Ontario Energy Board

Staff Discussion Paper

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

February 28, 2008

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1 Introduction

On August 2, 2007, the Ontario Energy Board (the "Board") initiated a consultation on the development of the principles and methodology for the third generation incentive regulation ("3rd Generation IR") mechanism for electricity distributors. This consultative process will lead to the issuance of a Board report setting out the principles and methodology for the 3rd Generation IR mechanism that will be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review.

Staff Scoping Paper issued

Also on August 2, 2007, a Board staff Scoping Paper entitled "3rd Generation Incentive Regulation for Electricity Distributors" (the "Scoping Paper") was issued for comment. The Scoping Paper described the context in which the 3rd Generation IR mechanism will be developed, proposed underlying principles to guide the work and issues to be considered, and proposed an approach to the upcoming consultations. The Board received written comments on the Scoping Paper from 16 interested stakeholders, and these are available on the Board's web site.

Stakeholder working group established

On September 7, 2007, a working group was established to provide assistance to Board staff by helping to carry out the analysis necessary for purposes of reviewing and evaluating options. The working group is comprised of six representatives of ratepayer groups, six representatives of distributors, and one representative of distributor employees. Distributor representation covers the range of large, medium and small distributors. This composition was selected to achieve an appropriate balance of the relevant interests, while maintaining the size of the working group at a level that would optimize its efficiency. Participants on the working group are listed in Appendix A.

On September 13, 2007, a stakeholder consultation conference was held to provide all interested stakeholders with an opportunity to exchange ideas with staff and each other on the issues and questions raised in the Scoping Paper.

1st Stakeholder Conference

The working group met several times over a period of 12 weeks. At those meetings, staff and the working group were informed by the advice of Board staff's expert consultant, Dr. Larry Kaufmann of the Pacific Economics Group ("PEG"). Dr. Kaufmann will continue to provide advice to staff throughout this consultation. Dr. Kaufmann's report entitled "Calibrating Rate Indexing Mechanisms for 3rd Generation Incentive Regulation in Ontario" (the "PEG Report") makes specific recommendations for the productivity and stretch factor components of the X-factor and provides a discussion of relevant IR precedents. The PEG Report is available on the Board's web site.

Pacific Economics Group advising

A second stakeholder consultation conference was held on December 14, 2007. The purpose of this conference was to provide all interested stakeholders with an update on the progress made by the working group and to provide participants with an opportunity to discuss key points and share ideas.

2nd Stakeholder Conference

Overview of this Paper

Staff has prepared this paper to solicit further input from all interested stakeholders on options for the 3rd Generation IR mechanism.

Staff believes that a rate adjustment mechanism that may be suitable for most electricity distributors – a "core plan" – should be developed. In the event that another approach to rate setting is more appropriate in any given case, the distributor may apply to the Board to have its rates set using that alternative approach.

A "core plan" that is suitable for most distributors

Staff invites comment from stakeholders in order to provide it and the Board with a thorough analysis of the issues.

Invitation for comment

Organization of this Paper

The paper is organized as follows. A long-term view of IR for electricity distributors and the criteria used by staff and the working group to develop three alternative approaches to IR are outlined in Section 1. Section 1 discusses three specific issues for 3rd Generation IR. It also briefly describes an array of options for dealing with those issues that Dr. Kaufmann presented to the working group and staff. Three alternative approaches selected by the working group and staff for further study are also discussed and evaluated in Section 1. Section 4 outlines staff's thinking on a reasonable core plan for the 3rd Generation IR mechanism. Sections 1 and 4 include a summary of associated key issues, an indication of stakeholder comments from consultations and an account of each of the major considerations. Section 5 outlines a number of potential implementation considerations.

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2 A Long-term View of Incentive Regulation

Scoping Paper

The Scoping Paper suggested five principles upon which a multi-year rate-setting methodology should be designed:

- The financial viability of the electricity distribution sector should continue to be balanced with the interests of consumers.
- The pursuit of economic efficiency should be encouraged.
- The incentive regulation framework must be sustainable.
- Rate volatility should be minimized.
- In practice, the rate-setting methodology should be predictable and understood by stakeholders, and capable of being implemented through efficient and effective regulatory process.

Stakeholder comments

In their written comments many stakeholders identified the importance of a vision for a long-term IR framework. One stakeholder commented that without such a vision there is a danger that Ontario will simply move from one arbitrary regulatory approach / mechanism to the next.

Distributors generally expressed concern that the work to develop the 3rd Generation IR mechanism needs to take into account the various political, economic, social, and technological factors that affect distributors. Specific examples cited include the Government's policy framework for demand and supply mix planning, including conservation targets; the Standard Offer Program; and the smart meter initiative. Factors such as aging infrastructure and the differences among distributors with regard to corporate objectives, structures and operating environments were also identified. Most stakeholders expressed similar concerns in their comments and many identified, as potentially desirable outcomes of IR, one or more of the following:

- reducing rate variability among distributors;
- raising standards for all distributors or providing specific benchmark objectives in specific areas of concern;

- improving efficiency;
- fostering business innovation;
- avoiding yearly cost of service applications;
- improving service quality;
- achieving the goals set out in the Integrated Power System Plan; and
- encouraging consolidation.

One distributor commented on the need for an incremental approach to further developing IR in the Ontario electricity distribution sector – that is, focusing attention now on the elements that need to be developed at the outset, so that the resulting model best reflects the circumstances in Ontario that are most likely to affect distributors in the next three to five years. This stakeholder suggested that attention could be focused on the development of a model for the more immediate future, but along evolutionary lines that would allow key lessons learned to be fed back and incremental improvements made, rather than a re-thinking of the whole concept at some later date.

Similarly, a stakeholder representing ratepayers commented that this consultation process should not be rushed or truncated just to get a new model or models issued in time to make 2009 rate adjustments. This stakeholder suggested that, if there is insufficient time to adequately develop a 3^{rd} Generation IR mechanism, then the 2^{nd} generation mechanism could be applied to those distributors that have had their rates rebased in 2008. The stakeholder noted that this may be more appropriate than insisting on applying a "new generation approach" that is not complete or that may be subject to significant changes.

Another stakeholder representing ratepayers commented that capital investment, revenue erosion, and/or diversity may not necessarily be issues depending on the type of framework adopted. This stakeholder noted, for example, that a rate freeze plan with an off ramp for when a distributor wants to file a cost of service rebasing application would not need to deal with the term of the plan (it would be indefinite and up to each distributor to determine when/if to rebase), and inflation and productivity factors would not need to be calculated. This stakeholder commented that such a plan could still allow for pass through items and unforeseen events on a case-by-case basis, and that capital investment and changes in revenue would only be relevant when the distributor's rates are rebased. Finally, this stakeholder commented that distributor diversity could be managed through the diversity provided by a rate freeze – some distributors may need to rebase frequently if they are dealing with substantial capital investment, rapidly changing consumption or issues specific to the areas they serve; other distributors may have lower capital investment requirements and insignificant changes in consumption and other issues that allow them to maintain the same rates for a longer period of time.

Incentive regulation as proxy for market mechanisms

Staff believes that incentive regulation can be a viable and flexible long-term approach to setting rates that are just and reasonable. Incentive regulation can promote efficiency improvements in the absence of market mechanisms. Designing such regulation of monopoly firms requires some form of external benchmark – making use of analytical tools and methods to assess relative efficiency and productivity changes over time. With the focus on efficiency improvements, appropriate regulation of quality of service emerges as an important issue. Quality of service comes at a cost and there can be a concern that the pursuit of profit incentives by distributors may have an adverse effect on quality of service.

Current state of incentive regulation

In Ontario, cost benchmarking is in its early days and currently only assesses operating, maintenance and administrative costs. Bringing capital costs into the analysis is anticipated in the next generation benchmarking. Comprehensive price cap regulation is in effect; however, in its current form it is transitional in nature. Empirical analysis could be carried out to calibrate the mechanism to reflect the specific circumstances in Ontario's electricity distribution sector and external performance measures (i.e., benchmarks). Finally, the form of service quality regulation in effect is a simple monitoring model – the indicators and standards established in 2000 are currently under review.

Summary of Working Group Discussion

Long-term view for an integrated and comprehensive IR framework

In general, the working group reiterated stakeholder comments on the need for a long-term framework. The working group expressed the belief that in the long-term there should be an integrated comprehensive IR framework in Ontario that includes service quality regulation and makes use of benchmarking to imitate the operation and outcomes of a competitive market.

Members of the working group noted that further work may be needed to review information required for benchmarking (e.g., to ensure consistency in financial reporting, to ensure completeness and accuracy of information, and to address capital valuation), and to confirm appropriate service quality standards (e.g., determine customer service expectations, and establish consistency in reporting of service quality performance).

Members of the working group also expressed the view that for the IR adjustment mechanism to be predictable and understood, stakeholders should be able to replicate any calculations to derive values for the parameters (e.g., the inflation factor and the X-factor). They also noted that transparency can be achieved by posting the calculations on the Board's web site.

Stakeholder consultations on distribution rate design

A consultation process is currently underway in relation to the review of rate design for electricity distributors (EB-2007-0031). Stakeholders noted this consultation is an important consideration to any long-term view for ratemaking – whether cost of service or IR. A key policy driver for this review is the province-wide implementation of smart meters, which is expected to be completed at the end of 2010. Consequently, implementation of any resultant rate design changes may not occur until 2010 or 2011.

In the rate design consultations, stakeholders have been discussing different approaches to rate design. Some stakeholders have expressed concern that approaches which emphasize price signals to encourage conservation through customer time-of-use distribution rates or customer demand charges will entail revenue recovery risk for distributors. These stakeholders have suggested that some form of regulatory risk mitigation mechanism be provided to complement these approaches if seriously considered by the Board (e.g., an expanded lost revenue adjustment mechanism or "LRAM").

The rate design consultation is in its early stages, and any potentially new distribution rate structures require further examination, development, and assessment. Until that time, the need for and form of risk mitigation measures cannot be ascertained. Whether some form of LRAM-like adjustment is required to mitigate risks to distributors and their ratepayers may be considered within the scope of the rate design consultations.

An incremental approach is appropriate

Staff and the working group suggest that taking an incremental approach towards a long term vision of comprehensive IR for electricity distributors is a practical approach for Ontario. Where it may not be currently feasible to fully implement an IR element that has been identified as an important feature of a long-term and comprehensive framework, this consultation may identify steps that could incrementally develop that element.

2.1 Criteria for 3rd Generation IR

Four criteria for 3rd Generation IR

Consistent with this view for an incremental approach, reflected in this paper is staff's belief that 3rd Generation IR should be sustainable and long-term in its outlook. It should be predictable and effective, and should be practical to the extent possible without sacrificing the other criteria.

A **sustainable** framework is flexible and reasonably able to handle changing and varied circumstances, while ensuring that the principles underlying the method by which the rate adjustments are determined are consistent between distributors.

A **predictable** framework facilitates planning and decision-making by ratepayers and electricity distributors.

An **effective** framework encourages distributors to implement efficiencies and allocates the benefits from greater efficiency between the distributor/shareholder and ratepayers in an appropriate manner. An effective framework also provides for prudent capital investment as required to ensure necessary infrastructure development and to maintain an appropriate level of reliability and quality of service.

Without sacrificing the other criteria, under a **practical** framework, the distributor's costs of administration should not exceed the benefits.

2.2 Building a Comprehensive and Sustainable IR Framework

This section discusses, at a high level, important milestones that staff and members of the working group have identified as necessary to take regulation of Ontario electricity distributors towards a comprehensive and sustainable IR framework. The framework implements mandatory service quality regulation and incorporates benchmarking. Timelines are not presumed; however, it is assumed that rate rebasing of distributors will continue to be staggered.

Reviewing information for comprehensive benchmarking

Work to review information required for comprehensive benchmarking should continue. As noted in the PEG Report, consistent data for Ontario electricity distributors is only available for the period 2002 to

2006. PEG used this data in their comparative cost work for the Board[1]. While benchmarking research for an earlier sample period of 1988 to 1997 was undertaken in the first generation performance-based regulation ("1st Generation PBR") plan, this dataset is not linked to the 2002-2006 data. Distributor data for the linking years, 1998 to 2001, would need to be collected from various sources and compiled into an appropriate form. Carrying out this work is not feasible in time for implementation of the 3rd Generation IR mechanism. While a significant investment of time and effort involving distributors, other stakeholders, and staff would be required to construct a robust and reliable link between the 2002 to 2006 dataset and the dataset employed earlier, staff believes it would resolve a recurring issue with stakeholders and hopefully facilitate the Board's ability to effectively regulate 80 plus distributors. The recurring issue with stakeholders regarding the missing data is that it impedes standard empirical studies on service quality and productivity.

It is important to ensure that data is defined consistently across companies (e.g., controlling for mergers over the sample period) and across time (e.g., similar cost definitions for a given company in all sample years). This will enable empirical studies to be conducted that can, in turn, be expected to provide a basis for developing better standards and more effective incentives in IR.

The current dataset may be informative to the Board's current ratemaking. In the future, with a complete set of Ontario distributor data, the Board would be able to rely on more transparent and easily understood techniques to calibrate the X-factors and in doing so can implement a more effective framework for Ontario electricity distributors.

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[1] Mark Newton Lowry, et al., Benchmarking the Costs of Ontario Power Distributors (Pacific Economics Group, April 25, 2007). (http://www.oeb.gov.on.ca/documents/cases/EB-2006-0268/report_Benchmarking-peg_20070427.pdf)

New and/or revised service quality standards

Rate rebasing at the end of 3rd Generation IR should provide for any new and/or revised service quality requirements; i.e., allow for the setting of base rates in the context of the new or revised standards.[2]

[2] If the new standards come into effect in 2008 or 2009, distributors that rebase in those years may have their base rates set in the context of the new or revised standards.

3 Issues and Options for 3rd Generation IR

Scoping Paper

The Scoping Paper proposed that 3rd Generation IR consultations consider all of the necessary elements of an IR mechanism framework including the form and term of the plan, the inflation and productivity factors, the potential for an earnings sharing mechanism ("ESM"), and the treatment of unforeseen events. The Scoping Paper also proposed that the consultations include a focus on specific issues associated with capital investment to support infrastructure maintenance and development, lost revenue due to changes in electricity consumption and distributor diversity.

Stakeholder comments

In general, written comments on the Scoping Paper confirmed that these specific issues are important. Some stakeholders proposed particular principles to guide examination of these issues and others suggested preferred options or recommendations on how the issues might be addressed in IR mechanism. Two stakeholders provided detailed issues lists in their comments.

Working group thoughts

The working group confirmed that the high level issues for the 3rd Generation IR mechanism are capital investment, lost revenue due to changes in consumption and distributor diversity.

The treatment of taxes, the amount and scope of information required for regulatory oversight, the importance of clear and explicit rules at the start of an IR term, and the need for a future vision of IR were also identified as important considerations in the review and evaluation of options by the working group.

This section describes the high level issues and discusses the current context for those issues. It also briefly describes alternative ways of dealing with the issues that were discussed by the working group and staff.

3.1 Capital Investment

Scoping Paper

With regard to capital investment, the issue as stated in the Scoping Paper is:

- Is there a need for special treatment of capital spending in an incentive regulation framework?

