Ontario Energy Board
EB-2006-0209

Staff Discussion Paper

On an Incentive Regulation Framework for Natural Gas Utilities

January 5, 2007

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Ontario Energy Board report, *Natural Gas Regulation in Ontario: A Renewed Policy Framework* dated March 30, 2005, outlined the key parameters that need to be addressed in an incentive regulation framework for natural gas utilities in Ontario.

Board staff has undertaken research, commissioned expert advice and consulted with stakeholders on the further development of such a framework.

This discussion paper outlines a potential incentive regulation framework. The key elements of the framework are:

- A price cap mechanism based on the following formula:

  $\%\Delta P = \% \Delta GDP\ IPI\ \ FDD – (X + DU) + Z + Y$

  where:
  - ΔP is the annual percentage change in price;
  - ΔGDP IPI FDD is the percentage change in the actual Canada GDP IPI for final domestic demand;
  - X includes the implicit input price differential, productivity differential, and stretch factor;
  - DU is the declining average usage factor (which is separate from the X factor);
  - Z provides for non-routine rate adjustments for events that are beyond the control of the utilities' management; and
  - Y captures routine (or expected) rate adjustments that have been established in the base year;

- A plan term of four or five years (i.e., base year plus 4 or 5 years); and

- Provision for off-ramps.

The services of the consulting firm Pacific Economics Group were retained to support Board staff in this process. Pacific Economics Group is conducting a Total Factor Productivity study and other analyses to be completed in early 2007.

1 INTRODUCTION

This discussion paper sets out Board staff's initial thoughts on an incentive regulation ("IR") framework for Union Gas Limited ("Union"), Enbridge Gas Distribution Inc. ("Enbridge"), and Natural Resource Gas Limited ("NRG"). In developing the concepts set out in this paper Board staff were informed by:

1. The incentive regulation policy described in the Ontario Energy Board's March 30, 2005 report entitled *Natural Gas Regulation in Ontario: A Renewed Policy Framework* (the "NGF Report");

2. The views of stakeholders expressed in consultations with Board staff;

3. Board staff's own research regarding incentive regulation mechanisms adopted and considered in other jurisdictions; and

4. The Pacific Economics Group ("PEG"), Board staff's technical expert.

In the NGF Report, the Ontario Energy Board ("Board" or "OEB") stated that a firm framework would ensure that consistent expectations are held by both utilities and customers. The framework should also meet the following criteria: establish incentives for sustainable efficiency improvements that benefit both customers and shareholders; ensure appropriate quality of service for customers; and create an environment that is conducive to investment, to the benefit of both customers and shareholders. The Board believed that a ratemaking framework that meets these criteria would ensure that the statutory objectives of consumer protection, infrastructure development and financial viability are met, and that rates would be just and reasonable.

The Board, in the NGF Report, addressed the following key parameters for an IR framework:

- Annual adjustment mechanism;
- Rebasing;
- Earnings sharing mechanism;
- The term of the plan;
- Off-ramps, Z factors and deferral or variance accounts;
- Service quality monitoring;
- Financial reporting; and
- Filing guidelines.

The Board, in the NGF Report, stated that an earning sharing mechanism ("ESM") should not form part of the IR plan. The Board believed that an ESM would reduce the utility's efficiency incentives.

The Board subsequently dealt with some of these parameters as follows:

- The Board undertook a consultation to amend the Gas Distribution Access Rule ("GDAR") to establish a service quality framework (standards and reporting requirements) for the natural gas utilities.

- The Board established 2007 as the test year to be used to set base year rates for Union and Enbridge. At this time, base year rates have been set for Union, and Enbridge's 2007 rate case proceeding is currently underway. With regard to NRG, the Board has stated that it will have another cost-of-service application in fiscal year 2008.

- The Board issued Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications to be used for setting the 2007 base year rates.

This discussion paper addresses the remainder of the parameters listed above. With the benefit of stakeholder consultation, this paper has been produced to share Board staff's current thinking on an incentive regulation framework.

1.1 Structure of the Discussion Paper

This discussion paper is organized as follows. Section 2 describes Board staff's view on the underlying principles of an IR plan while sections 3 and 4 address the IR plan design and other issues respectively.

1.2 Process and Stakeholder Meetings

Board staff focused its research, commissioned expert advice and consulted with stakeholders on the following parameters:

- The annual adjustment mechanism (i.e. inflation factor, and X factor including a stretch factor);
- The term of the IR plan;
- Routine and non-routine adjustments;
- The need for off-ramps;
- The reporting requirements that will apply during the term of the IR plan;
- Rebasing requirements;
- The treatment of demand side management ("DSM"); and
- The need for any other adjustments.

Starting in October 2006, Board staff held a number of meetings with stakeholders (listed in Appendix 1). At these meetings, Board staff outlined a list of key elements in an IR plan based on the above listed parameters to initiate discussion on the IR framework. Stakeholders were asked to review the list to confirm accuracy and completeness. Based on these stakeholder discussions, Board staff revised the list. On November 2-3, 2006, an all stakeholder meeting was held where stakeholders, Board staff and the Board's technical expert presented material. This meeting assisted Board staff in formulating the key elements of an IR plan. Then, at the November 24th stakeholder meeting, Board staff presented its current thinking on the generic IR framework for natural gas utilities. All material related to these consultations are available on the Board's website.

2 UNDERLYING PRINCIPLES

The Board's ultimate responsibility is to set rates that are just and reasonable. It has been left to the discretion of the Board to select, amongst available approaches, the rate-setting methodology that is optimally suited to achieving that end and to the Board's guiding objectives as set out in section 2 of the *Ontario Energy Board Act, 1998*.

In the NGF Report, the Board stated that an effective ratemaking framework must meet the following criteria:

- establish incentives for sustainable efficiency improvements that benefit both customers and shareholders;
- establish appropriate quality of service for customers; and
- create an environment that is conducive to investment to the benefit of both customers and shareholders.

Building upon this foundation, Board staff believes that the Board's statutory responsibility is best fulfilled, and its statutory objectives in relation to natural gas are best promoted, using a rate-setting methodology that is designed on the basis of the following principles:

1. **Storage, transmission and distribution rates should be predictable and stable.** This should provide an environment where utilities and consumers are better able to plan and make decisions.

2. **The rate adjustment mechanism should be clear.** The mechanism should be clearly articulated and not be subject to multiple interpretations by stakeholders.

3. **The pursuit of efficiency should be encouraged.** The plan should encourage greater economic efficiency by providing incentives for the implementation of sustainable operational efficiency improvements. The benefits of these efficiency improvements should be shared by customers and shareholders.

4. **Utilities should be encouraged to continue infrastructure investment to maintain safety and reliability.** The plan should encourage investment of funds to maintain safety and reliability of gas delivery.

5. **Customer service standards should be maintained.** Appropriate service quality standards are the cornerstone of consumer protection. A service quality framework should include performance standards, reporting requirements, and compliance measures to ensure customer service standards are maintained.

6. **DSM activities should be encouraged.** The IR framework and the conservation and demand management policies should be compatible.

7. **A balance between the financial viability of the utilities and the interests of natural gas consumers should be maintained.** A financially viable natural gas distribution sector will help to sustain a robust natural gas market in Ontario, which will benefit consumers in terms of price, reliability and safety.

8. **System expansion into new communities should be facilitated.** Not all parts of Ontario have access to natural gas service. The plan should ensure that where extension of such service is economically viable, the utility has a reasonable opportunity to earn a return on its investment in a timely manner.

In addition, the rate-setting methodology should be capable of implementation through a regulatory process that is efficient while at the same time addressing the concerns of interested parties and ensuring openness and transparency. The costs of administering the plan, including the costs imposed on all participants, should not exceed the benefits to be derived from the plan.

