INCENTIVE REGULATION

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Union Gas Limited
Incentive Regulation Proposal
Prefiled Evidence

Union Gas Limited
Incentive Regulation Proposal

1.0 INTRODUCTION

Union is proposing to implement a five year price cap regulatory framework that will take effect January 1, 2008. This framework will apply to Union's regulated rates for the storage, transportation and distribution of natural gas.

2.0 BACKGROUND

2.1 NATURAL GAS FORUM ("NGF") REPORT [MARCH 30, 2005]

In the NGF Report the Ontario Energy Board ("the Board") stated that it wanted to determine the most effective ratemaking framework that would fulfill its statutory objectives (page 18). The Board determined such a gas rate regulation framework would have to meet three criteria:

a) establish incentives for sustainable efficiency improvements that benefit both customers and shareholders,
b) ensure appropriate quality of service for customers, and
c) create an environment that is conducive to investment, to the benefit of both customers and shareholders.

On page 22 of the NGF Report, the Board concluded that:

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

The key parameters that the Board established in the NGF Report included rebasing, earnings sharing and term.

On the topic of rebasing, the Board concluded that, "[e]ach IR plan must begin with a robust set of cost-based rates, based on a thorough and transparent review" (page 25) and that the base rates will be determined through a hearing for each utility. The Board believes that rebasing "provides some assurance that there is an up-to-date and meaningful relationship between costs and rates".

With respect to earnings sharing, the Board concluded that these types of mechanisms had "incentive-diluting effects" (page 16) which reduced the effectiveness of the past PBR plans and that it "does not intend for earnings sharing mechanisms to form part of IR plans" (page 28).

On page 29 of the report, the Board stated that, "IR plans must contain longer rate-approval periods to ensure an incentive for utility shareholders to make productivity improvements and to benefit from them." The Board stated that five-year plans are generally the standard in PBR rate regulation (page 16), and that its preference was for a term of that length (page 29).

Having set its expectations for an IR framework, the Board identified a number of issues that needed to be addressed before the framework could be implemented and utility specific IR plans approved. A number of these issues have since been addressed by the Board such as:

- Data filing guidelines: The Reporting and Recordkeeping Requirements ("RRR") were issued December 22, 2004.
  OEB Website Link (also included as Appendix J):
  (http://www.oeb.gov.on.ca/documents/cases/RP-2003-0242/rrr_rulegasutility221204.pdf;)

- Base rates for each utility: The Rate Order for Union's 2007 base rates was approved on December 19, 2006, subsequent to the Board's June 29, 2006 Decision with Reasons.
  OEB Website Link:
  (http://www.oebdocs.oeb.gov.on.ca/newpdf/Final%20Dec_Rate%20Order_Union%202007_combined_20061219.pdf)

- Service Quality Requirements ("SQR"): The Gas Distribution Access Rule ("GDAR") was amended on March 27, 2006.

OEB Website Link:

(http://www.oeb.gov.on.ca/documents/cases/RP-2000-0001/gdar_final_report_021106.pdf

(Note: the version on the web was amended September 29, 2006 – the amendment related to SQRs is included in Appendix K)

The issues that remain to be dealt with include financial reporting framework under IR, the annual rate adjustment mechanism and the specific term of the IR plan (i.e. 3, 4 or 5 years). These are all the subject of this proceeding and of this prefiled evidence.

2.2 EB-2006-0209 CONSULTATIVE PROCESS

The stakeholder consultation process that concluded recently on IR has been comprehensive and inclusive. Individual stakeholder meetings began in September 2006 with additional stakeholder meetings taking place on November 2, 3 and 24, 2006. A draft discussion paper ("Board Staff Paper") was issued by Board staff on January 5, 2007 (Appendix A) which identified Board staff's conclusions and recommendations based on the consultation process that had taken place. The Pacific Economics Group's ("PEG") draft "Price Cap Index Design for Ontario's Natural Gas Utilities" report was released on March 30, 2007. A technical conference to gain a better understanding of that report was held on April 18, 2007. Through the consultation process, stakeholders have had an opportunity to gain a better understanding of other stakeholders' points of view, which should reduce the need for interrogatories and the scope of issues that will be dealt with during this proceeding.

On May 3, 2007, the Board identified that it was their intention to implement rates under a multi-year ratemaking framework and requested that both Enbridge Gas Distribution Inc. ("Enbridge") and Union file applications for rates that will commence January 1, 2008. Consequently on May 11, 2007, Union filed an application with the Ontario Energy Board for an order approving a multi-year incentive rate mechanism to determine rates for Union's regulated gas distribution, transmission and storage services effective January 1, 2008.

3.0 PLAN OBJECTIVES

As part of the consultation process, Union provided the following plan objectives on October 27, 2006. These principles are consistent with the evidence Union filed in the RP-1999-0017 rates proceeding and the submission Union made in the RP-2004-0213 NGF proceeding.

Fairness – There should be an appropriate balance between risks and opportunities for all stakeholders. The benefit of productivity improvements, both cost efficiency gains and growth, should ultimately be shared between customers and the utility.

Alignment – The ratemaking framework should provide for an alignment of interests between customers, the utility, and the regulator.

Earnings Opportunities – The ratemaking framework should provide the utility with the opportunity to earn a fair return, and an opportunity to earn a superior return for superior performance. This will help stimulate economic and efficient investment in required infrastructure.

Efficiency – The ratemaking framework should motivate fair and economic decision making by the utility (such as capital versus O&M spending).

Comprehensive – The ratemaking framework should allow the utility to manage its business in total, including growth opportunities, and not focus on individual aspects that can create distorted incentives. The emphasis should not be on cost cutting.

Rate Predictability & Stability – The customers and the utility should generally know what rates can be charged over a reasonable period of time.

Flexibility & Accountability – The ratemaking framework should provide the utility with the freedom to make and be accountable for certain pricing and service decisions without undue regulatory intervention.

Sustainability – The ratemaking framework should stand the test of time and not require significant amendments.

Simplicity – The framework and its results should be easily understood by all stakeholders and administered.

These objectives can only be met through the use of a comprehensive regulatory framework that affords Union an opportunity and incentive to grow revenue and implement cost management initiatives.

Union supports the comment on page 5 of the Board Staff Paper that "ratepayers be better off, or at least not worse off, in real terms, in moving from cost of service regulation to IR (in terms of rates, service quality and financial soundness)" as a guideline. This view supports an annual net adjustment (before Y and Z factors) approximately equal to the rate of inflation.

4.0 PROPOSAL OVERVIEW

4.1 SUMMARY

Union's proposed summary price cap formula results in an annual net adjustment (before Y and Z factors) to rates of approximately inflation. This annual increase will allow Union to make economic and efficient investments in required infrastructure, attach new customers and grow throughput while maintaining reasonable distribution costs for customers.

A summary of Union's price cap plan proposal is provided in Table 1 below:

Table 1
Union Price Cap Plan Proposal Summary

Parameter	Evidence Section	Proposal
Summary PCI	**5.7**	Productivity Differential 0.52 Input Price Differential 0.22 Average Use Factor -0.72 Stretch Factor 0.00 **X Factor** [A = sum of above] **0.02** Recent GDP IPI FDD Trend [B] 1.86 **PCI** [B-A] **1.84**
Base Rate Adjustments	**5.1**	Adjust the 2007 Board approved rates for: ▪ items from previous Board Decisions, and ▪ a one-time adjustment to reflect the 20-year trend weather normalization method
Plan Term	**5.2**	5 year term beginning January 1, 2008
Marketing Flexibility	**5.3**	Continue to have the flexibility to: ▪ Adjust fixed/variable rates on a revenue neutral basis ▪ Develop, on a timely basis, new services and change existing services when required
Price Cap vs. Revenue Cap	**5.4**	Price Cap
Inflation Factor	**5.6**	▪ GDP-IPI FDD Canada index (average of annualized quarterly changes of the last four quarters). ▪ Adjusted annually.
Service Group PCIs	**5.7.5**	| **Recent GDP IPI FDD Trend** | **X Factor Excluding Stretch and AU** | **Adjusted AU Factor** | **Net X Factor** | **PCI** General Service | 1.86 | 0.74 | -1.12 | -0.38 | 2.24 All other | 1.86 | 0.74 | 0.00 | 0.74 | 1.12
Y Factors	**5.8**	▪ Cost of gas and upstream transportation costs ▪ DSM cost increases and other affects ▪ Elimination of long-term storage deferral account ▪ Other deferral accounts
Z Factors	**5.9**	▪ Criteria as listed in Table 4 including a threshold of $1.5M ▪ Specific examples include: return on equity formula; late payment penalty litigation and damages; and permit fees
Non-Energy Services	**5.10**	▪ Outside of price cap
Off Ramps	**5.11**	▪ No off ramps required

Reporting	**6.0**	▪ Data filing guidelines ▪ Service quality requirements ▪ Rate setting filings ▪ Reporting at rebasing

4.2 APPROVALS REQUESTED

Union is seeking the approval of the Board to:

1. Adjust the 2007 base rates to reflect previous Board Decisions and other items as described in Section 5.1.
2. Adjust, during the plan term, the fixed monthly charge and the variable charge on a revenue neutral basis annually.
3. Propose rates, during the plan term, for the approval of the Board for new services or changes to existing services.
4. Implement a price cap framework with a five year term beginning January 1, 2008.
5. Adjust rates to reflect an annual increase of GDP IPI FDD as described in Section 5.6 plus a fixed X factor by service group of -0.38 for general service (M2, Rate 10 and Rate 01) and 0.74 for all other service groups as described in Section 5.7.5.
6. Administer the following Y factor rate adjustments outside of the price cap as described in Section 5.8:
    - Cost of gas and upstream transportation
    - DSM cost increases and other affects
    - Elimination of long-term storage deferral account
    - Other deferral accounts

7. Administer Z factor rate adjustments outside of the price cap as described in Section 5.9.

5.0 PROPOSAL PARAMETERS

5.1 BASE RATES

Union's 2007 rates will set the base for the IR term. These base rates meet the Board's requirements for a robust set of cost-based rates, based on a thorough and transparent review (page 25, NGF Report). As detailed below, adjustments yet to be made to the 2007 base rates include:

- Items from previous Board Decisions
    1. Splitting the M2 rate class into two rate classes (M1 and M2)
    2. Adjustments for the 2008 GDAR capital costs
    3. Treatment of S&T deferral accounts
    4. Demand Side Management ("DSM")
- A one time adjustment to reflect the 20-year trend weather normalization method

Items from Previous Board Decisions

Union will be required to implement the outcomes of previous Board Decisions during the plan term. In 2008, Union will be implementing changes to rates based on the Board Decisions in the EB-2005-0520 (2007 cost of service proceeding) and EB-2005-0551 Natural Gas Electricity Interface Review ("NGEIR") proceedings.

1. As approved by the Board in the EB-2005-0520 Decision with Reasons dated June 29, 2006 Union will be splitting the M2 rate class into two rate classes (M1 and M2) (see Appendix B for the excerpt from Union's evidence and the Board Decision). The effect of this split will be included in the January 1, 2008 rate order.

2. Union requested pre-approval to change rates effective January 1, 2008 to incorporate incremental capital and O&M costs required to implement the Bill-Ready phase of the GDAR. There was complete settlement of this issue in the Settlement Agreement (see Appendix C for the excerpts from Union's evidence and the Settlement Agreement). As such, Union will adjust 2008 base rates accordingly effective January 1, 2008 and include this adjustment in the 2008 rate order. Should there be any changes to the timing of the implementation of the Bill-Ready phase; Union will address the impact on base rates once a decision is made by the Board.

