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May 17, 2010

VIA RESS, E-mail and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario,
M4P 1E4

Dear Ms. Walli:

Re: Consultation on Distribution Revenue Decoupling
Enbridge Gas Distribution Inc. ("Enbridge")
Comments of Enbridge on Issues and PEG Report
Ontario Energy Board ("Board") File No.: EB-2010-0060

By correspondence dated March 22, 2010, the Board invited parties to attend a stakeholder meeting on April 19, 2010 regarding revenue decoupling and to provide comments on the issues identified by Board Staff and on the PEG report.

Enbridge attended the stakeholder meeting on April 19 and is now providing comments.

This submission is being filed through the Board's Regulatory Electronic Submission System along with two copies via courier.

Sincerely,

Shari Lynn Spratt

Encl.

ONTARIO ENERGY BOARD

CONSULTATION ON
DISTRIBUTION REVENUE DECOUPLING

COMMENTS OF
ENBRIDGE GAS DISTRIBUTION INC.

I. Introduction

On March 22, 2010, the Board issued a notice initiating a consultation process to examine the revenue adjustment and cost recovery mechanisms available to electricity and natural gas distributors to address revenue erosion from unforecasted changes in the volume of energy sold. The Board's notice set out seven issues identified by Board staff and it referred to a report by Pacific Economics Group Research LLC ("PEG") entitled *Review of Revenue Decoupling Mechanisms* (the "PEG Report").

In its March 22nd notice, the Board invited parties, including all rate regulated natural gas distributors, to comment on the seven issues and on the Report. These are the comments of Enbridge Gas Distribution Inc. (Enbridge) submitted pursuant to the Board's notice.

Enbridge will begin with general comments that are based on its many years of experience with issues relating to declining average use and revenue attrition. Then, Enbridge will comment on the PEG Report and, finally, it will respond to the seven specific issues identified by Board staff. In the course of these comments, Enbridge will refer to the presentation by PEG that was made at the stakeholder meeting on April 19, 2010 (the "Stakeholder Meeting").

II. General Comments on Revenue Decoupling

(i) The Regulatory Framework

Enbridge agrees with the Board that the regulatory framework for natural gas and electricity distributors should be aligned with the important conservation and efficiency goals of Ontario provincial government policy. A key element of this regulatory framework is a mechanism or set of mechanisms to ensure the ongoing financial health of the Province's utility sector, which plays a critical role in delivering services and programs to customers that achieve conservation goals.

In Ontario, as indeed throughout North America, average natural gas use per customer continues to decline. This is due, in part, to the effective administration of Demand Side Management programs which create incentives for customers in the effort to reduce energy usage. If conservation is to continue to play an important part in Ontario's energy future, then it is imperative that a supportive regulatory framework provide the right incentives to both customers and utilities.

Enbridge believes that it can offer valuable insights to the Board on issues related to revenue decoupling for a number of reasons that include the following:

(a) Enbridge has a very successful history of administration of DSM programs;

(b) Enbridge has been dealing with declining average uses for a number of years; and

(c) Enbridge has successfully managed severe revenue erosion challenges due to these declining average uses.

Throughout a long history of meeting these challenges, Enbridge's current regulatory construct has evolved to promote conservation in a meaningful way and to address successfully the issues associated with average use decline and revenue erosion. The evolution of this regulatory framework has been achieved with full input by ratepayer, environmental and other stakeholders.

It is entirely understandable that the Board would consider revenue decoupling issues now as it endeavours to ensure that a framework is in place for Ontario's electricity distributors to promote actively a culture of conservation. Enbridge believes that there are important lessons to be learned from the evolution of the regulatory framework for Ontario's natural gas utilities that may provide guidance for the electricity distribution sector as well. However, Enbridge also believes that there are differences between the gas and electricity sectors that may lead the Board to conclude that there should be differences in the regulatory framework for each sector.