As noted in the Scoping Paper, a number of distributors have commented in more than one consultation process that an IR framework needs to ensure that sufficient incentives are available in order to achieve efficiencies, recognizing the time patterns of costs and savings; and to provide for the appropriate, but expeditious review and approval of capital expenditure programs to support appropriate infrastructure maintenance and development.

In its July 23, 2007 “Report of the Board on Rate-making Associated with Distributor Consolidation” and associated covering letter, the Board indicated that electricity distributors’ concerns over partial rebasing to account for needed capital expenditures should be examined as part of the development of the 3rd Generation IR mechanism.

Stakeholder comments

In their written comments on the Scoping Paper, a number of stakeholders confirmed capital investment as an issue of particular concern. One distributor proposed that the IR framework should be conducive to investment to maintain a safe and reliable distribution system, service quality and financial health. Another distributor proposed that prudent investment should be encouraged in order to recognize that some distributors may require significant operations, maintenance and administration ("OM&A") and capital investments (to address aging infrastructure, conservation and demand-management ("CDM"), smart meters and distributed generation) during the term of an IR plan. This distributor commented that the regulatory framework should be sufficiently flexible to permit a distributor faced with these issues to adjust its rate base as appropriate during the IR term to ensure that it recovers sufficient revenue to finance its needs.

One stakeholder representing a ratepayer group commented that a multi-year cost of service approach should be considered, and noted that the Board has some experience with such an approach in relation to the regulation of Natural Resource Gas Limited which has used this methodology a number of times over the last decade.

A stakeholder representing another ratepayer group commented that the treatment of capital investment under IR should be symmetrical. This stakeholder noted that while ratemaking will need to address for distributors the treatment of extraordinary capital needs during the IR term, it should also address for ratepayers the issue of potential under-spending of any approved amounts allowed into rates during the IR term associated with distributor capital plans.

Another stakeholder noted that while the approach taken in the United Kingdom (discussed below) could hold promise in terms of addressing capital investment issues (because of its cost of service nature), it represents a significantly different paradigm from the index-based form of incentive regulation implemented for the Ontario electricity sector to date.

Board Staff Comments

In maintaining and operating its distribution system, a distributor plans for and incurs capital expenditures over time to maintain the integrity and reliability of its system, to accommodate growth and any new environmental or technical standards, and to meet its legal and regulatory obligations.

Accordingly, a distributor is responsible for making its investment decisions based on its business conditions, the needs and reasonable expectations of its ratepayers and the objectives of its shareholders, all within the context of regulated rates and subject to service quality standards set by the Board.

Any ratemaking framework (whether cost of service or IR) should provide for prudent capital investment. This is consistent with generally accepted ratemaking principles to the effect that rates should be effective in recouping revenue requirement and should promote the efficient use of resources.

Issue scope

Comments in consultations to date have been quite broad in scope with regard to the issue of capital expenditures. Among the government policy initiatives identified as driving the potential need for new investment in electricity distribution infrastructure are the smart meter initiative and the Standard Offer Program. Expenditures associated with these initiatives are currently dealt with through separate regulatory processes or instruments (e.g., smart meters via a Board-approved rate adder, and generation connections via provisions in the Board's Distribution System Code). It will be necessary to continue to deal with these expenditures during the term of 3rd Generation IR. Concern expressed by distributors over aging infrastructure and the need for increased investment in that infrastructure to maintain the appropriate levels of service, which may be beyond the levels supported by existing rates, also needs to be understood.

Some members of the working group noted that, as illustrated in Figure 1, since rate unbundling in 2001 rate rebasing reviews did not begin until 2006. Further, some members observed that in light of the rate adjustments made since rate unbundling, they believe that it would be difficult to argue that distributors have not been operating under a form of price cap and absorbing cost increases since 2001.

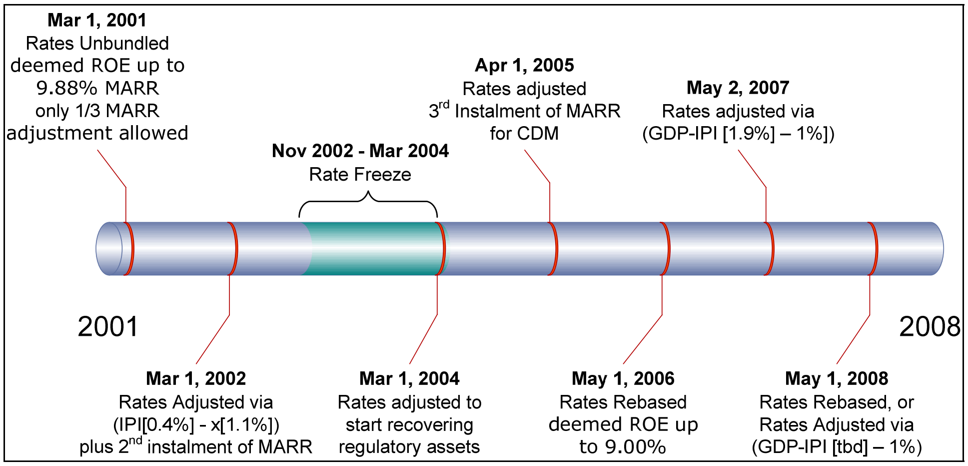

Figure 1: Distribution Rate Reviews Since 2001

Key assumptions

The following assumptions are important to understanding the issue of capital investment:

- Base rates at the start of 3rd Generation IR will include provision for capital investment-related amounts as determined by the Board based on a distributor's application for the cost of service rate review pursuant to section 78 of the Ontario *Energy Board Act, 1998*, based on a forward test year[3]. As amortization is not a good predictor of future capital expenditure needs,[4] forward test year amounts may include additional capital expenditures needed to reflect asset cost inflation, system growth, and needed service enhancements (additional infrastructure and accommodation of

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[3] Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications (November 14, 2006).
[4] Ontario Ministry of the Environment, "Toward Financially Sustainable Drinking-Water and Wastewater Systems" (August, 2007).

changes in technology and standards). IR rate adjustment mechanisms should be designed to reflect this assumption.

- The Distribution System Code ("DSC") contains the rules that distributors are required to follow to evaluate the economics of distribution system expansion projects, including the approach to determining capital contributions from the customer. Those rules and the Board's ratemaking assumptions and methodology should be consistent. Once a preferred approach to IR is determined, the DSC rules may need to be reviewed to ensure that consistency is maintained.

Summary of Working Group Discussion

Is there a need for special treatment of incremental capital spending in an IR framework?

It is still unclear as to whether special treatment of capital spending is necessary in an IR framework. Members of the working group differed on this matter. Some members of the working group expressed the belief that special treatment is necessary, and identified the following cost pressures that may affect distributors in the coming years:

- significant replacement of aging assets;
- lumpy capital expenditures to meet new growth (e.g., transformer stations) and/or customer choice of location for connection; and/or
- capital contributions paid by distributors to transmitters.

Other cost pressures that members of the working group identified include costs to meet significant employee retirement/workforce demographic changes and unpredictable weather and increasing storm damage as emerging cost drivers for their businesses.

Other members of the working group were not fully convinced that special treatment is necessary. The base rates going into 3rd Generation IR will reflect the capital requirements approved in a single forward test year review by the Board. Subsequently, some form of formulaic adjustment to rates could allow for some implicit growth in capital investment. An important design consideration for any multi-year IR plan is to provide for a level of investment needed to maintain service quality and reliability levels, without encouraging over-build of the system.

Some members of the working group commented that the analysis used to calibrate an IR adjustment, generally the total factor productivity (“TFP”) analysis, may be adjusted for capital investments that are predictably linked to outputs (e.g., growth in customers, growth in volume, asset aging, etc.). However, they expressed concern over how the TFP analysis would be adjusted for capital investments that are not linked to outputs, such as smart meter- and distributed generation-related capital expenditures. As noted previously, these latter types of expenditures have to date been dealt with outside of the rate adjustment index as either rate adders (for smart meters) or capital contributions (for connections to accommodate generators).

More demanding service quality standards and longer IR term may justify special treatment

Dr. Kaufmann, in his presentation to the working group and staff, highlighted two other specific issues associated with the question of whether special treatment of capital investment is needed in incentive regulation: service quality standards and the term of the IR plan. First, to the extent that service quality standards become more demanding, the need for expenditures will likely increase. As some of these expenditures may be capital investments, the rationale for some form of special treatment of these investments may be more apparent. This is not true if and where service quality regulation simply calls for existing standards to be maintained. Second, at rate rebasing, prudent investment costs can be recovered, including a consideration of the lost revenues resulting from the timing delay to reset rates. The longer the period of time between rate rebasings (i.e., the longer the IR plan term), the greater the potential need for some form of special treatment of materially significant investment needs. This is less true in plans with shorter plan terms.

Alternative capital investment mechanisms

Dr. Kaufmann presented a number of alternative capital investment mechanisms that might be used within the context of incentive ratemaking:

- Index-based price adjustments;
- Forward-looking test years (i.e., multi-year cost of service) with a sliding-scale/information quality incentive;
- Capital project pre-approval;
- Capital cost tracker with prudence reviews;
- Capital cost tracker without prudence reviews;
- Unit cost approach for specific capital projects; and
- Accelerated cost recovery.

Each is briefly discussed below. Further details and jurisdictional precedents are referenced in Dr. Kaufmann's presentation.[5]

Index-based price adjustment approach

Index-based price adjustments are common in North America. The Ontario gas and electricity distribution IR plans implemented to date have been index-based plans. In index-based plans, there is no explicit mechanism to deal with capital beyond a basic "inflation minus productivity" price indexing formula. The formula, which allows for some implicit growth in capital investment, is comprehensive in that it applies to all company costs.

Index-based plans offer the benefits of being relatively simple to implement and administer, and of providing strong performance incentives to the companies subject to them. However, if growth in investment costs exceeds what is allowed in the indexing formula, the company must wait until rebasing to recover the capital costs and associated return on capital.

The primary concern expressed by some members of the working group with the index-based price adjustment approach was that the implicit growth in capital investment may be insufficient to cover "business-as-

[5] Larry Kaufmann, Partner Pacific Economics Group, "Capital Investment Mechanisms: Some Options for IRM3".
(http://www.oeb.gov.on.ca/documents/cases/EB-2007-0673_filings/workinggroup/meeting_20071107/Capital%20investment_110707_2_20071179.pdf)

usual" incremental capital expenditures incurred during the IR term. These members of the working group expanded on a modified index proposal, referred to as a "modular approach", as an alternative way to treat capital under an indexed IR plan. The indexing formula would deal with OM&A and output related capital investment, and non-output related capital investment would be treated outside the indexing formula. The non-output related capital expenditures, identified by working group members as in relation to matters such as smart meters, significant replacement of aging assets and/or distributed generation-related investments, would be considered as "incremental" and would be reviewed by the Board on a case-by-case basis. One concern raised by some working group members with this modular approach is that it does not ensure a complete and balanced review of all aspects of the operation that influence the level of rates, it only reviews the one particular area associated with an incremental capital expenditure. In response, some members of the working group suggested that perhaps module application requirements could be designed to address this concern.

Multi-year cost of service approach

Under the most recent multi-year cost of service approach adopted in the United Kingdom (UK), the regulator determines a benchmark level of projected capital expenditures for each of the 14 distribution companies, and the 14 companies file forward looking capital expenditure projections over the five-year term of the distribution price[6] plan. The regulator then determines the amount of capital expenditures to be allowed in each distributor's prices. Consequently, the parameters of the price adjustment mechanism are set to recover those expenditures. To overcome forecast gaming, an incentive scheme has been introduced (a sliding scale/information quality incentive) that rewards companies for keeping forecasts close to benchmark levels, but allows adjustments for differences between actual and allowed costs.

[6] The term "price" is used in the UK to refer to a rate.

The sliding scale incentive mechanism

As described in the November 2004 "Electricity Distribution Price Control Review Final Proposals",[7] the sliding scale incentive mechanism is an approach that, in principle, allows companies to choose between getting a lower cost allowance, but with a "higher-powered incentive" that allows them to retain significant benefits if they can do even better than the low figure, and a higher allowance, but with a "lower-powered incentive" that gives relatively smaller reward for under spending the higher allowance. A sliding scale matrix is set by the UK regulator, Ofgem. The efficiency incentive rates and allowed expenditure levels are linear functions of the ratio of the distributor's forecast to Ofgem's consultant's view of benchmark expenditures for that distributor. Any additional income is then adjusted to ensure the matrix remains incentive compatible. In addition, companies that choose the low cost allowance get a reward (a small amount of additional return above the base cost of capital) for spending no more than their allowance, while companies that choose the high cost allowance do not (they are neither rewarded nor penalized if they spend their allowance). The aim is to set incentives so that companies that know they have lower capital expenditure needs will find it more beneficial to choose the lower allowance, while companies that know they need to spend relatively more will find it more beneficial to choose the higher allowance. Appendix One of the PEG Report provides further detail on this mechanism.

The multi-year cost of service approach adopted in the UK provides the benefit of allowing projected costs to be recovered via price trends. However, implementation of this approach requires established benchmarks and/or a detailed review of individual company operating and capital plans. Further, there is the added complexity of designing the forecast incentive scheme "correctly". Tracking of performance against

[7] Available at http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR4/Pages/DPCR4.aspx. This page contains information on the current price control applicable to electricity Distribution Network Operators (known as Distribution Price Control Review 4). This price control runs from 1 April 2005 until 31 March 2010).

forecast adds an additional level of regulatory and administrative burden during the price plan.

There was some discussion among the working group of the possibility of adopting this approach in Ontario. Some members of the working group indicated that it may not be possible for many distributors to prepare and file multi-year cost of service applications. However, other members of the working group indicated that it should be an option available to distributors that are capable of preparing such an application.

Project pre-approval and cost tracker approaches

In the capital project pre-approval approach, agreement is reached in advance between a company and its stakeholders in a process for approving on a project-by-project basis allowed capital cost, provisions for cost recovery, and consequences of cost over-runs and under-runs. In cost tracker approaches, the capital cost tracker mechanism is outside of – or added to – a rate indexing formula to track and recover capital costs. In cases where this mechanism includes a prudence review, it is an after the fact, Z factor-like application and review process. The capital project pre-approval and capital cost tracker with prudence review approaches rely on regulator oversight rather than inherent IR incentives to encourage efficiency. As a result, the working group had mixed reactions to these alternatives as viable options for the 3rd Generation IR mechanism. Specifically, some working group members were concerned with introducing intra-term, after-the-fact prudence reviews into the plan. Lack of precedents illustrating the application of the capital cost tracker without prudence review discouraged the group from considering it further. Also, the complexity in designing appropriate caps and/or controls on capital costs, in lieu of a specific prudence review, for each distributor may be prohibitive.

Unit cost approach

With regard to the establishment of unit cost benchmarks (e.g., $/km of asset) to roll allowed investment costs into either rate base or rate formulas, the working group expressed concern over the complexity of determining appropriate unit cost benchmarks. However, the working group expressed interest in the "end-of-term capital incentive" feature implemented in one of the cited precedents of the unit cost approach, as described below.