3. In the EB-2005-0520 and EB-2005-0551 proceedings, Union requested that five S&T deferral accounts (179-70, 179-72, 179-69, 179-73 and 174-74) be eliminated. In EB-2005-0520, Exhibit C1, Tab 3, Union stated that it agreed with the Board's direction that, "in a true IR framework, there should be no earnings sharing, and transactional services revenues should not receive special treatment" (page 24). Union further stated that it, "believes that the elimination of S&T transactional service deferral accounts in 2007 is consistent with and supports the Board's direction to reduce deferral accounts and eliminate earnings sharing mechanisms as part of transitioning

to an IR framework." The Board specified on page 112 of the EB-2005-0551 Decision with Reasons that the proposed elimination of the three transmission-related accounts should be considered as part of a comprehensive review that includes all deferral accounts under an incentive regulation mechanism. Therefore, Union is requesting the elimination of the following three deferral accounts (Transportation Exchange Services Account (179-69), Other S&T Services Account (179-73) and Other Direct Purchase Services Account (174-74)) beginning January 1, 2008. Board staff supported the elimination of the three deferral accounts in the Board Staff paper (page 22). The Long-Term Peak Storage Services Account (179-72) is discussed in Section 5.8.3 below.

4. DSM is discussed in Section 5.8.2

Weather Normalization Method

Union proposes that the 20-year declining trend weather forecasting method be fully implemented effective January 1, 2008 as an adjustment to base rates. This would result in an estimated impact to rates of approximately $7 million.

This adjustment would produce greater symmetry in weather risk (i.e. colder weather being as likely to occur as warmer weather.) Using the current 55% 30-year average and 45% 20-year declining trend blended method ("55/45 blend") represents a substantial risk to the company. The use of the 30-year average has a bias toward exceeding the actual number of heating degree days ("HDDs"). Forecasting the HDDs through use of the

55/45 blend to set the 2007 base rates means that Union's forecast of natural gas demands will be higher than is expected to occur. Unless changed, this abnormality would be carried through the IR plan term.

Chart 1 below shows that the 20-year declining trend more closely follows the actual heating degree days ("HDD") experienced by Union than does the 30-year average.

Chart 1

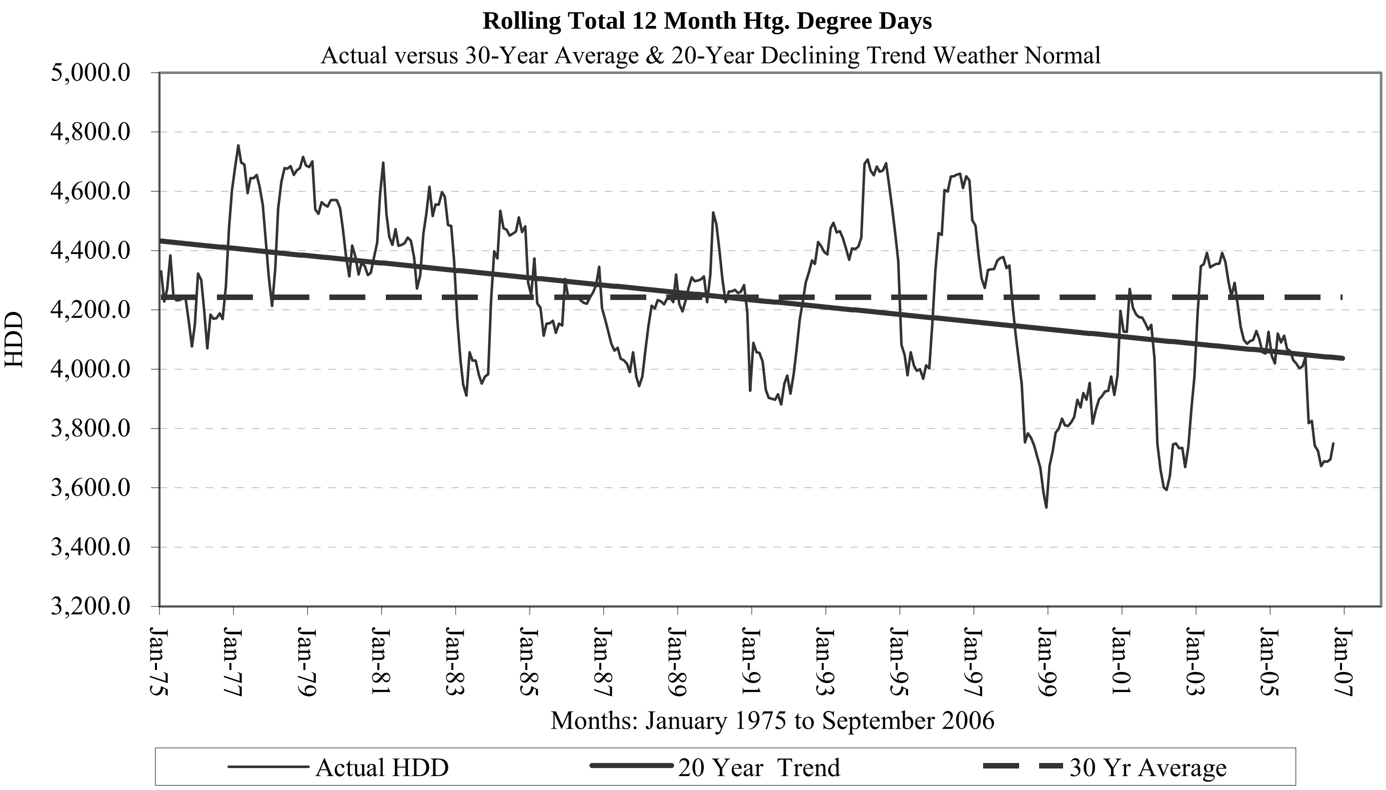
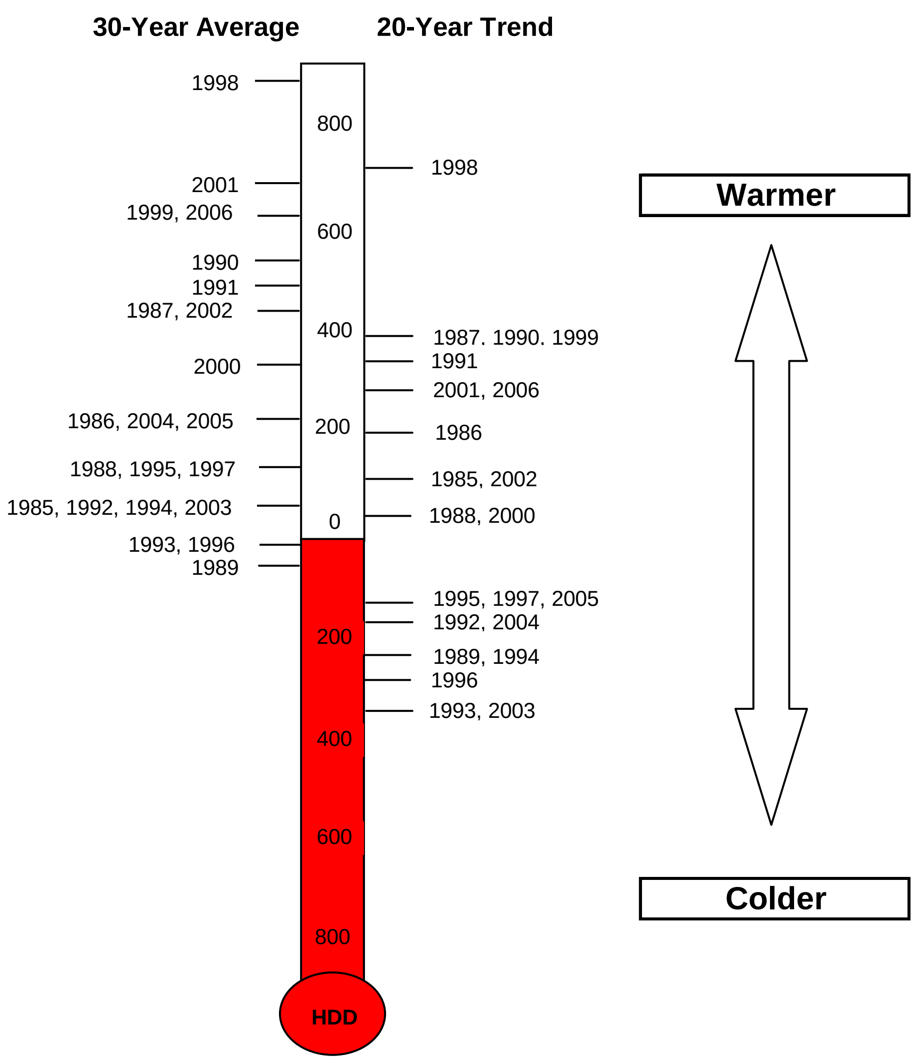


Chart 2 demonstrates how the 30-year average method consistently underestimates how warm the typical weather is compared to actual experience. The 20-year declining trend method shows a more balanced incidence of over and under forecasting of the number of HDD.

Chart 2
Comparison of Forecast versus Actual Heating Degree Days
For the 30-Year Average and 20-Year Trend Methods



Union's evidence in the RP-2003-0063 (2004 test year) and EB-2005-0520 (2007 test year) proceedings supports the 20-year declining trend method as being the most accurate weather forecasting method. Enbridge also proposed using the 20-year declining trend weather method in its 2007 rates application.

Union identified as part of the 2007 rates proceeding (EB-2005-0520, Exhibit A2, Tab 1, Schedule 1, page 23) that:

> *"Union continues to experience weather that has a significant warming trend which is not picked up by the 30-year average methodology or the Board ordered blended methodology. This warming trend has, therefore, not yet been fully recognized in the rates of Union's temperature-sensitive customers."*

Union's 2007 rates proceeding financial settlement was for 2007 only. No representations were made for rates beyond 2007. If a method that is intended to result in symmetrical risk is not achieving the intended outcome and another method would work better, Union believes that the better method should be adopted.

Union's evidence in its 2004 rates proceeding (RP-2003-0063, Exhibit C1, Tab 4, page 1) identified that:

> *"The primary objective of an acceptable weather normalization method is to set a weather normal level that will best reflect what future weather is typically expected to be. Union and customers will then be kept neutral with respect to weather in the long term. The 20-year trend method meets these requirements. The twenty-year trend method was selected after researching climate issues and examining other normalization methods in use today."*

In Enbridge's 2007 rates application (EB-2006-0034, Exhibit C2, Tab 4, Schedule 1, Page 1), it proposed using the 20-year declining trend weather method:

> *"The purpose of this evidence is to describe the proposed forecast methodology and to update the forecast of degree days for Fiscal 2007 and Fiscal 2008. Specifically, the Company is asking the Board to approve the use of the 20-Year Trend approach. The Company believes that this approach produces the best forecast, meaning that the use of the 20-Year Trend will minimize the variance between forecast and actual degree days and in turn reduce the related impact on shareholders and customers."*

The accuracy of Union's weather method was discussed during examination of the Enbridge panel (see Appendix D excerpt from EB-2006-0034 (Enbridge 2007 Rates Application), Transcript dated February 1, 2007; page 17, line 22 – page 21, line 27). Panel Chair Kaiser produced a schedule (Appendix E), which clearly showed that, based on historical analysis, the 20-year trend method produced the most accurate results.

The primary consideration of the weather normalization proposal is to set a normal weather level that will best reflect what future weather will be. The current Board approved 55/45 blend consistently estimates HDDs that are too high (see Chart 1). During the term of the price cap plan, Union will need to manage its business and overcome the negative consequences of the long-run warming trend even with an adjustment to the 20-year declining trend method.

Further detail is provided in the Supplemental Weather Normalization Evidence filed in Tab 2.

5.2 TERM OF THE PLAN

Union proposes a five year term commencing 2008 and ending 2012. A five year term will provide Union with an incentive to implement changes that will increase productivity with longer term paybacks which aligns with the NGF Report. Achieving productivity improvements frequently involves incurring implementation costs. The term of a price cap plan must be long enough to justify incurring the implementation costs required to pursue the productivity improvements.