Enbridge's view, as supported by the PEG Report and subsequently by PEG at the Stakeholder Meeting, is that the key differences between the sectors include:

(a) the volumetric profiles for gas and electricity consumption are different, with different historical and future patterns of average use, different drivers of demand, and different end-use applications;

(b) DSM programs are very well established in the gas industry, whereas conservation and efficiency initiatives are relatively new for many electricity distributors;

(c) in the electricity sector, there is greater involvement in conservation and efficiency efforts by organizations or bodies other than the distributors (such as the Ontario Power Authority) than in the natural gas sector;

(d) gas utilities frequently access a Lost Revenue Adjustment Mechanism (LRAM) and a Shared Savings Mechanism (SSM), whereas the electricity distributors tend to make use of these mechanisms much less frequently;

(e) the gas distributors are protected from declining uses by average use true-up variance accounts (AUTUVA); and

(f) the Board regulates only a few gas distributors, while it regulates many electricity distributors.

(ii) Objectives of Revenue Decoupling

Enbridge believes that an appropriate approach to revenue decoupling should meet multiple objectives. The PEG Report gives three objectives of revenue decoupling; these are efficient regulation, attrition relief, and the removal of financial disincentives for CDM/DSM.[1] With respect to the first of these three objectives, Enbridge's view is that regulatory efficiency, although always an important objective, should not over-ride the key factors that will determine the success of a revenue decoupling model. As indicated by PEG, these primary factors include supporting the incentive for conservation and efficiency and protecting utilities from the impact of declining average uses. Other considerations that should be taken into account are: (a) the potential effect on customers or customer behaviour of changes to rates, services or programs; and (b) the regulatory principles that underpin rate design, such as cost causality, rate stability, and predictability.

Enbridge believes that the success of a revenue decoupling model depends on its ability to balance these multiple objectives. For example, a high level of volumetric charges compared to fixed charges may, on the one hand, send a price signal to customers that promotes the conservation objective. On the other hand, another factor to be brought into the balance is the fact that the costs of a distributor are largely fixed - consideration should be given to the extent to which an unduly high level of volumetric charges may falsely signal to customers that increased conservation leads to lower

[1] PEG Report, page 20.

costs and lower rates, when actually increased conservation will not avoid or reduce fixed costs.

The costs of distribution are largely fixed because, to a large extent, they are comprised of infrastructure costs and labour costs. If gas consumption falls below forecast because weather is warmer than normal, or because conservation is greater than expected, the gas distribution system must still be operated and maintained in a safe and reliable manner and customer support services must still be provided with the usual level of quality.

The regulatory regime in most jurisdictions allows utilities to recover a certain portion of distribution charges by way of fixed charges, while the remainder of the costs must be recovered by way of variable or volumetric charges. Insufficient recovery of fixed costs through an unduly high level of volumetric charges means either a true-up in a later period or a negative impact on utility earnings. Thus, the fixed charges included in distribution rates are important to reflect cost causality and to provide distribution rate stability and predictability. At the same time, the price signal to customers is also important and the price signal remains strong when the fixed component of distribution rates is kept at an appropriate level relative to the customer's entire bill, including commodity costs and the variable component of distribution rates.

Through processes that include stakeholder input and that culminate with Board approval, Enbridge's regulatory model has evolved over many years in a way that balances the multiple objectives of revenue decoupling and rate design.

<u>(iii) The Gas Utility Model</u>

The gas utility regulatory model includes, for Enbridge, a revenue per customer cap, and, for Union, a price cap, to determine annual changes in rates for cost inflation and productivity. There are a number of other features of the gas utility model that remove the disincentive for utilities to promote conservation and deal with the potential for earnings attrition due to declining average use per customer. In the case of Enbridge, these include the following:

(a) the annual use of forward-looking forecasts for customer additions and volumes;

(b) an Average Use True Up Variance Account (AUTUVA) that addresses the impacts of changes in annual average use;

(c) revenue-neutral annual increases in the fixed customer charge;

(d) an LRAM to address the impacts on margin that are caused by over-performance or under-performance in the results of Enbridge's DSM efforts;

(e) annual inclusion of DSM expenses in rates, either as a pass-through or as a Y-factor under Enbridge's IR plan;

(f) a Demand Side Management Variance Account (DSMVA) that addresses the impacts of greater or lesser spending levels for conservation programs;[2] and

(g) a Shared Savings Mechanism (SSM) that provides a financial incentive to Enbridge to maintain management focus on conservation and to enable conservation to contribute directly to Enbridge's profitability.

