbridge does not weathernormalize the MDV volumes. Standardization is required to reflect mid-term contract mobility introduced with GDAR.

With respect to the issue of drafting, as Direct Purchase customers bring in approximately 60% of the supply into the province without the ability to balance on a frequent basis as imposed by the utilities, it stands to reason that system gas would be drafting on Direct Purchase supply from time to time.

B.2 Gas Marketer Group 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?

Standardized load balancing mechanisms should apply for consistency of operations and efficiency of deliveries and balancing of the system. The GMG supports the implementation of Mean Daily Volume (MDV) re-establishment with data that has been weather normalized and a replication of the three-point-balancing adopted by Union. However, the three-point-balancing and the weather normalized MDV re-establishment must be completed in conjunction with each other.

The GMG supports Enbridge's proposal to implement three-point- balancing and MDV re-establishment and requests that the Board codify this and direct that it be implemented as soon as reasonably possible, but no later than 12 months from the date of the Decision in this proceeding.

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

The mechanisms that should be used by natural gas distributors for load balancing is a combination of weather normalized MDV re-establishment, during the contract term, and three-point-balancing where the utility must also be in balance at the three check points. Currently, Union re-establishes MDV (weather normalized) and uses three-point-balancing as their load balancing mechanism.

Enbridge however, offers a few balancing tools, for example Suspensions, Make-up, Quasi- Add and Title Transfers. Suspensions occur when a retailer is permitted to deliver less than the contract MDV for a specified period. Make-up is the converse of suspensions and the retailer is allowed to deliver more than was previously contracted. Quasi-add allow for customer additions to a Pool, but must not exceed the original Pool MDV by more than 10%. Title Transfers on the other hand, allows for the transfer of inventory balances between pools, provided that the transferring inventory are not in the same positive or negative balance position. Again, these are not without shortfalls and have been frequently unavailable owing to business and weather restrictions. With the introduction of mobility (GDAR), the inability to change the MDV during the contract term and the problem of inventory position continues to compound this issue. As such the GMG would strongly support Enbridge's commitment to implement weather normalized MDV re-establishment in a timely manner.

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

The GMG contends that drafting can occur on either System Supply, or on Direct Purchase supply, dependent on the variables of weather, time of year, burner tip consumption, and the availability of suspensions. While Enbridge's response to GMG IR#26 does not agree with the position that system customers can draft on DP supply, during the Technical Conference Ms. Giridhar stated in lines 9 through 15 on page 121 of the November 27, 2008 transcripts:

"So, from that perspective, is the utility drafting from the direct purchase customer? Yes, at the time of the year when the direct purchase customer is packing the system, we are drafting from them, and vice versa, but that is the design of the system and the load balancing mechanism, and that is the mechanism that the direct purchase customer has chosen from the utility."

The frequency of balancing allowed by market participants has a direct impact on drafting, in that the greater the frequency, the less likely the issue of drafting will arise provided demand is accurately measured. GMG is agreeable to the three-point-balancing employed by Union provided the weather normalized MDV re-establishment occurs at the same time

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

Yes. The MDV/ DCQ re-establishment process should be standardized with the following considerations:

- o Normal and mobility attrition as a result of GDAR.
- Weather impacts
- Consumption pattern changes

With full mobility, brought about with the introduction of GDAR, the problem of excess supply and inventory was exacerbated. When a customer enrols with a vendor, that vendor purchases adequate

supply for the customer's contract term with the vendor, thereby ensuring the vendor has the supply to support the customer's delivery requirement. If a customer switches to another retailer, the first retailer's delivery obligation to the utility does not change in the case of Enbridge. Consequently, an unnecessary inventory position is built, as the first retailer continues to provide gas for the retailer's now phantom customer for the duration of the Pool's contract term. The second retailer will also be required to deliver an equal amount of gas for the same customer. This creates an inventory surplus and possible storage impact. It is in the interest of all parties to implement weather normalized MDV/DCQ re-establishment in a timely manner using an appropriate volume threshold to avoid excess supply and inventory positions.

Section C: Cost Allocation

C.1 Background

Fully Allocated Costing (FAC) and Stand Alone Costing (SAC) methodologies are not appropriate for the calculation of DPAC and System Gas fees. The GMG agrees with the utilities that an Incremental Costing (IC) approach should be used. If the activities associated with these services were no longer performed, the costs associated with each activity would fall away, indicating that an IC approach is appropriate. Transversely, if either FAC or SAC methodologies were to be employed, utilities would be at risk for non-recovery of fixed costs when customers move from system gas to direct purchase. As a result, utilities may implement measures to retain system supply customers in order to recover fixed costs.

Any changes to cost allocation principles by utilities should be proactively reviewed and approved by the OEB within the individual utility rate case.

C.2 Gas Marketer Group 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?

Regulated gas supply costs should include those items detailed in the Enbridge response to GMG IR#27, costed on an incremental basis:

- Gas Acquisition
- Risk Management
- Contract Management
- Nominations
- Invoicing, Payment Processing and Reporting
- Supervision
- Billing
- Fringe Benefits for labour components

Direct Purchase costs should include those items detailed in the Enbridge response to GMG IR#27, costed on an incremental basis:

- Contract Management
- Nominations
- Invoicing and Payment Processing
- Demand Forecasting and Supply Planning
- Direct Purchase Billing Adjustments
- Fringe Benefits for labour components

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?

In order to ease the load balancing burden on rate payers, access to storage according to percentage of overall load, should be an option for market participants. Retailers should be charged for injection/withdrawal storage costs at precedent rates already in existence in Union South territory. To address surety of supply and balancing concerns, significant financial penalties should be imposed for participants not delivering as required.

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 principles should be the purview of the Board alone. Any changes should only be made after approval of an Application is received.

Section D: Billing Terminology

D.1 Background

As noted in the Issues submission by GMG, there are currently no standards for billing terminology by the various gas distributors (Enbridge, Union, and NRG.) Each uses differing nomenclature and presentations for the many line items on the consumer bill. This differentiation in terminology makes it difficult for natural gas customers to make comparisons using the general information available to them by the OEB and to interpret and compare services and rates among competing offers. For example, all customers are charged a fixed monthly charge per service address, but for each distribution company this charge is named differently. Enbridge's charge is called a 'customer charge', and Union's charge is called 'monthly charge'. The OEB website defines the monthly charge as a 'customer charge'.

References used in the presentation of Delivery, Transportation, and Storage items also differ from distributor to distributor. Even the use of the metrics differ among distribution companies since Union uses the full term "cubic metres", whereas Enbridge uses the term "m³". Enbridge describes the elevation factor adjustment to measured consumption volumes as "PEF Value", and Union describes it as "Barometric pressure factor". Enbridge lists their gas supply charge rate in dollars, while Union lists their various rates in cents.

To an industry participant, these differences may be easily deciphered; however consumers are not familiar enough with the terminology to make an adequate comparison of competing gas supply offers. Both utility-affiliated and competitive natural gas marketers are responsible for understanding and explaining the different line items to consumers for the purposes of promoting their products, and without standardized billing terminology there is the potential for errors in both the explanation, and the comprehension of such.

The Gas Marketer Group strongly supports the harmonization of billing terminology amongst the natural gas distributors in order to facilitate and improve customer education and understanding of media, government, and distributor materials.

D.2 Gas Marketer Group 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?

Synergies with the power bill requirements should be applied to gas distributor invoice for a DCB environment. All charge categories should be displayed with common definitions for all distributors, using the Union Gas bill as a template, as it already has significantly greater detail than the Enbridge Gas bill. Common language/terminology is required for all market participants, customer education, and media communications in order to increase market awareness amongst consumers.

Section E: Implementation Issues

E.1 Overview

The changes contemplated in this proceeding are for the betterment of all consumers, and as such implementation costs should be recovered from all affected distribution customers. Whilst considering the changes proposed within this proceeding, it is important to separate proper market structure decisions from the associated costs, so as not to unduly influence the decision making process away from doing "what is right". So that improvements contemplated throughout this proceeding can be expedited, the implementation of all changes should be codified and completed no later than 12 months from the date of the Decision. Detailed implementation estimates should be reviewed by Interested Parties and approved by the Board prior to project initiation.

E.2 Gas Marketer Group Responses to the Board's Specific Questions

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

The cost of implementing changes should be provided by each distributor and reviewed for prudency prior to project initiation.

11.2 Who should bear those costs?

As the changes contemplated in this proceeding are for the betterment of all consumers, costs should be recovered from all affected distribution customers.

11.3 How and when should any such changes be implemented?

The implementation of all changes should be completed as soon as possible and no later than 12 months from the date of the Decision in these proceedings.

Appendix A: Example of DERS Monthly Default Supply Application

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EXECUTIVE SUMMARY

This information package was developed to assist all parties participating in the monthly Gas Cost Flow Through Rate (GCFR) process for Direct Energy Regulated Services Deferred Gas Account (DGA).

This document contains information used to derive a Rider F of \$5.584/GJ for Direct Energy Regulated Services (DERS) gas customers for January 2009.

1 DGA COST AND RECOVERY OVERVIEW

Schedule M-1: Monthly DGA Costs and Recoveries Schedule M-2: Monthly DGA Energy Balance Any special notes as required

2 RECONCILIATION MONTH SCHEDULES

Schedule R-1: Forecast and Actual DGA Costs and Recoveries

Schedule R-2: DGA Energy Balance and Degree Days

Schedule R-3: Actual Gas Purchases

Schedule R-4: Actual Gas Purchases - ON - System ATCO South Supplies Schedule R-5: Actual Gas Purchases - Nova Inventory Transfer Supplies

Schedule R-6: Forecast and Actual Unit Gas Prices Schedule R-7: Transportation and Storage Costs Schedule R-10: Actual Gas Purchases - Details

Any special notes as required

3 FORECAST MONTH SCHEDULES

Schedule F-1: Forecast Gas Purchases Schedule F-2: Forecast Unit Gas Prices Schedule F-3: Rider F Rate Derivation Any special notes as required

4 OTHER SCHEDULES

Schedule C-1: Cost of Credit Support

5 APPENDIX

As Applicable

INTRODUCTION

This section provides an overview of the Deferred Gas Account (DGA).

Schedules M-1 and M-2 show the DGA components as of December 23, 2008.

Schedule M-1 includes actual, estimated and forecast costs for the various gas supply components and actual, estimated and forecast dollars for the recovery components.

Schedule M-2 includes actual, estimated and forecast energy balance for the DGA.

In order to zero the forecast balance of the DGA on January 31, 2009, a Rider F of \$5.584/GJ should be implemented for DERS Gas Customers on January 01, 2009.