End-of-term capital incentive

In a settlement agreement accepted by the British Columbia Utilities Commission, Teresan Gas Inc.[8] describes an end-of-term capital expenditure incentive designed to encourage efficient capital spending in all years of the plan. The revenue requirement impact of amounts collected through rates but not spent are shared with ratepayers over the term of the IR plan through an ESM, and the balance is returned to ratepayers over a two-year period (i.e., is "phased out") after the end of the IR term. The amounts shared with/returned to ratepayers represent the estimated average avoided annual revenue requirement as a result of the capital expenditure variance and is referred to as a capital benefit. The mechanism could be asymmetric in that over-expenditures could be at the distributor's risk during the plan term while any benefits that result from under-expenditures would be partially shared and partially retained beyond the end of the plan term. This mechanism is intended to address under/over-spending of any approved capital adjustments allowed into rates during the term of an IR plan.

Accelerated cost recovery approach

Under an accelerated cost recovery approach, no explicit indexing formula adjustments or new mechanisms are provided; however, the regulatory framework and rules are designed to accelerate the recovery of capital costs. For example, construction work in progress might be included in rate base or an adjustment to depreciation allowed. While this alternative does provide for accelerated recovery of capital costs, and may provide more cash to the company, the working group noted that it does not provide any real incentives for efficiency.

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[8] British Columbia Utilities Commission, Order G-51-03 in response to an Application by Terasen Gas Inc. (formerly known as BC Gas Utility Ltd.) for Approval of a Multi-Year Performance-Based Rate Plan to Set Rates for 2004-2008 (July 29, 2003).

Staff invites comments from stakeholders on the options noted above.

Staff invites comment

3.2 Lost Revenue Due to Changes in Consumption

Scoping Paper

The current LRAM addresses revenue erosion resulting from distributor CDM activities. The Scoping Paper stated that consideration of alternative mechanisms to address lost revenue due to changes in electricity consumption, including those resulting from all forms of conservation, should be considered as part of the process to develop the 3rd Generation IR mechanism and/or during the Board's review of options for the fundamental redesign of electricity distribution rates. Therefore the question for consideration as identified in the Scoping Paper is:

- What alternative mechanisms might address lost revenue due to changes in electricity consumption?

Stakeholder comments

Two stakeholders made specific comments related to CDM matters. One stated that the Board should encourage Ontario's electricity distributors to aggressively and cost-effectively promote CDM and commented on roles that the Board might play in the government's policy framework for demand and supply planning.

The other stakeholder sought confirmation that the Board intended this consultation to consider alternatives to the current LRAM and the current shared savings mechanism ("SSM"). This stakeholder also commented that development of the 3rd Generation IR mechanism needs to consider the incentives or disincentives created by options and whether separate incentives are needed to address loss reduction and fuel switching (away from electricity). Further, this stakeholder suggested that this consultation should consider the proposal from the Electricity Distributors Association ("EDA") regarding a revenue stabilization adjustment mechanism ("RSAM") that would eliminate the impact of all variances from forecast in electricity demand whether from CDM, the economy, weather or customer growth.

All of the stakeholders representing ratepayer groups commented on the importance of symmetry when considering changes in electricity distribution throughput. One explained that, to the extent that revenue decreases or increases occur, the IR model should identify how these changes should be reflected in rates and commented that it would be unfair to ratepayers to only consider issues related to revenue erosion. Representatives of two ratepayer groups made reference in their comments to the Board's December 20, 2006 "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors" (the "2006 Report") regarding both return on equity ("ROE") and capital structure. They noted that the Board's conclusions in the 2006 Report were based on the assumption that distributors are exposed to various business risks, including risk due to variation in sales due to business cycles, and cautioned that if cost of capital matters are not to be revisited in this consultation then the 3rd Generation IR mechanism should not absolve the distributors of this business risk.

Board Staff Comments

On March 2, 2007, the Board issued its final "Report of the Board on the Regulatory Treatment of CDM Activities by Electricity Distributors".[9] In that Report, the Board identified a number of principles that guided the design of the CDM framework. Among other things, the Board stated that implementation of government policy should be facilitated and that regulatory certainty and predictability should be provided by the CDM framework. That Report also stated that this consultation and/or the consultation on the fundamental redesign of electricity distribution rates would examine different approaches to dealing with lost revenues.

[9] Please refer to the Board's web site for this Report and details of the related consultation (http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_cdm_regulatorytreatment.htm.

With regard to CDM-related incentives, specific alternatives to the current SSM, and the role of incentives in IR as they relate to fuel switching (an objective of some CDM programs) have not been identified.

Staff notes that a separate initiative is planned by the Board to consider loss reduction incentives, and this topic is therefore not considered by staff to be appropriate for inclusion in this consultation. Further information on this initiative will be issued in the future.

Continuation of current SSM

With regard to CDM-specific shareholder incentives, staff suggests that given the government's policy direction, it may be appropriate to maintain the current SSM for distribution rate funded CDM activities as described in the recently released draft "Guidelines for Electricity Distributor Conservation and Demand Management".

Revenue Cap Indexing Mechanisms

PEG overview of revenue cap indexing mechanism

The RSAM, discussed by the working group and summarized below, is like a form of IR indexing called a revenue cap. The following general description of revenue caps, from the 2006 PEG Report, is provided to give stakeholders an overview of this form of IR indexing plan.

Under a price cap, the distribution rate is the focus of control. Under a revenue cap, the revenue of the distributor is the focus of control.

Like price caps, revenue caps feature measures of price inflation and productivity. Revenue caps also include a measure of output growth such as demand, consumption or number of customers. Some revenue cap index plans restrict the growth in total revenue. Some plans restrict growth in revenue per customer. As such, over the term of the plan, a variance account is used to track the difference between actual revenues and allowed revenues until rates are adjusted to dispose of the difference. These arrangements are sometimes called revenue-decoupling mechanisms since they sever the link between revenue and output growth.

Like price caps, revenue caps do offer incentives for cost containment since they restrict the growth in allowed revenues. Another benefit of revenue cap plans is that they reduce windfall gains and losses from demand fluctuations. This may be an important consideration for distributors that face unusually volatile demand due, for instance, to sensitivity to weather, prices of competing products, or prices in the end product markets of business users. It follows that the stabilization of revenue may then lower the distributor's capital cost due to the reduced risk. However, this may in the process destabilize rates. For example, an economic recession in a distributor's service territory may place upward pressure on rates at times when rate increases are especially unwelcome. Revenue cap plan designers thus encounter the issue of whether the benefits of capital cost savings to customers offset the cost of greater rate stabilization. This reduced risk can also strengthen the incentives to a distributor to promote energy conservation. Under price caps, the promotion of conservation may reduce operating margins. While these reduced margins may be offset by mechanisms such as the LRAM, under revenue caps, rates rise automatically to offset this effect.

Revenue cap mechanisms typically do not specify how revenue limits are translated into rate limits. The distributor can, in principle, be provided flexibility in its rate options and service offerings.

Revenue caps can raise more concerns than price caps about the quality of core services. As with price caps, quality may suffer since there are incentives to cut costs. However, under a revenue cap revenues that are lost due to reduced output associated with falling service quality levels can be recovered through price increases to customers using the balancing account. Since this is not possible under price caps, the incentives to maintain service quality under a revenue cap are weaker in the absence of counterbalancing incentive provisions.

Regulatory costs associated with administration of revenue caps may be greater than under price caps. One reason is that there is the addition to the indexing formula of an output growth factor which adds controversy in plan design. Another reason is the need for periodic filings to implement the balancing account mechanism. There may, additionally, be a continued need to consider the allocation of revenue requirements between customer groups, service offerings, and rate design.

Summary of Working Group Discussion

Staff reviewed two alternative mechanisms or approaches with the working group for dealing with revenue erosion in the context of incentive ratemaking:

- A RSAM; and
- A "CDM" factor in an index based price adjustment.

Revenue stabilization adjustment mechanism

The RSAM was proposed to the Board in 2006 by the EDA.[10] The RSAM would use the variance between forecast and actual consumption as the basis for a lost revenue adjustment. It would eliminate the impact of all variances from forecast in electricity demand regardless of the cause (distributor-provided CDM programs, other CDM programs, the economy, weather, customer growth, etc.).

The RSAM is like a revenue cap or revenue decoupling mechanism. The primary benefit is that it offers revenue neutrality because it would remove the risk associated with all revenue variances. A disadvantage is that the change in risk profile may need to be reflected in capital structure or allowed ROE. It would also put the onus on distributors to produce the load forecasts required for implementation of the mechanism.

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[10] For comments received by the Board on the EDA's proposal, please refer to http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_cdm_revenuestabilization.htm.

Associated with those load forecasts are "after the fact" adjustments to actual results (e.g., weather normalization) to calculate variances for the purpose of establishing true-ups to revenues. While the RSAM could make distributors indifferent to gains and losses from demand fluctuations, it would transfer the risk of volume fluctuations to ratepayers, thus contributing to rate uncertainty. Countering this rate uncertainty, the reduction in risk would likely translate into a change in capital structure or allowed ROE that may in turn reduce rates to customers. These pros and cons were identified in comments received by the Board on the EDA's proposed RSAM.

"CDM factor" in an index based price adjustment

The second model presented was originally proposed by Hydro One Networks Inc. in its comments on the EDA's proposed RSAM.[11] In that model, an adjustment factor based on the CDM targets set by the Government of Ontario and/or the OPA would be included in the incentive regulation formula to reduce the impact of lower revenues due to the target reductions in per capita consumption. Conservation targets used to forecast the "CDM factor" might include: provincial targets disaggregated by demand; or rate-funded CDM; and distributor-specific targets as per contractual agreement with OPA. The proposed model is intended to provide annual adjustments that reflect both changes in provincial targets and actual provincial CDM results to ensure that any changes to the expected CDM programs are captured in a going forward manner.

Staff and the working group noted that the advantages of this model are that it more clearly supports government conservation targets and is generally consistent with the nature of IR adjustment mechanisms which may rely on the use of forecasted indices. However, drawbacks exist. The model sets revenues based on targets that may or may not be achieved. Further, it would be difficult to disaggregate the government

[11] Hydro One Networks Inc., EB-2006-0267- EDA LRAM Proposal for Electricity LDCs – Hydro One Networks' Comments (November 21, 2006). (http://www.oeb.gov.on.ca/documents/cases/RP-2004-0203/2006-11-submissions/h1n_211106.pdf)

and OPA conservation targets and allocate them across the over 80 distributors (easier to allocate if distributor specific). This may be a viable option when these impediments can be resolved.

Current regulatory framework for CDM

Staff also reviewed with the working group the current regulatory framework for CDM (i.e., status quo) in the electricity sector. Along with the current LRAM, the existing framework provides for:

- Annual application for CDM funding;
- Processes for adjustments during the term of the plan;
- Formulaic approaches for CDM targets, budgets, and distributor incentives;
- Determination of how costs should be allocated to rate classes;
- A framework for determining savings; and
- A framework and process for evaluation and audit.

Multi-year CDM planning & funding

A similar framework exists in the gas sector. In the gas sector, distributors have Board approved plans that span three years. This multi-year approach to planning, delivering and managing programs is consistent with the multi-year ratemaking plans that the Board is implementing in both sectors.[12] On February 8, 2008, the Board issued for stakeholder comment draft Guidelines for Electricity Distributor Conservation and Demand Management[13] and in those guidelines proposes extending the multi-year approach to the electricity sector.

Most members of the working group expressed confidence in the current regulatory framework and indicated that it continues to be appropriate in light of the OPA's growing involvement in coordinating funding for and management of CDM activities in the province.

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[12] Staff notes that the review of demand-side management matters in the gas sector remains independent of ratemaking. However, rate impacts stemming from those reviews are proposed to flow through an annual rate adjustment mechanism.
[13] Please refer to the Board's web site for this Report and details of the related consultation.
(http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_cdm_guidelines_elec.htm)

Status quo LRAM

Staff and the working group generally feel that the current LRAM is appropriate until the completion of the consultations on rate design for electricity distributors (EB-2007-0031) since that work would be looking closely at related issues.

Staff invites comment

Staff invites comments from stakeholders on the options noted above and on the option of maintaining the status quo vis-à-vis the Board's current LRAM for electricity distributors.

3.3 Distributor Diversity

Scoping Paper

The Scoping Paper noted that during the 2nd Generation IR consultation many participants commented that in the 3rd Generation IR mechanism the productivity factor should be more reflective of the status of the distribution sector in Ontario and account for differences amongst electricity distributors. For this consultation, the issue as expressed in the Scoping Paper is:

- How and to what extent should distributor diversity be reflected in an IR framework?

Stakeholder comments

One stakeholder representing a ratepayer group commented that diversity can present both opportunities and challenges to different organizations, but is not an insurmountable barrier to excellence. A distributor commented that the IR framework must be sustainable and sufficiently flexible to reflect distributor circumstances, and that flexibility in either the model or its parameters is needed. Another stakeholder representing a ratepayer group suggested that if a distributor does, indeed, face unique circumstances, such as rate of customer growth, need for replacement of aging capital, capital versus OM&A tradeoffs, changes in customer mix and or usage, or changes in financing costs, then it would seem that a combination of a multi-year cost of service filing and a rate freeze for years with no cost of service filing would provide maximum flexibility to distributors to reflect their circumstances. Several stakeholders commented that more than one model may be appropriate to recognize distributor diversity.

Board Staff Comments

When considering how and to what extent distributor diversity should be reflected in an IR mechanism, this consultation should consider how it might be flexible so as to handle changing and varied circumstances. This should result in a more practical model.

A "core plan" approach can provide flexibility

Staff also believes that a "core plan" approach is desirable. The aim is to develop a core plan for electricity distributors that is suitable for most. This does not mean trying to force fit a "one size fits all" plan on all distributors. Proactively providing for an appropriate level of flexibility to complement the core plan will allow for a more sustainable plan. As noted above, in the event that another approach to rate setting is more appropriate in any given case, the distributor may apply to the Board to have its rates set using that alternative approach. The onus would be on the applicant to demonstrate how and why deviation from the core plan is warranted. Staff suggests that a "core plan" approach would provide greater predictability and provide an environment where both distributors and ratepayers are better able to plan and make decisions.

Key assumptions

The following assumptions are important to understanding the issue of distributor diversity:

- As noted above in the discussion on capital investment, base rates at the start of 3rd Generation IR will have been determined based on a forward test year cost of service rate application under section 78 of the Ontario *Energy Board Act, 1998*. As such, these rates will reflect a degree of distributor diversity.
- The July 23, 2007 "Report of the Board on Rate-making Associated with Distributor Consolidation" sets out the Board's policy on selected rate-making issues in the context of certain

transactions in the electricity distribution sector. The Board's approach as set out in that Report built on and complements the work of the Board in relation to incentive regulation, and addresses the issues in a manner that does not unnecessarily increase the regulatory burden on distributors or other interested stakeholders. IR should therefore continue to complement this policy.

Summary of Working Group Discussion

IR that applies to 80 plus Ontario electricity distributors should reflect distributor diversity

Staff and the working group generally agree that the 3rd Generation IR mechanism should reflect distributor diversity. IR in Ontario applies to 80 plus Ontario distributors that differ in important ways, including customer and volume growth, customer density, capital investment needs (e.g., system age, replacement cycles), and efficiency at the outset of the plan. These diverse conditions can affect companies' cost, output and revenue growth differently. These sources of diversity can be addressed in the IR design through one or more of the following:

- Productivity factors;
- Stretch factors;
- Inflation factors;
- Capital investment mechanisms;
- ESMs and off-ramps; and
- Menus and modules.