Enbridge understands that Union's methodology has many similar features.

The use of forward-looking test year customer addition and volume forecasts ensures that the latest available information with respect to average use trends is incorporated into the rate adjustment process. The AUTUVA then picks up variances from forecast for the rate classes that are the main source of declining average uses. This reduces the potential for extremely large balances to accumulate in the AUTUVA, which in turn reduces the potential for significant volatility in rates or customer bills. Also, the model furthers the use of the most up-to-date available information in the current period's price signal to customers.

Moreover, amounts paid by customers are still dominated by variable charges, both through the distribution charge and, more importantly, through the commodity charge. On the Enbridge system, distribution charges (fixed and variable) for residential customers amount to about 30% of the total annual bill, including the cost of the commodity. Distribution charges for industrial customers represent less than 10% of the annual bill. Of the 30% of a typical residential customer's annual bill that represents distribution charges, roughly one-half of this is made up of fixed charges and the other one-half is volumetric charges. This means that about 15% of a residential customer's annual bill is comprised of fixed charges. Enbridge's approach appropriately balances cost causality, rate stability, and rate predictability with a very meaningful price signal to promote conservation.

The AUTUVA protects the utility from revenue attrition due to declining average uses and, accordingly, there is no disincentive to the promotion of conservation. In fact, due

[2] Note that the PEG Report is incorrect, in the case of Enbridge, when it states (at page 82) that the DSMVA recovers the revenue variances in a given class from the customers in that class.

to the SSM, the utility has every incentive to promote conservation. The LRAM protects the utility from revenue attrition net of declining average uses and DSM activities and the marginal effort to produce LRAM calculations is minimal because program evaluations and SSM calculations are completed anyway.

This multi-dimensional regulatory framework has proved to be very successful in balancing the interests of promoting conservation and protecting the utility from revenue attrition. Indeed, Enbridge has been actively involved in DSM for approximately fifteen years and is considered a North American leader in the design, development and delivery of DSM programs. At least in part due to its DSM activities, Enbridge has experienced a lengthy period of declining average uses and it has successfully managed the revenue effects of this pattern of declining usage.

Enbridge notes, though, that the success of any model depends on the prevailing circumstances. If, in the future, the renewable energy profile significantly changes the face of space heating, it may be that another revenue decoupling approach will become more appropriate for Enbridge. Similarly, if the demand for gas for water heating load drops off, this would affect the seasonality of gas distribution volumes and could change Enbridge's view regarding the best revenue decoupling model for its circumstances. Also, the introduction of a carbon pricing scheme in Ontario could affect the relative competitiveness of gas and electricity, thereby causing utilities to re-think their positions regarding approaches to revenue decoupling.

Enbridge believes that the circumstances of each individual utility should be a central factor in the determination of the regulatory framework that will apply to the utility. In other words, a "one size fits all" approach is neither necessary nor appropriate. It should be open to utility management to select from a number of different revenue decoupling methodologies in order to apply the model that best allows the particular utility to meet conservation goals while providing the level of protection from earnings attrition that management considers to be suitable for that utility.

The available alternative methodologies include those discussed in the PEG Report (LRAMs, Straight Fixed Variable Pricing, and Revenue Decoupling with true-ups) and the hybrid decoupling models currently employed by the gas distributors. The gas utility hybrid model offers benefits comparable to full decoupling, but also reduces the downside risks of full decoupling, at least for a utility in circumstances such as those experienced by Enbridge.