At the stakeholder meetings, stakeholders generally agreed with the above principles. One stakeholder proposed that financial viability of the industry needed to be included, and has been reflected above.

Other stakeholders suggested as a further principle that ratepayers be better off, or at least not worse off, in real terms, in moving from cost-of-service ("COS") regulation to IR (in terms of rates, service quality and financial soundness). Board staff believes that this is an underlying assumption of the IR plan.

3 INCENTIVE REGULATION PLAN DESIGN

3.1 Price and Revenue Caps

Price and revenue caps are common types of incentive regulation mechanisms. Under these mechanisms, prices or revenues are set independent of costs for some years. During this period, the utility can increase its profitability by improving performance. Thus, price and revenue cap mechanisms generate incentives for cost containment and other operational efficiencies.

3.1.1 Price Cap

A price cap plan sets the maximum rate escalation that the utility is allowed. It is called a cap because the utilities usually have the flexibility to charge rates that are less than the maximum allowed. Price cap index ("PCI") formulas vary from plan to plan but have the following general structure. The PCI growth rate is the difference between the growth in an inflation measure ("P") less an X factor, plus or minus non-routine adjustments due to extraordinary events ("Z"), as depicted in the following formula:

$$\boxed{growth\ PCI = growthP - X \pm Z}$$

3.1.2 Revenue Cap

A revenue cap limits the escalation in revenue that the utility is allowed. The revenue requirement in a year is set according to the previous year's revenue requirement indexed by an inflation factor and adjusted for an X factor, output growth and non-routine adjustments due to extraordinary events. A balancing account mechanism is established to capture the difference between actual revenue and the approved revenue requirement.

A revenue cap index ("RCI") typically has the following general form:

$$\boxed{growth\ RCI = growthP - X + growthO \pm Z}$$

Where "O" is a measure of output growth.

3.1.3 Comparison

Revenue caps differ from price caps in reducing both the incentive and risk to the utility associated with demand fluctuations. 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. Similarly, utilities will be protected in cases where they experience decline in throughput without corresponding decrease in costs.

Since prices (not quantities) are constrained under a price cap, revenue caps can be more compatible with energy efficiency programs. However, the design of a price cap can be adapted to meet energy efficiency objectives. For example, some price cap plans treat expenditures associated with energy efficiency programs as a rate adjustment. In contrast, under revenue caps, rates will automatically be adjusted to reflect the declining average usage in customer demands.

Price caps generally result in rates that are more stable and predictable than a revenue cap mechanism. This is a result of the balancing account under a revenue cap. Additionally, revenue caps typically do not specify how revenue growth would be reflected in rates.

Revenue caps have been used in circumstances where utilities have been exposed to declining average use per customer because they can provide automatic compensation. Under a revenue cap, the compensation is proportional to the declining average use that actually occurs during the term of the plan. The X factor can then be designed solely to reflect cost efficiency trends. Under a price cap, rate relief for declining average use per customer is accounted for in the X factor, or alternatively can be dealt with through a separate rate adjustment. In either case, the compensation is generally fixed for the term of the plan and is based on historical trends.

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.

While Board staff sees merits to a revenue cap approach, Board staff is of the view that a price cap better reflects the principles of rate stability and predictability and economic efficiency, as well as allowing for a more efficient regulatory process.

3.2 Inflation Factor

The inflation factor represents the change in the cost of the inputs purchased by the gas utilities.

Figure 1 outlines the different options for an inflation measure.

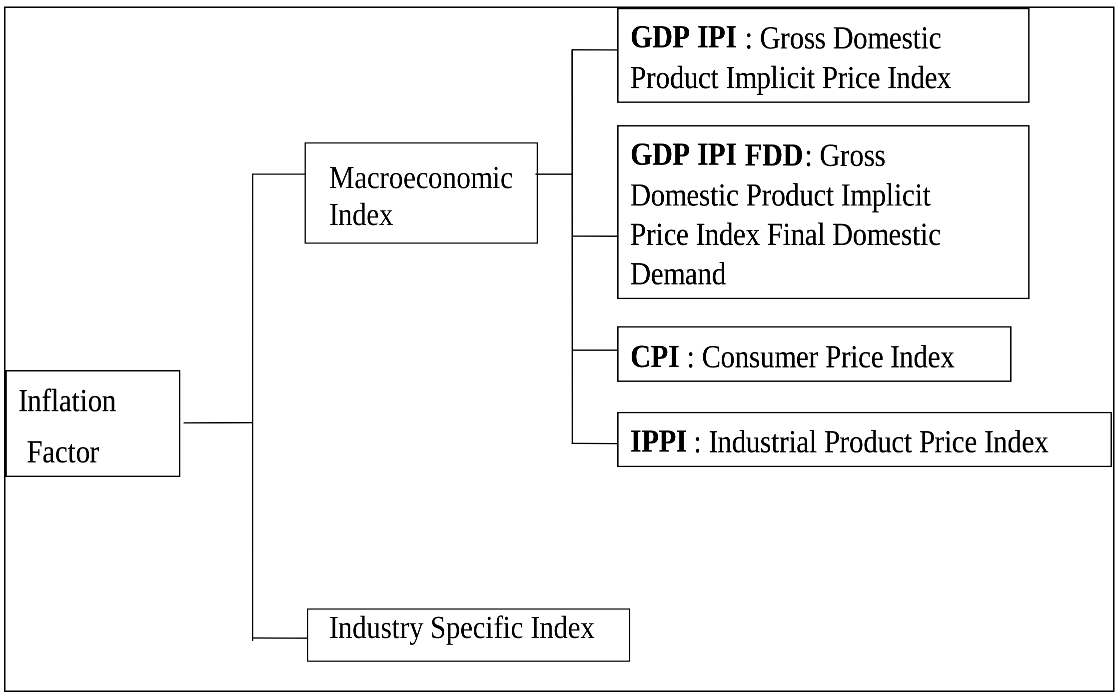

Figure 1: Inflation Factor Options

Board staff is of the view that the following criteria should be considered in selecting an appropriate index:

- Coverage: the index should accurately capture the likely change in the utilities' costs during the term of the IR plan;
- Simplicity: the index should be simple enough to be understood by rate payers. Complex calculations for the index estimation should be avoided;
- Credibility: the index must originate from a credible source or should be calculated on the basis of a robust study;
- Availability: the index should be available on a timely basis for the implementation of rates each year; and
- Stability: volatile indices should be avoided since one of the principles underlying the plan is that rates should be stable and predictable.

3.2.1 Industry Specific or Macroeconomic

Macroeconomic measures (outlined in Figure 1) 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.

Macroeconomic indices are economy-wide measures and therefore they do not track industry specific input price variations. In contrast, an industry-specific input price index (IPI) would be designed and calculated to specifically track the inflation of capital, labour and materials for natural gas utilities. The Board applied an IPI in its first generation incentive mechanism for electricity distributors. In the case of Union's and Enbridge's trial performance based regulation plans, the Board applied macroeconomic indices.

Board staff is of the view that an IPI would be more difficult to implement than a macroeconomic index because its design can be subject to controversy and its results tend to be very volatile if not smoothed.[1] Controversy can also arise over the best smoothing mechanism.

Therefore, Board staff sees the merit in using a macroeconomic index as the inflation factor with the caveat that the X factor would be adjusted to include an input price differential and a productivity differential. A detailed explanation of the input price and productivity differentials is outlined below in the X Factor section.

3.2.2 Macroeconomic index

Union and Enbridge indicated their preference for using an annual forecast of CPI as the inflation measure. The reasons outlined were: CPI is better understood than GDP IPI by ratepayers and CPI forecasts are available from consensus forecasts and a number of other sources.