Productivity factors and stretch factors

As is discussed in more detail in the PEG Report, most X-factors approved in North American price cap plans are calibrated to track industry TFP trends. The industry trend is an important external benchmark for the company to strive to achieve at a minimum. Stretch factors may be added to the industry TFP trend as a benefit-sharing mechanism. Using indexing or econometric techniques, the value for a productivity factor can be tailored to individual company conditions and for expected changes in those conditions over the term of the IR plan. In addition, the value of a stretch factor can be set to differ among companies to reflect differences in efficiency at the outset of an IR plan and hence the differences in potential for TFP gains under the plan.

Inflation factor

The inflation measure used in an IR adjustment can, in principle, be more reflective of distributor diversity. As discussed later in this paper, industry specific measures better reflect the changes in input price trends for the distributor because they better reflect changes in materials prices, exchange rates and interest rates, amongst other things. An industry specific measure may be more appropriate where there is uncertainty in input price trends due to factors such as expected worker retirement, labour shortages, or construction cost pressures. Since some working group members identified similar cost pressures on Ontario distributors, an industry-specific input price index ("IPI") may better reflect these cost pressures and how they may be felt by the diverse companies in the province.

Capital investment mechanisms

Section 3.1 profiled a number of alternative capital investment mechanisms that might be used within the context of incentive ratemaking. Since capital investment needs may vary among companies, some members of the working group expressed the view that implementation of a capital investment mechanism is an important design consideration for the 3rd Generation IR mechanism in order to effectively reflect distributor diversity.

Earnings sharing mechanisms and off-ramps

ESMs can be a "backstop" approach for dealing with diversity. If it is not possible to design an IR framework that reflects diversity in all company circumstances, ESMs can provide protection against excessively low or high earnings. Off-ramps can also be an alternative "backstop" approach for dealing with diversity. Off-ramps may allow a company to be taken off an IR plan to be subject of a cost of service or other review in predefined circumstances such as the case of extreme earnings outcomes. While ESMs and off-ramps can mitigate risk against extreme outcomes, they increase uncertainty, administrative burden and regulatory costs.

Menu approaches

Another way to allow for diversity is to offer menus of options to distributors. A menu approach was proposed in 1st Generation PBR. The menu proposed a relationship between the productivity factor and an ROE ceiling.[14] The following overview of that proposal was prepared for the working group by staff:

- A range of productivity factors was set so that each productivity level was associated with a specific ROE ceiling.
- The ROE ceiling was proposed to be subject to change from year to year to reflect annual adjustments to the Board-approved market-based rate of return on common equity.
- Actual returns achieved up to those ceilings were to the account of the shareholder. Actual returns achieved above those levels would be returned to ratepayers.
- ROE embedded in rate base was based on the methodology used by the Board in regulating natural gas utilities and was also applied in setting the transitional rates for Ontario Hydro Services Company (RP-1998-0001).

The Board found this approach too complex for 1st Generation PBR and approved a single productivity factor for all distributors combined with an earnings-sharing mechanism.[15]

However to illustrate how a menu might be set up, staff notes that the sliding scale/information quality incentive mechanism implemented in the UK, described in Appendix One of the PEG Report and referred to earlier in this paper, is a menu-like approach. It lays out efficiency incentive

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[14] OEB Staff Proposed Draft Electric Distribution Rate Handbook (June 30, 1999). Chapter 4 – Rate Adjustment Mechanism. (http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html).

[15] Staff notes that the earnings sharing mechanism was suspended with the three-year phase-in of MARR. Please refer to the Board's September 29, 2000 Decision with Reasons in proceeding RP-2000-0069 (In the matter of a proceeding under sections 129(7) and 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B to determine certain matters relating to the Minister's Directive dated June 7, 2000). (http://www.oeb.gov.on.ca/documents/cases/RP-2000-0069/decision.pdf)

rates and allowed expenditure levels that are functions of the ratio of the distributor's forecast to Ofgem's consultant's view of benchmark expenditures for that distributor. The distributor selects an expenditure level and in that choice inherits commensurate incentive rates. While the working group discussed this conceptually, specific designs were not presented or developed. The working group observed that in theory menus may be appealing as they offer some promise that company choices from menus can reflect diversity in conditions without disadvantaging ratepayers, but in practice setting the menu can be complex and controversial.

Distributor choice of regulatory model

As noted previously, some members of the working group identified a broad range of cost pressures that distributors may face over the coming years and suggested that since those pressures will not all affect distributors in the same way and at the same time, the IR framework should allow distributors to choose the regulatory model (i.e., cost of service, comprehensive price cap indexing, partial indexing, etc.) that best suits their individual circumstances. This raised the issue as to whether multiple approaches should be available to distributors. Examples of the multiple approaches discussed include the following: a comprehensive price index plan; a comprehensive multi-year cost of service plan; or a targeted plan that indexes OM&A and forecasts capital. Some members of the working group expressed concern over allowing such discretion as it may be conducive to gaming behaviour by distributors that switch between IR and cost of service, depending on which model best suits their circumstances at any given time. In its March 30, 2005 "Report of the Board on Natural Gas Regulation in Ontario: A Renewed Policy Framework",[16] the Board stated that an incentive regulation plan should be permanent in the sense that distributors do not have the option of switching back and forth between incentive regulation and cost of service plans.

[16] Ontario Energy Board, "Natural Gas Regulation in Ontario: A Renewed Policy Framework", (March 30, 2005).

Staff notes that a proposal for a "basket of regulatory mechanisms" was also put forward in the context of the consultation on rate-making issues associated with consolidation. As noted in the Board's July 23, 2007 "Report on Rate-making Associated with Distributor Consolidation", "[G]iven the diversity of distributors in Ontario, it is a challenge to design and implement regulatory mechanisms to meet all of their needs. However, from the standpoint of establishing a general approach that is clear and easily understood by all, a policy that enables distributors to design their own ratemaking approaches associated with consolidation would be counter to achieving a more predictable regulatory environment – for distributors and ratepayers. The Board does not believe that it is practical or appropriate to provide distributors with a "basket of mechanisms" to choose from through this policy. Board policy of a general nature can recognize diversity, and can do so without compromising predictability."

Working group focused on developing a "core plan"

Staff expressed concern in the working group over the inherent complexity in trying to design three or more distinct IR approaches for 80 plus electricity distributors to choose from, and identified implications of providing for multiple approaches, including:

- a need for eligibility criteria to identify which distributors would be eligible for which approaches;
- a need for multiple inflation and productivity factors because different inputs and assumptions are used to calculate factors for comprehensive plans versus partial plans;
- the impact on triggers for, and treatment of, unforeseen events;
- the impact on reporting requirements; and
- the impact on rebasing rules.

As stated at the start of this paper, staff believes that a rate-adjustment mechanism that may be suitable for most electricity distributors – a "core plan" – should be developed. The working group was encouraged to focus on development of one "core plan", rather than on the development of multiple approaches.

Choice in IR plan term

Another way to recognize distributor diversity in an IR plan is to give the distributor choice with regard to the length of the plan term. This flexibility is described in the Board's July 23, 2007 "Report on Rate-making Associated with Distributor Consolidation" as follows: "Allowing a distributor the option of scheduling the rate rebasing for the consolidated entity at any time up to the five-year limit accommodates distributors that may require an increase in operating, maintenance or capital expenditures shortly after closing of the transaction, as well as distributors that wish to have the benefit of a longer period in which to off-set transaction costs with efficiency savings. This flexibility does not come at the expense of consumer interests or financial viability, which are adequately protected through the Board's licensing regime and price cap incentive regulation mechanism."

Staff and the working group discussed what IR term length choices might be appropriate for 3rd Generation IR. Many members of the working group expressed concern that there are a number of rate-related studies, regulatory and policy initiatives underway that may significantly affect distributor costs and rates up to and including 2011. Specific examples include service quality regulation (EB-2008-0001), more comprehensive cost comparison work, and rate design for electricity distributors (EB-2007-0031). This suggested that a three-year term might be an appropriate minimum. While some members of the working group expressed interest in longer-term plans exceeding seven years, other members of the working group expressed the view that the term should not exceed five years. Some members of the working group suggested that, where a distributor requests a plan term of five years, some form of earnings sharing should be part of that distributor's IR plan so that any excess earnings would be shared between the shareholder and ratepayers. They also noted the importance of clearly defining up front how earnings would be calculated to provide stakeholders and distributors with greater certainty. Details on the design of such an ESM were not presented or discussed.

Staff notes that the various ways to reflect distributor diversity in an IR plan discussed above are not necessarily mutually exclusive. It may be appropriate to combine several of these mechanisms in 3rd Generation IR.

Staff invites comments from stakeholders on the options noted above.

Staff invites comment

3.4 Three Alternative Approaches that Address the Issues

After discussion of various mechanisms to address the issues, the working group expressed interest in three approaches that combine some of those mechanisms: the comprehensive price cap index approach with added flexibility to recognize incremental capital investment needs; the comprehensive multi-year cost of service approach; and a hybrid approach under which OM&A would be indexed and capital costs would be forecasted (this is also referred to as a "partial index approach").

Some trade-offs may be appropriate when designing an IR plan

Further detailing of these three approaches helped the working group identify and understand the importance of trade-offs in designing IR plans. For example, a plan that includes multiple cost of service (i.e., test year) projections may need forecasting incentives, end-of-term capital incentives and/or an ESM to create and balance appropriate incentives in the plan. In a comprehensive price cap plan, additional parameters may be needed to provide for incremental capital and/or CDM-related adjustments. If an incremental capital allowance is provided for as a pass through (i.e., cost of service treatment), then an end-of-term capital incentive may be needed to maintain an appropriate balance. If stretch factors are designed into the plan to share expected benefits between shareholders/companies and ratepayers up front and an ESM is designed into the plan to share achieved benefits between shareholders/companies and ratepayers after-the-fact, they may need to be calibrated to maintain an appropriate balance.

Appendix One of the PEG Report provides a review of important incentive regulation precedents. Below are brief discussions of the comprehensive multi-year cost of service approach like that used in the UK and the hybrid (or "partial indexing") approach. A comprehensive price cap index approach with added flexibility to recognize incremental capital investment needs is illustrated in section 4. A summary of staff's evaluation of these approaches based on the four criteria described in section 2.1 is also set out below.

Comprehensive multi-year cost of service approach

The maturity and sophistication of the comprehensive multi-year cost of service approach implemented in the UK is evident in the November 2004 "Electricity Distribution Price Control Review Impact Assessment".[17] Specifically, implementation of it requires established benchmarks. Ontario does not currently have established benchmarks. Also, as noted previously in this paper, staff and some members of the working group are concerned that it may not be possible for many distributors to prepare and file multi-year cost of service applications. As noted in the PEG Report, relying on more cost-based approaches to regulation will be costly in Ontario due to the number of companies and applications that would be involved. Implementation and administration of a framework like that which is in place in the UK as a "core plan" for 80 plus Ontario distributors may not be practical.

One feature of the UK approach that staff and the working group discussed that may have merit is the implementation of a sliding scale/information quality mechanism that provides a better balance between incentives for investment and cost efficiency. However, designing such a sliding scale/information quality mechanism "correctly" for 80 plus distributors may be a challenge.

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[17] Available at http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR4/Pages/DPCR4.aspx. This page contains information on the current price control applicable to electricity Distribution Network Operators (known as Distribution Price Control Review 4). This price control runs from 1 April 2005 until 31 March 2010).

Staff invites comments from stakeholders on the adaptation of a sliding scale like incentive mechanism in 3rd Generation IR. Specifically, if this kind of incentive were to be included how might it be designed, and how would the Board know it has been designed "correctly."

Staff invites comment

Partial or targeted indexing plans were briefly discussed by the working group. As noted previously, under this approach OM&A is often indexed and capital costs are forecasted. Some members of the working group suggested that, similar to the OM&A targeted plan approved by the Board in April, 1999 for Enbridge Consumers Gas, OM&A could be subject to an index (i.e., inflation less a productivity offset). Capital, it was suggested, could be addressed in a cost of service manner (either on an annual basis or on a multi-year basis). In general, working group members expressed concern over the potential for cost gaming under this type of plan (i.e., substituting or switching capital and OM&A spending to maximize earnings). Reliance under targeted plans on more cost-based approaches for capital regulation is also a practical concern in Ontario due to the number of companies and applications that would be involved.

The hybrid approach

Table 1 summarizes staff's evaluation of the three alternative approaches based on the four criteria described in 2.1. As is evident in the table, in contrast to the UK and hybrid approaches, a comprehensive price cap index continues to be a relatively simple approach that will, along with the implementation of mandatory service quality requirements, provide balanced incentives for efficiency improvements and greater predictability to distributors and ratepayers. Proactively providing for an appropriate level of flexibility to complement the core plan in the form of some provision for incremental capital investment adjustments may contribute to the development of a more sustainable plan.

The comprehensive price cap index

Staff invites comments from stakeholders on the three alternative approaches noted above, and on staff's evaluation of them.

Staff invites comment

Table 1: Summary Evaluation of the Three Alternatives

	Evaluation			
	Sustainability	**Predictability**	**Effectiveness**	**Practicality**
	A sustainable framework is flexible and reasonably able to handle changing and varied circumstances, while ensuring that the principles underlying the method by which the rate adjustments are determined are consistent between distributors.	*A predictable framework facilitates planning and decision-making by ratepayers and electricity distributors.*	*An effective framework encourages distributors to implement efficiencies and allocates the benefits from greater efficiency between the distributor/shareholder and ratepayers in an appropriate manner. An effective framework also provides for prudent capital investment as required to ensure necessary infrastructure development and to maintain an appropriate level of reliability and quality of service.*	*Without sacrificing the other criteria, under a practical framework, the distributor's costs of administration should not exceed the benefits.*
Comprehensive Multi-Year Cost of service Approach	High - allows projected costs to be recovered via price trends	Medium – price adjustment trajectory established at start of plan; however, there is a lot of variability between plans	Medium – with service quality requirements and forecasting incentives	Low – requires established benchmarks and/or detailed review of individual company operating and capital plans; incentive schemes are complex; administrative burden during the price plan to track performance against forecast
Hybrid Approach	Low – severing treatment of OM&A and capital may increase pursuit of operating efficiencies, but may result in allocative inefficiency (e.g., gold plating)	Medium – if capital review and approval prospective rather than retrospective	Low – severing treatment of OM&A and capital may increase pursuit of operating efficiencies, but may result in allocative inefficiency (e.g., gold plating)	Low – detailed review of individual company operating and capital plans; indexing or econometric approaches to determine indexing parameters complex; administrative burden during the price plan to track performance against forecast
Comprehensive Price Cap Index Approach	High – with some provision for incremental capital investment	High – price adjustment trajectory established at start of plan; consistent assumptions set inflation and productivity index adjustment	High – indexing parameters set to mimic competitive market	Medium – indexing or econometric approaches to determine indexing parameters complex; administrative burden during the price plan to track performance against forecast associated with incremental capital investment

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4 Elements of a Core Plan

In addition to the PEG Report, staff was informed by advice provided in the June 13, 2006 report prepared for staff by PEG entitled "Second Generation Incentive Regulation for Ontario Power Distributors" (the "2006 PEG Report"). That Report provides a comprehensive discussion of the criteria for the design of regulatory systems, the advantages of incentive regulation over traditional cost of service regulation, and the major issues in the design of an incentive plan.