SCHEDULE M-1 MONTHLY DGA COSTS AND RECOVERIES

			Α	B Actual	C Estimate	D Estimate	E Forecast
Line	Description	Units	Previous Period Adjustment	Oct-08	Nov-08	Dec-08	Jan-09
1	Opening Cumulative DGA Balance	\$,000	208	2,431	(375)	1,057	6,436
	Gas Supply Costs				,		
2	Purchases	\$,000	(3)	28,461	40,368	64,066	58,197
3	Daily Trade Averaging Adjustment	\$,000	0	0	0	0 1,000	0
4	Storage	\$,000	0	0	0	0	0
5	Imbalances	\$,000	(2,154)	0	0	0	0
6	Total Gas Supply Costs	\$,000	(2,157)	28,461	40,368	64,066	58,197
	<u>Adjustments</u>						
7	Transportation	\$,000	0	16	59	90	92
8	TCPL (AB) Fuel Recovery	\$,000	0	0	0	0	0
9	Procurement	\$,000	0	26	26	26	26
10	Bad Debts	\$,000	0	187	187	182	177
11	Working Capital	\$,000	0	38	37	37	36
12	Credit Charge	\$,000	0	18	32	46	51
13	Net Gas Costs	\$,000	(2,157)	28,745	40,709	64,446	58,578
	Recoveries						
14	Net Calendar Sales*	\$,000	66	24,740	40,794	69,729	52,049
15	Transportation Imbalance Sales	\$,000	0	0	0	0	0
16	Excess System Sales	\$,000	0	1,101	1,252	0	0
17	Penalty Revenue	\$,000	0	98	96	96	93
18	Total Recoveries	\$,000	66	25,938	42,141	69,825	52,142
19	Current DGA Balance	\$,000	2,223	(2,806)	1,433	5,379	(6,436)
20	Closing Cumulative DGA Balance	\$,000	2,431	(375)	1,057	6,436	0

^{*} Net Calendar Sales excludes 2008 return margin amounts.

SCHEDULE M-2 MONTHLY DGA ENERGY BALANCE

Line	Description	Units	A Actual Oct-08	B Estimate Nov-08	C Estimate Dec-08	D Forecast Jan-09
	Gas Supply Costs					
1	Purchases	TJ	4,552	6,154	9,782	9,431
2	Storage	TJ	0	0	0	0
3	Imbalances	TJ	0	0	0	0
4	Total Energy	TJ	4,552	6,154	9,782	9,431
	<u>Adjustments</u>					
5	TCPL (AB) Fuel Recovery	TJ	0	0	0	0
6	Net Energy	TJ	4,552	6,154	9,782	9,431
	Recoveries					
7	Calendar Sales	TJ	4,237	5,968	9,719	9,359
8	Transportation Imbalance Sales	TJ	0	0	0	0
9	Excess System Sales	TJ	170	191	0	0
10	Total Recoveries	TJ	4,406	6,160	9,719	9,359
11	Load Balancing / UFG Estimate	TJ	(146)	6	(63)	(72)

SPECIAL NOTES

INTRODUCTION

This section provides details of the Deferred Gas Account (DGA) components for October 2008.

Schedule R-1 shows the forecast and actual DGA cost and recovery components for October 2008 as of September 24, 2008 and December 23, 2008 respectively.

SCHEDULE R-1 FORECAST & ACTUAL DGA COSTS AND RECOVERIES

October 2008

			Forecast Sep 24, 2008	Actual Dec 23, 2008	Actual less
Line	Description	Units	2006	2006	Forecast
	Gas Supply Costs				
1	Purchases	\$,000	29,308	28,461	(847)
2	Daily Trade Averaging Adjustment	\$,000	0	0	0
3	Storage	\$,000	0	0	0
4	Imbalances	\$,000	0	0	0
5	Total Gas Supply Costs	\$,000	29,308	28,461	(847)
	<u>Adjustments</u>				
6	Transportation	\$,000	22	16	(6)
7	TCPL (AB) Fuel Recovery	\$,000	0	0	0
8	Procurement	\$,000	26	26	0
9	Gas Supply - Related Bad Debts	\$,000	189	187	(2)
10	Working Capital	\$,000	38	38	0
11	Credit Charge	\$,000	18	18	0
12	Net Gas Costs	\$,000	29,600	28,745	(856)
	Recoveries				
13	Net Calendar Sales*	\$,000	27,901	24,740	(3,161)
14	Transportation Imbalance Sales	\$,000	0	0	0
15	Excess System Sales	\$,000	0	1,101	1,101
16	Penalty Revenue	\$,000	99	98	(1)
17	Total Recoveries	\$,000	28,000	25,938	(2,062)

^{*} Net Calendar Sales excludes 2008 return margin amounts.

Schedule R-2 shows the forecast and actual DGA energy balance for October 2008 as of September 24, 2008 and December 23, 2008. It also shows the normal and actual degree days for October 2008.

SCHEDULE R-2 DGA ENERGY BALANCE & DEGREE DAYS October 2008

Line	Description	Units	Forecast Sep 24, 2008	Actual Dec 23, 2008	Actual less Forecast
	Gas Supply Costs				
1	Purchases	TJ	4,800	4,552	(248)
2	Storage	TJ	0	0	0
3	Imbalances	TJ	0	0	0
4	Total Energy	TJ	4,800	4,552	(248)
	<u>Adjustments</u>				
5	TCPL (AB) Fuel Recovery	TJ	0	0	0
6	Net Energy	TJ	4,800	4,552	(248)
	Recoveries				
7	Calendar Sales	TJ	4,778	4,237	(541)
8	Transportation Imbalance Sales	TJ	0	0	0
9	Excess System Sales	TJ	0	170	170
10	Total Recoveries	TJ	4,778	4,406	(371)
11	DGA UFG	TJ	(22)	(146)	(124)
12	Degree Days	DD	320	279	(41)

Schedule R-3 shows the actual DGA purchase gas components for October 2008 as of December 23, 2008.

SCHEDULE R-3 ACTUAL GAS PURCHASES October 2008

Line	Description	Units	Actual December 23, 2008
1	ON-System ATCO Supplies	\$,000	15,198
2		TJ	2,460
3		\$/GJ	6.177
4	Nova Inventory Transfer Supplies	\$,000	13,261
5		TJ	2,092
6		\$/GJ	6.340
7	Total Purchases	\$,000	28,459
8		TJ	4,552
9		\$/GJ	6.252

Schedule R-4 shows the actual DGA ON-System ATCO South gas components for October 2008 as of December 23, 2008.

SCHEDULE R-4 ACTUAL GAS PURCHASES - ON-SYSTEM ATCO SUPPLIES

		October 2008	Actual
Line	Description	Units	December 23, 2008
1	Long Term Indexed	\$,000	6,649
2		TJ	1,122
3		\$/GJ	5.925
4	Total Long Term	\$,000	6,649
5		TJ	1,122
6		\$/GJ	5.925
7	Short Term (Monthly Index)	\$,000	1,652
8		TJ	279
9		\$/GJ	5.920
10	Short Term (Daily Index)	\$,000	6,898
11		TJ	1,059
12		\$/GJ	6.512
13	Total Short Term	\$,000	8,549
14		TJ	1,338
15		\$/GJ	6.389
16	Total ON-System ATCO Supplies	\$,000	15,198
17		TJ	2,460
18		\$/GJ	6.177

Schedule R-5 shows the actual DGA Nova Inventory Transfer purchase gas components for October 2008 as of December 23, 2008.

SCHEDULE R-5 ACTUAL GAS PURCHASES - NOVA INVENTORY TRANSFER SUPPLIES

	Octo	ober 2008	Actual
Line	Description	Units	December 23, 2008
1	Long Term Indexed	\$,000	0
2		TJ	0
3		\$/GJ	0.000
4	Total Long Term	\$,000	0
5		TJ	0
6		\$/GJ	0.000
7	Short Term (Monthly Index)	\$,000	1,835
8		TJ	310
9		\$/GJ	5.920
10	Short Term (Daily Index)	\$,000	11,425
11		TJ	1,782
12		\$/GJ	6.413
13	Total Short Term	\$,000	13,261
14		TJ	2,092
15		\$/GJ	6.340
16	Total Nova Inventory Transfer Supplie	es \$,000	13,261
17		TJ	2,092
18		\$/GJ	6.340

Schedule R-6 shows the forecast and actual unit gas prices for October 2008 as of September 24, 2008 and December 23, 2008 respectively.

SCHEDULE R-6 FORECAST AND ACTUAL UNIT GAS PRICES October 2008

Line	Description Units		Forecast Sep 24, 2008	Actual Dec 23, 2008	Actual less Forecast	
1	AECO Monthly Index	\$/GJ	6.0719	5.9105	(0.1614)	
2	AECO Daily INDEX	\$/GJ	6.1255	6.4081	0.2826	

Notes:

- The forecast unit price in Line 1 is the weighted average price of the transactions made up to and including September 22, 2008 on the AECO/NGX Intra-Alberta October (Near Month) instrument as reported by NGX.
- The actual unit price in Line 1 was the weighted average price of the transactions made up to and including September 30, 2008 on the AECO/NGX Intra-Alberta October (Near Month) instrument as reported by NGX.
- 3. The forecast unit price in Line 2 is the arithmetic average of the October, AECO/NGX Intra-Alberta Settlement prices on September 16, 17, 18, 19 & 22, 2008.
- 4. The actual unit price in Line 2 is the total weighted average price of the daily, weighted average prices each day in October, 2008 as reported by NGX and includes all weekend deals.

Schedule R-7 shows the actual contract storage and transportation costs for October 2008 as of December 23, 2008.

The TCPL (AB) transportation costs reflect Firm Transportation Receipt charges on the NOVA Gas transmission system and the AP FSR transportation costs reflect Firm Service Receipt charges on the ATCO Pipelines system.

SCHEDULE R-7 TRANSPORTATION & STORAGE COSTS October 2008

Line	Description	Units	Actual December 23, 2008
1	Contract Storage	\$,000	0
2	Transportation AP OPR	\$,000	15
3	Transportation AP FSR	\$,000	1
	Total		16

The R-10 schedules show the actual day gas sales and purchases for the reconciliation month as at the filing date.

Short term transaction totals in schedules R 10 B & D are shown only if all four of these criteria are satisfied:

- 1. Transactions are done for the same time frame (e.g. same day or yesterday).
- 2. Transactions are done for the same point (i.e. NIT, ATCO North or ATCO South).
- 3. Transactions are done using the same pricing regime (i.e. fixed vs. index based).
- 4. Both regulated and deregulated deals are transacting in the same direction (i.e. both selling or both buying).