Board staff reviewed the different macroeconomic price indices in terms of the criteria of coverage, simplicity, availability, stability and credibility. Table 1 highlights the advantages and disadvantages of each of these indices.[2]

---

[1] See PEG's presentation dated November 2-3, 2006 available from the OEB website

[2] A detailed explanation of the advantages and disadvantages of each index was presented at the stakeholder meeting on November 10, 2006. This presentation is available from the OEB website

Table 1: Index Comparison

Criteria	GDP IPI FDD	GDP IPI	CPI	IPPI
Coverage	✓ Broad coverage of goods and services relevant to the gas industry (capital, labour, materials)	✓ Broad coverage of goods and services relevant to the gas industry (capital, labour, materials)	× Limited coverage of goods and services relevant to the gas industry	× Limited coverage of goods and services relevant to the gas industry
Simplicity	× Lower customer familiarity than CPI ✓ Facilitates the calculation of input price and productivity differentials used in X factor calibration	× Lower customer familiarity than CPI ✓ Facilitates calculation of X factor, since the TFP trend of the economy corresponds to GDP IPI	✓ Customer familiarity × Does not facilitate calculation of X factor	× Lower customer familiarity than CPI × Does not facilitate calculation of X factor
Availability	✓ Published annually for Canada and Ontario and quarterly for Canada × Subject to future revisions	✓ Published annually for Canada and Ontario and quarterly for Canada × Subject to future revisions	✓ Published monthly ✓ Subject to fewer and minor future revisions	✓ Published monthly × Subject to future revisions
Stability	✓ Less volatile due to the exclusion of petroleum products, gas exports, and other price-volatile exports	× More volatile than GDP IPI FDD	× More volatile than GDP IPI FDD	× Very volatile
Credibility	× Very few forecasts available. None are publicly available	× Few forecasts available; not in consensus forecast. Some are publicly available	✓ Forecasts widely available from consensus, banks, public institutions	✓ Forecasts published by consensus. Few publicly available forecasts

The above assessment, which attributes equal weight to each of the five criteria, ranks the GDP IPI FDD and the CPI equally. Board staff however thinks that the GDP IPI FDD should be used as the inflation factor in the IR plan. Board staff recognizes that GDP IPI FDD could be more difficult to explain to ratepayers than CPI. However, Board staff's view is that this potential complexity is offset by the advantages of GDP IPI FDD in terms of coverage, volatility and the simplicity it brings to the calculation/calibration of the X factor.

3.2.3 Implementation Details

Board staff also examined the availability of a provincial and federal version of the GDP IPI FDD, and whether this index should be fixed or variable during the plan term. In addition, Board staff researched whether the index should be an actual or a forecast value.

Canada or Ontario GDP IPI FDD

GDP IPI FDD is published for Ontario and Canada. Board staff notes that the differences between the federal and provincial indices are minor.

GDP IPI FDD Ontario is published annually in April of the following year. The federal version is published annually in February of the following year and also quarterly. Since a rate order needs to be in place by December 15th (for Union and Enbridge in order to implement rates effective January 1st), the inflation adjustment would have a two year lag if an annual index were used.

To avoid this time lag so that rates reflect the most recent inflation trend, Board staff sees the benefit of using the quarterly GDP IPI FDD Canada index. Specifically, a simple average of the annualized changes of the last four quarters should be used.

Union raised concerns over Stats Canada's revisions to the GDP IPI FDD. Board staff understands that published statistical data may be subject to revision by Stats Canada. However, Board staff shares the view of another stakeholder who commented that using an annualized approach (i.e., average of the annual changes for the last four quarters) minimizes the impact of the revisions in a particular quarter. It should be noted that the annual change in GDP IPI FDD published by Stats Canada is also calculated using this methodology.

Moreover, in the 2000-2003 revisions to the Income and Expenditure Accounts, Stats Canada acknowledged that “in general, price indexes at the most detailed level employed in the deflation of GDP were unrevised”.[3] Board staff believes that the use of the GDP IPI FDD (which excludes exports) will reduce a source of revisions, especially those related to changes in the exchange rate.

Fixed or variable

In its July 21, 2001 Decision with Reasons in proceeding RP-1999-0017, the Board rejected a fixed inflation factor for Union’s PBR plan because a fixed inflation factor would unnecessarily increase the risk exposure for all parties.

On that basis, the inflation factor should be adjusted every year to take into account the most recent inflation trend.

Forecast or actual value

Enbridge and Union expressed concern over the use of an actual value as a proxy for future inflation rather than a forecast value. They also indicated that they did not see the merit of having a “true up” mechanism to reflect actual inflation, as an adjustment after-the-fact serves little purpose.

Board staff is not convinced that a forecast value should be used for two reasons. First, there are very few forecasts available of GDP IPI FDD and the forecaster with the best performance[4] does not publish GDP IPI FDD forecasts. Therefore, the opportunity to mitigate the risk of forecasting errors is minimal. Second, Board staff believes that with relatively stable inflation levels (as the ones seen in the last 15 years), the inflation of a previous year is a reasonable proxy of inflation in the following year. As illustrated in Table 2 on the next page, over the last five years, the cumulative error of GDP IPI FDD Canada (measured as the difference between actual and the lagged GDP IPI FDD) is lower than the cumulative error of the CPI forecast.

[3] Statistics Canada Catalogue No 13-010-XIE, p 29
[4] As identified by the Campbell and Murphy study on “The Recent Performance of the Canadian Forecasting Industry” published in Canadian Public Policy, Vol XXII, no 1 2006

Table 2

Year	GDP IPI FDD CAN Actual	GDP IPI FDD CAN Year ending June of Previous Year (1)	Difference GDP IPI FDD Actual vs Previous Year	CPI CAN Actual	CPI CAN Forecast (2)	Difference CPI Actual vs Forecast
2001	1.7	1.8	-0.1	2.5	2.4	0.1
2002	2.3	2.3	0.0	2.2	1.6	0.6
2003	1.4	1.7	-0.3	2.8	2.4	0.4
2004	1.7	2.3	-0.6	1.8	1.6	0.2
2005	1.8	1.2	0.6	2.2	1.9	0.3
Cumulative Error in 5 years			**-0.3**			**1.7**

(1) Calculated as the simple average of the four annualized changes in the quarterly GDP IPI FDD index from Stats Canada.
(2) Data from consensus forecast: average of 16 forecasts issued in December of the previous year.

3.3 X Factor[5]

Index research is widely used in North American regulation to design rate escalation mechanisms. A key result of the research is that the trend in the prices charged by an industry that earns, in the long run, a competitive rate of return is equal to the industry's unit cost trend. This trend is, in turn, equal to the difference between an industry's input price and total factor productivity ("TFP") trends. The growth rate formula for a price cap index can thus include the difference between an input price index for the industry and an X factor that is calibrated so that the price cap index tracks the unit cost trend of the industry. This approach to X factor design was used by the Board in its first incentive regulation regime for electricity distributors.

The term "calibration" is employed because a stretch factor is commonly added to the X factor to share with customers the expected benefits of improved performance that are occasioned by the move from COS to incentive regulation. The stretch factor will be higher the greater the expected performance improvement.

The standard formula for index-based X factor design is different when an index such as GDP IPI is used as the inflation measure in the price cap index escalation formula. As a measure of inflation in the prices of consumer products and other final goods and services, GDP IPI is a measure of output price inflation. As such, it already reflects the input price and productivity trends of the economy, much as an index of inflation in the rates charged by a group of power distributors would reflect their input price and productivity trends. Apart from the stretch factor, an X factor is therefore needed in a price cap index driven by GDP IPI growth only to reflect the difference between the input price and productivity trends of the industry and the economy.