4.1 Form

Price cap index approach

Staff's evaluation of the three alternatives that the working group expressed interest in suggests that a comprehensive price cap index is the approach that best meets the criteria identified in this paper. In comparison with the other alternatives, it is staff's view that the price cap index is sustainable, and is more predictable, effective, and practical.

Therefore, staff proposes the Board retain a comprehensive price cap index-based adjustment mechanism for electricity distributors.

4.2 Term

3 to 5 year term

As stated previously, staff and the working group see merit in allowing for flexibility in the plan term. In light of discussions with the working group, staff suggests that distributors have the choice of plan term which could vary from three to five years. This choice could be made on application in the first year of the plan. Subsequently, the rates of the distributor would not be expected to be subject to rebasing before the end of the plan term other than through an eligible off-ramp.

4.3 Inflation Factor

For 2nd Generation IR mechanism, the Board adopted the Canada Gross Domestic Product Implicit Price Index for final domestic demand ("GDP-IPI FDD") as the inflation factor. There are no explicit adjustments in the 2nd Generation IR mechanism to the inflation factor. For the 2nd Generation IR mechanism, this was acceptable because it was a less controversial and easier to implement solution over the period of the Board's Multi-year Rate Plan while a number of important rate-related studies would be carried out.

An industry-specific IPI better tracks input price trends

As discussed previously in this paper, one aim of IR is to promote efficiency improvements in the absence of market mechanisms. IR should therefore reward distributors for performance while ensuring that ratepayers also benefit from performance improvements and are protected from substandard performance. Distributors should not be enriched simply because a rate adjustment mechanism rewards them for costs they do not have. Likewise, ratepayers should not be enriched as a result of an adjustment mechanism that does not compensate distributors for legitimate industry input costs that are a result of market forces. While an economy-wide index such as the GDP-IPI FDD with associated input price differential ("IPD") and productivity differential ("PD") adjustment factors[18] may somewhat approximate industry input costs at the start of an IR term, it will not continue to track input cost trends as well as an industry-specific IPI, since IPD and PD get fixed at the beginning of the IR term and remain unchanged even if the actual differential changes over time. The PEG Report includes further discussion of inflation measures

[18] As explained in the PEG Report, when a macroeconomic inflation index is used, the price cap index (PCI) can be calibrated to track the industry unit cost trend when the X-factor has two calibration terms: a productivity differential (PD) and an input price differential (IPD). The PD is the difference between the TFP trends of the industry and the economy. X will be larger, slowing PCI growth, to the extent that the industry TFP trend exceeds the economy-wide TFP trend that is embodied in the macroeconomic inflation index. The IPD is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.

and what impact the selection of a macroeconomic versus an industry specific factor entails when calibrating an X-factor.

An industry-specific IPI provides for an adjustment reflective of the distribution industry's input costs. Staff suggests that this is important to a sustainable and effective IR framework. As has been recognized in several Board staff and consultant papers, including the PEG Report, distributors are far more capital intensive than the economy as a whole. Their costs are much more affected by changes in financing costs and the price of equipment and raw materials than is the input cost of the economy as a whole. Therefore, an economy wide index, such as GDP-IPI FDD, does not accurately represent the changes in input costs for electricity distributors. To bring it closer to changes in distributor input costs, the GDP-IPI FDD would need to be adjusted for an IPD and a PD to account for the differences between the two indices.

Industry-specific IPI suggested for the 3rd Generation IR mechanism

For the 3rd Generation IR mechanism, therefore, staff and most of the working group prefer implementation of an industry-specific IPI rather than a macroeconomic index.

Data readily available from public sources

An industry-specific IPI can be constructed and updated using data that is readily available from Statistics Canada, the Bank of Canada and Human Resources and Social Development Canada ("HRSDC"). The methodology and proposed options are described in Appendix B, prepared by a working group member. Using this information, staff constructed an industry-specific IPI over the 17 year period commencing in 1989. Using publicly available data from the above mentioned sources, staff found the calculations to be relatively simple.

Specific Illustration

An industry-specific IPI formula

The industry-specific IPI described below is similar to the index that was approved for 1st Generation PBR. As mentioned in Appendix B, this index is a weighted average of the prices of three input factors (capital, labour and materials):

$$IPI = (w_k * P_k) + (w_l * P_l) + (w_m * P_m) \qquad [1]$$

where:

- P_k is the Capital Price Sub-Index;
- P_l is the Labour Price Sub-Index;
- P_m is the Materials Price Sub-Index;
- w_k is the weight of capital;
- w_l is the weight of labour; and
- w_m is the weight of materials.

Capital price sub-index

The Capital Price Sub-Index can be calculated using a cost of service price of capital approach. Under this approach, the cost of capital is determined by looking at the change in the cost of acquiring capital assets (i.e., acquisition cost) as well as the opportunity cost of making the capital investment. Therefore, the cost of using capital is defined as the opportunity cost plus depreciation times the acquisition price, as shown in equation (2).

$$PK_t = (r_t + d) * CAP_t \qquad [2]$$

where:

- r_t represents a risk free rate of return. In the industry-specific IPI of 1st Generation PBR, this risk-free rate was established as the rate of Government of Canada marketable bonds - average yield over 10 years.[19] The same risk free rate could be used for the calculation of r_t;
- d is the depreciation rate. Since depreciation rates do not tend to change over time the same rate (5.67%) that was used in 1st Generation PBR could be used. This rate was calculated from

[19] As reported by the Bank of Canada in http://www.bankofcanada.ca/en/rates/bond-look.html, Statistics Canada CANSIM reference number v122487

distributor specific data on level of capital stock and capital stock retirement; and

- **CAP_t** represents the acquisition price of capital. The *Electric Utility Construction Price Index (EUCPI) – Distribution Systems* as reported by Statistics Canada[20] was used as this acquisition price index in 1st Generation PBR. The same index could be used for 3rd Generation IR. Concern was expressed in the working group about the use of a Construction Price Index for electric utilities that may include construction of generation facilities. In the past, the EUCPI series comprised five models of electric utility plant as explained by Statistics Canada in the description of the Index: distribution systems; transmission lines; transformer stations; hydro-electric generating stations; and fossil-fuel fired generating stations. However, at present the EUCPI series no longer includes the generation models, only distribution and transmission-line systems are included and separate indices are available for each component.

Staff acknowledges that some distributors own transmission assets. However, those assets represent a minor percentage of the total asset base of distributors. Accordingly, the inclusion of a second sub-index to account for those assets would result in a construction price index that would not significantly differ from the main Distribution index. The benefits of the precision that this inclusion may add to the industry-specific IPI may not outweigh the costs in terms of the increase in complexities to the calculation (e.g., determining distributor eligibility for a blended index and determining appropriate weights for the transmission and distribution sub-indexes). It may be most practical, without losing effectiveness, for the industry-specific IPI to use the sub-index that accounts for the construction of Distribution systems only.

Labour price sub-index

The Labour Price Sub-Index used in 1st Generation PBR was the distributor's line crew wage rate submitted by the distributors to the Board

[20] Statistics Canada CANSIM reference number v735224 - 327-0011

in their PBR filings. This data is no longer available, but as explained in Appendix B, there are various options that can be used as measures of labour cost changes. Staff analysed the options in Appendix B and suggest that the *Construction Union Wage Cost Rate Index for Ontario* and the *Effective wage increase in base rates (or Wage Adjustment) for Utilities in Canada* could be good proxies of labour costs for Ontario distributors.

The *Construction Union Wage Rate Index Ontario* is calculated by Statistics Canada. It is available monthly, during the month following the reference month. It measures monthly changes over time in the collective agreement rates for trades engaged in building construction in the metropolitan areas of Ontario. Staff notes that the sampling of this index is very broad, since it includes the main construction trade categories and some of them may not be relevant for electricity distributors.[21] Nonetheless, this index has previously been proposed by PEG as the recommended input price of labour in the calculation of the X-factor of gas distributors in Ontario.

The w*age adjustment in base rates* series is calculated by HRSDC. The wage information on collective bargaining negotiations and settlements pertains to all bargaining units covering 500 or more employees. National and provincial series are available. National series are also available by industry. The wage adjustment for utilities reflects wage adjustments in the electric power, natural gas, steam supply, water supply, and sewage removal industries in all jurisdictions in Canada. The Ontario series reflects wage adjustments for all industry sectors in Ontario. Both series are available on a monthly, quarterly or annual basis from the HRSDC website. The annual rate is available in February, following the reference

[21] Trades included in the composite index are: structural trades, architectural and finishing trades, mechanical and electrical trades, engineering and equipment trades, carpenter, crane operator, cement finisher, electrician, labourer, plumber, reinforcing steel erector, structural steel erector , sheet metal worker, heavy equipment operator, bricklayer, and painter, plasterer, roofer, truck driver, asbestos mechanic.

year. These series are also available from Statistics Canada on a quarterly basis.[22]

Figure 2 shows 20-year trends for the alternative indices discussed above.

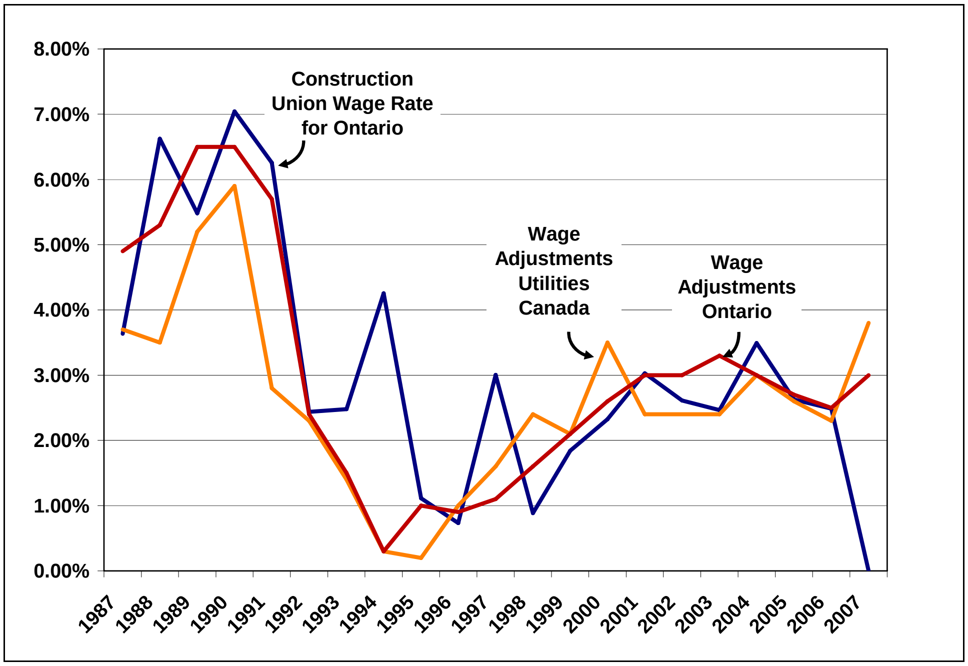

Figure 2: Labour Price Changes

Staff notes that both *wage adjustments indices* exclude data for small and medium companies given that only major wage settlements involving bargaining units of 500 or more employees are included in the calculation. However, the *wage adjustments for utilities Canada* may be a good proxy of the labour index for electricity distributors in Ontario because it reflects wage adjustments to a labour force that has similar skills.

Materials price sub-index

Staff suggests that the industry-specific IPI could use the same Materials Price Sub-Index that was used in 1st Generation PBR. This index is the *All Finished Goods Industrial Producer Price Index (IPP")* published by

[22] v4385818 and Statistics Canada v4327102.

Statistics Canada[23] and measures price changes for major finished goods that are most commonly used for immediate consumption. The IPPI reflects the prices that producers receive. It does not reflect what the consumer pays. Unlike the Consumer Price Index, the IPPI excludes indirect taxes and all the costs that occur between the time a good leaves the plant and the time the final user takes possession of it, including the transportation, wholesale, and retail costs

Input weights for capital, labour and materials

The fixed cost shares that were used in 1st Generation PBR for establishing the weights of each input are summarized in Table 2. Staff notes that these cost shares are based on 1993 data and that an update of the calculation would be desirable. Therefore, PEG calculated cost shares for capital and OM&A from the period 2002-2006. These shares were calculated as simple averages of all Ontario distributors. Although the data did not allow for a break down of OM&A into labour and materials, new weights could be estimated based on the shares from 1st Generation PBR as shown in Table 2. For the purposes of this consultation, the updated cost shares are used for establishing the weights of each input.

Table 2: Weights for Use in Calculating an Industry-specific IPI

Input	1st Generation	Share	2002-2006
Capital w_k	**0.5110**		**0.6318**
OM&A	**0.4989**	**100%**	**0.3682**
Labour w_l	0.3514	70%	0.2577
Materials w_m	0.1475	30%	0.1105

[23] Statistics Canada CANSIM reference number v1574476 - 329-0039

Implementation Issues

Volatility a concern raised by some stakeholders

Staff gathered data on the GDP-IPI FDD over a 17 year period, and compared it with the calculated industry-specific IPI,[24] as illustrated in Figure 3.

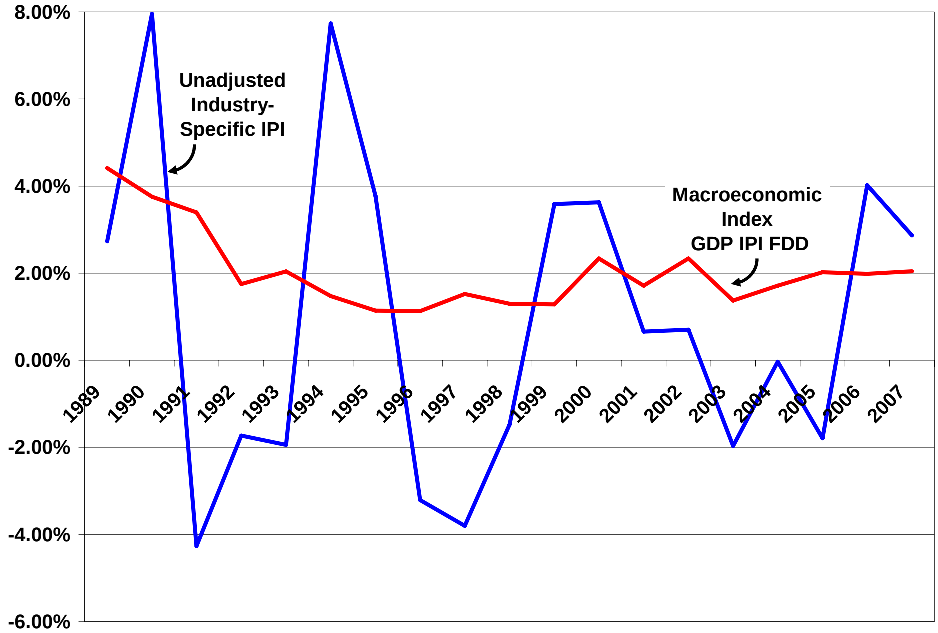

Figure 3: Illustrative Industry-specific IPI vs GDP-IPI FDD Growth Rates

The industry-specific IPI is more volatile than the GDP-IPI FDD. As illustrated in Figure 6, the source of the volatility is the capital sub-index and, in a more recent period, the materials sub-index.