5.3 MARKETING FLEXIBILITY

Union should have the ability, as it currently does under cost of service regulation, to adjust the fixed monthly charge and the variable charge on a revenue neutral basis annually. Union has been slowly (in increments of $1 or $2 per year) moving the fixed monthly charge towards full customer-related cost recovery. Union does not believe that it should have less flexibility under the price cap plan than it had under cost of service to pursue this type of rate alignment.

With the ability to adjust the fixed monthly charge and the variable charge on a revenue neutral basis, there would be no need to adjust the fixed monthly charge as part of the price cap formula. Union does not believe that it would be appropriate to apply the price cap equally to fixed and variable charges as it would result in fixed monthly charges that are not whole numbers (e.g. $16.32 rather than $17.00). Union's practice has been to have fixed monthly charges that are whole numbers.

Union requires the flexibility to respond to a changing energy marketplace by developing, on a timely basis, new services and by making any necessary changes to existing services when required. As noted below in Section 5.4, as part of the NGEIR proceeding (EB-2005-0551), Union identified potential new services for power generators.

Union agrees with the Board Staff Paper (page 20) that the onus should be on the utility to apply to the Board for approval of the rates for new regulated services and changes to existing rate schedules (including terms and conditions of service). In addition, Union may need to seek Board approval of changes to rate schedules to account for Board decisions in generic proceedings during the incentive regulation plan term.

Union would expect that the threshold that it would have to meet before the Board would consider making rate schedule modifications would be no different under incentive regulation than it is under cost of service regulation. For example, if changes in the marketplace (such as high gas commodity costs) drive the need to make changes to overrun or penalty provisions, the burden of proof on the utility to justify the change should be the same under incentive regulation as it is under cost of service regulation.

5.4 PRICE CAP VS. REVENUE CAP

Union believes that a price cap mechanism should be used. A price cap mechanism better addresses the two items that matter most to customers: the price and quality of the service they receive.

A price cap plan will provide greater incentives for the utility to implement productivity improvements compared to cost of service regulation. It will also provide Union the flexibility to respond to a changing energy marketplace by encouraging the development of new services on a timely basis and changes to existing services when required. For example, as part of the NGEIR proceeding (EB-2005-0551), Union identified potential new services for power generators. In the June 13, 2006 Settlement Agreement (page

12), parties agreed to look at modifying these services once Union and customers gained sufficient operating experience:

> *"Parties agree that once sufficient operating experience has been gained and in any event no later than March 31, 2009, interested customer groups and Union will convene to evaluate and discuss the experience and success of the services offered as a result of this proceeding. At that time, any party may propose further modifications to the rate schedules."*

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

As noted in the Board Staff Paper (page 7):

> *"Under a revenue cap, the difference between actual revenue and the approved revenue requirement is captured in a balancing account, and the ratepayer is at risk for this balance. Therefore, utilities may be less aggressive in promoting customer attachments and throughput growth."*

A revenue cap may result in greater controversy and regulatory administration. As further noted by Board staff:

> *"Regulatory cost can be greater under a revenue cap. This is due in part to the potential controversy in the design of the output growth factor in the revenue cap index formula. Additionally, there might be a continued need to consider the allocation of the revenue requirement amongst service offerings, customer rate classes, and rate design matters."*

As a matter of principle, Union supports a price cap form of incentive regulation as it better aligns the utility's activities with customer interests. Union also believes that a price cap mechanism was intended by the Board in its NGF Report.

5.5 FORMULA

The pricing formula as described below should:

- Apply to regulated rates only and not to the price of unregulated services.
- Include a macroeconomic inflation factor reset annually with no true-ups.
- Include an X factor fixed for the term of the plan.

The basic components of the formula are:

%Δ Price = % Δ Inflation factor – X factor + Y factor + Z factor

- *Δ Price*: The annual percentage change in price.
- *Δ Inflation Factor:* The percentage change in the macroeconomic inflation factor (per Section 5.6).
- *X Factor:* Includes a productivity differential, an input price differential, and an average use factor (per Section 5.7).
- *Y Factors:* Routine (or expected) rate adjustments established in the base year (per Section 5.8).
- *Z Factor*s: Rate adjustments outside of the price cap for costs that are beyond the control of the utility's management (per Section 5.9).

5.6 INFLATION FACTOR

Union supports the use of the quarterly Gross Domestic Product Implicit Price Index Final Domestic Demand ("GDP IPI FDD") Canada index, as recommended on page 12 of the Board Staff Paper, as the macroeconomic inflation factor. Although Union believes that there are benefits to using the Consensus forecast of the Consumer Price Index ("CPI") as the inflation factor (such as customer familiarity, availability of forecasts and not being subject to revision), Union notes that the productivity report produced by the Pacific Economics Group ("The PEG Report") uses GDP IPI FDD to determine the proposed X factor.

Macroeconomic vs. Industry Specific

Union agrees with comments in both the Board Staff Paper and the PEG Report that a macroeconomic inflation measure should be used:

As noted on page 9 of the Board Staff Paper:

> *"Macroeconomic measures … track growth in the prices of a wide range of goods and services. They have been used extensively in IR plans in North America and around the world because they are readily available and generally published by a trusted source. Statistics Canada ("Stats Canada") publishes actual values of these measures. Forecast values of some of these measures are available from banks and forecasting companies. Also, macroeconomic indices are more easily understood by the public than industry specific measures."*

As noted on page 13 of the PEG Report:

> *"Macroeconomic inflation measures have noteworthy advantages over industry-specific measures in rate adjustment indexes. One is that they are available from*

respected and impartial sources such as the Federal government. Customers are more familiar with them, and this facilitates acceptance of rate indexing generally. There is no need to go through the chore of annual index calculations. Controversies over the design of an industry-specific price index are side stepped."

Benefits of GDP IPI FDD vs. CPI

An assessment completed by Board staff (Board Staff Paper, Table 1: Index Comparison, page 10) ranked GDP IPI FDD and CPI equally. Board staff stated that, although GDP IPI FDD could be more difficult to explain to ratepayers than CPI, this potential complexity is offset by the advantages of GDP IPI FDD. The advantages of GDP IPI FDD noted in Table 1 include:

- Coverage: Broad coverage of goods and services relevant to the gas industry (capital, labour, materials)
- Simplicity: Facilitates the calculation of input price and productivity differentials used in X factor calibration
- Availability: Published annually for Canada and Ontario and quarterly for Canada
- Stability: Less volatile due to the exclusion of petroleum products, gas exports, and other price-volatile exports

GDP IPI FDD Implementation

Union agrees with Board staff that if GDP IPI FDD is selected as the inflation factor, then a simple average of the actual annualized changes of the last four quarters should be used. As noted on page 12 of the Board Staff Paper, there are very few forecasts available for

GDP IPI FDD and the inflation forecaster with the best performance historically does not publish GDP IPI FDD forecasts.

The method that will be used to set the inflation factor should include a process to reset the inflation factor annually with no true-ups.[1] It should be adjusted in the fall, prior to the year in which the pricing mechanism will be applied. A fall adjustment would therefore reflect the simple average of the actual annualized changes for the four quarters ending June, March and the previous December and September (note: preliminary GDP IPI data is normally available 2 months after the end of the quarter).

5.7 X FACTOR

Board staff hired the Pacific Economics Group ("PEG") to prepare a study on "Rate Adjustment Indexes for Ontario's Natural Gas Utilities". PEG provided draft reports on March 30, 2007 and June 8, 2007 and a final report ("PEG Report") on June 20, 2007 (Appendix F).

The X factor derivation provided by PEG includes the following components:

1) **Input Price Differential** (the difference between the input price trends of the economy and the gas utility industry);
2) **Productivity Differential** (the difference between the productivity trends of the gas utility industry and the economy);

[1] As noted on page 73 of Union's November 10, 2004 NGF Submission, "GDPPI restatements were contentious".

3) **Average Use Factor** (to account for average use trends by gas utility customers); and

4) **Stretch Factor** (to share the benefits of expected performance gains).

Table 2 below identifies the X factor included in the PEG Report adjusted for Union's proposal:

Table 2
Union X Factor Proposal

	%	%	
PEG Report			
PD	0.52		
IPD	0.22		
AU	-0.72		
Stretch	0.50		
X Factor	**0.52**	**0.52**	**A**
Union's Adjustment			
Stretch Factor Elimination (Section 5.7.2)		**0.50**	**B**
Proposed X factor [2]		**0.02**	**C (A-B)**
GDP IPI (most recent trend) [3]		**1.86**	**D**
Net annual rate mechanism adjustment		**1.84**	**E (D-C)**

The rate indexing research that supported PEG's proposed price cap index ("PCI") design and overall IR framework recommendations for Union and Enbridge appear to be strong

[2] Fixed for the term of the plan
[3] Updated annually (see Section 5.6)

conceptually and generally consistent with the approach in other jurisdictions. Specifically, Union supports the use of industry Total Factor Productivity ("TFP") trends which are external to the company rather than company specific TFP trends.

Productivity differentials (which implicitly contain an average use component) and input price differentials are standard components of a price cap formula when a macro-economic inflation factor such as GDP IPI FDD is used. As indicated on page 12 of the PEG Report, the majority of rate indexing plans approved throughout the world do not feature industry-specific inflation measures. It is Union's understanding that the average use factor was shown separately from the productivity differential at the request of stakeholders as it would help stakeholders understand the separate impacts associated with improved cost efficiency and use per customer trends.

Separate average use factors are typically not required in a price cap formula because productivity differentials are calculated using revenue output weights rather than cost elasticity output weights. Given the desire to separately identify the impacts of declining average use per customer, it became necessary for PEG to calculate its proposed productivity differentials using cost elasticity output weights. PEG also then needed to calculate an average use factor, which is the difference between the revenue and cost elasticity weighted output indexes. Irrespective of whether i) revenue output weights are used or ii) cost elasticity output weights are used with an average use factor shown separately, both approaches result in the same combined outcome.

Union supports the use of a productivity differential based on gas industry productivity trends which can be derived using the econometric research approach.

5.7.1 Average Use Factor

In Union's view it is imperative that the price cap formula include an average use factor to capture the effects of declining average use per customer. Union has been experiencing flat to declining total distribution throughput growth at the same time that the number of customers and costs continue to grow. The rates approved by the Board under cost of service regulation have recognized that the utilities are experiencing declining average use. The major contributors to declining average use include:

- Improved efficiency of furnaces, water heaters, and other gas-fired equipment
- Decline in number of persons per household
- Tighter building envelopes (e.g. better building insulation)
- High and volatile natural gas prices which are likely to persist for the foreseeable future.[4]

The drivers and impacts of energy efficiency gains in the residential sector between 1990 and 2004 are identified in Appendix G on page 18 of the Canadian Gas Association document entitled "Declining Average Customer Use of Natural Gas: Issues and Options

[4] Page vi of the CGA Report : "*Based on the NRCan price forecast, high natural gas prices are likely to continue. This trend coupled with the trend toward higher efficiency gas equipment, tighter building envelopes and more pressure to achieve greater savings from DSM, means that it is likely that declines in average use will continue for the foreseeable future*".

for Canada's Natural Gas Distribution Utilities" prepared by IndEco Strategic Consulting Inc. ("CGA Report"):

> *"In the residential sector, improvements in energy efficiency are estimated to have resulted in a 21% reduction in energy use. This improvement is due to upgrading in the thermal envelope of houses and to the increased efficiency of residential space heating and cooling equipment, water heating equipment, and appliances. In the residential sector, space heating accounts for 59% of energy end-use, water heating accounts for 22% of energy end-use, and appliances account for 13% of energy end-use, with major appliances representing 8%.*

Page vii of the CGA Report Executive Summary also notes that:

> *"Utilities, such as ATCO Gas, AltaGas, Enbridge Gas Distribution and Union Gas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector."*

As part of the PEG Report, the proposed average use factor has been established using historical data to 2005. As a result, the utility will be at risk for the acceleration in declining average use which has been Union's most recent experience.