The growth in a TFP trend index is the difference between the trends in summary output and input quantity indexes. The growth in the summary output quantity index is a weighted average of the growth in subindexes that represent various output dimensions (e.g., the number of customers served and throughput). In a TFP index that conforms to the index logic conventionally used in price cap index design, the weights are the shares of billing determinants in the utility's total revenue. These weights reflect the impact of output growth on revenue and not on cost.

Rates for energy distribution services commonly feature customer charges (sometimes called access) and either volumetric charges or demand charges. Rate designs frequently do not reflect the drivers of distribution costs well. For example, distribution costs are commonly driven chiefly by customer growth, whereas distribution revenues are commonly driven chiefly by delivery volumes

---

[5] This section was written by Board staff's technical expert from PEG

and contract demand. Under these circumstances, a TFP index calculated in the conventional manner using revenue shares will be sensitive to trends in average use, and will differ from a TFP index designed to measure only cost efficiency trends. Measured TFP growth will be slowed by declining average use and accelerated by increasing average use. Research by PEG has shown that declines in average use are being experienced by many gas utilities today. Contributing factors include high gas prices and improvements in the efficiency of gas-fired equipment.

During the consultation process, stakeholders provided several comments that have a bearing on the design of X factors for Ontario gas utilities:

1. Enbridge and Union expressed concern that the rate escalation mechanism should provide needed rate relief for declining average use per customer trend in the province by some means.

2. Other stakeholders voiced concern about a productivity differential that is sensitive to declining average use per customer trends. Stated reasons included:
   - a desire to understand the separate impacts on TFP of improved cost efficiency and declining average use per customer trends; and
   - a concern that the declining average use per customer trend should affect only rates for residential, commercial, and other customers with weather-sensitive demand.

3. Enbridge expressed concern that the price cap index may not allow enough price escalation to fund needed main replacement programs and system expansions. Absent such funding, Enbridge requested that funding for main replacement programs and system expansions be dealt with through a cost pass-through.

4. Some parties expressed an interest in investigating whether a separate X factor for transmission services would be warranted.

3.3.1 Overview of the Research

Board staff has retained PEG to undertake input price and productivity research in support of X factor design. PEG will work with participating Ontario utilities to develop the data needed to measure their recent historical input price, output price (i.e. rate) and productivity trends. A sample period of at least ten years ending in 2005 is desirable for this research.

The study will also consider the input price and productivity trends of a sample of 38 U.S. gas utilities. These trends will be calculated from a sample of U.S. data of a period of more than ten years gathered by PEG.

If the data obtained from Ontario gas utilities are satisfactory, PEG expects that the productivity differentials that are used in X factor design will be based at least partly on Ontario experience. The productivity trends of U.S. distributors may also be used to calculate the productivity differentials, in addition to serving as a "reality check" for the Ontario results.

The proposed X factor is the sum of three terms:
- Input Price Differential ("IPD"): The difference between the input price trends of the economy and the industry;
- Productivity Differential ("PD"): The difference between the productivity trends of the economy and the industry; and
- Stretch Factor.

Each of these terms is described below.

3.3.2 Calculating the Input Price Differential

PEG will compute an IPD by comparing the input price trend of Ontario gas utilities to the input price trend of the Canadian economy. The input price trend of the utilities will be computed as a cost-weighted average of the growth in subindexes representing trends in the prices of 3 input groups: labour, materials & services, and capital. Cost weightings capture the impact of input price growth on cost. Cost weights will be based on the shares of the input groupings in the total costs of the Ontario gas utilities. The input price subindexes will be drawn chiefly from Stats Canada data. In conformance with the index logic discussed above, the input price trend of the Canadian economy will be calculated as the sum of the trend in GDP IPI FDD and one of Stats Canada's multifactor productivity indexes for Canada's private business sector.

3.3.3 Calculating the Productivity Differential

The TFP growth of the Ontario and U.S. gas utilities will be decomposed into two terms: the growth in their cost efficiency and a term that captures the effect of average use trends on TFP. The growth in cost efficiency will be measured with a TFP index that features an output quantity index based on cost elasticity weights rather than revenue weights. This decomposition is well established in literature.

Cost elasticities are measures of the cost impact of business condition variables. The elasticity of cost with respect to the number of customers, for instance, is the percentage change in cost that results from a one percentage change in customers. The output quantity subindexes will include the number of customers and one or more measures of throughput.

The cost elasticity estimates will be based on original econometric research conducted by PEG on the impact of output and other business conditions on the historical costs of gas utilities. The sample for this research will include U.S. data and may also include Ontario data. PEG has undertaken several econometric studies of gas distribution costs and has used the elasticity estimates in its productivity research on several occasions.

PEG will calculate the PD by comparing the productivity trends of the gas utility industry and the Canadian economy. The productivity trend of the economy will be measured using one of Stats Canada's multifactor productivity indexes for Canada's private business sector. The productivity trend of the industry will be measured using the elasticity-weighted output quantity indexes that are designed to measure trends in cost efficiency.

3.3.4 Stretch Factor

With regard to the stretch factor, the following considerations suggest that the move from COS to IR will bolster incentive power substantially:

- The utilities have come in for rate cases frequently in recent years. Enbridge, for example, has filed rate cases annually for several years.
- The proposed plan term is four or five years.
- The plan does not contain an earnings sharing mechanism.

Therefore PEG anticipates that the plan should involve a material strengthening of performance incentives.

3.4 Single or Multiple Price Caps

A single price cap for all customer rate classes is a common feature in IR plans. However, Board staff recognizes that there could be circumstances that would warrant a differentiated X factor or a separate rate adjustment for the different lines of business (e.g., distribution, storage, and transmission) or by customer rate class. For example, declining average use could affect rate classes differently and may justify a differentiated X factor or separate rate adjustment for each rate class.

Taking into consideration these situations, Board staff sought stakeholder views on the appropriateness of each of the following variations: a single price cap for all customers; a different price cap for each of the utility's lines of business; and a different price cap for each customer rate class.

One stakeholder expressed the view that Union's transmission and distribution / storage capital expenditures profiles might be different. Therefore, it might be necessary to examine the costs underpinning these functions to determine if these services should have a different X factor.

Board staff's view is that the productivity performance of each function performed by the utilities could differ significantly due to differences in technology, capital expenditures or the potential for cost reductions. Absent any empirical information, Board staff asked PEG to undertake further analysis to determine whether a different X factor for Union's transmission services is required and feasible given the available data.

PEG's preliminary assessment is that there is a lack of available data to properly conduct this type of study. Further, distribution rates for Union's small volume consumers bundle transmission and distribution services. Therefore Board staff does not consider that this issue should be further pursued at this time.

Union and Enbridge raised the issue of declining average use in the context of an IR plan. They explained that the decline in average use is attributable to several factors including: more efficient gas appliances; better home insulation; and customer response to higher natural gas prices. They also pointed out that they have been compensated for declining average use under COS regulation.

Some parties suggested that if the effect of declining average use is included in the IR plan (either in the X factor or as a separate factor), then having a different price cap for each rate class may be justified. In their view, declining average use may affect customer rate classes differently, and inter-class cross subsidization should be minimized.