Schedule R 10 A S - Actual Spot Gas Purchases by Trade Day October 2008

Direct Energy Regulated Services

Nova Inventory Transfer Supplies

	Ye	sterday (YD)		AECO YD			Same Day (SD))		AECO Daily
		Avg. Cost	Total Cost	Daily Average	Fixed	Avg. Cost	Index Related	Avg. Cost	Total Cost	Index
DAY	GJ's	\$/GJ	\$	\$/GJ	GJ's	\$/GJ	GJ's	\$/GJ	\$	\$/GJ
1	(15,300)	6.4598	(98,835.00)	6.4164	0	0.0000	0	0.0000	0.00	6.2276
2	(16,300)	5.9080	(96,301.00)	5.9880	0	0.0000	0	0.0000	0.00	6.3449
3	3,000	5.9940	17,982.00	5.7883	0	0.0000	0	0.0000	0.00	5.9940
4	42,000	5.8367	245,140.00	5.8240	0	0.0000	0	0.0000	0.00	5.8277
5	0	0.0000	0.00	5.9578	60,000	5.8771	0	0.0000	352,625.00	5.8979
6	0	0.0000	0.00	5.9469	5,000	5.9800	0	0.0000	29,900.00	5.9513
7	0	0.0000	0.00	6.0667	0	0.0000	30,000	5.9436	178,308.00	5.9411
8	15,000	6.1900	92,850.00	6.2053	10,000	6.1150	40,000	6.0468	303,022.00	6.0443
9	0	0.0000	0.00	6.2634	0	0.0000	80,000	6.2045	496,360.00	6.1945
10	2,000	6.2626	12,525.20	6.2157	220,000	6.3432	160,000	6.1802	2,384,340.00	6.2626
11	5,000	6.1973	30,986.50	5.9393	0	0.0000	40,000	6.2048	248,192.00	6.1973
13	(27,000)	5.9266	(160,018.20)	6.0506	0	0.0000	0	0.0000	0.00	5.9266
14	0	0.0000	0.00	6.1842	30,000	6.0833	60,000	6.0854	547,626.00	6.0821
15	14,000	6.4900	90,860.00	6.4919	0	0.0000	60,000	6.1814	370,886.00	6.1781
16	(9,000)	6.4909	(58,418.10)	6.8586	31,000	6.4881	0	0.0000	201,130.00	6.4909
17	0	0.0000	0.00	6.2917	0	0.0000	30,000	6.5979	197,937.00	6.6159
18	0	0.0000	0.00	6.0269	0	0.0000	80,000	6.2291	498,332.00	6.2726
19	0	0.0000	0.00	6.6403	40,000	6.0875	0	0.0000	243,500.00	6.0838
20	0	0.0000	0.00	6.8532	5,000	6.7200	20,000	6.7713	169,026.00	6.7663
21	(19,000)	7.2728	(138,182.50)	7.2879	0	0.0000	60,000	6.8305	409,832.00	6.8247
22	(10,000)	7.1725	(71,725.00)	7.0217	0	0.0000	40,000	7.3113	292,452.00	7.3063
23	0	0.0000	0.00	6.5323	0	0.0000	30,000	7.0268	210,805.00	7.0260
24	(33,000)	6.4547	(213,006.00)	6.5653	0	0.0000	120,000	6.5589	787,068.00	6.5680
25	17,500	7.0186	122,825.00	6.9996	10,000	6.5500	0	0.0000	65,500.00	6.5560
26	43,000	7.0137	301,590.00	6.9818	25,000	6.9660	0	0.0000	174,150.00	6.9145
27	9,000	6.7700	60,930.00	6.7736	25,000	6.7930	20,000	6.7949	305,723.00	6.7874
28	(10,000)	6.7641	(67,641.00)	6.7644	0	0.0000	10,000	6.7641	67,641.00	6.7641

December 23, 2008

29	(20,000)	6.7522	(135,044.00)
30	40,600	6.3584	258,150.50
31	0	0.0000	0.00
	31,500		194,668.40

6.5707
6.1874
5.6965
TOTALS

ŀ	480,600		900,000		8,787,308.00
	19,600	6.1871	0	0.0000	121,268.00
	0	0.0000	20,000	6.5842	131,685.00
ſ	0	0.0000	0	0.0000	0.00

Schedule R 10 C S - Actual Spot Gas Purchases by Trade Day October 2008

Direct Energy Regulated Services

ON- System ATCO Supplies

YD table is not applicable for this schedule.

	Ye	sterday (YD)		AECO YD			Same Day (SD)			AECO Daily
		Avg. Cost	Total Cost	Daily Average	Fixed	Avg. Cost	Index Related	Avg. Cost	Total Cost	Index
DAY	GJ's	\$/GJ	\$	\$/GJ	GJ's	\$/GJ	GJ's	\$/GJ	\$	\$/GJ
1	0	0.0000	0.00	0.0000	0	0.0000	2,200	6.2126	13,667.72	6.2276
5	(2,000)	5.9700	(11,940.00)	0.0000	0	0.0000	0	0.0000	0.00	5.8979
6	2,000	5.9800	11,960.00	0.0000	0	0.0000	43,000	5.9111	254,175.90	5.9513
7	(4,000)	5.9400	(23,760.00)	0.0000	0	0.0000	59,000	5.9102	348,704.40	5.9411
8	0	0.0000	0.00	0.0000	0	0.0000	32,950	6.0382	198,958.44	6.0443
9	0	0.0000	0.00	0.0000	0	0.0000	59,500	6.2193	370,050.25	6.1945
10	0	0.0000	0.00	0.0000	0	0.0000	103,200	6.1965	639,478.80	6.2626
14	(3,000)	6.1500	(18,450.00)	0.0000	0	0.0000	48,500	6.1105	296,356.85	6.0821
15	0	0.0000	0.00	0.0000	0	0.0000	36,000	6.2142	223,711.60	6.1781
16	0	0.0000	0.00	0.0000	0	0.0000	23,000	6.5200	149,960.70	6.4909
17	0	0.0000	0.00	0.0000	0	0.0000	126,000	6.6261	834,890.40	6.6159
20	0	0.0000	0.00	0.0000	0	0.0000	52,500	6.8082	357,430.75	6.7663
21	(1,000)	7.2700	(7,270.00)	0.0000	0	0.0000	46,500	6.8691	319,411.05	6.8247
22	0	0.0000	0.00	0.0000	0	0.0000	43,000	7.3522	316,145.90	7.3063
23	0	0.0000	0.00	0.0000	0	0.0000	53,000	7.0710	374,763.00	7.0260
24	0	0.0000	0.00	0.0000	0	0.0000	75,000	6.5889	494,167.50	6.5680
27	0	0.0000	0.00	0.0000	0	0.0000	36,600	6.8269	249,864.84	6.7874
28	0	0.0000	0.00	0.0000	0	0.0000	56,400	6.7963	383,309.24	6.7641
29	0	0.0000	0.00	0.0000	0	0.0000	69,400	6.7846	470,853.68	6.7522
30	0	0.0000	0.00	0.0000	0	0.0000	59,500	6.6131	393,478.50	6.5830
31	0	0.0000	0.00	0.0000	0	0.0000	32,000	6.1332	196,262.40	6.1729
	(8,000)		(49,460.00)	TOTALS	0		1,057,250		6,885,641.92	

Schedule R 10 G S - Actual Spot Gas Purchases by Delivery Day October 2008

PEAKING Demand Supply Contracts

Nova Inventory Transfer Supplies

		Same Day (SD)		AECO Daily
	Index Related	Avg. Cost	Total Cost	Index
DAY	GJ's	\$/GJ	\$	\$/GJ
1	0	0.0000	0	6.2276
16	50,000	6.5159	325,795	6.4909
17	0	0.0000	0	6.6159
21	40,000	6.8497	273,988	6.8247
22	0	0.0000	0	7.3063
24	120,000	6.7045	804,540	6.5680
27	0	0.0000	0	6.7874
TOTALS	210,000		1,404,323	

Schedule R 10 I S - Long Term & Short Term Purchases October 2008

Direct Energy Regulated Services

ON-System Atco Supplies

<u>Trade</u>	<u>From</u>	<u>To</u>	Volume(GJ)	<u>Price</u>	<u>Value</u>
180946	10/01/2008	10/31/2008	291	5.786	1,684
536832	10/01/2008	10/31/2008	5,441	5.788	31,493
263586	10/01/2008	10/31/2008	480	6.056	2,907
180893	10/01/2008	10/31/2008	1,116,000	5.925	6,612,858
Total Long Te	rm Indexed		1,122,212	5.925	6,648,941
523444	10/01/2008	10/31/2008	186,000	5.920	1,101,213
523371	10/01/2008	10/31/2008	93,000	5.920	550,607
Total Short Te	erm(Monthly Index)		279,000	5.920	1,651,820

Schedule R 10 J S - Long Term & Short Term(Monthly Index) Purchases October 2008

Direct Energy Regulated Services

Nova Inventory Transfer Supplies

<u>Trade</u>	From	<u>To</u>	Volume(GJ)	Price	<u>Value</u>
524654	10/01/2008	10/31/2008	310,000	5.920	1,835,355
Total Short Te	erm(Monthly Index)		310,000	5.920	1,835,355

This section provides details of the Deferred Gas Account (DGA) components for January 2009.

Schedule M-1 in Section 1 shows the forecast costs for the various gas supply categories, gas cost adjustments and the forecast dollars for the various recovery components for January 2009.

Schedule M-2 in Section 1 shows the forecast energy balance of the DGA for January 2009.

Schedule F-1 shows the forecast of gas purchases for January 2009 by pricing mechanism. As shown in Schedule F-1, most of the gas purchases have AECO Monthly or Daily Index pricing mechanism.

Most of the Other purchase category is also influenced by AECO index pricing mechanism.

SCHEDULE F-1 FORECAST GAS PURCHASES January 2009

Line	Description	Units	Forecast December 23, 2008
1	AECO Monthly Index	TJ	4,517
2	AECO Daily Index	TJ	4,913
3	Other	TJ	1
	Total	TJ	9,431

Schedule F-2 shows the forecast of the unit gas prices for January 2009.

SCHEDULE F-2 FORECAST UNIT GAS PRICES January 2009

Line	Description	UNIT	Forecast December 23, 2008
1	AECO Monthly Index	\$/GJ	6.2663
2	AECO Daily Index (1)	\$/GJ	6.0830

Notes:

- 1. The forecast unit price in Line 1 is the weighted average price of the transactions made up to and including December 17, 2008 on the AECO/NGX Intra-Alberta January (Near Month) instrument as reported by NGX.
- 2. The forecast unit price in Line 2 is the arithmetic average of the January, AECO/NGX Intra-Alberta Settlement prices on December 11, 12, 15, 16 & 17, 2008.

In order to zero the forecast balance of the DGA on January 31, 2009, a Rider F of \$5.584/GJ should be implemented on January 01, 2009. Schedule F-3 shows how this rate is calculated.

SCHEDULE F-3 RIDER F RATE DERIVATION

January 2009

Line	Description	Units	Reference	Value
1	Opening Cumulative DGA Balance	\$,000	Schedule M-1, Line 1, Column E	6,436
2	Net Gas Cost Estimate	\$,000	Schedule M-1, Line 13, Column E	58,578
3	Transportation Imbalance Sales Estimate	\$,000	Schedule M-1, Line 15, Column E	0
4	Excess System Sales Estimate	\$,000	Schedule M-1, Line 16, Column E	0
5	Penalty Revenue Estimate	\$,000	Schedule M-1, Line 17, Column E	93
6	Net Monthly Gas Cost Recovery	\$,000	Line 2 less Line 1 less Lines 3 - 5	52,049
7	Forecast Monthly Sales	TJ	Schedule M-2, Line 7, Column D	9,359
8	GCFR	\$/GJ	Line 6 divided by Line 7	5.562
9	2008 Approved Return Margin	\$/GJ	Decision 2008-374	0.0223
10	Rider F	\$/GJ	Line 8 + Line 9	5.584

SPECIAL NOTES

SCHEDULE C - 1 COST OF CREDIT SUPPORT

LEGEND: bp Basis points (100 bp = 1%)
LC Letter of credit
PCG Parental company guarantee