III. Enbridge's Response to the PEG Report

The following comments are provided by Enbridge in response to the points made in the PEG Report about the natural gas sector. The comments made here may or may not be applicable to Union Gas Limited (Union) or to Ontario's varied electricity distributors.

A more generic discussion of the points is provided in response to the Board Staff issues, below.

The conclusion reached in the PEG Report is that "current revenue decoupling arrangements" for Ontario's major natural gas distributors, Enbridge and Union, are reasonable.[3] During the Stakeholder Meeting, PEG confirmed this viewpoint and stated that there is less opportunity for improvement in the gas sector than in the electricity sector.

The PEG Report goes on, though, to suggest two "small refinements" for the gas sector that "merit consideration in the next round of IRs".[4] The first suggestion is that LRAMs "could be" eliminated and the second suggestion is that a Revenue Decoupling with true-ups mechanism could be adopted.

(i) LRAMs

PEG suggests that elimination of LRAMs be considered for reasons of regulatory efficiency. According to PEG, a Revenue Decoupling with true-ups model would capture lost revenues in the true-up mechanism and the additional effort of an LRAM calculation would not be justified.

However, it is clear from both the PEG Report and the PEG presentation at the Stakeholder Meeting that, because the gas distributors carry out program evaluations and SSM calculations as part of the DSM regulatory framework, there are no large gains in regulatory efficiency to be achieved through elimination of the LRAM. In other words, the effort to produce the LRAM calculations is insignificant when evaluation reports and SSM calculations are prepared anyway. Enbridge agrees with PEG that elimination of the LRAM would contribute little or nothing to regulatory efficiency. In addition, the LRAM continues to be a meaningful element of the gas utility hybrid model, because the AUTUVA does not capture revenue attrition for all rate classes.[5]

(ii) Revenue Decoupling with True-ups

The second refinement suggested for consideration in the PEG Report is the Revenue Decoupling with true-ups model. One of the advantages that PEG sees in this model is that it would provide a "small simplification" by reducing the use of weather normalization calculations in the decoupling true-up mechanism.

However, as PEG accepted during the Stakeholder Meeting, the opportunity to produce any regulatory efficiency due to a reduction in weather normalization effort would be

3 PEG Report, page 92.
4 PEG Report, pages 92-3.
5 For example, Enbridge's AUTUVA applies to Rate 1 and Rate 6 and does not apply to large volume contract rate classes.

minimal. Weather normalization would still be needed for financial reporting, budgeting, and rate-setting. In other words, regardless of whether or not a Revenue Decoupling with true-ups model is implemented, weather normalization of volumes would still be important, so there is virtually no benefit from reduced effort on weather normalization.

Perhaps the most important reason for PEG's suggestion regarding consideration of a Revenue Decoupling with true-ups model is that this approach might foster experimentation with rate designs. Specifically, PEG suggests that, under this model, rates could be designed with lower fixed charges and higher volumetric charges, thereby sending stronger price signals to customers about energy conservation.

As set out above, Enbridge's current fixed and variable charges have evolved over many years in a way that appropriately balances the objectives of revenue decoupling and rate design. Enbridge believes that it would be highly undesirable at this time for it to lower current fixed charges and increase current variable charges, or to implement an inverted block structure. Not only would this abruptly change an approach that has evolved over many years with great success, it would create problems for customers: These problems include the following:

~ The monthly consumption of heat sensitive customers (space and water heating) is many times higher in the winter than it is in the summer. If distribution costs were to be recovered primarily through volumetric charges, it would result in higher bills for winter months particularly when the weather is colder than normal. This outcome would be magnified using an inverted block structure.

~ greater concerns that arise when energy conservation measures are successful and rates must subsequently be increased due to the mismatch between recovery of the fixed costs of providing service and reduced revenue available to meet those fixed costs;

~ negative impact on fixed or low income customers, who typically exhibit more weather-sensitive consumption patterns.