Drivers of accelerated declining use are noted on page vi and vii of the Executive summary of the CGA Report:

> *"We may be moving into a different era. In the past historical experience was a good predictor of the gas market in the future. Today, it may not be as reliable due to short to medium term supply shortages in natural gas, restructuring in the Canadian economy due to a high Canadian dollar relative to the US dollar, greater consumer awareness of energy efficiency and government pressure on gas utilities and others to assist customers to reduce gas bills. These factors could bring us to the tipping point of an accelerated declining average use."*

Declining use of Union's general service group is identified in Charts 3, 4, 5, 6, 7, 8 and 9 below.

(Note: This customer group excludes a small number of larger volume Rate 10 industrial customers that are billed by the contract customer billing system, approximately 87 customers).

Chart 3
Residential Rate M2
Annual Weather Normalized Average Consumption (NAC) using the 55/45 Blend

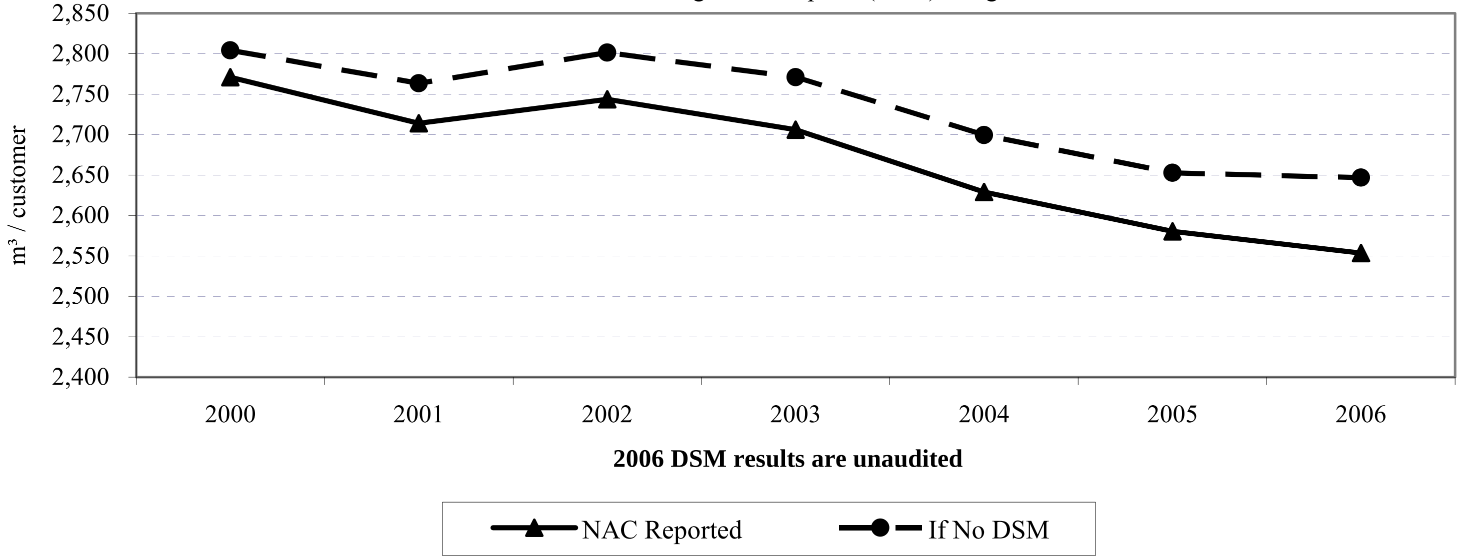


Chart 4

Residential Rate 01

Annual Weather Normalized Average Consumption (NAC) using the 55/45 Blend

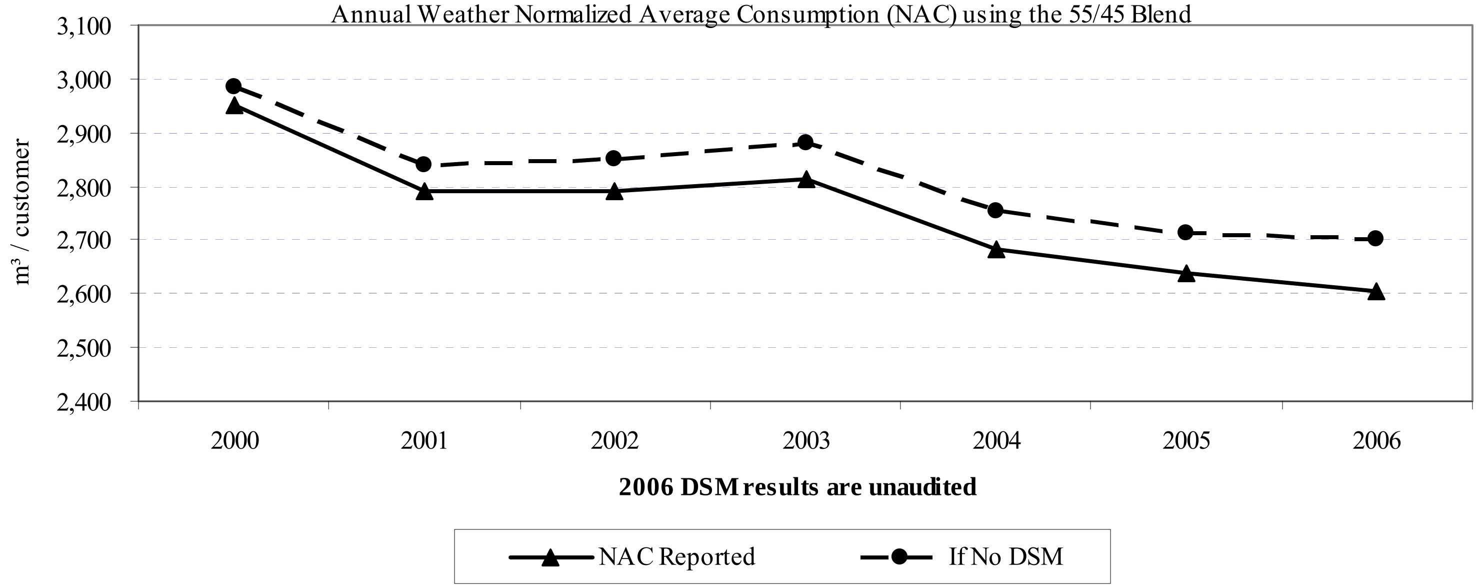


Chart 5

Commercial Rate M2

Annual Weather Normalized Average Consumption (NAC) using the 55/45 Blend

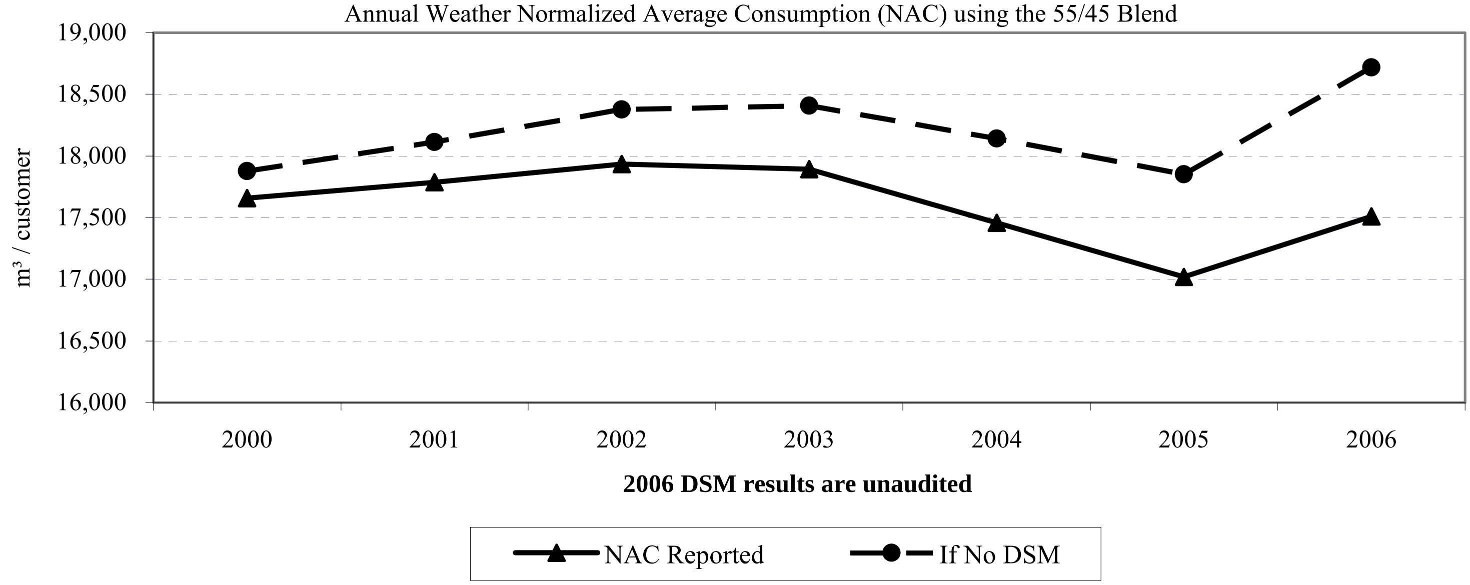


Chart 6

Commercial Rate 01

Annual Weather Normalized Average Consumption (NAC) using the 55/45 Blend

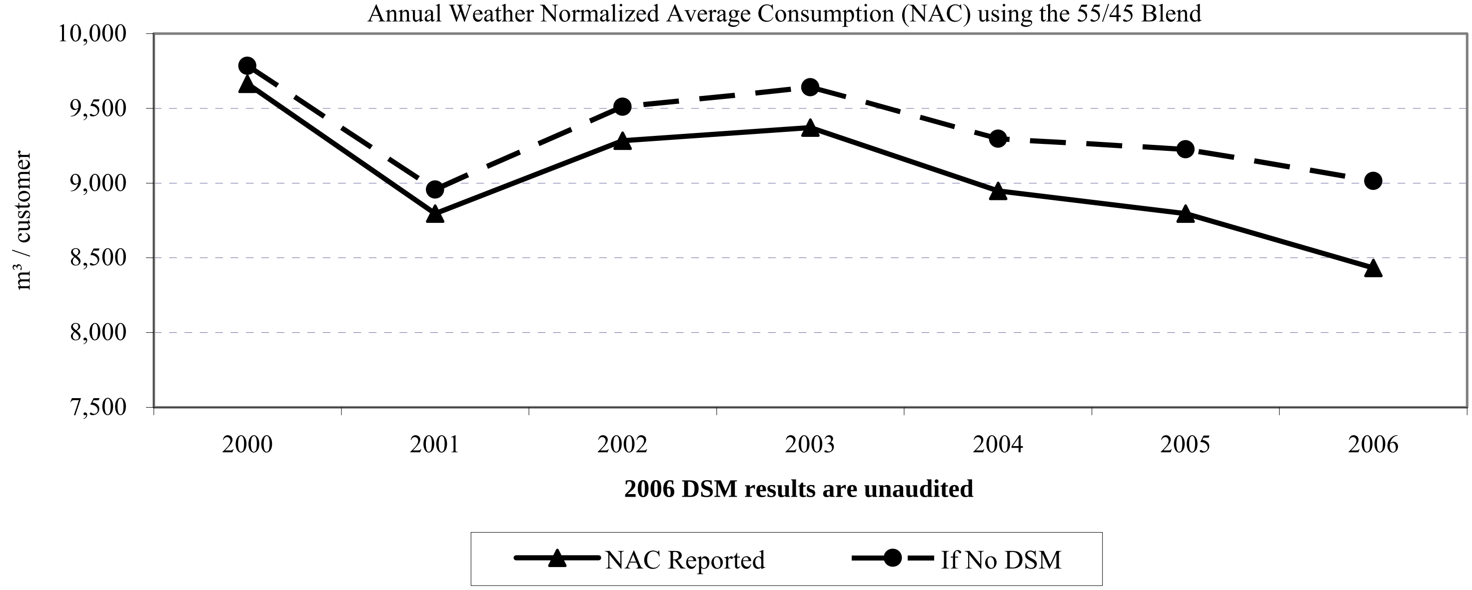


Chart 7

Commercial Rate 10

Annual Weather Normalized Average Consumption (NAC) using the 55/45 Blend

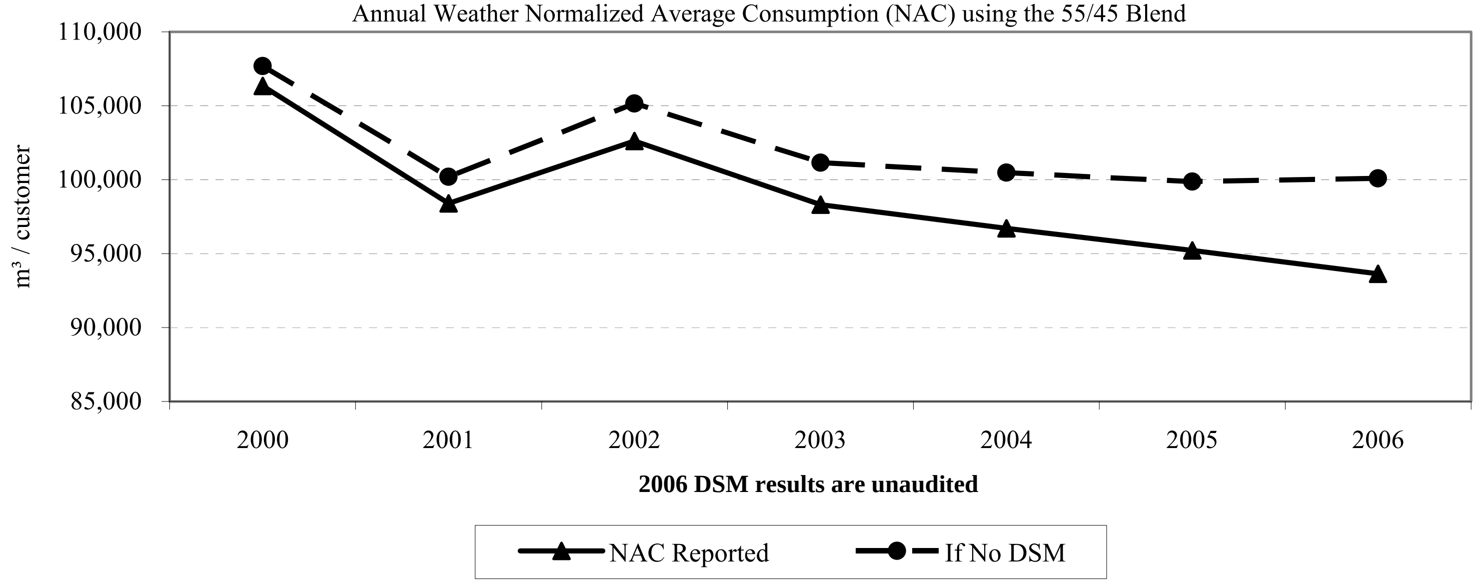


Chart 8

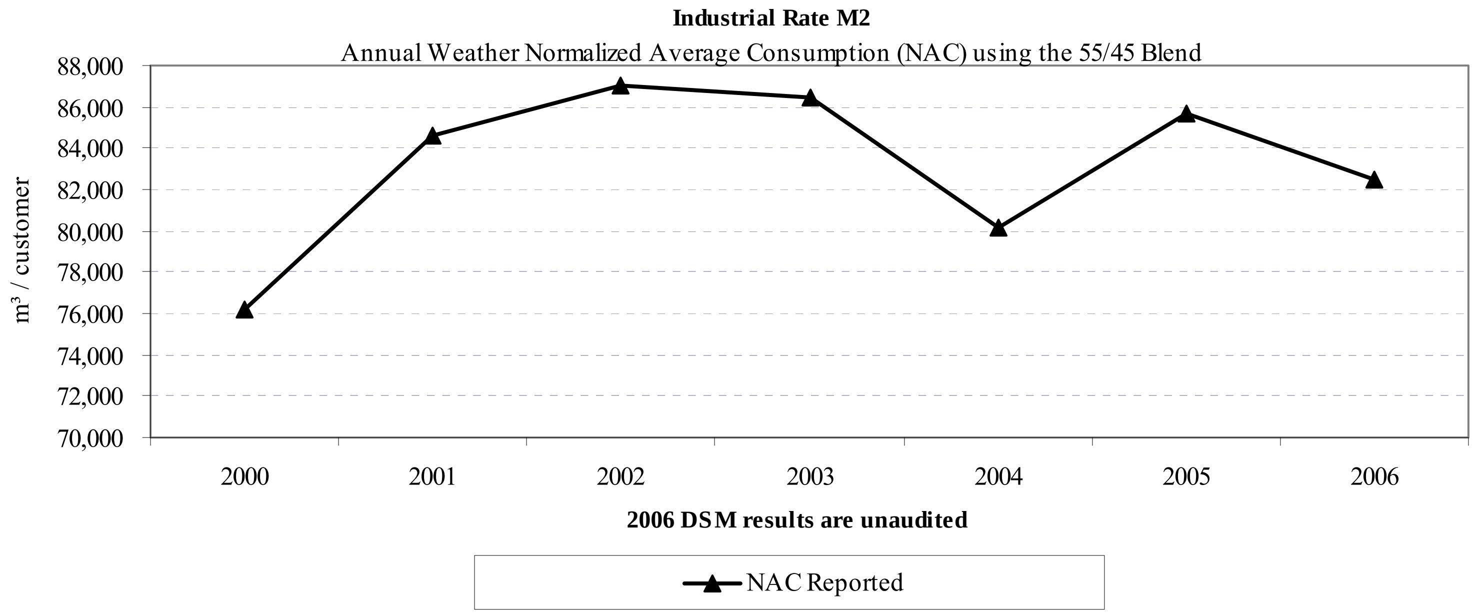
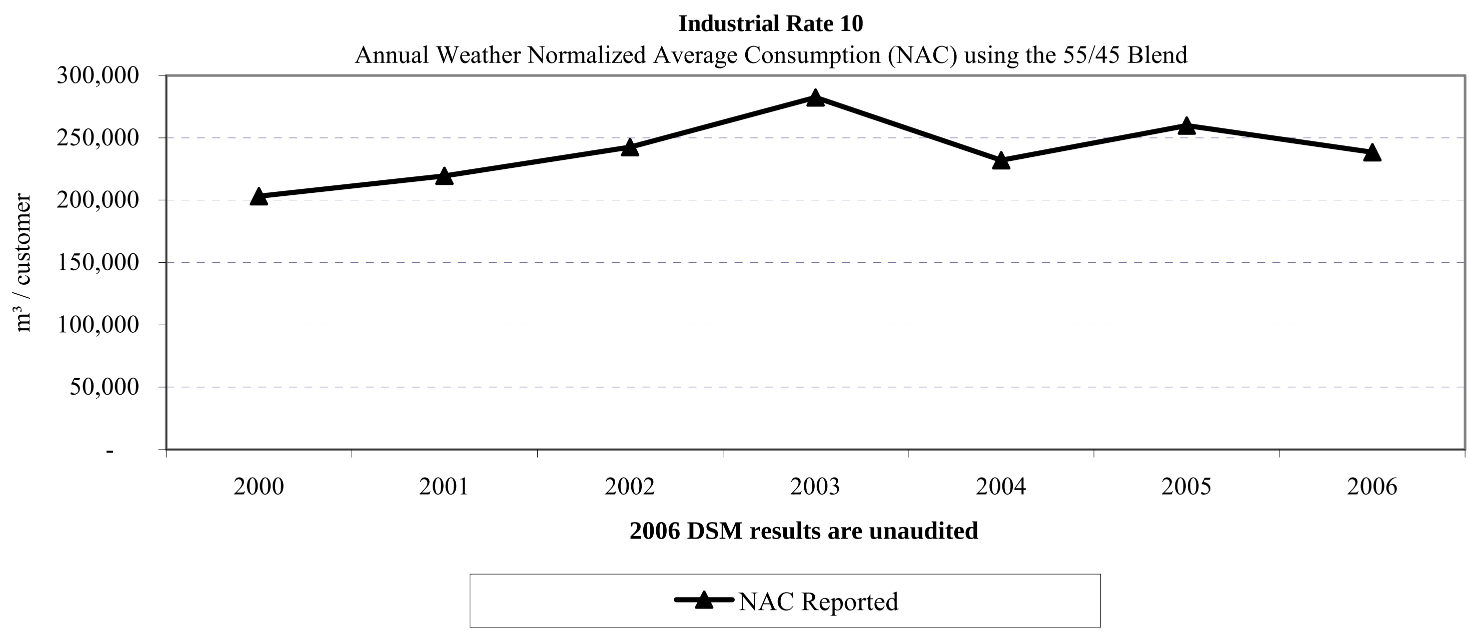


Chart 9



The approach PEG used to calculate the total average use factor appears to Union to be reasonable.

5.7.2 Stretch Factor

In Union's view there is no justification for a stretch factor during its next IR plan term. The proposed stretch factor is purely an ad hoc add-on; its value cannot be determined from the logic of price indexing as are the other components of the price cap formula. A stretch factor is usually added to an IR plan when there is a belief that, during the term of the plan, the utility will have both an incentive and an ability to increase productivity at a greater percentage than that determined by the historical industry TFP trend.