Board staff recognizes that declining average use is being experienced by many gas utilities in North America. This trend has financial implications for the gas utilities that "increase the need for rate escalation".[6] As a result, a number of gas utilities in North America have rate mechanisms that separate or decouple the recovery of fixed system costs from the volume of gas delivered to customers or use novel rate methodologies to stabilize earnings or revenue flow.[7]

Therefore, Board staff sees merit in investigating this issue further. PEG will undertake analysis to determine the extent of declining average use, and whether it differs materially among rate classes. PEG advised Board staff that the declining average use factor ("DU factor") could take the form of the difference between the recent historical trends in industry output quantity indexes that are measured using revenue and cost elasticity weights. This approach would effectively ensure that the overall growth in the rates charged by Ontario gas utilities be is limited by the growth in TFP index based on revenue-share

[6] Lowry, Getachew and Fenrick (2006): "Regulation of Gas Distributors with Declining Use per Customer", Dialogue, Vol. 14 No. 2
[7] Ryan K: "Exploring the Philosophy of Rate Design" in American Gas, November 2006

weights. PEG will also undertake analysis to determine whether the declining average use factor should be fixed or variable throughout the plan term.

Board staff agrees with stakeholders that different adjustments by rate class would be warranted if the reduction in average use varies significantly by customer group. Board staff also thinks that any adjustment that may be warranted should take the form of a factor separate from the X factor.

3.5 Rate Design

Union and Enbridge have indicated a preference for rate re-design flexibility during the term of the plan. For example, they would like the ability to re-balance the recovery of fixed costs through fixed charges and variable charges while being revenue neutral at the rate class level. Also, Union and Enbridge may require modifications to their rate schedules for services to gas-fired power generators.

Other stakeholders suggested that allowing rate re-design during the IR plan term would not result in rate predictability and stability. Stakeholders felt that if a declining average use factor was incorporated into the price cap there would be no need to re-design rates for this purpose.

Board staff has two concerns over rate re-design during the term of the plan.

First, Board staff believes that the price cap should be applied equally to the fixed and variable charges at the rate class level to maintain the current fixed/variable ratio. Staff considers that different percentage changes to the fixed and variable charges (even though revenue neutral at the rate class level) could result in large rate increases for some customers within a given rate class. For example, increases in the monthly customer charge will benefit larger customers to the detriment of low volume users. Therefore, Board staff agrees that rate re-design during the plan term would be contrary to the principle of rate predictability and stability.

Second, if the declining average use is recognized in the price cap, this should alleviate some of the concerns that Union and Enbridge have expressed regarding their exposure to declining average use.

Despite these concerns, Board staff recognizes that there could be changes in the marketplace during the term of the plan. For example, changes to gas-fired power generator services and/or changes in market conditions that lead to inappropriate customer behaviour could prompt the utilities to propose changes to their respective rate schedules.

Board staff believes that rate re-design should be addressed at rebasing. However, as previously mentioned, if material changes in the marketplace occur that would warrant amendments to existing rate schedules (including terms and conditions of service), the utilities should have the opportunity to apply for rate re-design during the plan term. The onus would be on the utilities to fully justify their application. This process is discussed below in the Rate Setting Filings section.

3.6 Routine and Non-Routine Adjustments

Routine and non-routine adjustments are treated as separate rate adjustments in the price cap index formula.

3.6.1 The Z factor

A Z factor provides for non-routine rate adjustments intended to safeguard customers and the gas utility against unexpected events that are outside of management's control. Examples include changes in tax rules[8] and natural disasters.

Enbridge and Union suggested that the Board adopt high-level criteria for allowing certain costs to be recovered such as changes mandated by legislation at all levels, changes in Generally Accepted Accounting Principles ("GAAP") and changes in regulatory rules. Other parties advocated the need for a more detailed set of criteria that would limit Z factors. Also, many stakeholders suggested that non-routine adjustments should be symmetrical and therefore not be limited to cost increases only. Furthermore, these stakeholders proposed that the onus be on the gas utilities to bring forward Z factors that may increase or decrease the prices ultimately paid by ratepayers.

In assessing the need to establish a criteria set, Board staff relied on the conclusions outlined in the NGF report. As a result, Z factors should be limited to well-defined and well-justified cases only. Board staff agrees that the Z factor adjustment should be symmetrical (i.e., positive or negative amounts) and that the onus should be on the gas utilities to bring forward Z factor events.

[8] It should be noted that changes to federal tax laws would already be incorporated into the inflation factor (GDP IPI FDD)

In order for amounts to be considered for recovery as a Z factor, staff is of the view that the amounts should satisfy all four criteria set out in Table 3 below.

Table 3: Z factor Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to operational requirements created by the Z factor event. A significant portion of the expenditure should be demonstrably linked to addressing new operational requirements, as opposed to upgrading current procedures and systems to gain efficiencies under the guise of addressing the event. At least 75% of the amount should be directly and demonstrably linked to the Z factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amount must have a significant influence on the operation of the gas utility; otherwise it should be expensed in the normal course and addressed through organizational productivity improvements. Board staff recommends that the threshold amount be $1.0 million* for individual items.
Inability of Management to Control	To qualify for Z factor treatment, the amount must be attributable to some event outside of management's control (i.e., the event causing the amount must be exogenous to the utility).
Prudence	The amount must have been prudently incurred.

* This materiality threshold would be applicable to Union and Enbridge. An appropriate amount would need to be determined for NRG.

The above criteria set is consistent with the Board's previous findings in its July 21, 2001 Decision with Reasons in proceeding RP-1999-0017 (comprehensive PBR plan for Union Gas).

3.6.2 The Y factor

A Y factor captures routine (or expected) rate adjustments. Examples of these pass-through adjustments include variances in upstream costs such as gas supply, transportation and balancing expenses, and DSM costs.

Board staff thinks that these expected pass-through adjustments should be limited to the variance and deferral accounts established in the utility's base year rate case. Therefore, during the plan term, there would be no additions to the accounts established in the base year unless an account is established in another Board proceeding. For example, the deferral and variance accounts established in the Settlement Agreement and the November 7, 2006 Decision with Reasons in the NGEIR and Storage proceeding (EB-2005-0551) need to be included.

During the Storage and NGEIR proceeding, Union proposed to eliminate three transactional transportation deferral accounts (179-69, 179-73, and 179-74) effective January 1, 2007. In its Decision with Reasons, the Board stated that this proposal should be considered as part of the development of the IR mechanism.

Board staff agrees with Union that these three transmission-related deferral accounts should be eliminated. Since Transactional Transportation Services are part of the gas utility's monopoly service, the Transactional Transportation Services revenue should not be treated any differently, from a ratemaking perspective, than any other regulated revenue. In addition, Union stated that the revenue derived from these services can be forecasted as accurately as any other revenue. Under the current regulatory regime, forecast revenue act as an offset to the revenue requirement, and there are no variance accounts to capture variances relative to forecast. The utilities thus bear the risk of any under earnings, and can reap the benefits of over earnings. This treatment is also consistent with the Board's view that "an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variances accounts".[9]

3.7 Miscellaneous Non-Energy Services

Miscellaneous non-energy services pertain to services such as meter unlocks and removal, administration fees for returned cheques, etc. A detailed list of these services and associated charges for both Enbridge and Union are found in Appendix 2.

During the consultation process, Enbridge and Union questioned whether the Board regulates these services. In response to this issue, Board staff notes that in its November 7, 2003 Decision with Reasons in proceeding RP-2002-0133, the Board found that the term "rate" as defined in section 3 of the *Ontario Energy Board Act, 1998* was sufficiently broad to include service charges levied by a distributor. Consequently, the Board found that approval of service charges was within its jurisdiction. The Board noted that this interpretation was consistent with how the Board had been regulating service charges for Union and electricity distributors. In proceeding RP-1999-0017, the Board ordered that Union file its "miscellaneous" charges as part of its rate order and file supporting cost data for any changes to the charges. In electricity, the Board approves "specific service charges" as a part of its rate review process for electricity distributors, and guidance in this regard is set out in the Electricity Distribution Rate Handbook.

In Enbridge's 2003 rate case, the Board approved the list of service charges and directed that Enbridge include the schedule of such charges in its rate order.