December 19, 2008

Supply Sources	Security Type	Credit Charge (bp)	September Payable	October Payable	November Payable	December Payable	January Payable	Actual Oct-08	Estimate Nov-08	Estimate Dec-08	Forecast Jan-09
(SOUTH) ATCO Gas Supply Contracts											
ATCO	PCG	40.0	42,542	31,493	0	33,692	0	23	11	9	11
Canetic Resources Inc.	N/A		4,892	2,907	0	3,237	0				
Enerplus Resources Corporation	N/A		2,658	1,684	4,245	5,351	0				
Shell Canada Limited	PCG	40.0	7,627,500	6,612,858	8,283,618	8,915,445	0	4,319	4,516	5,166	3,029
Forecast (with credit support)	PCG	40.0	0	0	0	0	8,190,054	0	0	0	2,244
Forecast (without credit support)			0	0	0	0	7,520				
Sub To	tal		7,677,592	6,648,942	8,287,863	8,957,725	8,197,574	4,342	4,527	5,175	5,284
DEML Supply Contracts											
Counterparty 1	PCG	40.0	0	0	0	1,703,295	0	0	0	467	579
Counterparty 2	PCG	40.0	0	0	34,430	0	0	0	9	11	0
Counterparty 3	PCG	40.0	305,734	128,908	3,541,670	5,071,637	0	136	1,014	2,554	1,723
Counterparty 4	PCG	40.0	0	101,446	639,277	238,182	0	28	210	275	81
Counterparty 5	PCG	40.0	1,297,997	2,903,273	1,578,785	5,931,729	0	1,222	1,419	2,144	2,015
Counterparty 6	PCG	40.0	316,884	1,703,720	2,307,572	658,404	0	571	1,211	939	224
Counterparty 7	N/A		(22,966)	(359,628)	(296,904)	449,339	0				
Counterparty 8	PCG	40.0	0	1,156,520	3,265,528	2,098,992	0	317	1,288	1,649	713
Counterparty 9	PCG	40.0	127,975	1,602,425	117,554	683,585	0	481	577	226	232
Counterparty 10	PCG	40.0	270,210	111,826	57,792	61,595	0	119	54	36	21
Counterparty 11	PCG	40.0	0	0	0	181,900	0	0	0	50	62
Counterparty 12	PCG	40.0	576,416	933,051	8,480,807	8,813,746	0	445	2,640	5,203	2,994
Counterparty 13	PCG	40.0	0	194,508	0	0	0	53	66	0	0
Counterparty 14	PCG	40.0	0	0	550,288	435,114	0	0	151	300	148
Counterparty 15	PCG	40.0	0	1,530,046	2,008,764	661,524	0	419	1,070	842	225
Counterparty 16	PCG	40.0	2,058,481	3,331,862	2,414,384	1,345,774	0	1,590	1,793	1,162	457
Counterparty 17	PCG	40.0	564,296	775,926	106,284	998,502	0	398	293	309	339
Counterparty 18	PCG	40.0	0	395,088	66,200	0	0	108	152	22	0
Counterparty 19	PCG	40.0	119,926	2,968,956	5,171,639	10,408,635	0	853	2,426	4,552	3,536
Counterparty 99	PCG	40.0	0	0	0	11,104,545	0	0	0	3,042	3,773
Forecast (with credit support)	PCG	40.0	0	0	0	0	41,034,024	0	0	0	11,242
Sub To	tal		5,614,953	17,477,927	30,044,070	50,846,498	41,034,024	6,740	14,373	23,783	28,363
Natural Gas Exchange	N/A		2,005,897	3,231,729	782,888	2,329,484	0				
Forecast			0	0	0	0	8,965,372				
Sub To	tal		2,005,897	3,231,729	782,888	2,329,484	8,965,372				
Required LC	L/C	*** 37.5 / 60	10,000,000	10,000,000	15,000,000	20,000,000	20,000,000	3,185	8,247	10,192	10,192
PCG to Bank to Support LC	PCG	40.0	10,000,000	10,000,000	15,000,000	20,000,000	20,000,000	3,397	4,932	6,795	6,795
Sub To	tal							6,582	13,179	16,987	16,986
TOTA	AL		15,298,442	27,358,598	39,114,821	62,133,707	58,196,970	17,664	32,079	45,945	50,634
			13,270,112	41,330,570	57,11.,0=	~= , ,	30,170,770		- *	- >	,

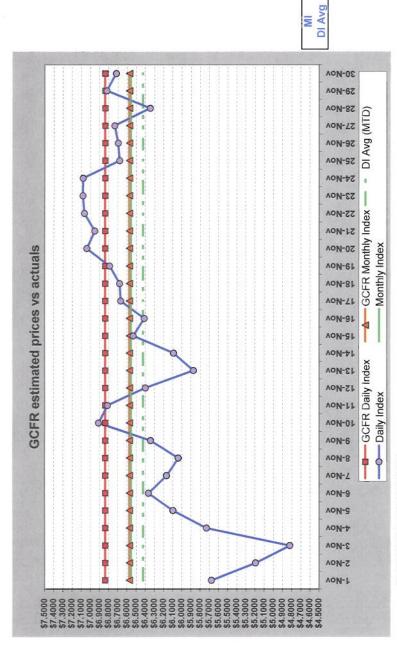
Footnote:

- * Natural Gas Exchange numbers include only the costs associated with the purchase and sale of natural gas. It does not include any NGX fees.
- ** The Natural Gas Exchange credit charge is based upon the full amount of the letter of credit and supporting parental guarantee. The parental guarantee Charges for all other counterparties must cover approximately 55 days of credit exposure.
- *** Effective Dec 1/08, DERS converted to a committed letter of credit facility whereby a fixed amount of credit has been reserved for regulated gas purchasing. The utilized portion of the facility bears a rate of 60 basis points whereas the unutilized portion is 20 basis points

Appendix B: Example of DERS voluntary supplemental information submitted with GCFR filing

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GCFR Estimated Prices vs. Actuals



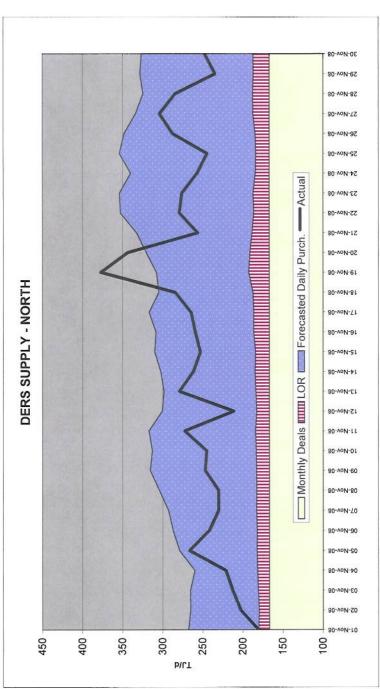
(\$0.016)

\$6.5568 \$6.4259

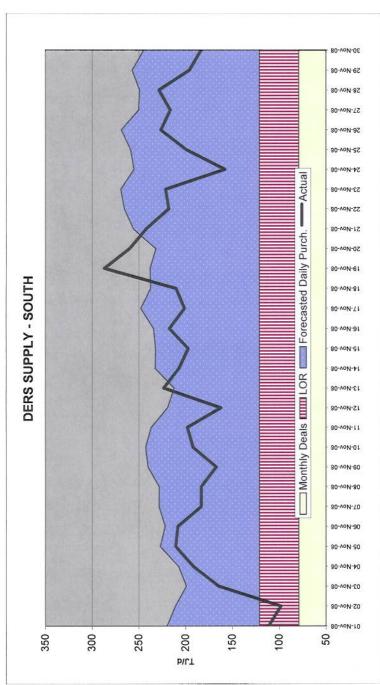
Fcst \$6.5728 \$6.8365

Month
the
6
Rest
Prices +
Daily
*

^{*} Wholesale prices as reported by NGX.



	LI	5,010	537	3,806	(1,597)	7,756	9,353
MONTH TOTALS		Monthly Deals	LOR	Forecasted Daily Purch.	Temp, Diff.	TOTAL	GCFR



2		ILOR — Forecasted Daily Purch.	- 80-von-et - 80-von-et - 80-von-et - 80-von-et
1	>		80-voN-51 - 80-voN-51 - 80-voN-61 - 80-voN-41
7	>	■ Monthly [30-voN-80 - 30-voN-e0 - 30-voN-01
/			80-voN-80 80-voN-70
			- 80-voN-20
11			80-voN-60 80-voN-90
300			Monthly Deals IIIII LOR

2,370 1,266 3,549 (1,222)

recasted Daily Purch.

Temp. Diff.

Monthly Deals

LOR

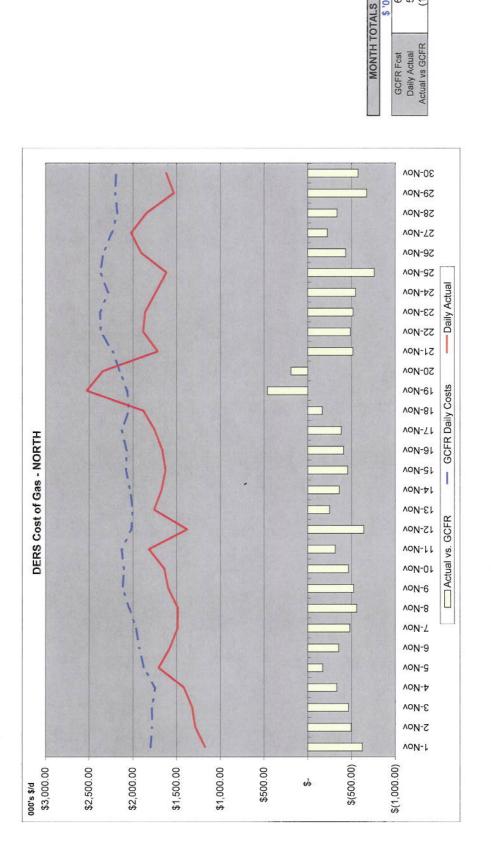
MONTH TOTALS

7,185

GCFR

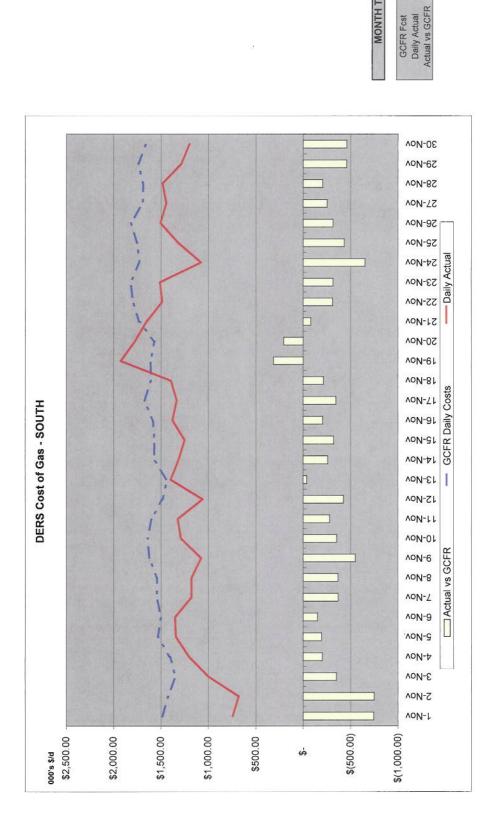
5,963

TOTAL



\$ '000s 62,640 50,912 (11,728)

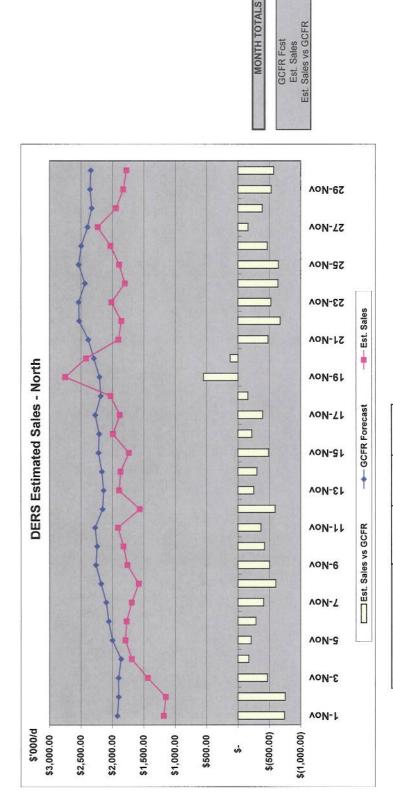
Supplemental Attachment of Gas Marketer Group Evidence Submission in EB-2008-0106. Exhibits E8, E14, E19 - Appendix B