Enbridge has a number of other concerns about the Revenue Decoupling with true-ups model as it would apply to Enbridge. To begin with, Enbridge believes that it is unrealistic to assume that annual true-ups would be simple. More likely, annual true-ups would be complicated and highly controversial. The dollar amounts of total revenue to be trued-up based on the revenue decoupling model could be significant and it is likely that customers would question payment of higher rates and higher bills in future periods due to conservation or warmer weather in a previous period that contributed to lower than expected revenues.

Enbridge also is concerned about the bill and rate volatility that would result from implementation of a Revenue Decoupling with true-ups model. Large variances in revenue (for example, due to weather) could significantly impact rates from one period to another and this in turn would have significant bill impacts. For example, a year of warm weather would produce a revenue shortfall that would mean higher rates in the following year and conversely a cold winter would cause customers' bills to be very large and the revenue true-up in the following year would mean lower rates.

Enbridge's analysis reveals that, with the current rate design structure, the full Revenue Decoupling with true-ups methodology would produce material true-up amounts. With distribution rates based entirely on volumetric charges, the true-up amounts would be in the range of $30 million to $100 million per year. The magnitude of the true-ups - and rate volatility - would increase substantially with an inverted block rate design, because most of the impact of weather or declining average uses would fall in the last, most expensive rate block.

The use of this methodology could also result in large inequities between rate classes. For example, a warm winter or significant conservation efforts affecting residential customers would result in a large true-up balance to be recovered in the next period and the impact of this recovery would fall partly on industrial customers. Alternatively weak economic performance or significant conservation affecting industrial customers would result in a large true-up balance for the next period and the impact of this true-up would fall partly on residential customers.

The solution to the prospect of inequity in the recovery of true-up balances would be to design true-up accounts for different rate classes. Enbridge believes, however, that this would complicate the regulatory process and would create both greater controversy and greater risk for Enbridge.

While an appropriate price signal for customers promotes the goal of energy conservation, Enbridge believes that a full revenue decoupling model would not provide a good price signal. With large true-up balances accumulating periodically, customers would pay in the future for circumstances that affected distribution revenues in the past. If, as has been suggested, a smoothing mechanism were to be put into place, the outcome would be to spread farther out into the future the rate impacts of circumstances affecting revenues in earlier periods and thereby diluting price signals. Also, since the ultimate price signal is dominated by the level and movements of commodity prices, Enbridge is skeptical that the great effort, controversy and complication involved in the implementation of the new revenue decoupling model would result in any better price signal for customers.

Finally, Enbridge is also concerned that movement to a Revenue Decoupling with true-ups model would result in unintended consequences for Enbridge, or its customers, or both. The experiences in Oregon and Maine described in the PEG Report reinforce this concern, as does PEG's presentation at the Stakeholder Meeting, which indicated relatively little experience in North America with revenue decoupling models. According to the presentation, there are, in the United States, approximately 8 states with renewed decoupling plans, approximately 4 states with expired plans and approximately 14 states with pilot plans.

Another benefit that PEG attributes to the Revenue Decoupling with true-ups model is that it could reduce the frequency of rate proceedings. However, the two major gas distributors already have Incentive Regulation plans with five year terms. These plans include both an X-factor that focuses the utilities on improving cost performance and an earnings sharing mechanism that gives ratepayers a share of earnings above a certain level. In the case of the gas distributors, the extent of currently achieved revenue decoupling and the impacts of such on rate design have evolved over many years in a manner that balances interests effectively and results in an efficient regulatory process. It is not clear that full revenue decoupling offers any potential for meaningful improvement in regulatory efficiency relative to the regulatory framework that is currently in place.

The Board has said that sound regulatory principles include fairness, minimizing intergenerational inequity and minimizing rate volatility.[6] Enbridge agrees with these principles. The application of these principles over the years of development of the gas utility hybrid model by gas distributors, stakeholders and the Board has resulted in a balance that could be upset for no appreciable gain if a Revenue Decoupling with true-ups model is adopted.