[24] The IPI was calculated using a labour index calculated from *wage adjustments for utilities Canada*

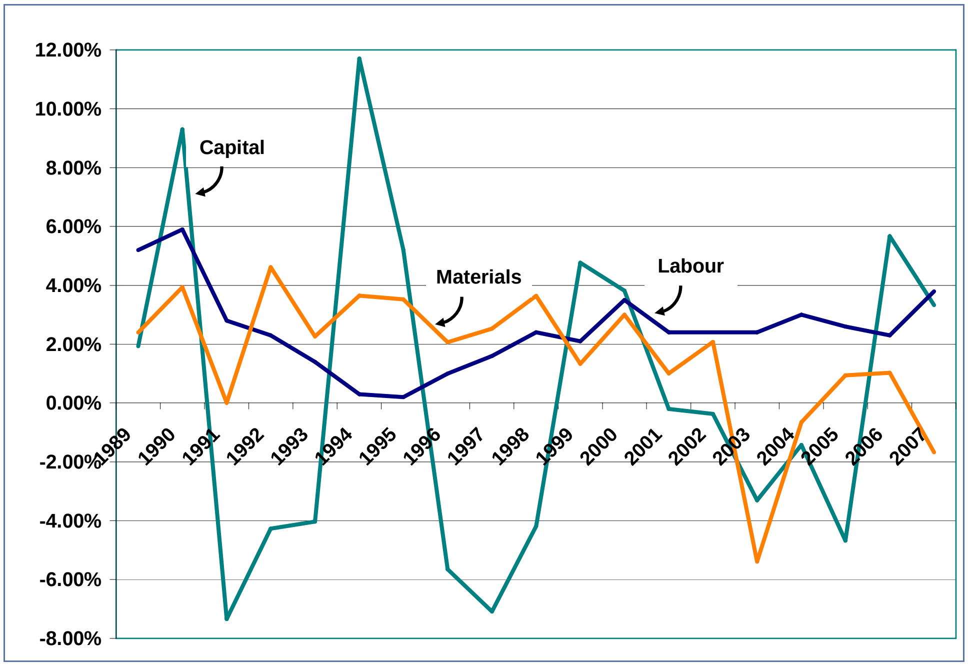

Figure 4: industry-specific IPI Sub-index Growth Rates

Some members of the working group expressed concern over this volatility. However, other members of the working group noted that commodity rates are now adjusted several times per year based on "input prices" (i.e., commodity cost changes). Many of these price changes which occur throughout the year could be several orders of magnitude greater than any annual change under the proposed distribution rate adjustment mechanism. For example, on November 1, 2006 the regulated price plan prices changed by almost 5% from the May, 2006 prices. By comparison, adjustment related to the capital component of the industry-specific IPI could be far less volatile than potential changes due to commodity pass-through. Conceptually, therefore, Ontario consumers are familiar with price volatility and therefore volatility associated with the capital cost embedded in the industry-specific IPI ought not to be an impediment to the use of the industry-specific IPI approach. As discussed in the PEG Report, there are also jurisdictional precedents on methods to deal with such volatility.

Volatility could be limited

Smoothing the capital sub-index is one option. In California, a three-year moving average has been used to determine the capital sub-index measure of the industry-specific IPI implemented in that jurisdiction. The PEG Report observes that distributors procure capital inputs over a multi-year period and can vary the timing of at least some equipment purchases and asset financings in response to changes in prices (e.g., deferring capital goods purchases in a year when the prices of commodities embedded in assets are high until a later year when prices are expected to fall). It follows then that multi-year investments, whether in capital stock or otherwise, will get embedded in rates at rebasing – at the start of a plan, and again at the end of a plan. Therefore, an average of various years in the capital index can still track the price of capital inputs. The same rationale may not be valid for labour or materials, where procurement is more specific to a year's period.

The Board dealt with capital sub-index volatility in 1st Generation PBR by limiting sub-index change to 50% of actual growth. The PEG Report notes, however, that counting only half of the calculated growth in the capital price in allowed inflation is more arbitrary than smoothing all capital input price changes over a multi-year period and, over time, is likely to under-compensate distributors for the growth in their actual input price inflation.

A three-year moving average used to determine the capital sub-index measure of the industry-specific IPI could be a way to address volatility. Figure 5 illustrates the potential impact of smoothing the capital sub-index with a three year weighted average.

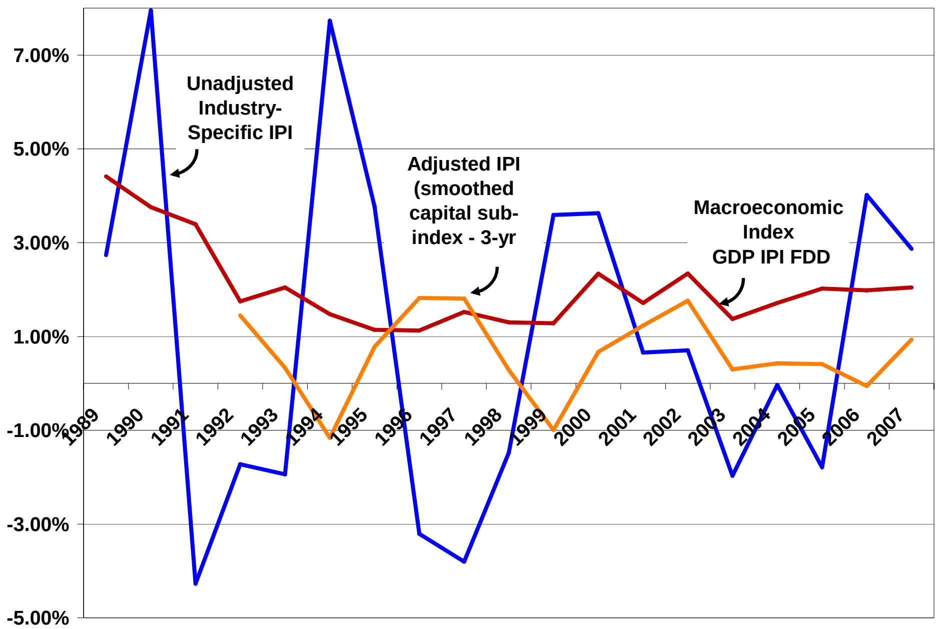

Figure 5: Comparative Growth Rates

Staff's illustrative analysis, summarized in Table 3, indicates that the smoothing methodology reduces the spread between the minimum and maximum values for the capital sub-index from 19.05% to 4.96%, and the overall industry-specific IPI from 12.22% to 2.98%.

Table 3: Summary of Comparative Growth Rates

		Unadjusted Industry-Specific IPI					
				Adjusted Industry-Specific IPI			
Year	Macro Index (GDP FDD CAN)	IPI	Capital Sub-Index (1992=1)	Labour Sub-Index	Materials Sub-Index	Smoothed Capital Sub-Index (3-year mov. avg)	IPI
1988	3.68%						
1989	4.41%	2.73%	1.93%	5.20%	2.39%		
1990	3.76%	7.95%	9.31%	5.90%	3.94%		
1991	3.39%	-4.27%	-7.34%	2.80%	0.00%		
1992	1.75%	-1.73%	-4.27%	2.30%	4.62%	0.58%	1.45%
1993	2.04%	-1.94%	-4.03%	1.40%	2.26%	-0.44%	0.33%
1994	1.48%	7.73%	11.71%	0.30%	3.65%	-2.63%	-1.16%
1995	1.14%	3.77%	5.21%	0.20%	3.52%	0.51%	0.78%
1996	1.13%	-3.21%	-5.65%	1.00%	2.06%	2.13%	1.82%
1997	1.52%	-3.80%	-7.09%	1.60%	2.53%	1.76%	1.81%
1998	1.30%	-1.48%	-4.19%	2.40%	3.65%	-1.27%	0.29%
1999	1.28%	3.59%	4.77%	2.10%	1.33%	-2.83%	-0.99%
2000	2.34%	3.63%	3.81%	3.50%	3.00%	-1.14%	0.67%
2001	1.71%	0.66%	-0.20%	2.40%	1.00%	0.72%	1.23%
2002	2.34%	0.70%	-0.37%	2.40%	2.07%	1.38%	1.76%
2003	1.37%	-1.97%	-3.31%	2.40%	-5.39%	0.53%	0.30%
2004	1.71%	-0.03%	-1.43%	3.00%	-0.65%	-0.65%	0.43%
2005	2.02%	-1.79%	-4.68%	2.60%	0.94%	-0.85%	0.41%
2006	1.98%	4.02%	5.67%	2.30%	1.02%	-1.57%	-0.06%
2007	2.04%	2.87%	3.33%	3.80%	-1.68%	-0.10%	0.94%
min	1.13%	-4.27%	-7.34%	0.20%	-5.39%	-2.83%	-1.16%
max	4.41%	7.95%	11.71%	5.90%	4.62%	2.13%	1.82%
spread	3.28%	12.22%	19.05%	5.70%	10.00%	4.96%	2.98%

Staff also notes that the use of a moving average for the capital sub-index may also facilitate use of the *Electric Utility Construction Price Index (EUCPI) – Distribution Systems*, since it is not available for the Board's May 1st distribution rate-change implementation date as explained below. A moving average of the annual index values for 2005, 2006, and 2007 (the most recent full three years) provides a trend that could reasonably be used in the industry-specific IPI in 2008.

Finally, while volatility still exists with a smoothed capital sub-index, this volatility may be acceptable in light of the advantages to using an industry-specific IPI as discussed above and in the PEG Report.

Another implementation consideration is data availability. Table 4 summarizes the indices discussed above and when they would be available relative to a May 1st implementation date for rate adjustments.

Data availability

Table 4: Summary of Sub-Indices

Variable	Source	Frequency	Base	Publication Date	Annualized Method, Implementation
r_t	Bank of Canada	Monthly	N/A	Beginning of next month	Average of last 12 months (January to December)
CAP_t	Statistics Canada v735224 - 327-0011	Annual	1992=100	October following year, preliminary release of first half of the year in October same year	Partial index for Jan to Jun of previous year
P_l	Human Resources and Social Development Canada	Annual	N/A	February following year	Last available year. Annual index (base 1992=100) calculated from annual changes
P_m	Statistics Canada v1574476 - 329-0039	Monthly	1987=100	Two months following reference month.	Annual index (base 1992=100) calculated from annual changes in the index as of December of each year (December to December variation).

For the Capital Price Sub-Index, staff notes that the most recent year of the *Electric Utility Construction Price Index – Distribution Systems* will not be available for implementing rates on May 1st. While a partial half year index is available for use, it only reflects six months and is subject to revision once the annual figure is released. The unadjusted industry-specific IPI values shown in Table 3 include this partial figure; the smoothed industry-specific IPI values do not. As mentioned above, if this sub-index is smoothed using the last three available years, there is no need to use a partial figure.

Capital sub-index

The Labour Price Sub-Index could be calculated based on the *Annual wage adjustment rates*. The method for calculating this sub-index is explained in Appendix B. To be consistent with the Capital Price Sub-

Method of calculating labour sub-index

Index base year, the base year for calculating changes in the annual wage adjustment rate should be 1992. This data is available in February of the following year, thus it is available for May 1st implementation.

Method of calculating materials sub-index

The Materials Price Sub-Index could be calculated as an annual sub-index based on the *All Finished Goods Industrial Producer Price Index (IPPI)* monthly index and with 1992 as the base year. Details of this calculation are provided in Appendix B. Statistics Canada releases the December index in February; hence it is available for May 1st implementation.

Alternative sub-indices

In the event that either Statistics Canada or the Bank of Canada or HRSDC stop the publication of the identified sub-indices during the term of the IR plan, alternative sub-indices will be required. Table 5 suggests alternatives and how they might be implemented.

Table 5: Summary of Alternative Sub-Indices

Variable	Alternative and Source	Frequency	Base	Publication Date	Annualized Method, Implementation
r_t	Benchmark bonds, issued by the Government of Canada, 10-year original maturity, average yield Bank of Canada V39055:	Monthly	N/A	Beginning of the month following the reference month	Average of last 12 months (January to December)
CAP_t	Machinery and equipment price indexes purchased by Utilities; for Canada Total domestic and imported. Statistics Canada v41232160	Quarterly	1992=100	March following reference quarter	Annual index calculated from annual changes in the index for the 4th quarter of each year r
P_l	Construction Union Wage Rate Index Ontario, including selected pay supplements Statistics Canada v734371	Monthly	1992=100	In the month following reference month	Annual index calculated from annual changes in the index as of December of each year (December to December variation).
P_m	GDP-IPI FDD Canada Statistics Canada	Annual	2002=100	End of February following reference year	Annual index rebased (1992=100). Rebasing as explained on rebasing section.

Data revisions

Another implementation consideration is data revision. Published statistical data are subject to revision. Acknowledging that revisions will occur, it is appropriate to factor them in to the update of the industry-specific IPI. The approach to address data revisions during the term of the IR plan could be the same that the Board approved for revisions of the GDP-IPI FDD in 2nd Generation IR mechanism. Details of this approach are provided in Appendix C.

Statistics Canada may do a significant methodological change, or rebase a series. In such a case, standard techniques for linking the old and new series together should be used. Appendix C illustrates an approach.

Staff invites comment

Staff invites comments from stakeholders on the industry-specific IPI methodology, inputs and assumptions, including:

- the choice of sub-indexes;
- the choice of the Labour Price Sub-Index and how well the *Construction Union wage rate* or the *Wage adjustments for utilities in Canada* can track changes in the labour prices of electricity distributors;
- whether the volatility of industry-specific IPI should be limited and, if so, whether the use of a smoothed capital index is appropriate;
- methods to annualize non annual series and to deal with revisions and series rebasing; and
- primary and secondary preferences for alternative material, labour, and capital sub-indexes in the event of data termination.

Further, staff invites comments from stakeholders that would prefer the use of a macroeconomic inflation factor, like the GDP-IPI FDD, whether an IPD should be derived and if so, whether the industry-specific IPI methodology could be used to drive the IPD.

4.4 Productivity Factor

Like the selection of the GDP-IPI FDD inflation measure, the selection of the 1% X-factor was, for 2nd Generation IR mechanism, a function of simplicity and transparency, and was supported by work done by PEG.

Stakeholder comments on Scoping Paper

For the 3rd Generation IR mechanism, one stakeholder in its written comments on the Scoping Paper commented that there should be multiple X-factors. This stakeholder recommended three different levels of X-factors or productivity factors, using the distributor cost analysis in a report prepared for Board staff by its consultant, PEG, entitled "Benchmarking the Costs of Ontario Power Distributors"[25] (EB-2006-

[25] Mark Newton Lowry, et al., Benchmarking the Costs of Ontario Power Distributors (Pacific Economics Group, April 25, 2007).

0268) as the basis for stratifying distributors into three separate X-factor categories. The three categories could be high cost, average cost and low cost distributors and the X-factors could be 1.5%, 1.0% and 0.5%, respectively. This stakeholder noted that having different X-factors would recognize where each distributor is at the beginning of the 3rd Generation IR mechanism, and those at the higher cost level would be required to reduce more costs and to pass these savings onto the ratepayers.