It should be recognized that Union has not applied annually for rate adjustments. Union has experienced only 3 cost of service rate cases in the last 10 years (to set rates for 1999, 2004, and 2007). Rates were established under the trial PBR plan structure for 2001, 2002 and 2003. After the 2004 cost of service rates were implemented, Union was essentially under a rate freeze for 2005 and 2006. Union has therefore had significant motivation to implement productivity improvements over the last 10 years.

Union will already be stretched to manage its business within an annual inflationary increase. During the IR period, Union will manage the risks under the price cap formula relating to: declining use per customer beyond the amount provided in the price cap formula; changing workforce demographics; compensation and pension and benefit cost pressures; natural gas price volatility; and changes in the exchange rate.

- Declining use per customer is discussed in further detail in Section 5.7.1.
- Changing workforce demographics were discussed in detail in Union's 2007 rate case proceeding, EB-2005-0520. In Exhibit A2, Tab 1, Schedule 1, page 23, Union noted that one of the most significant issues emerging within the Canadian workplace is the aging workforce and the critical shortage of skilled labour. As the aging workforce impact is expected to be more pronounced at Union than in many other companies, Union launched a Workforce Development and Enhancement Initiative that outlines a multi-year targeted approach to address what has become a critical strategic issue for the organization and the industry. Union bears the risk of the requirements for workforce development that exceed what has been included in base rates and adjusted with the annual net price escalator during the incentive regulation plan term.
- Union will also assume the risk associated with increased pension and benefit costs that are greater than inflation. In the EB-2005-0520 proceeding, Union described the cost pressures it faces with pension and benefit costs (Exhibit D1, Tab 3). The primary driver of increases in benefits costs continues to be medical and dental costs in excess of inflation. Medical and dental benefits costs were forecast to increase 15% per year in the years 2006-2008 (Exhibit D1, Tab 3, Appendix A, page 7).
- As described in EB-2005-0520, Exhibit A2, Tab 1, Schedule 1, page 15, the price of natural gas has become increasingly volatile and susceptible to weather fluctuations and supply interruptions. The escalation of natural gas prices will have a negative

business impact by increasing internal operating costs and decreasing customer throughput and revenue.