48,171 39,116 (9,055)

MONTH TOTALS

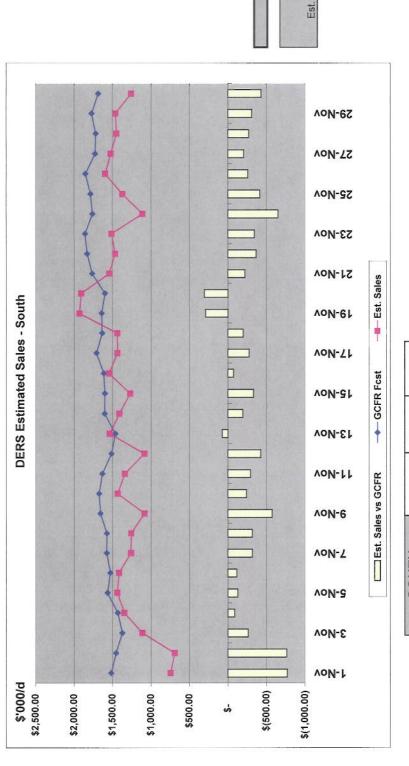
Supplemental Attachment of Gas Marketer Group Evidence Submission in EB-2008-0106. Exhibits E8, E14, E19 - Appendix B



66,412 54,521 (11,891)

NOKIH	1	GCFR			2
\$000.\$	ES	stimates	⋖	ctuals	#0
Cost of Gas	69	62,640	S	\$ 50,912	\$ (11,728)
Sales	↔	66,412	S	54,521	69
Differential	49	(3,772)	S	(3,609)	

DERS South - Estimated Sales

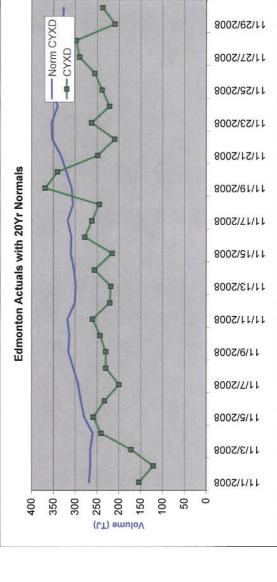


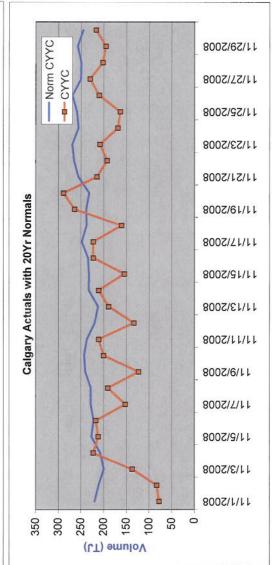
48,692 40,794 (7,898)

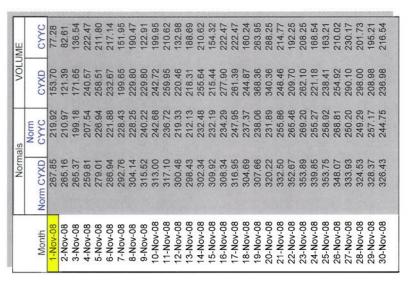
GCFR Fost Est. Sales .: Sales vs GCFR

MONTH TOTALS

SOUTH		GCFR				
\$000, \$	ŭ	stimates	4	Actuals		Diff
Cost of Gas	4	48,171	4	39,116	S	(9,055
Sales	↔	48,692	69	40,794	Ø	(7,898)
Differential	69	(521)	S	(1,678)		

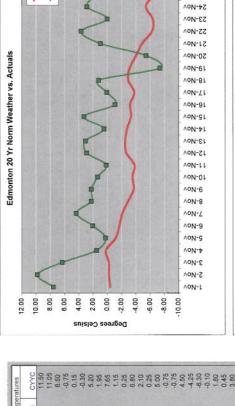






Normal Weather vs. Actuals

	100	WOLLING OF	I CITING	remperatores
	Norm	Norm		
Month	CYXD	CYYC	CYXD	CYYC
1-Nov-08	-0.40	-0.54	7.55	11.50
2-Nov-08	-0.21	0.22	9.80	11.05
3-Nov-08	-0.23	1.22	6.30	6.50
4-Nov-08	0.16	0.51	1.50	-0.75
5-Nov-08	-1.18	-1.13	0.25	0.15
6-Nov-08	-1.73	-0.70	2.05	-0.30
7-Nov-08	-2.14	-1.25	4.35	5.20
8-Nov-08	-2.93	-1.24	2.25	1.95
9-Nov-08	-3.72	-2.25	2.25	7.65
10-Nov-08	-3.55	-2.46	1.35	1.15
11-Nov-08	-3.83	-1.95	0.15	0.25
12-Nov-08	-2.67	-0.49	2.90	6.80
13-Nov-08	-2.53	0.12	3.05	2.10
14-Nov-08	-2.80	-1.60	0.45	0.25
15-Nov-08	-3.33	-1.57	3,25	5.00
16-Nov-08	-3.22	-1.75	-1.10	-0.75
17-Nov-08	-3.82	-2.90	0.05	-0.75
18-Nov-08	-2.97	-2.01	1.20	4.50
19-Nov-08	-3.17	-2.07	-7.40	-4.25
20-Nov-08	-4.05	-1.55	-5.45	-6.30
21-Nov-08	-4.90	-3.57	0.95	-0.10
22-Nov-08	-6.31	-4.38	3.65	1.80
23-Nov-08	-6.39	-4.69	00.00	0.45
24-Nov-08	-5.42	-3.52	2,85	3.80
25-Nov-08	-6.38	-3.83	1.65	4.25
26-Nov-08	-5.99	-4.66	0.50	0.30
27-Nov-08	-5.00	-3.09	-1,95	-1.40
28-Nov-08	-4.35	-3.01	-2.50	1.00
29-Nov-08	-4.62	-3.68	3.70	1.55
30-Nov-08	-4.48	-2.63	1.75	-0.25



6.66 1.93 (1.81) 6.36 1.820 1.37 8.14 8.14 (2.02) (3.15) 2.24 3.60 7.10

3.55 4.20 5.68 14.83 17.58 20.62 8.45 6.30 1.03 (3.51) 3.32 6.15 6.15 6.15 6.15

North 4,00 4,00 6,50 (13,33) (15,58) (16,27) (16,27) (16,27) (16,27) (16,27) (16,27) (16,27) (16,27) (16,27) (16,27) (16,27) (16,27) (10,42) (