X-factor could be calibrated to consider distributor diversity

For the 3rd Generation IR mechanism, staff and the working group believe it desirable to calibrate an X-factor that attempts to consider distributors' diverse conditions and productivity capabilities with respect to both the productivity factor and a stretch factor. Dr. Kaufmann presented and led discussions with staff and the working group on various ways to derive X-factors.

It is apparent from consultations to date that the determination of the X-factor in an IR plan is controversial. Members of the working group held diverse views as to the appropriate specificity of an X-factor; that is, should there be one X-factor for the whole sector, should there be three to five X-factors in the sector based on some form of peer grouping of the distributors, or should each distributor get an individual X-factor? The working group was unanimous in its view that implementing a single X-factor for all distributors in Ontario would not reflect the diversity of those companies in the sector. Discussions on how to derive individual X-factors that everyone could accept with confidence lead to the conclusion that it is not practical at this time. However, a peer group approach is possible for the 3rd Generation IR mechanism.

Should distributors select their X-factor?

Another issue where working group members differed is how to assign an X-factor to a distributor. The X-factor may be assigned to the distributor by the Board based on empirical analysis. This approach calculates X-factors to recognize diversity in terms of the external factors that will

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(http://www.oeb.gov.on.ca/documents/cases/EB-2006-0268/report_Benchmarking-peg_20070427.pdf) affect potential productivity growth. As an alternative, the X-factor may be selected by the distributor from a pre-defined menu. As previously mentioned, in 1st Generation PBR staff presented a menu approach to assigning the X-factor that offered distributors some flexibility and opportunity for increased earnings in exchange for acceptance of a higher X-factor. Some members of the working group expressed preference for a menu approach. Other members expressed preference for the Board assigning an X-factor to the distributor based on empirical analysis.

Staff invites comment

Staff invites comments from stakeholders on the use of the kind of menu approach described on page 36 of this paper. Specifically, if this kind of approach were adopted, how might it be designed, and how would the Board know it has been designed “correctly.”

Standard TFP approach should be based on at least a 10-year series of data

Working group discussions revealed that a standard TFP approach (an approach commonly used in other jurisdictions) for Ontario is problematic due to the lack of a 10-year series of data to calculate it. As explained in the PEG Report, a TFP trend calculated on four years of data may be tenuous, as a longer period is important to reveal a systemic trend with more confidence. Further, some members of the working group expressed concern that surveying distributors for the data needed to close the gap (i.e., 1997 to 2001) may not help as their confidence in the resultant series from 1997 to 2007 may not be high due to several industry restructuring related events that occurred over that time. Some members of the working group proposed that the Board adopt the 1st Generation PBR TFP analysis for the 3rd Generation IR mechanism; however, other members of the working group expressed concern that the relevance of a 10-year old TFP study to today’s context is unclear. One option raised by members of the working group is to retain the 1% X-factor that is currently in effect under the 2nd Generation IR mechanism until work is completed to compile the needed 10-year data series. Some interest was expressed by some working group members to learn more about data envelopment analysis and stochastic frontier analysis, two alternative approaches to benchmarking. Dr. Kaufmann provided staff and the working group with a report containing an extensive discussion of different benchmarking methods.[26]

PEG's proposed X-factor calibration

Various ways to derive X-factors are summarized in the PEG Report. Also, in the PEG Report, Dr. Kaufmann proposes that for Ontario distributors, the X-factor be comprised of two elements: (1) an industry TFP-based component reflecting TFP growth potential; and (2) an efficiency benchmark-based stretch factor. In PEG's proposed approach, the industry TFP growth potential would be estimated using U.S. data, and the stretch factor would be based on Ontario data.

Staff invites comment

Staff invites comments from stakeholders on PEG's proposed approach to deriving X-factors for 3rd Generation IR.

4.5 Continued Migration to Common Capital Structure and Provision for Incremental Capital Investment

Continued Migration to Common Capital Structure

Adjustment for change in capital structure will continue

The Board will continue to include an adjustment to rates in 2009 and 2010 as outlined in its 2006 Report to transition distributors to the single deemed capital structure of 60% debt and 40% equity.

Provision for Incremental Capital Investment

A modular approach to deal with incremental capital investment

In its 2006 Report, the Board addressed the issue of the treatment of capital investment and concluded that there was no need for a capital investment factor in the 2nd Generation IR mechanism. Board staff does

[26] Lawrence Kaufmann, Ph.D., Partner, Pacific Economics Group and Margaret Beardow, Principal, Benchmark Economics, "External Benchmarks, Benchmarking Methods, and Electricity Distribution Network Regulation: A Critical Evaluation". (http://www.oeb.gov.on.ca/documents/cases/EB-2007-0673_filings/workinggroup/meeting_20071129/BenchmarkingMethds2001_PEG.pdf).

not understand that conclusion as necessarily applying to the 3rd Generation IR mechanism. Staff therefore identified the treatment of capital expenditures as an issue in the Scoping Paper and the issue has been further considered in consultations and working group meetings to date.

As discussed in section 3.1, views of members on the working group differed as to whether special treatment of capital spending is necessary in an IR framework. However, as an option, staff and the working group suggest that the "modular approach" might be reasonable. This could allow for the intra-term approval by the Board and appropriate pass-through of incremental capital expenditures associated with growing capital program demands. This could be calculated as a separate parameter in the price cap formula, or it could be calculated and added to the current K-factor in the price cap formula.

To minimize the dilution of incentives under the price cap mechanism, staff suggests the following approach and treatment of incremental capital for the 3rd Generation IR mechanism.

The Incremental Capital Investment Module

Z-factor-like treatment

Staff suggests that intra-term incremental capital investment could be treated like a Z-factor except that, unlike a Z-factor, these "events" (or more appropriately called "drivers" in this context) are in the control of the distributor's management. As noted previously, examples of cost pressures that may affect distributors in the coming years discussed by the working group and identified as potential drivers include:

- significant replacement of aging assets;
- lumpy capital expenditures to meet new growth (e.g., transformer stations) and/or customer choice of location for connection; and
- capital contributions paid by distributors to transmitters.

Eligibility criteria

For incremental capital expenditures to be considered for recovery, staff suggests that the amounts would have to satisfy the eligibility criteria set out in Table 6, below. The first criterion is generally the same as that for a Z-factor. However, the second and third criteria have been modified to recognize the nature of the module – that it is intended to address investment proposed by management to respond to the claimed driver.

Table 6: Incremental Capital Investment Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

Materiality threshold

As is the case for a Z-factor, staff suggests that recovery of incremental capital investments would be subject to a materiality threshold. In its comments on the Scoping Paper, one stakeholder recommended that the mechanism should adjust rates for capital programs that increase net fixed assets by 5%. Alternatively, in light of feedback provided by the working group, the materiality threshold could be established at 3% of net fixed assets, the same level as that being proposed for Z-factors. The threshold must be met on an individual driver basis in order to be eligible for potential recovery.

Application requirements

The intent for this "incremental capital investment module" is that it would only be invoked by a distributor intra-term and that any Board-approved amounts and rate base treatment would be fully resolved through comprehensive rebasing. To invoke the module, a distributor would make specific application to the Board for review and approval with an application similar to that for a Z-factor. If a module is implemented by the Board, filing guidelines should be prepared for this purpose, and could be based in large part on existing materials. Staff suggests that information regarding the following would also be informative for the Board in considering such an application: the distributor's asset management plan; and a discounted cash flow analysis similar to that described in Appendix B of the DSC, to calculate the incremental revenue requirement impact for the remaining years of the IR term. Staff therefore also suggests that this information be considered when developing filing guidelines. Staff assumes that these applications would, in the normal course, be considered by the Board through a hearing process.

The modular approach outlined above is intended to be a flexible and practical means of accommodating reasonable spikes in incremental capital investment needs during 3rd Generation IR. However, staff suggests that distributors with an inordinate capital spending program may best be accommodated through rebasing.

The inclusion of an "incremental capital investment module" should reduce the need for the off-ramp related to capital investment needs that is currently available in the 2nd Generation IR mechanism. However, staff notes that this added flexibility may have unintended consequences for comprehensive IR – that is a gross shift of risk and cost out of the rate adjustment mechanism. This could have the effect of interfering with the ability of IR to encourage distributors to seek efficiency improvements under the plan by undermining its comprehensiveness. Capping the total of a distributor's pass-through amounts allowed in one or more modules may reduce the risk of this unintended consequence. However, since the module amounts require specific application to the Board, capping amounts may not be necessary as each application will be subject to Board review on a case-by-case basis.

As noted previously, the working group expressed interest in the "end-of-term capital incentive" described on page 24. However, implementation and administration of an incentive like that for 80 plus Ontario distributors may not be practical.

Staff invites comment

Staff invites comments from stakeholders on the "incremental capital investment module" concept as described above. Staff also invites comment from stakeholders on the need to mitigate any risks associated with a capital investment module in the 3rd Generation IR mechanism. If some form of mitigation is considered necessary, staff invites views on an appropriate mechanism.

4.6 Treatment of Unforeseen Events

Z-factors allow adjustment for unusual events beyond the control of the distributor's management. Examples include changes in tax rules and natural disasters.

Limited Z-factors

For 2nd Generation IR mechanism, Z-factors are limited to events genuinely external to the regulatory regime and beyond the control of management and the Board – changes in Board policy are not eligible for Z-factor treatment. As noted in its 2006 Report, the Board can always assess the implications of Board regulatory policy changes and make provision for them at the relevant time.

Appendix D replicates the detailed requirements for Z-factors found in the 2006 Report.

Eligibility criteria

Staff suggests that, for amounts to be considered for recovery in a Z-factor, the amounts must satisfy the 2nd Generation IR eligibility criteria set out in Table 7, below. Also, consistent with 2nd Generation IR assumptions, staff notes that changes in tax rules may result in positive or negative amounts.

Table 7: Z-Factor Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amounts must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amounts must have been prudently incurred. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

A number of issues related to Z-factor claims from electricity distributors were discussed in a recent Board decision on storm damage costs.[27] These include the current materiality threshold, capitalization of Z-factor costs, cost allocation, and the means of collecting approved amounts from ratepayers. Each of these is discussed below.

Materiality threshold of 3%

Currently, for expenses, the materiality threshold is 0.2% of total distribution expenses before taxes; and for capital cost recovery, the materiality threshold is 0.2% of net fixed assets. One stakeholder in its written comments on the Scoping Paper recommended that the threshold be raised to 10% of OM&A expenditures. As is noted in the storm damage costs decision, experience to date indicates that the current materiality thresholds are too low and parties in that proceeding highlighted this as an issue. Based on staff's review of Z-factor claims made to date and feedback from members of the working group, a threshold of 3% may be appropriate. Therefore staff suggests that the materiality thresholds be changed to 3%. As is currently the case, the threshold must be met on an individual event basis in order to be eligible for potential recovery.

[27] Ontario Energy Board, Decision with Reasons in proceeding EB-2007-0514, EB-2007-0595, EB-2007-0571, EB-2007-0551 (In the matter of applications by Canadian Niagara Power Inc. – Fort Erie, Canadian Niagara Power Inc. – Port Colborne, Peterborough Distribution Inc. and Lakeland Power Distribution Ltd. for the combined proceeding on storm damage costs) (July 31, 2007).

With regard to the capitalization of Z-factor costs, in the recent storm damage costs proceeding, one party to that proceeding expressed the view that Z-factors are intended to address unforeseen, temporary matters – as such, any resultant approved amounts associated with them should be transitory adjustment to rates, not permanent adjustments. Therefore, this party concluded that Z-factor costs should be treated as entirely OM&A. Staff invites comment from interested parties on whether capitalization as applied in cost of service rate setting is relevant to Z-factor treatment in incentive regulation rate setting, or whether this should be determined on a case-by-case basis.

Should the treatment of Z-factor costs be prescriptive or be determined on a case-by-case basis?

To ensure that the burden on each class of customers is not unreasonable, the Board determined in the storm damage costs decision that Z-factor costs should be allocated between classes on the basis of distribution revenue. Staff invites comments from stakeholders as to whether this should be clarified in Appendix D as a general Z-factor rule.

Should there be consistency in allocation methodology?

In the storm damage costs decision, the Board also decided that the use of time-specific rate riders (whether reflecting a temporary fixed charge and/or a temporary volumetric charge) is transparent and has the advantage of not requiring another regulatory process to remove the riders. Therefore, Z-factor amounts should be recovered from ratepayers via rate-riders. Staff therefore suggests this be adopted as a general Z-factor rule.

Z-factor amounts to be recovered via rate riders

In the storm damage costs decision, the Board identified causation as a standalone issue. Specifically, the Board stated the issue as “the appropriateness of the Z-factor cost claims relative to the value associated with the risk for this type of event that is currently imputed in distributors’ rates.” This recognizes that, generally, some measure of cost recovery for unforeseen events is already included in distribution rates for Ontario distributors. The Board noted in its decision that distributors should make every effort to demonstrate that damage inflicted

Clarification in Z-factor filing guideline

on their systems by extraordinary events is genuinely incremental to their experience or reasonable expectations. Board staff suggests that this could be made clearer in the guidelines that set out in Appendix D in relation to what is required from a distributor when applying for disposition of Z-factor related costs.

4.7 Off-ramps

An off-ramp is based on a pre-defined set of conditions under which the IR plan would be terminated or modified before its normal end-of-term date, usually because of extreme events that cannot be effectively addressed, or that should not be addressed through Z-factor treatment or some other IR mechanism such as earnings sharing.

For the 2nd Generation IR mechanism, there are limited adjustments available to distributors. Therefore, the Board provided for an off-ramp if these adjustments proved insufficient for specific cost pressures (e.g., additional capital investment). Where this is the case, distributors are expected to file a comprehensive cost of service application and not to rely on the simplified filing requirements for the incentive mechanism.

Stakeholder comments on the Scoping Paper

One stakeholder, in its written comments on the Scoping Paper, recommended that the Board consider applying a trigger mechanism in the 3rd Generation IR mechanism with a relatively large annual ROE dead band of ±6%, such that where a distributor performs outside of this earnings dead band a regulatory review might be initiated. This stakeholder expressed concern that administrative deficiencies in areas such as data consistency and completeness (e.g. insufficient data on capital stock and vintage) continue to plague the Board's efforts at efficiency estimation quantification, and that while significant data analysis questions remain outstanding, some form of trigger to a regulatory review may be appropriate.

A variation on this approach was adopted in the recent Union Gas settlement agreement accepted by the Board.[28] In that mechanism, the trigger points are set at ±3% ROE and are based on weather normalized earnings.

Staff invites comment

Staff invites comments from interested parties on whether one or more off ramps should be available to distributors in 3rd Generation IR and if so, what form they might take.

4.8 Earnings sharing

An earnings-sharing mechanism ("ESM") adjusts a company's price restrictions when its rate of return has been in a certain range over a recent historical period. A typical ESM provides for rate adjustments when the actual (pre-sharing) return differs from a target return by certain prescribed amounts.

Stakeholder comments on the Scoping Paper

One stakeholder, in its written comments on the Scoping Paper, proposed the implementation of an ESM in 3rd Generation IR.

Some members of the working group expressed concern that over-earning be addressed in the IR framework, especially if the Board gives distributors choice in plan term and a distributor selects a longer term. Also, they commented that ratepayers do not have access to full information regarding a distributor's financial results and do not have the same ability as distributors to seek Z-factor relief. As such, these members of the working group believe that the use of an ESM would provide a level of ratepayer protection during the plan.