- The estimated exchange rate used in Union's 2007 forecast preparation was 0.818 U.S. $ (Exhibit A2, Tab 1, Schedule 1, page 19). The April 2007 Bank of Canada Monetary Policy Report indicated that the Canadian dollar traded in the 0.845 to 0.875 U.S. $ range in the first quarter of 2007. Since early April, the Canadian dollar has moved above this range as a result of several developments, including the rise in commodity prices and relatively stronger economic data in Canada than in the United States. As the value of the Canadian dollar rises, it is expected to have negative effects on the competitiveness of the Canadian manufacturing sector, which would reduce Union's throughput and revenues.

Therefore, Union's proposed PCI, provided in Section 5.7, has been adjusted to eliminate the stretch factor.

5.7.3 Two Approaches to Capital Cost Measurement

PEG calculated the input price and productivity trends using two approaches to capital cost measurement:

Geometric Decay ("GD")

PEG stated that this approach has been extensively used in both scholarly cost research and in index research in support of PCI designs. It features replacement (current dollar) valuation of utility plant and a constant rate of depreciation.

Cost of Service ("COS")

PEG stated that this is a novel approach to capital costing that better reflects the way capital cost is calculated for purposes of ratemaking in traditional regulation. It features book (historical dollar) valuation of capital and straight line depreciation. Input price and productivity indexes computed using COS costing tend to be more sensitive to recent investment activity.

PEG recommended that the COS method be used. The COS approach appears reasonable as compared to the other research results provided by PEG. Union has not attempted to reproduce or otherwise validate the PEG Report results. As an independent and experienced expert, Union is relying on PEG's productivity expertise and the PEG Report to establish the performance standards.

5.7.4 Summary PCIs

The PEG Report states that its recommended PCI growth *"would be materially slower than the growth in GDPIPI. Ontario gas consumers would, in other words, experience growth in rates for gas utility services that are below the general inflation in the prices of final goods and services in Canada"*.

As stated in Section 5.7.2, Union believes that there is no justification for a stretch factor and proposes that it be eliminated from the recommended PCI formula. This would produce an annual net rate adjustment (before Y and Z factors) that approximates inflation.

5.7.5 Service Group PCI's

PEG recommends that there be separate PCIs for each rate class that contains residential customers and that all other service classes would be subject to a different common PCI. Adjusted X factors were determined by calculating a special adjustment ("ADJ") which PEG identifies as being the sum of separate calculations of the revenue effect and the cost effect. PEG then calculated the PCI growth for each group by taking the difference between the recent trend in the GDP IPI FDD and the adjusted X factors.

Union does not understand how the ADJ can be determined using PEG's approach without doing a productivity study by rate class. Therefore, Union recommends a simpler and more intuitive approach to calculate the X factor applicable to the general service rate classes (M2, Rate 01 and Rate 10). This would be calculated by adjusting the company wide average use factor by the combined revenue share of the general service rate classes. Further, Union recommends that there not be an average use factor adjustment for rate classes other than the general service rate classes. Using the COS method, this would result in PCIs, including the elimination of the stretch factor, for Union's service groups as outlined in Table 3:

Table 3
Union's Proposed PCIs by Service Group

	Recent GDPIPI Trend	X Factor Excluding Stretch and AU	Adjusted AU Factor	Net X Factor	PCI
General Service	1.86	0.74	-1.12 [5]	-0.38	2.24
All other	1.86	0.74	0.00	0.74	1.12

5.8 Y FACTOR

Y factor items are those components of a utility's rate structure adjusted by something other than the IR index formula, and are treated as periodic pass-through items. Management typically has little or no control over these items. Union proposes the following Y factor items:

- Cost of gas and upstream transportation
- DSM cost increases and other affects (e.g. throughput affects)
- Elimination of long-term storage deferral account
- Other deferral accounts

5.8.1 Cost of Gas and Upstream Transportation

The cost of gas supply, upstream transportation and gas supply related balancing will continue to be passed through to customers through the Quarterly Rate Adjustment Mechanism ("QRAM"), including the prospective disposition of gas supply related deferral accounts.

[5] Summary COS AU -0.72 divided by Union's general service 2005 revenue share 0.644.

The NGF Report identified that the Board will develop guidelines through a consultation process to standardize the QRAM process across gas utilities. Union expects that the Board will complete this process during the price cap plan term. If necessary, Union will modify the meth used to establish commodity prices to reflect any changes approved by the Board as a result of that process.

5.8.2 DSM

In 2006, the Board convened a generic proceeding to address a number of common issues related to DSM activities for natural gas utilities (EB-2006-0021). During the three phases of that proceeding the following were developed: i) generic plan parameters, ii) input assumptions, and iii) a specific plan for each utility. As agreed to in the Partial Settlement agreement, and as confirmed by the Board in its August 25, 2006 Decision, Union's 2007 DSM budget of $17.0 million will be increased to $18.7 million beginning January 1, 2008 and to $20.6 million beginning January 1, 2009. In addition, the DSMVA, LRAM and SSM deferral accounts will continue throughout the three-year term of the DSM plan (2007-2009). Consequently, Union's rates for 2008 and 2009 should be adjusted for the increase in the annual DSM budget and future rates will be adjusted for the disposition of any DSM-related deferral account balances.

5.8.3 Long-Term Peak Storage Services Account (179-72)

Union will be increasing its share of long-term storage transaction margins by increments of 25% starting in 2008. The Board approved the phase-out of long-term margin sharing in its EB-2005-0551 Decision with Reasons, Section 7.3, dated November 7, 2006 (see Appendix H for the excerpt from the Board Decision). Therefore, Union's rates for 2008-2011 will be adjusted to reflect this phase-out.

5.8.4 Other Deferral Accounts

There will be no additions to the deferral accounts established in the base year unless an account is established in another Board proceeding or an item would otherwise qualify as a Z factor during the price cap plan term. If an item like permit fees (discussed in Section 5.9) qualifies as a Z factor, it would be logical that this item would also qualify for a deferral account. A deferral account may be required until rates can be adjusted to incorporate the adjustment. A deferral account may also be required in instances where it takes longer than a year to quantify the annualized impact accurately.

5.9 Z FACTOR

A Z factor provides for rate adjustments intended to safeguard customers and the gas utility against unexpected costs that are outside of management's control and therefore not included in the proposed price cap. A Z factor is any amount that satisfies the four criteria summarized in Table 4:

Table 4
Z Factor Criteria

Criteria	Description
Causation	Amounts should represent an increase or decrease in costs resulting from, attributed to or in respect of, directly or indirectly, a Z factor event.
Materiality	The threshold amount should be $1.5 million (1) per Z factor event. The Z factors will be symmetrical (i.e. cost increases or decreases).
Inability of Management to Control	The amount must be attributable to a Z factor event which means an event, change, effect or occurrence outside of management's control. The criteria would exclude changes that relate to the Canadian economy in general or to changes in federal tax laws as these would eventually be captured in the inflation factor, albeit on a delayed basis. However, the criteria would include changes to provincial and municipal tax laws. (Z factors should capture the change in costs associated with changes in legislation, regulatory requirements and Generally Accepted Accounting Principles).
Prudence	The amount must be prudently incurred.
Note: (1) A $1.5 million per item threshold is consistent with the threshold approved by the Board for Union's trial PBR plan (in RP-1999-0017) where the Board accepted a threshold for individual items of $1.5 million pre-tax.	

Specific examples of possible Z factors include:

- Return on Equity ("ROE") Formula: Changes in the ROE formula used by the NEB and OEB and changes in the OEB approved capital structure for other utilities in the province. If cost of capital changes are approved by the NEB or OEB, utilities should have the opportunity to apply for a similar change during the price cap plan term. At the time of application, all parties would have a chance to address the merits and timing of any proposal.
- Late Penalty Payment ("LPP"): Costs associated with litigation and damages. (Note: No specific inclusion for LPP in the price cap plan framework is required if the Board was to expand the current deferral account definition to include any payments from settlement or litigation.)

- Permit Fees: Costs associated with the implementation of permit fees by municipalities. (Note: The Ontario government recently passed a Regulation that allows municipalities to charge permit fees when natural gas utilities are performing maintenance on, repairing or improving natural gas pipelines. These permit fees were not contemplated during the setting of Union's 2007 base rates.)

5.10 MISCELLANEOUS NON-ENERGY SERVICE CHARGES

Miscellaneous Non-Energy Service Charges (Appendix I) should be outside of the price cap formula. If Union requires any changes to its Miscellaneous Non-Energy Service Charges during the plan term, Union will provide the Board with evidence that supports the change.

Union's proposed treatment under a price cap plan aligns with how miscellaneous non-energy services are handled under cost of service regulation. The price of miscellaneous non-energy service charges typically does not change during a cost of service rates proceeding and the forecast of revenues are treated as an offset to the revenue requirement of energy services.

Union did not make any changes to non-energy service charges during its trial PBR term and has made only one change since that time. Union restructured the way in which it collects the Direct Purchase Administration Charges ("DPAC") as part of the 2004 rates proceeding. In its 2007 rates proceeding, Union proposed changes to the level of DPAC.

During the settlement negotiations, parties agreed not to change the DPAC referencing the expectation that the Board intends to review system supply and direct purchase cost allocation issues in a future proceeding.

5.11 OFF-RAMPS

An off-ramp is an event that leads to a review of the price cap plan structure. It is designed to protect both customers and the utility. Customers benefit from being served by a financially viable utility.

Union believes that, in a properly constructed IR plan, there is no need for off-ramps. A net annual rate adjustment of approximately inflation, along with the other proposed parameters of this plan, would be sufficient to avoid the need to define off-ramps while providing ratepayers with reasonable rates for services.

6.0 REPORTING REQUIREMENTS

Union believes a monitoring and reporting process is integral to a well-structured price cap plan. Union supports financial reporting requirements that are not overly onerous and that serve a specific purpose. There should be no additional constraints on the utility's ability to manage its business other than what exists today (e.g. legislation, Undertakings, ARC, GDAR and RRR).

Union proposes that the reporting requirements include:

- Data filing guidelines (Section 6.1)
- SQRs (Section 6.2)
- Rate setting filings (Section 6.3)
- Reporting at rebasing (Section 6.4)

6.1 REPORTING AND RECORDKEEPING REQUIREMENT ("RRR")

The Board identified in the NGF Report (page 33) that it would consult with stakeholders and modify the RRR as necessary to meet the requirements for financial reporting in the new ratemaking framework. Subsequently, the Board issued the "Natural Gas Reporting and Record Keeping Requirements (RRR) Rule for Gas Utilities" on December 22, 2004 (see Appendix J). This information to be provided quarterly and annually to the Board for monitoring purposes could also be made available to the public. It is at a level that allows the Board and stakeholders to analyze the performance of the utilities.

6.2 SERVICE QUALITY MONITORING

One of the implementation items identified in the NGF Report (page 32) was the development of the service quality requirements in preparation of an incentive regulation framework. The Board identified that they would consult with stakeholders and modify the Gas RRR as necessary to meet the requirements.

The consultation process noted above began in the summer of 2005. The GDAR was amended on March 27, 2006 to include the new SQRs (Appendix K). A process to determine the SQR reporting requirements was initiated in early 2007 and determined by March 22, 2007 (Appendix L). The reporting will be part of the RRR annual filing with the first SQR report due on April 30, 2008. Union believes that this compliance process is sufficient to monitor service quality.