[9] NGF Report, at page 31

That schedule was subsequently filed as Rider "G" and has been included in the utility's rate handbook in each rate application, including Quarterly Rate Adjustment Mechanisms ("QRAMs").

Enbridge and Union proposed that the miscellaneous non-energy service charges should be outside of the price cap mechanism. They raised the concern that many of these charges are third-party charges and, as a result, the utilities would like the opportunity to apply for changes to these charges during the plan term. Other parties suggested that these charges should remain unchanged during the plan term and that all changes should be dealt with at the time of rebasing.

Board staff thinks that the miscellaneous non-energy charges should be outside of the price cap and generally remain unchanged during the plan term. Board staff believes that the onus should be on the utilities to provide evidence that supports a change to the charges during the plan term.

3.8 Term of the Plan

Most of the consumer groups indicated a preference for a shorter term plan while other stakeholders favoured a longer term plan.

In the NGF Report, the Board stated that three years represents the minimum term that may be expected to give rise to productivity incentives, and expressed a preference for a plan term of five years. Therefore, Board staff thinks a plan term of four or five years (i.e., base year plus 4 or 5 years) will allow the utilities to have greater opportunities to implement sustainable efficiency improvements that benefit customers and shareholders.

During the consultation process, stakeholders raised the concern that the COS rebasing would be resource intensive and that Board staff should consider staggering the applications. Board staff is of the view that Enbridge and Union should start their IR plans on January 1, 2008 but have different plan terms. This would mean that one of the utilities would have a plan term of four years while the other would have a plan term of five years. Board staff recognizes that the utilities might not have the same opportunities to implement sustainable efficiency improvements, and therefore the utility with the shorter term plan should have a lower stretch factor.

While Board staff considers that the commencement date and four or five-year term noted above would be suitable for Union and Enbridge, Board staff also considers that the commencement date and plan term for NRG should be determined by the Board following further examination of NRG's changing customer base. The upcoming generic hearing to establish the elements of the IR plan could be an appropriate forum for that examination.

3.9 Off-Ramps

An off-ramp is a pre-defined set of conditions under which the IR plan would be terminated or modified before its end date, usually because of some unforeseen event.

Some consumer groups raised concerns regarding the absence of an ESM in the IR plan. Some stakeholders suggested that a deadband be established around the return on equity ("ROE") to account for over earnings, while others thought that an off-ramp should apply to both over and under earnings. An ROE outside of the deadband would trigger an off-ramp.

Enbridge and Union were of the view that off-ramps for under earnings are not necessary since they could apply to the Board if conditions were such that the continued use of the IR mechanism would threaten their financial viability. They also stated that it would be difficult to quantify at the outset the basis point spread that would threaten their financial viability since the financial markets determine their credit ratings.

Board staff agrees that if a utility were to experience a sustained financial decline, then the IR plan may need to be re-examined by the Board. Also, Board staff is of the view that achieving sustained "supernormal profits" would be an indication that the IR plan may need to be reviewed.

To address stakeholder concerns, Board staff reviewed historical normalized ROE to determine an appropriate reference point for an over earnings parameter to be used as an off-ramp. Over the last 20 years, Enbridge has achieved actual normalized ROEs as high as 345 basis points above its approved ROE. [10] Union has achieved 240 basis points above its approved ROE during the period 1990-2002.[11] Board staff believes that an IR plan should provide an appropriate balance of risk and reward. Therefore, Board staff sees the advantage of using a reference point that is greater than what was achieved under COS regulation.

Board staff is of the view that when the actual normalized ROE exceeds the approved ROE on a sustainable basis (i.e. two consecutive years) by 400 basis points or more, the Board should initiate a review of the IR plan.

Some parties were of the view that this threshold was too low and that it should be increased to 500/600 basis points while others thought it was too high and that it should be reduced to 300 basis points. Board staff thinks that the 400 basis points is an appropriate reference point that balances the needs of customers and shareholders.

[10] EB-2006-0034, Exhibit 1, Tab 24, Schedule 45
[11] RP-2002-0158 / EB-2002-0484, Exhibit J2.31, Attachment #1

Board staff is also of the view that the off-ramps should be symmetrical. This means that the off-ramps should address economic events that would not otherwise be eligible for a Z factor but nonetheless threaten the financial viability of the utilities.

Board staff is of the view that when the actual normalized ROE is below the approved ROE on a sustainable basis (i.e. two consecutive years) by 400 basis points or more, the Board should initiate a review of the IR plan.

3.10 Demand Side Management (DSM)

In 2006, the Board convened a generic proceeding (EB-2006-0021) to address a number of common issues related to DSM activities.

In its August 25, 2006 Decision with Reasons for Phase 1 of that generic proceeding, the Board determined the following:

- A three-year term for the first DSM plan;
- Processes for adjustments during the term of the plan;
- Formulaic approaches for DSM targets, budgets, and utility incentives;
- How costs should be allocated to customer rate classes;
- A framework for determining savings;
- A framework and process for evaluation and audit; and
- The role of the gas utilities in electricity conservation and demand management activities and initiatives.

The Board also outlined the DSM budgets for the DSM plan. The budget for Enbridge is $22.0 million in 2007, $23.1 million in 2008 and $24.3 million in 2009. Union's budget for each of those years is $17.0 million, $18.7 million and $20.6 million.

The Board also approved the structure and application of the LRAM, shared savings mechanism and demand side management variance account.

The second phase of the generic proceeding dealt with the input assumptions and the Board issued its Decision on October 18, 2006 on that particular matter.

During the current consultations, stakeholders generally agreed with Board staff's view that DSM activities in the years 2007-2009 as outlined in the Board's Decision with Reasons in proceeding EB-2006-0021 should be considered as a Y factor (i.e., as a cost pass-through adjustment). Furthermore, if the DSM plan is extended beyond fiscal year 2009, these DSM activities would continue to be treated as a Y factor throughout the plan term.

There was also agreement that DSM initiatives contribute to declining average use. However, concerns were raised about the potential for double counting. In particular, the continued use of the LRAM and compensating for declining average use in the X factor (or in a separate factor) could lead to double counting. The reason for this, as some parties observed, is that embedded within the utilities' actual normal average uses are volumetric losses captured in the LRAM. Board staff supports the continued use of the LRAM and therefore believes that the derivation of the declining average use factor should avoid or minimize double counting.

3.11 Reporting Requirement

Under an IR plan, the utilities should be required to make periodic reports to the Board. These reporting requirements would allow the Board to monitor the utilities' performance throughout the plan term.

Board staff found little consensus among stakeholders regarding the information, timing and frequency of the reporting requirements for the IR plan. There was general consensus, however, that reported information should be in the public domain. Some consumer groups suggested that Enbridge and Union report information on a quarterly basis, others on a semi-annual basis, while others also proposed a mid-term review in the third year of the IR plan. Union and Enbridge indicated a preference for annual reporting requirements and thought that the existing Gas Reporting and Record-Keeping Requirements ("Gas RRRs") were adequate.

With respect to efficiency improvements, some parties thought that the utilities should outline a plan for achieving sustainable efficiencies and update it annually to track progress. Also, they believed that Enbridge and Union should differentiate sustainable efficiencies from unsustainable (short term cost-cutting) efficiencies.

In the NGF Report, the Board stated that it would consult with stakeholders and modify the Gas RRRs as necessary to meet the requirements for financial reporting in the new ratemaking framework. The Board also stated that it would ensure that the appropriate financial information would be accessible to stakeholders but that it did not intend to institute a formal public process for reviewing this information.