Norm CYXD

-CYXD

√0N-0£

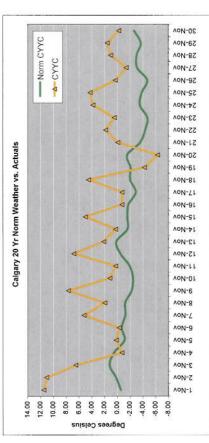
√0N-62

28-Nov

VON-YS

NON-92

VON-22



Temperature

Per CCFR Fillings	North Beta =	14.35835	2									
Actual A	ha ==	100.0	77						Per GCFR Filing	<u>u</u>		
CVYCD <		GCFR 20Yr AveTem	p by Day	GCFR 20YrAveTempHDD b	y Day				GCFR Current Month Act	ual Temperatures (Env Car		
Avertemp Avertemp Avertemp Avertemp AvertempHDD Avertemp Avertemp AvertempHDD Actual MeanTemp MeanTemp HDD Actual MeanTemp MeanTemp HDD Actual H 4.9 10.035 27.83		CYXD	CYYC	CYXD	CYYC	CYXD	CYYC		CYXD	CYYC		CYYC
0.4 0.53 14.9 16.035 267.85 219.92 01.Nov-08 7.56 11.5 153.823 0.2126 0.22 0.22 1.218 1.20.97 02.Nov-08 6.3 6.5 17.10468 0.15 1.14.725 1.4285 266.37 1.20.94 0.20.04 6.3 6.5 17.10468 0.16 0.51 1.47.75 1.4285 226.84 20.754 0.04Nov-08 6.5 0.75 24.056 1.175 1.1255 1.66.75 2.26.94 227.64 0.50Nov-08 2.05 0.05 0.15 2.05 1.056 1.7146 2.06.06 0.05 0.05 0.15 2.05 0.05	ormal		AveTemp	AveTempHDDA	veTempHDD			Actual		leanTemp		
-0.2155 0.22 14.7125 14.286 266.16 71.09 9.8 11.05 17.13453 -0.2756 1.215 1.4126 14.286 259.87 200.84 02-Nov-08 6.15 0.75 14.1446 -0.2756 1.1275 1.1275 1.1428 229.87 226.84 06-Nov-08 6.25 0.15 226.85 -1.775 -1.1275 1.16775 16.275 229.76 222.84 06-Nov-08 0.25 0.15 226.85 -2.135 -1.2875 1.6775 229.76 222.84 06-Nov-08 2.25 1.95 0.95<	00-08	-0.4	-0.535	14.9	16.035	267.85	219.92	01-Nov-08		11.5	153.6985	77.27864
-0.2275 1.215 14.7275 14.285 266.37 199.18 03-Nov-08 6.5 17.1846 -1.776 -1.617 1.434 14.99 226.94 20.754 05-Nov-08 1.5 -0.75 240.6666 -1.776 -1.627 1.68275 1.68275 273.01 226.94 05-Nov-08 1.5 0.15 21.6666 22.6666 -0.3 226.666 -0.3 -0.3	ov-08	-0.2125	0.22	14.7125	15.28	265.16	210.97	02-Nov-08	8.6	11.05	121.3923	82.61218
0.16 0.51 14.34 14.99 259.87 207.54 04.Nov-08 1.5 -0.75 240.566145 -1.77 -1.77 -1.07 16.275 16.275 16.276 226.84 06-Nov-08 0.55 0.15 226.6145 -1.73 -0.7 16.235 16.755 292.76 228.43 06-Nov-08 2.55 0.15 223.665 -2.135 -1.2825 16.7375 16.735 292.76 228.43 06-Nov-08 2.25 1.95 223.665 223.665 1.95 1.99 643.5 22.25 1.95 229.78 22.25 1.95 1.99 643.5 22.25 1.96 2.245 1.96 2.245 1.96 2.245 1.96 2.25 1.96 2.25 1.96 2.25 1.98 4.35 2.25 1.98 4.35 2.25 1.98 4.35 2.25 1.98 2.25 2.26 2.26 2.25 2.26 1.98 2.25 2.26 2.26 2.26 2.26 <td>80-vo</td> <td>-0.2275</td> <td>1.215</td> <td>14.7275</td> <td>14.285</td> <td>265.37</td> <td>199.18</td> <td>03-Nov-08</td> <td>6.3</td> <td>6.5</td> <td>171.6465</td> <td>136.5401</td>	80-vo	-0.2275	1.215	14.7275	14.285	265.37	199.18	03-Nov-08	6.3	6.5	171.6465	136.5401
-1,1776 -1,1276 -1,6776 16,6776 16,6276 226,94 226,94 05-Nov-08 0.26 0.15 226,648 -1,173 -1,275 -1,2375 16,237 16,237 222,138 05-Nov-08 2.05 0.03 226,668 220,797	80-vo	0.16	0.51	14.34	14.99	259.81	207.54	04-Nov-08	1.5	-0.75	240.5666	222.4693
-173 -07 16 23 16 23 286 94 221 88 06-Nov-08 2.05 -0.3 222 6695 -2.375 -1.285 1.1285 16.535 16.785 292.76 228.43 06-Nov-08 2.05 1.95 199 6483 -2.275 -1.285 17.4275 16.735 304.44 228.43 07-Nov-08 2.25 1.95 199 6483 -3.72 -2.2475 17.2427 17.35 17.35 17.70 242.68 10-Nov-08 2.25 7.65 229.3978 -3.545 -2.455 18.045 17.735 17.70 242.68 10-Nov-08 2.25 1.95 220.398 -2.6726 -0.485 17.00 242.68 17.00 0.0 2.25 1.95 220.70 2.25 1.95 220.70 2.25 1.05 220.70 2.25 1.05 220.70 2.25 1.05 220.70 2.25 1.05 220.70 2.25 1.05 220.70 2.25 2.20.70 2.25	80-vo	-1.1775	-1.1275	15.6775	16.6275	279.01	226.94	05-Nov-08	0.25	0.15	258.5145	211.8022
2.135 1.2525 16 63.5 16 73.5 292.76 228.43 07-Nov-08 4.35 5.2 199.6453 2.9276 -1.2375 17.4275 16.7375 304.14 228.25 06-Nov-08 2.25 1.95 229.7978 -3.545 -2.455 18.045 17.7455 313.00 242.68 10-Nov-08 2.25 7.65 229.7978 -3.545 -2.455 18.045 17.735 317.710 242.68 10-Nov-08 1.35 1.16 242.7203 -2.635 0.1225 -1.695 17.705 15.3775 29.843 272.73 11.40v-08 2.95 229.730 -2.8025 -1.595 17.7302 17.095 302.34 222.48 14.Nov-08 0.15 0.25 229.730 -2.8025 -1.596 17.745 17.04 309.32 232.19 14.Nov-08 0.15 0.25 229.730 -2.8025 -1.596 17.7475 17.2475 308.34 234.24 14.Nov-08 0.15	80-vo	-1.73	-0.7	16.23	16.2	286.94	221.88	06-Nov-08	2.05	-0.3	232.6695	217.1358
2.975 -1.275 17.4275 16.7376 304.14 228.25 08-Nov-08 2.25 1.95 229.7978 -3.72 -2.2475 18.22 17.7475 315.62 240.22 09-Nov-08 2.25 1.95 229.7978 -3.645 -1.9625 18.33 17.4625 317.00 242.68 11.Nov-08 1.35 1.15 12.20 229.96 12.20 1.00 2.20 229.96 229.96 229.96 229.96 229.96 229.96 229.96 229.96 229.96 220.00	10v-08	-2.135	-1.2525	16.635	16.7525	292.76	228.43	07-Nov-08	4.35	5.2	199.6453	151.9481
-3.72 -2.2475 18.22 17.7476 315.52 240.22 09-Nov-08 2.25 7.65 229.7978 -3.545 -2.455 18.045 17.7475 313.00 222.68 10-Nov-08 1.35 1.15 242.7223 -2.543 -0.485 17.1725 15.985 377.0 236.72 12-Nov-08 0.15 0.25 259.9503 -2.6725 -0.485 17.1725 15.986 300.48 279.33 12-Nov-08 0.15 0.25 259.9503 -2.6725 -0.485 17.3025 17.095 302.34 272.48 17-Nov-08 0.15 0.25 256.428 -2.8025 -1.596 17.2475 308.34 222.78 14-Nov-08 0.15 27.344 216.439 -3.22 -1.7475 17.2475 308.34 222.78 14-Nov-08 0.15 216.439 -3.82 -1.754 17.2475 30.25 227.99 16-Nov-08 0.15 216.439 -2.96625 -2.0075 17.	10v-08	-2.9275	-1.2375	17.4275	16.7375	304.14	228.25	08-Nov-08	2.25	1.95	229.7978	190.4681
-3.545 -2.455 18.045 17.955 373.00 242.68 10-Nov-08 1.35 1.15 242.7203 -3.64 -0.485 17.4725 15.387 377.10 236.72 11-Nov-08 0.15 0.25 259.639 -2.6725 -0.486 17.1726 15.387 228.43 272.13 11-Nov-08 0.15 0.25 250.4489 -2.63 0.1226 17.3026 17.095 302.34 222.48 14-Nov-08 0.45 0.25 256.6428 -3.22 -1.596 17.3026 17.095 302.34 222.48 14-Nov-08 0.45 0.25 256.6428 -3.22 -1.596 17.2475 308.34 222.48 14-Nov-08 0.45 0.25 275.488 -3.22 -2.96625 -2.0076 17.46626 17.5075 308.34 224.29 14-Nov-08 0.05 0.75 244.874 -2.96625 -2.0076 17.46626 17.5075 304.69 227.37 18-Nov-08 -1.4	Nov-08	-3.72	-2.2475	18.22	17.7475	315.52	240.22	09-Nov-08	2.25	7.65	229.7978	122.91
-3.83 -1.9525 18.33 17.4525 317.10 236.72 11.Nov-08 0.15 0.25 259.950 -2.6725 -0.485 17.1725 15.985 300.48 279.33 12.Nov-08 2.9 6.8 220.444 -2.8025 -1.595 17.3025 17.095 302.48 222.48 14.Nov-08 0.45 0.25 215.434 -2.8025 -1.595 17.3025 17.095 302.92 232.19 14.Nov-08 0.45 0.25 215.4394 -3.22 -1.7475 17.2475 309.92 232.19 15.Nov-08 -1.1 -0.75 215.4394 -3.22 -1.7475 17.2475 309.92 232.19 15.Nov-08 -1.1 -0.75 215.4394 -3.1725 -2.086 17.4062 17.5075 308.34 224.29 15.Nov-08 -1.1 -0.75 215.4384 -3.1726 -2.0875 17.6045 320.22 231.89 20.Nov-08 -1.4 -4.25 340.3571 -3	Nov-08	-3.545	-2.455	18.045	17.955	313.00	242.68	10-Nov-08	1.35	1.15	242.7203	199.9499
2.6725 -0.485 17.1725 15.985 300.48 279.33 12-Nov-08 2.9 6.8 220.4649 -2.572 -0.485 17.1725 15.984.3 272.13 13-Nov-08 3.05 2.1 218.311 -2.53 0.1225 17.3025 17.005 302.34 232.48 14-Nov-08 3.05 2.1 256.48 -3.22 -1.7475 17.2475 309.92 232.29 15-Nov-08 -0.75 215.4394 -3.22 -2.9 17.83 17.07 309.92 234.29 15-Nov-08 -0.75 215.4394 -3.22 -2.9 17.805 18.3 234.29 15-Nov-08 -0.75 215.4394 -3.82 -2.0075 17.46625 17.5075 304.69 237.37 18-Nov-08 -0.75 24.4874 -3.1725 -2.0075 17.5045 326.22 237.89 20-0.05 -0.75 24.4874 -6.3075 -4.3075 19.0675 326.46 237.89 20-0.06 22-Nov	Nov-08	-3.83	-1.9525	18.33	17.4525	317.10	236.72	11-Nov-08	0.15	0.25	259.9503	210.617
-2.53 0.1226 17.03 15.375 298.43 272.13 13-Nov-08 3.05 2.1 -2.8025 -1.596 17.3025 17.096 302.34 232.48 14-Nov-08 0.045 0.25 256.642 -3.33 -1.57 17.3025 17.095 309.92 232.48 14-Nov-08 0.045 0.25 256.642 -3.32 -1.57 17.2475 308.34 234.29 16-Nov-08 0.05 -0.75 277.8983 -2.96625 -2.0075 17.46626 17.5076 304.69 237.37 18-Nov-08 -0.75 244.8741 -3.1725 -2.065 17.46626 17.5076 307.66 238.06 21.00v-08 -7.4 -4.25 244.8741 -3.1726 -2.065 17.6725 17.565 307.66 238.06 21.00v-08 -6.37 244.8741 -4.9025 -1.546 17.6725 17.565 307.66 237.89 20-Nov-08 -6.36 1.8 -6.3075 -4.9525 <t< td=""><td>Nov-08</td><td>-2.6725</td><td>-0.485</td><td>17.1725</td><td>15.985</td><td>300.48</td><td>219.33</td><td>12-Nov-08</td><td>2.9</td><td>8.9</td><td>220.4649</td><td>132.9845</td></t<>	Nov-08	-2.6725	-0.485	17.1725	15.985	300.48	219.33	12-Nov-08	2.9	8.9	220.4649	132.9845
-2.8025 -1.595 17.3025 17.095 302.34 232.48 14-Nov-08 0.45 0.25 255.6428 -3.33 -1.57 17.83 17.07 309.92 232.19 15-Nov-08 3.25 5 55.6439 -3.32 -1.57 17.2475 308.34 234.29 15-Nov-08 -1.1 -0.75 275.8983 -2.96625 -2.0075 17.46625 17.5075 304.69 237.37 18-Nov-08 -0.75 24.8741 -3.82 -2.065 17.64625 17.565 307.66 238.08 18.Nov-08 -7.4 -4.25 24.8741 -3.1725 17.655 307.66 238.08 20-Nov-08 -7.4 -4.25 24.8741 -3.1725 19.0675 32.20.22 237.89 20-Nov-08 -5.45 -6.3 340.3571 -4.9025 -3.5675 19.4025 19.0675 332.50 256.86 21-Nov-08 -6.3 340.3571 -6.3826 -2.4855 20.1925 353.89 <	Nov-08	-2.53	0.1225	17.03	15.3775	298.43	212.13	13-Nov-08	3.05	2.1	218.3111	188.6903
-3.33 -1.57 17.83 17.07 309.92 232.19 15-Nov-08 3.25 5 5 215.4394 -3.22 -1.7475 17.2475 308.34 234.29 16-Nov-08 -11 -0.75 277.8983 -3.22 -2.9 17.46625 17.5075 308.34 237.37 18-Nov-08 -11 -0.75 277.8983 -2.96625 -2.0075 17.46625 17.5075 308.469 237.37 18-Nov-08 -1.2 4.4 24.8741 -3.1725 -2.965 17.6055 17.5076 307.66 238.06 18-Nov-08 -5.45 -6.3 340.3571 -4.0475 -1.545 18.5475 17.045 320.22 237.89 20-Nov-08 -5.45 -6.3 340.3571 -4.9026 -3.5675 26.36 22.Nov-08 3.65 1.8 248.4637 22.Nov-08 3.65 1.8 248.4637 -6.3075 -4.6925 20.1925 353.89 26.26.20 22.Nov-08 0.45 29.0	Nov-08	-2.8025	-1.595	17.3025	17.095	302.34	232.48	14-Nov-08	0.45	0.25	255.6428	210.617