6.3 RATE SETTING FILINGS

To set annual rates during the price cap plan, Union will file the following information annually by October 1st:

- A draft rate order;
- A rate handbook with all supporting documentation including the inflation factor, X factor, and other rate adjustments, as well as an explanation of how rates have been adjusted to effect the price cap formula; and
- The deferral and variance account balances for the current fiscal year (eight months of actuals and four months of forecast). The list will include the balances proposed for clearance, the method for clearance, unit rates for clearance, and the proposed timing of the clearance.

The final rate order would need to be issued by December 15th, for implementation January 1st of the next rate year.

Union may apply for rate-related changes (i.e., rate re-design proposals and Z factors) during the plan term. If the rate-related changes are minor in nature and customer impacts are minimal, these changes could be included in the rate setting filing. However, if the rate-related changes are significant and require a longer review period, a separate application would need to be made.

6.4 REPORTING AT REBASING

There should be reporting clarity in advance of rebasing. Otherwise, assembling the cost of service filing data after the fact will be time consuming and onerous, if possible at all.

Union believes that the current Minimum Filing Requirements ("MFR") (see Appendix M) is sufficient to meet the rebasing reporting needs. Under the current MFR and assuming a five year term, Union would provide Historical Year (actuals) for 2011 (with comparisons to 2010 actuals where required), Bridge Year (a combination of actuals and forecast) data for 2012 and Test Year (forecast) data for 2013.

Union believes that a review of the key parameters of the price cap plan for the next incentive regulation plan term (e.g. 2014 – 2018 or longer) is appropriate. Union supports an update to the PEG Report, as noted on page 9 of the Board Staff Paper, assuming that such an update would be used for the next incentive regulation plan term (e.g. 2014 – 2018 or longer).

7.0 SUMMARY

The appropriate incentive regulation model for Union is a price cap framework, which would result in an annual net adjustment to rates of approximately inflation as shown in the table below. The annual increase over the five year term beginning January 1, 2008 will allow Union to make economic and efficient investment in required infrastructure, attach new customers and grow throughput. If the parameters are set properly, no off-ramps or earnings sharing are required.

Table 5
Highlights of Union's Proposal

<table>
<tr><th>Parameter</th><th colspan="6">Proposal</th></tr>
<tr><td rowspan="7">Summary PCI</td><td colspan="3">Productivity Differential</td><td colspan="3">0.52</td></tr>
<tr><td colspan="3">Input Price Differential</td><td colspan="3">0.22</td></tr>
<tr><td colspan="3">Average Use Factor</td><td colspan="3">- 0.72</td></tr>
<tr><td colspan="3">Stretch Factor</td><td colspan="3">0.00</td></tr>
<tr><td colspan="3">X Factor [A = sum of above]</td><td colspan="3">0.02</td></tr>
<tr><td colspan="3">Recent GDP IPI FDD Trend [B]</td><td colspan="3">1.86</td></tr>
<tr><td colspan="3">PCI [B-A]</td><td colspan="3">1.84</td></tr>
<tr><td>Base Rate Adjustments</td><td colspan="6">Adjust the 2007 Board approved rates for:
▪ items from previous Board Decisions, and
▪ a one time adjustment to reflect the 20-year trend weather normalization method</td></tr>
<tr><td>Plan Term</td><td colspan="6">5 year term beginning January 1, 2008</td></tr>
<tr><td>Marketing Flexibility</td><td colspan="6">Continue to have the flexibility to:
▪ Adjust fixed/variable rates on a revenue neutral basis
▪ Develop, on a timely basis, new services and change existing services when required</td></tr>
<tr><td>Price Cap vs. Revenue Cap</td><td colspan="6">Price Cap</td></tr>
<tr><td>Inflation Factor</td><td colspan="6">▪ GDP-IPI FDD Canada index (average of annualized quarterly changes of the last four quarters).
▪ Adjusted annually.</td></tr>
<tr><td rowspan="3">Service Group PCIs</td><td></td><td>Recent GDP IPI FDD Trend</td><td>X Factor Excluding Stretch and AU</td><td>Adjusted AU Factor</td><td>Net X Factor</td><td>PCI</td></tr>
<tr><td>General Service</td><td>1.86</td><td>0.74</td><td>-1.12</td><td>-0.38</td><td>2.24</td></tr>
<tr><td>All other</td><td>1.86</td><td>0.74</td><td>0.00</td><td>0.74</td><td>1.12</td></tr>
<tr><td>Y Factors</td><td colspan="6">▪ Cost of gas and upstream transportation costs
▪ DSM cost increases and other affects
▪ Elimination of long-term storage deferral account
▪ Other deferral accounts</td></tr>
<tr><td>Z Factors</td><td colspan="6">▪ Criteria as listed in Table 4 including a threshold of $1.5M
▪ Specific examples include: return on equity formula; late payment penalty litigation and damages; and permit fees</td></tr>
</table>

Non-Energy Services	Outside of price cap
Off Ramps	No off ramps required
Reporting	▪ Data filing guidelines ▪ Service quality requirements ▪ Rate setting filings ▪ Reporting at rebasing

As noted in the attached letters of support (Appendix N), Union is very committed to the communities it serves and is an active community partner and supporter. Union's participation includes corporate giving as well as corporate sponsorship of employee volunteerism in support of various community initiatives and events. Growth and expansion of communities requires that both the community and the utility work together. An appropriate price cap formula will allow Union to continue to be an active community participant.

8.0 IMPLEMENTATION OF RATE CHANGES

As well as ensuring that rates are set on a prospective basis, the regulatory approval schedule needs to allow sufficient time to communicate and explain the implications of the Board's incentive regulation decision to stakeholders. In particular, customers, shareholders, investment analysts, and debt rating agencies will view the price cap plan parameters as significant and Union will need time to communicate their implications to all interested parties.

If rates are not set on a prospective basis, Union is concerned with the impact of implementing retroactive rate changes on its customer relations. In the past, Union's customers have clearly made known their dissatisfaction with retroactive rate adjustments.

Union Gas Limited
Supplemental Weather Normalization Evidence

The purpose of this evidence is to supplement and update Union's proposal at Exhibit B, Tab 1, pages 12-16 to reflect the full effect of the 20 year declining trend weather normalization method in Union's rates effective January 1, 2008.

1.0 WEATHER NORMALIZATION

Weather normalization is an estimation method used to calculate the average or typical annual weather effect on natural gas consumption for a future year. The weather forecast is "normalized" to calculate the expected gas use by consumers in a coming year, based on expected average weather conditions. This estimate of gas consumption is then used to determine the revenue forecast. It is important that over time the estimates produced by the weather normalization method are as accurate as possible and that weather risk is symmetrical. The estimate may not be correct every year, but over time, the method of normalization should achieve a balance in the magnitude of over- and under-estimates.

The weather normalization method is also used for planning and managing Union's gas supply (including commodity purchases and upstream transportation capacity planning), planning of facilities expansions, allocating upstream transportation capacity to direct purchase customers, and allocating storage capacity to customers electing semi-unbundled and unbundled service.

2.0 ENBRIDGE'S 2007 RATES PROCEEDING (EB-2006-0034)

Enbridge analyzed nine weather normalization methods in its recent 2007 rates proceeding (EB-2006-0034). Enbridge's evidence was essentially an update of the evidence Union presented in its 2004 rates proceeding (RP-2003-0063). Like Union, Enbridge used Toronto Pearson weather data as the base for its calculations.

Enbridge added the "Energy Probe" method as a replacement to the Leo de Bever method. The Energy Probe method is a variant of the Leo de Bever method with two additional explanatory variables: a time trend and a simple 5 year moving average. Enbridge also included a 50/50 blend method of the 30 year average and the 20 year declining trend methods to replicate one of the possible results from the method that was approved for Union in the RP-2003-0063 proceeding. The only other difference was that Enbridge's historical data is on a fiscal year ending September 30 basis, while Union's historical data is on a calendar year ending December 31 basis. However, the differences in fiscal years is not material.

Enbridge's analysis showed that the 20 year declining trend was the most appropriate method for its Central region (the Greater Toronto Area) which accounts for 80% of Enbridge's volumes.

During the EB-2006-0034 proceeding, the Chair of the Board panel produced a schedule that calculated percentage differences between the 20 year declining trend method, 50/50 blend method, and the Energy Probe method relative to actual heating degree days

("HDD"s) in Enbridge's Central region. The schedule was designated Exhibit K4.4, and has been reproduced as Appendix E to the evidence filed in Tab 1. That schedule showed that the 20 year declining trend method was the most accurate for Enbridge's Central region.

The other analysis performed by Enbridge identified that the 50/50 blend method was best suited for Enbridge's Niagara region (based on the criteria of accuracy, symmetry and stability) and the Energy Probe method was best suited for Enbridge's Eastern region. Enbridge proposed in its final argument the method that was best suited for each region be implemented for that region.

In its EB-2006-0034 Decision, the Board followed Enbridge's recommended approach and approved three weather normalization methods for Enbridge:

- the 20 year declining trend normal for the Central region (Greater Toronto Area)
- the 50/50 blend normal for the Niagara region
- and the Energy Probe normal for the Eastern region (Ottawa)

3.0 UNION'S 2004 RATES PROCEEDING (RP-2003-0063)

In the RP-2003-0063 proceeding, Union proposed to change the way in which it calculated weather normalized consumption, moving from the 30 year rolling simple average method to the 20 year declining trend method.

To set the context for assessing potential new weather normalization methods, Union established five objectives in the RP-2003-0063 proceeding: symmetry, accuracy, stability, sustainability and simplicity. These objectives are described in further detail in Appendix A. Symmetry, accuracy and stability were quantitatively measured, whereas sustainability and simplicity were qualitatively measured. Stability, sustainability and simplicity were assigned the least weight in Union's analysis of the best method to use.

Enbridge used the three quantitatively measured objectives (symmetry, accuracy and stability) as its criteria in analyzing the various weather normalization methods in the EB-2006-0034 proceeding. This difference in evaluation technique removed the two subjective criteria and also the criteria with the lowest weights. If Union had performed its analysis in 2004 using only the three quantitative criteria, the conclusions would not have changed. Union would still have proposed the 20 year declining trend method.

In the RP-2003-0063 proceeding, Union analyzed the following methods using the criteria it developed: 30-year rolling simple average, trend methods (30-years and 20-years), Enbridge's historical weighted trend (also known as the Leo de Bever method), 20 year trend with forecast information, 20-year rolling simple average and 10-year rolling simple average method.

In its RP-2003-0063 Decision, the Board expressed concerns with the statistical evidence presented by Union. In order to reduce rate shock and test the suitability of changing the weather normalization method the Board weighted the 30 year rolling simple average and the 20 year declining trend 70/30. Further, the Board indicated that it would allow 5% changes in the weightings per year until a 50/50 weighting was established. Although Enbridge presented essentially the same analysis and evidence in the EB-2006-0034 proceeding, and the results of the traditional statistical regression diagnostic tests were questioned, the Board did not raise any of the statistical concerns in Enbridge's EB-2006-0034 Decision as the Board referenced in Union's RP-2003-0063 Decision. Nevertheless, Union will address each of the concerns raised about the statistical data below.

One concern raised by the Board was whether an estimator derived from ordinary least squares was more or less appropriate than using a more sophisticated regression technique. A trend line by construction is the estimate with the minimum error.[1] The linear trend method employed by Union and Enbridge is a simple mathematical representation of declining HDD over time. The method does not seek to explain, nor need it explain, the causes of the declining HDD. Rather, the method seeks to allow Union and Enbridge to state a "normal" HDD in the future, i.e. one that will not be biased in forecast error and is relatively accurate and relatively stable. In its EB-2006-0034 Decision, the Board concluded that a linear trend method is the appropriate method to be used (page 10).