Board staff has reviewed reporting requirements in other jurisdictions.[12] This review found that reporting requirements range from quarterly to annual filings. Terasen Gas Inc. ("Terasen"), regulated by the British Columbia Utilities Commission ("BCUC") and under a four year IR plan, has an annual review process with semi-annual customer advisory council meetings. The BCUC also

[12] A summary of the jurisdictional review is available from the OEB website

approved the inclusion of a "No Surprises" clause. This clause is intended to ensure that any significant changes or company restructurings are disclosed to interested parties by the utility in a timely manner. Many stakeholders in the current consultation supported this clause.

Board staff is of the view that the utilities should file the following information with the Board: annual financial filings; and annual service quality monitoring information. Further detail is outlined below.

3.11.1 Annual Gas Reporting and Record-Keeping Filings

To monitor the utilities during a multi-year rate plan, Board staff sees merit in amending the Gas RRRs to include the following additional information:

- Standard ROE calculation schedules: ROE calculations should include actual and weather-normalized financial information. The specific methodology will need to be determined. The purpose of this requirement is to support the off-ramp determination.

- Capital expenditures: Annual actual capital expenditures by USoA accounts should be included. This requirement will support rebasing at the end of the plan term.

In addition, Board Staff is of the view that the Gas RRR should be amended to include Service Quality Requirements ("SQR") filings. These new financial and SQR filings should be publicly available.

"No Surprises" Clause

As previously mentioned, this clause is intended to ensure that any significant changes or company restructurings are disclosed to interested parties by the utilities in a timely manner. While many stakeholders supported the inclusion of this clause, Board staff is not convinced that information disclosure after the fact would add value to the process. Board staff would benefit from further stakeholder input on why this information should be required, and the expectations as to how this information is to be used by the Board.

3.11.2 Service Quality Monitoring

Subsequent to the NGF Report, the Board undertook a consultation to amend the GDAR to implement the following service quality standards for the natural gas utilities:

- Telephone Answering Performance;
- Billing Performance;
- Meter Reading Performance;
- Service Appointment Response Times;
- Gas Emergency Response;
- Customer Complaint (Written) Response; and
- Disconnection/Reconnection.

The actual performance should be reported annually as part of the Gas RRRs.

Some of the consumer groups raised concern over the lack of incentives a utility would have to maintain service standards. In particular, it was suggested that the standards should include financial rewards and penalties as a means to encourage utilities to achieve service quality performance measures.

Board staff recognizes that stakeholders place great importance on performance standards being achieved by utilities. The current performance standards set out in the GDAR are mandatory, and achievement of the standards can therefore be monitored and adequately enforced through the Board's existing compliance process.

Through the compliance management process, Board staff can monitor trends in service quality and identify any concerns that might arise. Concerns regarding non-compliance with the GDAR performance standards, as well as concerns regarding the timeliness and accuracy of performance standard information filings, can be addressed through informal or formal enforcement action. The former would normally involve discussions between Board staff and the utility to achieve a fair and appropriate resolution of the issue. The latter can include the imposition of financial penalties.

3.12 Rebasing Requirements

In the NGF Report, the Board stated that it would expect to see, during the plan term, measures that are designed to improve the utility's productivity on a sustained basis – not temporary, unsustainable budget cuts. The Board also stated that it would, during rebasing, expect an analysis of the relationship between operation, maintenance and administration costs ("O&M") and capital expenditures, the timing of capital expenditures and the associated impacts on shareholders and customers. The Board also cautioned that sudden and significant increases in costs at the time of rebasing will be viewed unfavourably, unless thoroughly justified.

Board staff thinks that the Board should also review, at the time of rebasing, the key parameters of the IR plan for continued appropriateness. Furthermore, at the time of rebasing, it will be necessary to update the TFP study (i.e., the X and stretch factors will need to be re-examined). This exercise will require detailed data from the gas utilities. Therefore, to ensure data continuity, PEG will include a list of the data requirements in its TFP study.

The timing of expenditures (i.e., O&M and capital) that are made periodically is an issue of mounting interest in IR schemes. Some timing issues may be revealed at rebasing. In considering these rebasing rules, Board staff sees the merit in amending the Board's Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications ("MFR") to include actual COS data for each year of the IR plan term (e.g. 2008 - 2012) in the same format as required by the MFR.

In addition, Board staff is of the view that an average of spending over the IR plan should act as a guide to assess the validity of the utility's proposed O&M expenses and capital expenditures at the time of rebasing.

During the stakeholder consultation process, PEG suggested that rebasing could take into account an efficiency carryover mechanism that would act to bolster long-term performance incentives. For example, PEG indicated that the new rates could be set by applying a weight to the revenue requirement that would result from a COS review, and a one-year extension of the existing IR mechanism.

Some parties questioned whether this approach would not translate into just and reasonable rates. The concept of an appropriate efficiency carryover mechanism is however of interest to Bard staff. Comments from stakeholders on such a mechanism are encouraged.

3.13 Rate Setting Filings

To set annual rates during the IR plan, Board staff thinks that Enbridge and Union should file the information identified below annually by October 1st. This would allow the Board to issue a Rate Order by December 15th for new rates to be implemented for January 1st of the next rate year. Since NRG's fiscal year begins October 1st, it should be required to file the information identified below annually by July 1st with a rate order issued by September 15th:

- A draft rate order;
- A rate handbook with all supporting documentation including the inflation factor, X factor, stretch factor, and other rate adjustments, as well as an explanation of how rates have been adjusted to effect the IR formula; and
- The deferral and variance account balances for the current fiscal year (8 months of actuals and 4 months of forecast). The list should include the balances proposed for clearance, the methodology for clearance, unit rates for clearance, and the proposed timing of the clearance.

Board staff thinks that the process for these filings should be similar to the QRAM review process in that it would be fairly mechanical. This process would allow interested parties and Board staff to make submissions, and the utilities would have the opportunity to reply. An Excel spreadsheet model should be created for use by the utilities. This model would show the calculations supporting the draft rate order.

Other Rate-related Changes during Plan Term

A utility may apply for rate-related changes (i.e., rate re-design proposals and Z factors) during the plan term. However, as noted earlier the onus should be on the utility to demonstrate why the changes or adjustments are required.
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 should be made on a sufficiently timely basis. It is possible that significant rate-related changes requiring particularly lengthy review may not be implemented until the following rate year.

4 OTHER ISSUES

4.1 Return on Common Equity

The return on common equity ("ROE") compensates investors for the risk associated with providing share capital to a utility business. The cost of that capital will vary with the perceived risk of the investment. In general, the rate of return to the investor should be commensurate with the risk of the utility as compared to that in the market.

The Board currently uses a formula-based approach to set the rate of return on common equity for regulated gas utilities. This approach was initially outlined in the Board's "Draft Guidelines on A Formula-Based Return on Common Equity" and was first applied to set fiscal 1998 rates for Enbridge. In 2003, the Board held a review of the ROE setting methodology in response to applications from the gas utilities (RP-2002-0158). The Board found that there was no compelling reason to adopt a different cost of capital methodology.

During the current consultation process, Union and Enbridge commented that the ROE outcome should be adjusted annually to recognize the capital intensiveness of the natural gas business. Other stakeholders did not agree since there would be some degree of double counting as the GDP IPI index includes some consideration of changes in cost of capital.

In its December 20, 2006 "Report on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors", the Board determined that changes in ROE and debt rates are implicitly recognized in changes in the GDP IPI and that no further explicit adjustment for changes in these parameters would be required.