(iii) Revenue Decoupling and Risk

The final point made by PEG with respect to a Revenue Decoupling with true-ups model is that this methodology could achieve a reduction in operating risk that would reduce financing costs and produce savings that could be shared with customers. However, the Board has recently conducted an extensive review of the cost of capital for regulated utilities in Ontario. During this review, the Board heard from a number of experts on cost of capital. With respect, Dr. Lowry is not a cost of capital expert and he confirmed this during the Stakeholder Meeting.

Contrary to PEG's suggestion, there is no indication that a Revenue Decoupling with true-ups model necessarily reduces the risk of a utility and the model may even increase elements of the utility's risk profile. The PEG Report itself emphasizes the cost

[6] See EB-2008-0408, Report of the Board, Transition to International Financial Reporting Standards, July 28, 2009, page 7, principle 2.

risk faced by a utility operating under a multi-year rate plan with a revenue decoupling true-up:

> While reducing revenue risks, decoupling by itself does not guarantee that a utility will recover a cost. In particular, a utility operating under a decoupling true up plan must still manage its cost to ensure that it is equal to or less than the allowed revenue. This can be challenging, especially when the firm is operating under a multiyear rate plan.[7]

In addition, Enbridge believes that a full revenue decoupling true-up could increase regulatory risk. As discussed above, the dollar amounts of the true-ups could be very large and highly volatile. It is questionable whether the impact of these true-ups on customers would be well received and as a result uncertainty about approval of the true-ups, or about the effect of mitigating caps, could increase utility risk.

PEG introduces the concept of hard or soft caps to manage the disposition of true-up amounts. Here again Enbridge sees potential for greater financial risk. The potential for under-recovery of revenues (hard cap) or for recovery of revenues only over an extended period of time (soft cap) increases uncertainty faced by investors.

Finally, the very reason why a Revenue Decoupling with true-ups model may be attractive is in response to higher risks faced by the utility. That is, the Revenue Decoupling model may become more attractive as the risks of declining average use increase. The pace of declining average use could increase due to conservation or other effects, including standards (such as building codes or minimum appliance efficiency specifications) or greater reliance on renewable energy sources. A revenue decoupling mechanism alleviates the increased business risk associated with these developments, but it does not result in any net reduction to the overall risk profile of a utility. It may very well be that revenue decoupling is simply an offset to an equal or larger increase in business risk due to revenue attrition.

IV. Board Staff Issues

Issue 1 In light of developments in metering, CDM, and demand side management ("DSM"), among possible others, is the implementation of further or modified revenue decoupling mechanisms for electricity and/or gas distributors warranted at this time and if so, why? For example, is the Board's current Lost Revenue Adjustment Mechanism adequate in light of the contemplated introduction of CDM targets for all electricity distributors in the Province?

[7] PEG Report, page 18.

A further or modified revenue decoupling mechanism is not needed for Enbridge at this time.

For the electricity distributors, there may be a need to implement revenue decoupling mechanisms, particularly in light of the discussion during the Stakeholder Meeting about the concern of smaller electricity distributors that it is cost prohibitive to make an LRAM filing. In any event, though, the implementation of any particular revenue decoupling methodology depends on the specific circumstances of the individual utility. Each utility should be able to consider its specific circumstances in order to choose a methodology, if any, that is the most appropriate for it. The available alternatives should include an LRAM, SFV pricing, Revenue Decoupling with true-ups, and a hybrid approach like the gas utility hybrid model.

Issue 2 What factors should be considered when assessing the suitability of Ontario's current mechanisms and of alternative approaches? Are any of these factors more or less important than others? If so, why?

The PEG Report lists the following factors that are relevant to assessing the suitability of alternatives:

~ administrative costs;
~ ability to remove disincentives for a utility to undertake DSM programs; and
~ ability to protect against earnings attrition for utilities.