-3.22 -1.75 17.72 17.2475 308.34 234.29 16-Nov-08 -1.1 -0.75 277.8983 -3.82 -2.9 18.32 18.4 376.95 247.95 17-Nov-08 -0.75 261.3862 -2.96625 -2.0075 17.46625 17.5075 304.69 237.37 18-Nov-08 1.2 4.5 244.8741 -3.1725 -2.065 17.6072 17.565 307.66 238.06 19.Nov-08 -7.4 -4.25 348.3559 -4.0475 -1.545 18.5475 17.045 320.22 258.6 22-Nov-08 -5.45 -6.3 -6.3075 -4.3075 20.8925 20.1925 352.89 269.20 22-Nov-08 0.6 24.4637 -6.3826 -3.825 20.1925 353.89 255.27 22-Nov-08 0.5 0.75 22.1041 -6.3826 -3.825 20.1925 353.75 258.92 25-Nov-08 0.5 0.3 254.924 -5.9875 -4.66 20.4875 </td <td>Nov-08</td> <td>-3.33</td> <td>-1.57</td> <td>17.83</td> <td>17.07</td> <td>309.92</td> <td>232.19</td> <td>15-Nov-08</td> <td>3.25</td> <td>2</td> <td>215.4394</td> <td>154.3186</td>	Nov-08	-3.33	-1.57	17.83	17.07	309.92	232.19	15-Nov-08	3.25	2	215.4394	154.3186
-3.82 -2.9 18.32 18.4 376.95 247.95 17-Nov-08 0.05 -0.75 261.3862 -2.96625 -2.0075 17.46625 17.5075 304.69 237.37 18-Nov-08 1.2 4.5 244.8741 -3.1725 -2.065 17.665 307.66 238.06 19-Nov-08 1.2 4.5 244.8741 -4.0475 -1.545 17.645 17.645 320.22 231.89 20-Nov-08 -7.4 -4.25 348.355 -4.0475 -1.545 18.5475 17.045 332.50 255.86 21-Nov-08 -5.45 -6.3 340.3571 -4.0475 -1.545 19.4025 19.0175 353.89 269.20 22-Nov-08 0.01 0.045 224.4637 -6.3825 -3.8275 258.92 269.20 23-Nov-08 0.5 0.045 234.128 -5.9875 -4.66 20.4875 20.16 348.07 268.812 26-Nov-08 0.5 0.3 254.9249 -5.0875 </td <td>Nov-08</td> <td>-3.22</td> <td>-1.7475</td> <td>17.72</td> <td>17.2475</td> <td>308.34</td> <td>234.29</td> <td>16-Nov-08</td> <td></td> <td>-0.75</td> <td>277.8983</td> <td>222.4693</td>	Nov-08	-3.22	-1.7475	17.72	17.2475	308.34	234.29	16-Nov-08		-0.75	277.8983	222.4693
-2.96625 -2.0075 17.46625 17.5075 304.69 237.37 18-Nov-08 1.2 4.5 244.8741 -3.1725 -2.065 17.6725 17.565 307.66 238.06 19-Nov-08 -7.4 -4.25 368.3559 -4.0475 -1.545 18.5475 17.045 320.22 231.89 20-Nov-08 -5.45 -6.3 340.3571 -4.9025 -3.5675 19.0675 19.0675 32.50 255.86 21-Nov-08 -5.45 -6.3 340.3571 -6.3075 -4.9025 20.8075 19.8775 352.67 265.46 22-Nov-08 -6.3 1.8 220.09.6961 -6.3925 -4.6925 20.1925 353.89 269.20 23-Nov-08 0.95 1.8 220.1041 -5.415 -3.5175 19.915 19.0175 353.85 256.27 24-Nov-08 0.55 3.8 250.1041 -5.9875 -4.66 20.4875 18.50 353.75 258.92 25-Nov-08 0.5 0.3	4ov-08	-3.82	-2.9	18.32	18.4	316.95	247.95	17-Nov-08	0.05	-0.75	261.3862	222.4693
-3.1725 -2.065 17.6725 17.565 307.66 238.06 19-Nov-08 -7.4 -4.25 368.3559 -4.0475 -1.545 18.5475 17.045 320.22 231.89 20-Nov-08 -5.45 -6.3 340.3571 -4.9025 -3.5675 19.0675 32.50 255.86 21-Nov-08 0.95 -0.1 248.4637 -6.3075 -4.3775 20.8075 19.8775 352.67 265.46 22-Nov-08 0.95 -0.1 248.4637 -6.3925 -4.6925 20.1925 352.87 265.46 22-Nov-08 0.95 1.8 220.09.6961 -5.415 -3.5175 19.915 19.0175 339.85 255.27 24-Nov-08 0.65 0.35 221.1828 -5.9875 -4.66 20.4875 19.325 353.75 258.92 25-Nov-08 0.55 0.3 254.929 -5.0025 -3.867 26.887 26.887 26.Nov-08 0.5 0.3 254.929 -5.0025 <t< td=""><td>4ov-08</td><td>-2.96625</td><td>-2.0075</td><td>17.46625</td><td>17.5075</td><td>304.69</td><td>237.37</td><td>18-Nov-08</td><td>1.2</td><td>4.5</td><td>244.8741</td><td>160.2447</td></t<>	4ov-08	-2.96625	-2.0075	17.46625	17.5075	304.69	237.37	18-Nov-08	1.2	4.5	244.8741	160.2447
-4.0475 -1.545 18.5475 17.045 320.22 231.89 20-Nov-08 -5.45 -6.3 340.3571 -4.9025 -3.5675 19.0675 32.50 258.86 21-Nov-08 0.95 -0.1 248.4637 -6.3075 -4.3775 20.8075 19.0675 32.67 265.46 22-Nov-08 3.65 1.8 209.6961 -6.3925 -4.6925 20.1925 353.89 269.20 23-Nov-08 0.95 -0.1 248.4637 -5.415 -3.5175 19.915 19.0175 339.85 255.27 24-Nov-08 0.95 3.8 221.1828 -5.9875 -4.66 20.4875 20.16 348.07 268.812 25-Nov-08 0.5 0.3 254.924 -5.0025 -3.00 19.5025 333.93 250.20 25.80 25-Nov-08 0.5 0.3 254.924 -5.0025 -3.8175 18.8475 18.512 324.53 249.29 25-Nov-08 -1.95 -1.4 290.1029	40v-08	-3.1725	-2.065	17.6725	17.565	307.66	238.06	19-Nov-08	4.7-	-4.25	368.3559	263.9524
-4.9025 -3.5675 19.4025 19.0675 332.50 255.86 21-Nov-08 0.95 -0.1 248.4637 -6.3075 -4.3775 20.8075 19.8775 352.67 265.46 22-Nov-08 3.65 1.8 209.6961 -6.3925 -4.8925 20.1925 353.89 269.20 23-Nov-08 0.95 1.8 262.1041 -5.415 -3.5175 19.915 19.0175 339.85 255.27 24-Nov-08 2.85 3.8 221.1828 -5.415 -3.5175 20.8825 19.325 353.75 258.92 25-Nov-08 0.5 0.3 254.924 -5.9875 -4.66 20.4875 20.16 348.07 268.812 25-Nov-08 0.5 0.3 254.924 -5.0025 -3.0125 18.512 324.53 249.29 27-Nov-08 -1.95 -1.4 290.1029 -4.48 -3.6775 18.13 326.43 244.75 30-Nov-08 -1.95 -0.25	Nov-08	-4.0475	-1.545	18.5475	17.045	320.22	231.89	20-Nov-08	-5.45	-6.3	340.3571	288.2496
-6.3075 -4.3775 20.8075 19.8775 365 1.8 209.6961 -6.3925 -4.6925 20.8025 20.1925 36.67 265.46 22-Nov-08 3.65 1.8 209.6961 -5.415 -3.5175 20.8925 20.1925 353.89 269.20 23-Nov-08 0.45 262.1041 262.1041 -5.415 -3.5175 19.915 19.0175 339.85 255.27 24-Nov-08 2.85 3.8 221.1828 1 -6.3825 -3.825 20.8825 19.325 258.92 25-Nov-08 1.65 4.25 238.4128 1 -5.9875 -4.347 -4.66 20.4875 18.59 333.93 250.20 27-Nov-08 -1.95 -1.4 290.1029 2 -4.347 -3.012 18.475 18.512 32.837 257.17 29-Nov-08 -1.55 1.55 208.972 -4.48 -2.63 -2.63 30-Nov-08 -1.75 -0.25 20.35 236.972	Nov-08	-4.9025	-3.5675	19.4025	19.0675	332.50	255.86	21-Nov-08	0.95	-0.1	248.4637	214.7653
-6.3925 -4.6925 20.8925 20.1926 353.89 269.20 23-Nov-08 0 0.45 262.1041 -5.415 -3.5175 19.915 19.0175 339.85 255.27 24-Nov-08 2.85 3.8 221.1828 -5.3825 -3.825 20.8825 19.325 353.75 258.92 25-Nov-08 1.65 4.25 238.4128 -5.9875 -4.66 20.4875 20.16 348.07 268.812 26-Nov-08 0.5 0.3 254.9249 -5.0025 -3.09 19.5025 18.59 333.93 250.20 27-Nov-08 -1.95 -1.4 290.1029 -4.3475 -3.0125 18.8475 18.512 324.53 249.29 28-Nov-08 -2.5 1 29 -4.615 -3.6775 19.115 19.1775 328.37 257.17 29-Nov-08 -2.5 1 29 -4.48 -2.63 -2.64.37 26.43 244.75 30-Nov-08 1.75 -0.25 236.977 <td>Nov-08</td> <td>-6.3075</td> <td>-4.3775</td> <td>20.8075</td> <td>19.8775</td> <td>352.67</td> <td>265.46</td> <td>22-Nov-08</td> <td>3.65</td> <td>1.8</td> <td>209.6961</td> <td>192.246</td>	Nov-08	-6.3075	-4.3775	20.8075	19.8775	352.67	265.46	22-Nov-08	3.65	1.8	209.6961	192.246
-5.415 -3.5175 19.915 19.0175 339.85 255.27 24-Nov-08 2.85 3.8 221.1828 -6.3825 -3.825 20.8825 19.325 353.75 258.92 25-Nov-08 1.65 4.25 238.4128 -5.9875 -4.66 20.4875 20.16 348.07 268.812 26-Nov-08 0.5 0.3 254.9249 -5.0025 -3.09 19.5025 18.59 333.93 250.20 27-Nov-08 -1.95 -1.4 290.1029 -4.3475 -3.0125 18.8475 18.5125 324.53 249.29 28-Nov-08 -2.5 1 -4.615 -3.6775 19.115 19.1775 328.37 257.17 29-Nov-08 3.7 1.55 208.9782 -4.48 -2.63 -2.64.75 326.43 244.75 30-Nov-08 -0.25 20.25 20.25	Nov-08	-6.3925	-4.6925	20.8925	20.1925	353.89	269.20	23-Nov-08	0	0.45	262.1041	208.2466
-6.3825 -3.825 20.8825 19.325 353.75 258.92 25-Nov-08 1.65 4.25 238.4128 -5.9875 -4.66 20.4875 20.16 348.07 268.812 26-Nov-08 0.5 0.3 254.9249 -5.0025 -3.09 19.5025 18.59 333.93 250.20 27-Nov-08 -1.95 -1.4 290.1029 -4.3475 -3.0125 18.8475 18.5125 324.53 249.29 28-Nov-08 -2.5 1 -4.615 -3.6775 19.115 19.1775 328.37 257.17 29-Nov-08 1.75 -0.25 -4.48 -2.63 18.98 18.13 326.43 244.75 30-Nov-08 1.75 -0.25	Nov-08	-5.415	-3.5175	19.915	19.0175	339.85	255.27	24-Nov-08	2.85	3.8	221.1828	168.5414
-5.9875 -4.66 20.4875 20.16 348.07 268.812 26-Nov-08 0.5 0.3 254.9249 -5.0025 -3.09 19.5025 18.59 333.93 250.20 27-Nov-08 -1.95 -1.4 290.1029 -4.3475 -3.0125 18.8475 18.5125 324.53 249.29 28-Nov-08 -2.5 1 298 -4.615 -3.6775 19.115 19.1775 328.37 257.17 29-Nov-08 3.7 1.55 208.9782 -4.48 -2.63 18.98 18.13 326.43 244.75 30-Nov-08 1.75 -0.25	Nov-08	-6.3825	-3.825	20.8825	19.325	353.75	258.92	25-Nov-08	1.65	4.25	238.4128	163.2078
-5.0025 -3.09 19.5025 18.59 333.93 250.20 27-Nov-08 -1.95 -1.4 290.1029 -4.3475 -3.0125 18.8475 18.5125 324.53 249.29 28-Nov-08 -2.5 1 -4.615 -3.6775 19.115 19.1775 328.37 257.17 29-Nov-08 3.7 1.55 208.9782 -4.48 -2.63 18.98 18.13 326.43 244.75 30-Nov-08 1.75 -0.25 236.977	Nov-08	-5.9875	-4.66	20.4875	20.16	348.07	268.812	26-Nov-08	0.5	0.3	254.9249	210.0244
-4.3475 -3.0125 18.8475 18.5125 324.53 249.29 28-Nov-08 -2.5 1 298 -4.615 -3.6775 19.115 19.175 328.37 257.17 29-Nov-08 3.7 1.55 208.9782 -4.48 -2.63 18.98 18.13 326.43 244.75 30-Nov-08 1.75 -0.25 236.977	Nov-08	-5.0025	-3.09	19.5025	18.59	333.93	250.20	27-Nov-08	-1.95	4.1-	290.1029	230.1733
-4.615 -3.6775 19.115 19.1775 328.37 257.17 29-Nov-08 3.7 1.55 208.9782 244.75 30-Nov-08 1.75 -0.25 236.977 2	Nov-08	-4.3475	-3.0125	18.8475	18.5125	324.53	249.29	28-Nov-08	-2.5	-	298	201.7278
-4.48 -2.63 18.13 326.43 244.75 30-Nov-08 1.75 -0.25 236.977	Nov-08	-4.615	-3.6775	19.115	19.1775	328.37	257.17	29-Nov-08	3.7	1.55	208.9782	195.209
	Nov-08	-4.48	-2.63	18.98	18.13	326.43	244.75	30-Nov-08	1.75	-0.25	236.977	216.5432