[1] Minimum Least Square Error (MSE) is a basic and commonly used statistical procedure. This error analysis procedure finds the minimum error that is present in either a causal or time series statistical pattern. The MSE is the average of the total least squares of all the errors observed from the equation estimates. The square of the error is computed as this addresses both the presence of positive and negative errors and the effect of small and large errors.

Another concern raised in the RP-2003-0063 proceeding was the application of traditional statistical regression diagnostic tests (i.e. the adjusted R^2, the t-test and the F-test) and why Union had not applied these analytical tools. Union did not employ these tools because they are not relevant to the setting of the trend line. That is because these diagnostic tests are relevant primarily when evaluating a cause and effect relationship. Union was not, and Enbridge was not, seeking to establish a cause and effect relationship between the number of HDDs and the year in which they occurred. All Union and Enbridge were trying to do with the simple trend line is to have an estimator that would produce the most symmetrical, accurate and stable result in setting the normalized HDDs over time.

The issue of heteroskedasticity/non-stationarity, which is the increasing variability over time of a variable, was also raised in the RP-2003-0063 proceeding. The presence of heteroskedasticity can mean that the statistical regression diagnostic test results (i.e. the adjusted R^2, the t- test and the F-test) are no longer valid. As discussed above, the results of the statistical regression diagnostic tests were not the criteria Union used to select the best method. Accordingly, Union did not provide a Chow test for heteroskedasticity in its RP-2003-0063 pre-filed evidence. However, Union was asked to provide the results of the Chow test and did so in response to Undertaking N3.4 (see Appendix B). The Chow test results showed that heteroskedasticity was not an issue.

4.0 RELATIONSHIP BETWEEN TORONTO DATA AND UNION

The weather normalization evidence in both Union's 2004 rates proceeding (RP-2003-0063) and Enbridge's 2007 rates proceeding (EB-2006-0034) were based on Toronto Pearson airport weather data. The statistical correlation between weather in Union's franchise area and Toronto Pearson airport is very high: 99 percent for Union's Southern Operations area and 94 percent for Union's Northern & Eastern Operations area. This means that Union can and should use the Toronto Pearson data as the basis for evaluating weather normalization methods.

5.0 NO DIFFERENCE BETWEEN WHAT ENBRIDGE PROPOSED FOR ITS CENTRAL REGION AND UNION'S SOUTHERN AND NORTHERN & EASTERN OPERATIONS AREAS

The Board has now approved the use of the 20 year declining trend method in Enbridge's Central region. The weather data for this area is based on Toronto Pearson weather data. Union can find no differences in the analysis Enbridge provided for its Central region and the analysis that Union undertook for its Southern and Northern & Eastern Operations areas.

6.0 THE 20 YEAR DECLINING TREND IS APPROPRIATE

Union's evidence in Tab 1 proposes to reflect the full effect of the 20 year declining trend weather normalization method, effective January 1, 2008. This proposal is based on

Union's belief, supported by its evidence filed in the RP-2003-0063 proceeding and by the Board's recent EB-2006-0034 Decision, that the 20 year declining trend weather normal method is the best weather normalization method.

The two tables presented below provide an analysis of the three weather normalization methods the Board approved for Enbridge, on the same basis as the tables provided by the Chair of the Board panel (Exhibit K4.4) in the EB-2006-0034 proceeding.

The tables indicate that the 20 year declining trend method is more accurate than the two other methods examined for both Union's Southern Operations area and Union's Northern & Eastern Operations area. This is the conclusion that can be reached by analyzing the average error of each method. The lower the average error, the more accurate the results.

In terms of symmetry, the 50/50 blend method is the most symmetrical in the Southern Operations area on a frequency count. The 20 year declining trend method is as symmetrical as the 50/50 blend method in the Northern & Eastern Operations area. These results can be found by comparing the number of times the method over-estimated the number of HDDs relative to the number of estimates. For example, the 20 year declining trend method over-estimates just over 50% of the time in the Northern & Eastern Operations area, indicating the desired symmetry is present in the 20 year declining trend method.

The 50/50 blend method performs best in terms of stability for both the Southern Operations Area and the Northern & Eastern Operations area. This method is more stable because it includes a component of the 30 year rolling simple average which smoothes variations over time.

Like Enbridge, Union believes that accuracy and symmetry are equally important. Although it is important to Union to have stable HDD forecasts over time, Union views stability as less significant than accuracy and symmetry.

Table 1
Union Southern Operations Area Weather Normal Comparison

Test Year	Actual HDD	Blended 50 50 Method			20 Year Declining Trend Method			Energy Probe Method		
		Estimate	Diff.	% Diff.	Estimate	Diff.	% Diff.	Estimate	Diff.	% Diff.
1990	3,572	3,965	394	11.0%	3,950	379	10.6%	4,014	443	12.4%
1991	3,631	3,983	352	9.7%	3,977	346	9.5%	4,151	520	14.3%
1992	4,031	3,926	(105)	(2.6)%	3,872	(159)	(3.9)%	3,886	(145)	(3.6)%
1993	4,105	3,876	(229)	(5.6)%	3,779	(326)	(7.9)%	3,732	(373)	(9.1)%
1994	4,055	3,902	(152)	(3.8)%	3,828	(226)	(5.6)%	3,843	(211)	(5.2)%
1995	3,987	3,904	(83)	(2.1)%	3,826	(161)	(4.0)%	3,955	(32)	(0.8)%
1996	4,153	3,918	(235)	(5.7)%	3,847	(306)	(7.4)%	4,004	(149)	(3.6)%
1997	4,005	3,907	(99)	(2.5)%	3,824	(181)	(4.5)%	4,008	3	0.1%
1998	3,225	3,942	717	22.2%	3,890	666	20.6%	4,024	799	24.8%
1999	3,641	3,944	303	8.3%	3,896	255	7.0%	3,999	358	9.8%
2000	3,876	3,874	(2)	(0.1)%	3,780	(96)	(2.5)%	3,795	(82)	(2.1)%
2001	3,467	3,851	384	11.1%	3,745	278	8.0%	3,775	308	8.9%
2002	3,636	3,869	234	6.4%	3,784	148	4.1%	3,847	211	5.8%
2003	3,958	3,824	(134)	(3.4)%	3,707	(251)	(6.3)%	3,821	(137)	(3.5)%
2004	3,786	3,798	12	0.3%	3,677	(109)	(2.9)%	3,887	101	2.7%
2005	3,778	3,818	40	1.1%	3,709	(69)	(1.8)%	3,874	96	2.5%
2006	3,332	3,817	484	14.5%	3,715	383	11.5%	3,814	482	14.5%

	Blended 50 50 Method		20 Year Declining Trend Method		Energy Probe Method	
ACCURACY: Average Error	111	3.5%	34	1.4%	129	4.0%
Frequency Over Estimated	9		7		10	
Total Number of Estimates	17		17		17	
SYMMETRY: frequency / total	52.9%		41.2%		58.8%	
STABILITY: std. dev.	55		87		112	

Table 2
Union Northern & Eastern Operations Area Weather Normal Comparison

Test	Actual	Blended 50 50 Method			20 Year Declining Trend Method			Energy Probe Method		
Year	HDD	Estimate	Diff.	% Diff.	Estimate	Diff.	% Diff.	Estimate	Diff.	% Diff.
1990	4,994	5,252	258	5.2%	5,194	200	4.0%	5,146	152	3.1%
1991	5,019	5,285	267	5.3%	5,244	226	4.5%	5,350	331	6.6%
1992	5,489	5,251	(238)	(4.3)%	5,182	(306)	(5.6)%	5,182	(307)	(5.6)%
1993	5,460	5,216	(244)	(4.5)%	5,115	(345)	(6.3)%	5,095	(366)	(6.7)%
1994	5,294	5,270	(24)	(0.5)%	5,214	(79)	(1.5)%	5,260	(34)	(0.6)%
1995	5,358	5,268	(90)	(1.7)%	5,206	(151)	(2.8)%	5,306	(51)	(1.0)%
1996	5,550	5,275	(275)	(5.0)%	5,220	(330)	(5.9)%	5,270	(280)	(5.1)%
1997	5,384	5,267	(117)	(2.2)%	5,210	(175)	(3.2)%	5,299	(85)	(1.6)%
1998	4,457	5,316	858	19.3%	5,303	846	19.0%	5,339	882	19.8%
1999	4,754	5,314	560	11.8%	5,303	549	11.5%	5,332	578	12.2%
2000	5,158	5,226	68	1.3%	5,160	2	0.0%	5,163	4	0.1%
2001	4,592	5,179	587	12.8%	5,077	486	10.6%	5,168	576	12.6%
2002	4,997	5,189	192	3.9%	5,107	110	2.2%	5,234	237	4.7%
2003	5,111	5,104	(7)	(0.1)%	4,960	(151)	(3.0)%	5,206	95	1.9%
2004	5,148	5,089	(60)	(1.2)%	4,953	(195)	(3.8)%	5,404	255	5.0%
2005	4,829	5,089	259	5.4%	4,948	119	2.5%	5,269	440	9.1%
2006	4,423	5,084	662	15.0%	4,949	527	11.9%	5,145	722	16.3%

ACCURACY: Average Error	156	3.6%	78	2.0%	185	4.2%
Frequency Over Estimated	9		9		11	
Total Number of Estimates	17		17		17	
SYMMETRY: frequency / total	52.9%		52.9%		64.7%	
STABILITY: std. dev.	80		122		87	

EVALUATION CRITERIA FOR WEATHER NORMALIZATION METHODS

The five objectives that Union established in the RP-2003-0063 proceeding to evaluate weather normalization methods are: symmetry, accuracy, stability, sustainability and simplicity.

- Symmetry – the method should result in an unbiased normal temperature condition where there are equal expectations of positive variations and negative variations from actual HDDs. The smaller the mean percent error (MPE), the more symmetrical the method. In the case of the Bias Frequency, the closer the ratio is to 1:1, the less biased (more symmetrical) the method.

- Accuracy – the method should result in a point estimate that has a minimum variance over time between the normal HDD and the actual HDD value. Accuracy is an error measure that indicates over time the difference between the estimator and actual weather. The most precise accuracy measurement tool is the root mean square error (RMSE). For the RMSE, smaller test results mean greater accuracy.

- Stability – the new method should result in year over year normalized HDD estimate that does not vary significantly. Stability is a measure of variation; the standard deviation is used to measure variance. Increasing instability means that the fluctuation from one year's forecast to the next is increasing over time. The increase in variation of the historical weather statistics is a direct contributing factor to increasing instability. For stability, a smaller standard deviation means that the method provides a more stable estimate because the difference between the forecast HDDs in two consecutive years is less significant.

- Sustainability – the new method should stand the test of time and not require significant amendments in the near future. Sustainability is a qualitative assessment of the company being able to understand and maintain the tools underlying the method, over an extended period. The greater the reliance on external participants in the calculation of the methods the lower the assessment of its sustainability.

- Simplicity – the method and its results should be easily understood and administered. Simplicity addresses the need for internal and external stakeholders to understand and accept the approach that is being taken to calculate the weather normal. The greater the reliance on simple arithmetic methods and limited steps between the input data and the results, the easier it will be to understand the outcome.

Exhibit N3.4
Vol. 3, para. 354

UNION GAS LIMITED

Undertaking of Mr. Fogwill
To Mr. Aiken

Please perform the Chow test, on a best-efforts basis.

A Chow test was performed on the 20 Year trend equation for the Toronto Pearson data period 1983 to 2002. The test result for this equation is 2.85. The Chow test result of 2.85 indicates that the estimated trend is the same during the first 10 years of the 20 year period as it is during the last 10 years of the period.

Witness: Allan Fogwill
Question: October 8, 2003
Answer: October 14, 2003
Docket: RP-2003-0063