Other factors to be considered may include the following:

~ success of CDM/DSM programs to date;
~ ability of the current regulatory framework to promote conservation goals and utility financial health;
~ utility preference;
~ particular utility exposure to earnings attrition and declines in average use; and
~ other circumstances specific to a particular utility.

All of these considerations are important, but the most weight should be given to the unique or specific circumstances of each utility. In assessing the circumstances of an individual utility, weight should also be given to the views of utility management about the best approach. Given that a key objective is to remove concerns about revenue attrition so that there is no disincentive to conservation efforts, management obviously is well-placed to assess which methodology is most likely to address any such concerns.

Issue 3 What, if any, are the implications of the wide-spread deployment of smart meters for the Board's approach to revenue decoupling?

The application of Time of Use (TOU) pricing is not an issue for the gas sector.

For the electricity sector, the apparent purpose of TOU pricing is to send price signals to customers. To the extent that consistency with this purpose of TOU pricing is considered to be important, revenue decoupling models should promote the right price signals. This can best be accomplished with LRAMs, or with a hybrid approach, like the gas utility hybrid model. However, the over-riding consideration should be the regulatory framework that best meets the particular circumstances of an individual utility.

Issue 4 What scope for further or modified revenue decoupling might be appropriate? For example, should the impact of all variances from forecast in commodity demand be eliminated regardless of the cause (i.e., distributor-provided CDM/DSM programs, other CDM/DSM programs, the economy, weather, customer growth, etc.)? Why or why not?

Further or modified revenue decoupling mechanisms are not needed for Enbridge at this time.

The electricity distributors should be able to select the regulatory framework that, in their particular circumstances, best suits the goals of promoting conservation and removing earnings attrition due to declining average uses. For some utilities, this may mean eliminating the impact of all variances from forecast in commodity demand regardless of the cause. These utilities could choose from methodologies that include SFV pricing, Revenue Decoupling with true-ups, or a hybrid approach like the gas utility hybrid model.

As a general rule, Enbridge supports the proposition that utilities should be compensated for reductions in demand regardless of the cause. Because the costs of a distribution system are largely fixed in nature, feasibility analyses depend largely on volumes that are expected to be billed in the future. If a utility is faced with a future of declining volumes and revenues, and is not afforded any protection from this risk, then the risk profile of the utility's investments, and of the utility, increases.

Issue 5 Are there alternative approaches, beyond those identified in the PEG Report, which better address revenue erosion due to changes in consumption? What are the costs, benefits and implications of implementing the alternative approach?

The PEG Report provides three alternative approaches to revenue decoupling, as follows:

- ~ SFV pricing;
- ~ Revenue Decoupling with true ups; and
- ~ LRAMs.

Another alternative is a hybrid model, like the gas utility hybrid model. As stated above, a hybrid model accomplishes the objectives of revenue decoupling, but also limits the downside from implementation of any one single form of decoupling for some utilities.

<u>Issue 6</u> Is there a preferred approach (or elements of an approach) and if so, what are the important implementation matters that must be considered? What are the costs, benefits and implications of implementing the preferred approach or of refraining from doing so?

Consistent with the conclusion in the PEG Report that current decoupling arrangements for gas distributors are reasonable, the preferred approach for Enbridge at this time is the regulatory framework now in place.

Other utilities should be free to select from the available alternatives, based on their specific circumstances. There should not be a "one size fits all" approach.

<u>Issue 7</u> Can or should the preferred approach need to be the same in both the gas sector and the electricity sector? Why or why not? Would any other form of differentiation based, for example, on a specific distributor characteristic(s) be appropriate? If so, what might be the defining characteristic(s)?

The approach need not be the same for the gas and electricity sectors. While the experience of the gas distributors with the gas utility hybrid model may provide useful information for the electricity sector, there are a number of relevant differences between the two sectors. Some of the key differences are listed above.[8] Scope should be allowed for differentiation between individual utilities, based on their specific circumstances.

[8] See pages 2-3.