Pricing Table

Date	GCFR Daily Index	GCFR Monthly Index	xapı	DI Avg (MTD)	(0)	Daily Index	Mor	Monthly Index
01-Nov-08	\$ 6.8365	8 6.6	6,5728	\$	6.4259	5.6746	w	6.5568
02-Nov-08	\$ 6.8365	\$ 6.6	6.5728	8	6.4259	5.1930	w	6.5568
03-Nov-08	\$ 6.8365	\$ 6.6	6.5728	9	6.4259	4.8178	s	6.5568
04-Nov-08	\$ 6.8365	8	6.5728	8	6.4259	5.7306	s	6.5568
05-Nov-08	\$ 6.8365	\$ 6.0	6.5728	9	6.4259	6.0961	w	6.5568
90-vov-90	\$ 6.8365	\$ 6.5	6.5728	9	6.4259	6.3642	s	6.5568
07-Nov-08	\$ 6.8365	\$ 6.5	6.5728	\$	6.4259	6.1668	49	6.5568
08-Nov-08	\$ 6.8365	\$ 6.5	6.5728	8	6.4259	6.0393	49	6.5568
90-Nov-08	\$ 6.8365	\$ 6.6	6.5728	s	6.4259	6.3413	s	6.5568
10-Nov-08	\$ 6.8365	\$ 6.5	6.5728	9	6.4259	6.9094	S	6.5568
11-Nov-08	\$ 6.8365	\$ 6.5	6.5728	s	6.4259	6.8130	69	6.5568
12-Nov-08	\$ 6.8365	\$ 6.5	6.5728	s	6.4259	6.3966	49	6.5568
13-Nov-08	\$ 6.8365	\$ 6.5	6.5728	8	6.4259	5.8727	w	6.5568
14-Nov-08	\$ 6.8365	\$ 6.5	6.5728	s	6.4259	9680'9	69	6.5568
15-Nov-08	\$ 6.8365	\$ 6.5	6.5728	s	6.4259	6.5298	49	6.5568
16-Nov-08	\$ 6.8365	\$ 6.5	5728	s	6.4259	6.4089	s	6.5568
17-Nov-08	\$ 6.8365	\$ 6.5	6.5728	S	6.4259	6.6665	w	6.5568
18-Nov-08	\$ 6.8365	\$ 6.5	6.5728	s	6.4259	6.6797	s	6.5568
19-Nov-08	\$ 6.8365	\$ 6.5	6.5728	8	6.4259	6.7871	69	6.5568
20-Nov-08	\$ 6.8365	\$ 6.5	5728	8	6.4259	7.0384	w	6.5568
21-Nov-08	\$ 6.8365	\$ 6.5	5728	\$	6.4259	6.9511	49	6.5568
22-Nov-08	\$ 6.8365	\$ 6.5	5728	S	6.4259	7.0644	€	6.5568
23-Nov-08	\$ 6.8365	\$ 6.5	5728	s e	6.4259	7.0806	49	6.5568
24-Nov-08	\$ 6.8365	\$ 6.5	5728	s	6.4259	7.0782	49	6.5568
25-Nov-08	\$ 6.8365	\$ 6.5	5728	\$	6.4259	6.6797	69	6.5568
26-Nov-08	\$ 6.8365	\$ 6.5	6.5728	9	6.4259	6.6944	↔	6.5568
27-Nov-08	\$ 6.8365	\$ 6.5	5728	s	6.4259	6.7339	69	6.5568
28-Nov-08	\$ 6.8365	\$ 6.5	5728	\$	6.4259	6.3441	69	6.5568
29-Nov-08	\$ 6.8365	\$ 6.5	5728	s	6.4259	6.8187	49	6.5568
30-Nov-08	\$ 6.8365	\$ 6.5	6.5728	S	6.4259	6.7150	49	6.5568

\$ 6.8886 \$ 6.4259 \$ 6.4259 \$ 7.1000 \$ 7.1000 \$ 2.640 \$ 8.8171 \$ 9.353 7 185 lies M1-schedule \$ 9.353 7 185 9.353 7.186 9.353 9	From F2 Schedule GCFR Monthly Index	es 6 5728	
Index	GCFR Daily Index	. 45	
tate \$ 6.58840 (ate Month Supply Costs M1-schedule Ba.17	From Daily Workshe	eet	
tate \$ 6.4259 Tate \$ 7.1680 See An Onth Supply Costs M1-schedule 5.1680 See An Onth Supply Costs M2-schedule 7.186 See An Onth Supply Costs M2-schedule 7.186 See An Onth Supply Costs M2-schedule 6.9363 See An Onth Supply Costs M1-schedule 6.9363 See An Onth Supply Costs M2-schedule 6.9363 See An Onth Supply Costs M1-schedule 6.9363 See An Onth Supply Costs M1-schedule 6.9363 See An Onth Supply Costs M1-schedule 6.9363 See An Onth Supply Costs M2-schedule 6	Monthly Index	\$ 6,556	
tate \$ 7.1680. ted Month Supply Costs M1-schedule \$ 9.363 ol 7,186 ted Month Supply Costs M2-schedule \$ 9.363 ol 7,186 ted Month Sales M1-schedule \$ 9.363 ol 7,186 ted Month Sales M1-schedule \$ 9.363 ol 7,186 forth Supply Costs M1-schedule \$ 9.363 ol 7,186 forth Sales M1-schedule \$ 50,912 so onth Sales M1-schedule \$ 50,912 so onth Sales M1-schedule \$ 50,912 forth Sales M1-schedule \$ 50,913 forth Sales M1-schedule \$ 50,913 forth Sales M1-schedule \$ 50,913	DI Avg (MTD)		
tate \$ 7.1680 tate \$ 5.1000 ted Month Supply Costs M1-schedule ted Month Supply Costs M2-schedule ol	NORTH		
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\$ 62,640 ted Month Supply Costs M2-schedule 9,363 ol ted Month Sales M1-schedule 68,412 48,692 ad Month Supply Costs M1-schedule 5 50,912 \$ 39,116 Toth Supply Volume M2-schedule 7,756	Forecasted Month S	upply Costs M1-schedule	Forecasted Month - Column E
ted Month Supply Costs M2-schedule ol ted Month Sales M1-schedule de Month Supply Costs M1-schedule de Month Supply Costs M1-schedule s 50,912 s 39,116 forth Supply Volume M2-schedule f,963 f,756 forth Sales M1-schedule	North \$	\$ 62,640	
ted Month Supply Costs M2-schedule 7,186	South \$		-
9,363 led Month Sales M1-schedule 66,412 48,692 8 50,912 \$ 50,912 \$ 50,912 \$ 50,912 \$ 50,912 \$ 50,912 \$ 50,912 \$ 50,913 Sonth Supply Volume M2-schedule 7,756	Forecasted Month S	upply Costs M2-schedule	
red Month Sales M1-schedule 68,412 48,692 48,692 5	North Vol	9.35	Line 1
ted Month Sales M1-schedule 66,412 48,692 48,692 48,692 50,912 \$ 39,116 Forth Supply Volume M2-schedule 7,756 7,766 7,766 7,766 7,766 7,766 7,766	South Vol	7,18	
66.412 48.692 48.692 49.692 60.912 \$ 39.116 Forth Supply Volume M2-schedule 5,963 forth Sales M1-schedule 5,963 forth Sales M1-schedule	Forecasted Month S	ales M1-schedule	
48,692 Month Supply Costs M1-schedule	North \$	66,417	Line 14
Month Supply Costs M1-schedule \$ 50,912 \$ 39,116 forth Supply Volume M2-schedule 7,756 6,963 forth Sales M1-schedule \$ 54,521	South \$	48,69,	
\$ 50,912 \$ 39,116 Tonth Supply Volume M2-schedule 7,756 7,756 5,963 Tonth Sales M1-schedule 5,4621	Estimated Month Su	pply Costs M1-schedule	Estimated Month - Column D or C depending on which month you are working or
Sep. 116 North Supply Volume M2-schedule 7,786 7,786 fouth Sales M1-schedule	North \$		
forth Supply Volume M2-schedule 7,766 7,766 7,766 forth Sales M1-schedule 5,963	South \$		
7,756 5,963 forth Sales M1-schedule 54,521	Actual Month Supply	/ Volume M2-schedule	
fouth Sales M1-schedule 54.521	North	7,756	
forth Sales M1-schedule 54,521	South		
54,521	Actual Month Sales		
	North \$	54,52	

Regulated Purchases

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