This is also consistent with the Board's July 21, 2001 Decision with Reasons in proceeding RP-1999-0017 regarding Union's three-year PBR plan. In that Decision, the Board found that the ROE adjustment is captured in the annual changes of GDP IPI FDD. In particular, the Board noted that "the effect which inflation might have on the determination of a fair allowance for ROE is, to a significant extent, captured by annual changes in the GDP-IPI component of the PCI. The impact of the differences in capital intensity between Union and industrial companies in general is captured in part through the appropriate determination of the input price differential. In the Board's judgment, the components of a fair ROE, which reflect the risks to which the utility is exposed, are captured under a PBR approach, to a large extent, through the application of an appropriate price cap escalator that includes the I-factor and the X-factor".

Therefore, Board staff does not believe that an annual adjustment to the ROE is required.

4.2 Union's proposed weather-normalization methodology

In its Decision with Reasons in proceeding RP-2003-0063, the Board accepted Union's change to its weather normalization methodology. In particular, the Board allowed Union to forecast heating degree days based on a 70:30 weighting of the 30-year average forecast and 20-year trend forecast for fiscal year 2004. For each year thereafter, the Board indicated that it would consider 5% decreases and increases to the weighting of the 30-year and 20-year methodology respectively until such time as a 50:50 weighting is in place.

For the 2007 test year, Union's rates reflect a weighting of 55:45.

During the current consultation process, Union suggested using a 20-year trend forecast in its weather normalization methodology starting January 1, 2008. This would reflect a 0:100 weighting and would require a variance account to track adjustments to base rates during the plan term. Union's rationale was that this adjustment would result in symmetrical risk, that is, colder weather would be as likely to occur as warmer weather.

Most stakeholders disagreed with Union's suggestion, stating that the 2007 settlement agreement in proceeding EB-2005-0520 was accepted on the grounds that base rates would be adjusted for only one more year to reflect a 50:50 weighting.

Board staff agrees and believes that the base rates should be adjusted to reflect a 50:50 weighting in fiscal 2008.

4.3 Replacement Mains and System Expansion

This section addresses the treatment of capital investments for: regular main replacements, main relocations, system integrity and safety projects, and cast iron/steel main replacement programs. It also encompasses the treatment of system expansion to new communities (i.e., those not currently served by natural gas).

During the consultation, Enbridge expressed concerns over cost recovery of its main replacement program which includes an annual budget of $50.6 million for cast iron and $2.2 million for bare steel in each of 2007, 2008, and 2009.

Enbridge proposed that these costs be treated as a Y factor (or cost pass-through) to expedite cost recovery since otherwise it would not earn a return on these investments until rebasing.

Board staff is of the view that a comprehensive plan that encompasses both capital and O&M expenses creates stronger and more balanced incentives. For example, a plan that focuses only on O&M expenses may weaken incentives to control capital costs thereby reducing the overall potential performance incentives. In a capital intensive business such as natural gas distribution, containing capital expenditures is a key to good cost management. Therefore, Board staff sees advantages in dealing with all aspects of a utility's operations in a comprehensive fashion rather than using a "targeted" IR approach.

More specifically, staff expects that as a result of its mains replacement program, Enbridge will realize substantial O&M savings prior to rebasing. In addition, the TFP study conducted by PEG will examine input prices and productivity trends of 38 U.S. natural gas utilities. The TFP trends of these utilities will reflect all of their expenditures for capital replacement and customer attachments. As a result, it is expected that the X factor will reflect these considerations. Consequently, staff is of the view that the establishment of a cost pass-through mechanism for main replacement programs (including relocations) and safety and reliability projects is not warranted.

With regard to system expansions, Enbridge indicated that it may no longer invest to serve new communities under a comprehensive IR plan even if a project meets the profitability test (i.e., individual projects with a profitability index ("PI") of 0.8 and a rolling portfolio PI of 1.1 or more) specified in the "Guidelines for Assessing and Reporting on Natural Gas Distribution System Expansion in Ontario (1998)" resulting from the Board's EBO 188 proceeding.

Board staff expects the utilities to continue to use the existing guidelines for system expansion. System expansions to new communities are expansions to communities that are not currently served by natural gas. In general, these communities are relatively small and may require expansion of the existing system by upwards of 10 to 50 kilometers. Conversion to natural gas generally occurs over a 5 – 10 year period (unless the existing heating is propane) because connections take place as furnaces need replacement. As a result, these projects generally have lower profitability indexes (even though these projects meet the EBO 188 guidelines). Thus, if not encouraged, the conversion to a "cleaner energy" could be compromised under an IR regime.

Therefore Board staff believes that a cost pass-through is an appropriate way to encourage the continuation of system expansion to new communities. Staff believes that this treatment should however be limited to projects that require a leave to construct approval from the Board. This would ensure that there would be a public review of costs and benefits associated with the expansion. The costs should also be offset by revenues generated from the new connections during the plan term. This approach recognizes that some of these projects have a “faster” conversion rate. For example, if the existing heating is propane, the conversion rate is usually faster.

Board staff notes that to avoid double counting, the TFP study will need to consider the expenditures pertaining to system expansions.

APPENDIX 1

List of Participants in EB-2006-0209

City of Kitchener
Consumers' Coalition of Canada
ECNG
Enbridge Gas Distribution Inc.
Energy Probe
Green Energy Coalition
Hydro One Networks Inc.
Industrial Gas Users Association
London Property Management Association
Ontario Power Generation
Pollution Probe
School Energy Coalition
TransCanada Energy
TransCanada PipeLines Limited
Union Gas Limited
Vulnerable Energy Consumers Coalition

APPENDIX 2

Enbridge Miscellaneous Non-Energy Services

	Rider "G" Service Charges	Rate ($)
1	New Account Charge	25.00
2	Appliance Activation Charge	65.00
3	Meter Unlock Charge	65.00
4	Lawyer Letter Handling Charge	15.00
5	Statement of Account Charge	10.00
6	Cheques Returned Non-Negotiable Charge	20.00
7	Red Lock Charge	65.00
8	Removal of Meter	260.00
9	Cut Off at Main	1,200.00
10	Valve Lock Charge	125.00 – 260.00
11	Safety Inspection	65.00
12	Meter Test	97.50
13	Street Service alteration	32.00
14	NGV Rental Cylinder	12.00
	Other (ad-hoc request)	
15	Labour – hourly charge	130.00
16	Cut Off at Main – commercial & special request	custom quoted
17	Cut Off at Main – other	1,200.00
18	Meter In-out (residential)	260.00
19	Request for Service Call Information	30.00
20	Temporary Meter Removal	260.00
21	Damage Meter Charge (proposed for 2007)	360.00

Union Miscellaneous Non-Energy Services

	Service	Fee
	Residential Customer Class Service	
1	Connection Charge	$35
2	Temporary Seal - Turn-off (Seasonal)	$22
3	Temporary Seal - Turn-on (Seasonal)	$35
4	Landlord Turn-on	$35
5	Disconnect/Reconnect for Non-Payment	$65
	Commercial/Industrial Customer Class Service	
6	Connection Charge	$38
7	Temporary Seal - Turn-off (Seasonal)	$22
8	Temporary Seal - Turn-on (Seasonal)	$38
9	Landlord Turn-on	$38
10	Disconnect/Reconnect for Non-Payment	$65
	Statement of Account/History Statements	
11	History Statement (previous year)	$15/statement
12	History Statement (beyond previous year)	$40/hour
13	Duplicate Bills * (if processed by system)	No charge
14	Duplicate Bills * (if manually processed)	$15/statement
	Dispute Meter Test Charges	
15	Meter Test - Residential Meter	$50 flat fee for removal and test
16	Meter Test - Commercial/Industrial Meter	hourly charge based on actual costs
	Direct Purchase Administration Charges	
17	Monthly fee per bundled t-service contract	$75.00
18	Monthly per customer fee	$0.19

Notes:

* Duplicate bill charges only apply when customer wants two copies of a bill. List bills from the last billing period will be replaced free of charge.