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[28] Ontario Energy Board, Decision in proceeding EB-2007-0606 (In the matter of an application by Union Gas Limited for an Order or Orders approving or fixing a multiyear incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008). (http://www.oeb.gov.on.ca/documents/cases/EB-2007-0606/dec_union_enbridge_20080117.pdf)

Should an ESM be part of 3rd Generation IR?

As noted in the 2006 PEG Report, ESMs are a means of adjusting rates for a wide range of risky external developments. This can be appealing where risks are substantial or there is lack of technical expertise to implement alternative risk mitigation measures such as industry specific input price indexes. Unlike up front rate reductions and X-factor stretch factors that are designed to share expected productivity improvements with ratepayers at the start of and during an IR plan, ESMs share benefits after they are realized.

In accordance with the recently accepted settlement agreement for an incentive regulation framework for Union Gas referred to above,[29] an asymmetrical ESM of +2% actual earnings above the calculated ROE for that year will be in effect during the term of the Union Gas plan. In the case of Enbridge's settlement agreement for an incentive regulation framework, the deadband before earnings sharing applies is +1% actual earnings above the calculated ROE[30].

Staff invites comment

Staff invites comments from stakeholders on whether an ESM should be part of 3rd Generation IR and if so whether an asymmetrical ESM as described above might be appropriate. If such a mechanism were to be implemented, what should the appropriate deadband be, if any, and should the 3rd Generation IR mechanism stretch factors be adjusted and how and by how much?

4.9 Service Quality

Service quality provisions are an important consideration in incentive regulation plan design.

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[29] Ibid.

[30] Ontario Energy Board, Decision in proceeding EB-2007-0615 (In the matter of an application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing a multiyear incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008). (http://www.oeb.gov.on.ca/documents/cases/EB-2007-0615/dec_union_enbridge_20080211.pdf)

The Board's commitment to the implementation of an effective service quality regulation regime in association with incentive rate regulation in the electricity distribution sector was most recently confirmed by the initiation of a consultation process (EB-2008-0001) to address the matter earlier this year.

In its January 4, 2008 letter launching the consultation process, the Board indicated that service quality regulation will be addressed by means of the implementation of mandatory standards rather than through the IR framework. While the Board also indicated that this may change in the future, Board staff has proceeded on the basis that the mandatory standards approach will remain in effect for the foreseeable future and has therefore not included service quality as an element for consideration in the IR rate adjustment mechanism.

Also on January 4, 2008, the Board issued for written comment a Board staff Discussion Paper that provides background on the development of service quality regulation in Ontario and identifies staff's proposals regarding modifications to existing service quality measures and the adoption of new ones. It is anticipated that the service quality consultation process will culminate in amendments to the DSC and to the Board's Reporting and Record Keeping Requirements.

4.10 Reporting Requirements

At this time, staff does not suggest any additional reporting requirements for 3rd Generation IR.

However, if an ESM were implemented in 3rd Generation IR, additional reporting requirements may be appropriate to support these mechanisms.

Staff invites comments from stakeholders on the need for additional reporting requirements for 3rd Generation IR.

Staff invites comment

5 Implementation Considerations

5.1 How Adjustments Would be Determined

5.1.1 Conservation and Demand Management

Status quo vis-à-vis CDM

As previously discussed, staff suggests the continuation of the status quo vis-à-vis CDM. As such, CDM-related costs which are to be recovered through distribution rates (i.e., any new spending on CDM, revenues from recovery of a lost revenue adjustment claim, or a shared savings claim) should continue to be dealt with separately from the IR rate adjustment.

5.1.2 Treatment of Taxes

A distributor's allowance for taxes (whether PILs or actual taxes) currently includes provision for income tax and the Ontario capital tax.

Taxes not to be adjusted by the price cap index

Staff and the working group believe that, due to anticipated reforms in tax law and legislation, a distributor's allowance for taxes should not be adjusted by the price cap index. Rather, the allowance for taxes would be removed prior to the index adjustment, and the recalculated amounts layered back in after new base rates have been calculated. This approach has been implemented in the 2008 2nd Generation IRM rate adjustments, and staff suggests that it be continued in future years regardless of which IR plan a distributor is subject to.

Also, as discussed in Section 4.6 on Treatment of Unforeseen Events, and consistent with 2nd Generation IRM, material changes in tax rules during 3rd Generation IR should be treated as a Z-factor.

5.1.3 Deferral and Variance Accounts

Deferral and variance account balances will be dealt with in accordance with the provisions of the *Ontario Energy Board Act, 1998*.

The Board recently announced to stakeholders its intention to launch an initiative for the review and disposition of the commodity deferral or variance account (Account 1588 of the Uniform System of Accounts) based on the consideration of account disposition thresholds or "disposition triggers." The Board is required to make an order at least every three months to determine whether and how the amounts recorded in Account 1588 shall be reflected in rates. The Board will also consider whether to extend this initiative to deferral accounts similar in nature to Account 1588, such as the RSVA and RCVA deferral accounts. Currently, the Board is required to make an order at least annually in respect to non-commodity deferral or variance accounts.

In its 2006 Report, the Board determined that, to the extent possible, it will limit reliance on the creation of new deferral accounts during the term of the IR scheme to well-defined and well-justified cases only. With the exception of accounts needed to support an ESM, if adopted, staff does not believe that any further accounts would be required for 3rd Generation IR. Z-factor rules should continue to govern the need for, and treatment of, deferral accounts.

5.1.4 Application of the Price Cap Index

Index applied to rates, excluding taxes

Consistent with 1st Generation PBR and the 2nd Generation IR mechanism, the 3rd Generation IR price cap index would be applied uniformly across all customer classes and to both the monthly service charge and volumetric rate. As stated above, the index would not be applied to taxes.

Also, consistent with practice to date in Ontario, the index would not be applied to specific service charges. Assumptions used to derive the price cap index may not be appropriate to specific service charges. The Board carried out a generic review on specific service charges in 2005,[31] and is currently carrying out further related consultations in respect of the provision of specific services and the application of associated charges (EB-2007-0722). Until this work is complete, staff suggests that it is appropriate for distributors to continue to apply to the Board for a review of their specific service charges on a case-by-case basis.

There are a number of components to distribution rates that will need to be extracted from rates before the index is applied. This includes smart meter amounts, rate adders/riders, and CDM amounts. A "de-construction" of 2008 rates would be carried out prior to adjusting base rates. After adjusting base rates with the price cap index, rate elements would be "re-constructed" to derive 2009 rates. That is, the appropriate rate adders/riders would be layered in after the new base rates have been calculated.

As a practical matter, implementation of this approach may mean that some of the de-construction could occur at the base revenue requirement level. The resultant monthly fixed rate and volumetric rate (both excluding taxes) for all customer classes will, however, have been adjusted uniformly by the price cap index amount. That is, if the price cap index is 1%, then the index will be applied so that the rates, excluding taxes, will all be adjusted upwards by 1%.

5.1.5 Adjustments to Revenue-to-Cost Ratios

On November 28, 2007, the Board released a report on the "Application of Cost Allocation for Electricity Distributors" which outlines the Board's

[31] Chapter 11 of the 2006 Electricity Distribution Rate Handbook addresses specific services charges.

expectations on how electricity distributors are to adjust the revenue-to-costs ratios to bring them within the range stated in the report.

The cost allocation policies reflected in the report are to be followed by distributors whenever they apply for rates on a cost of service basis. In the event that a rate mitigation plan is required by the Board as a result of the cost of service review, then base rates will need to be adjusted accordingly prior to the application of the price cap index.

5.2 Rebasing Rules

The timing of expenditures (i.e., operating, maintenance, replacement capital, etc.) that are made periodically is an issue of mounting interest in incentive regulation schemes. Some timing issues may be revealed at rebasing.

Forward test year cost of service

Staff assumes that rebasing at the end of 3rd Generation IR will be based on a forward test year cost of service filing. Benchmarking evidence should be used as an input to the review and may be applied to the proposed costs.

Historical plant continuity

Under the existing filing requirements, distributors are required to provide a detailed variance analysis between the Test Year and Bridge Year, and between the Test Year, the Historical Year and the last Board Approved Test Year. In addition, as it relates to capital expenditures, staff suggests that the distributor be required to provide historical plant continuity information for each year of the plan term since the last Board Approved Test Year. This approach was adopted in the recent Union Gas and Enbridge settlement agreements accepted by the Board.

Further, as mechanism to mitigate against the gaming of expenditure forecasts and/or the timing of expenditures, capital expenditure amounts in the rebasing year could be determined as an average of these amounts.

The 2006 PEG Report identifies other rebasing rules that might be considered. For example, new rates could be set as an average of the rates resulting from a new rate case and the rates resulting from one year's continuation of the 3rd Generation IR plan. Alternatively, a revenue requirement could be set as a weighted average of the new cost of service as established in a rate case and of an external cost benchmark.

Staff invites comments from stakeholders on the above.

Staff invites comment

Appendix A: Composition of the Working Group

The following people participated on the working group.

Working Group Member	Representing
Mr. Randy Aiken	Energy Probe & London Property Management Association
Mrs. Chris Amos	Waterloo North Hydro Inc.
Mr. Doug Bradbury	Canadian Niagara Power
Mr. Wayne Clark	Association of Major Power Consumers in Ontario
Ms Paula Conboy	The Coalition of Large Distributors (Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.)
Ms Julie Girvan	Consumers Council of Canada
Mr. Bill Harper	Vulnerable Energy Consumer's Coalition
Ms Judy Kwik	Power Workers' Union
Dr. Andy Poray	Hydro One Networks Inc.
Mrs. Margaret Maw	Cornerstone Hydro Electric Concepts Association Inc. (an association of 16 electricity distributors)
Mr. Jay Shepherd	School Energy Coalition
Mr. Maurice Tucci	Electricity Distributor Association

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Appendix B: Calculation of Industry-Specific IPI

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The IPI is a weighted-average of three cost sub-indexes:

1. the capital service price sub-index;
2. the labour price sub-index; and
3. the materials price sub-index.

These indexes are weighted by the input cost shares of these three inputs. For example, in the 1st Generation PBR, the IPI used cost shares of 50% capital, 35% labour (OM&A), and 15% materials and services.

The IPI in Place for 1st Generation PBR

In 2002, Board Staff calculated an update to the IPI in place for 1st Generation PBR (see Table 8 below) that is available on the OEB's website (http://www.oeb.gov.on.ca/documents/backgrounder_ipi_210102.pdf) as follows:

1. Bond Rate was the long-term Canada Bond Rate (over 10- years), CANSIM v122487 (B140013);
2. Depreciation rate was the average depreciation rate for a typical utility calculated from the 48 LDCs in the OEB TFP study;
3. CAP (Capital Asset Price) was calculated from Electric Utility Construction Price Index – Distribution Systems, CANSIM v735224;
4. Labour Price was calculated from average change in Line Crew Wage Rate for the typical utility calculated from the 48 LDCs in the OEB TFP study submitted to the Board in their PBR filings; and
5. Materials Price was calculated the Industrial Product Price Index – All Finished Goods, CANSIM v1574476.

Table 8: Calculation of IPI Update for 1st Generation PBR

Calculation of Input Price Index (IPI) for Electricity Distributors' Price Cap

	Bond Rate[1]	Deprec	CAP[2]	P_k	Capital Index 1988=1	% chg	Labour Index[3] 1988=1	% chg	Materials Index[2] 1988=1	% chg
1988	10.23%	0.0567	109.4	0.174	1.00	---	1.00	---	1.00	---
1998	5.30%	0.0567	138.8	0.152	0.88		1.30		1.30	
1999	5.55%	0.0567	142.6	0.160	0.92	5.08%	1.31	0.66%	1.33	
2000	5.89%	0.0567	145.8	0.169	0.97	5.38%	1.34	2.10%	1.36	2.61%
2001	5.47%	0.0567	143.3	0.160	0.92	-5.30%	1.37	2.33%	1.40	2.81%

Weights	
Capital	0.5011
Labour	0.3514
Materials	0.1475
	1.0000

	IPI	% chg
1988	100.00	---
1999	111.66	
2000	115.62	3.5%
2001	114.71	-0.8%

One of the issues with the approach used in 1st Generation PBR may be the availability of transparent and public data. Therefore, some options are suggested below.

Options for transparent and publicly available sources on a go forward basis

Both the labour price index and the materials and services price index can be determined from off-the-shelf statistics available from Statistics Canada. For labour costs, several other sources are available. In its productivity work for the Gas LDCs, PEG used Construction Union Wage Rates Indexes for Ontario, which are produced monthly. This should also be an appropriate source of labour cost change for the electric LDCs. Statistics Canada also produces data on major wage settlements for Ontario for all industries, and major wage settlements in the utility industry for Canada, produced quarterly (latest available is Q3 2007). Either of these should also be an acceptable measure of labour cost changes.

For the materials index, PEG used the Ontario GDP-IPI FDD in their productivity research for gas LDCs. This is the annual GDP price deflator for Ontario GDP which comes from the Provincial Economic Accounts. For 2006, the annual preliminary figure was released in April with a revision released in November 2006. Data for 2007 would likely stick to this schedule. A reasonable alternative to this measure is to use the Ontario CPI which is published monthly by Statistics Canada, or the core CPI for Canada (the benchmark inflation rate used by the Bank of Canada) which is also published monthly.

The capital service price index is calculated from long bond rate, capital asset price inflation, and a depreciation rate for assets. Bond yields are available from many sources (Statistics Canada, Chartered Banks, etc.) on a timely basis. An alternative to using these sources is to use the Board approved WACC (ROE and debt rates calculated according to their guidelines). The capital asset price data comes from Statistics Canada's electricity distribution system construction price index which is released bi-annually. The depreciation rate would need to be calculated by the Board based on the average service life for LDC assets.

Appendix C: industry-specific IPI Implementation Details

Calculation of Labour Sub-Index Based on Annual Wage Adjustment Rates

The sub index for labour was calculated applying the formula:

Labour Sub Index $_Y$ = Labour Sub Index $_{Y-1}$ * (1+ % annual wage adjustment rate $_Y$)

For the initial (base) year, which was chosen as 1992 for consistency with the other sub indices, the sub index equals 100. So that Sub Index $_{1992}$ = 100. Figure 6 illustrates this calculation.

Year	*Annual wage adjustment rates*	*Calculated Sub Index*
1992	2.30%	100
1993	1.40%	101
1994	0.30%	102
1995	0.20%	102
1996	1.00%	103
1997	1.60%	105
1998	2.40%	107
1999	2.10%	109
2000	3.50%	113
2001	2.40%	116
2002	2.40%	119
2003	2.40%	122
2004	3.00%	125
2005	2.60%	128
2006	2.30%	131
2007	3.80%	136

Base year 1992 =100

Sub Index $_{1993}$ = 100*(1+ 0.014)

Sub Index $_{2007}$ = 131*(1+ 0.038)

Annual data as published by HRSDC

Figure 6: Calculation of Labour Sub-Index based on Annual wage adjustment rates

Calculation of the Annual Materials Sub-Index Based on All Finished Goods Industrial Producer Price Index (IPPI)

For each year the value of the materials sub index is calculated applying the formula[32]:

Material Sub Index $_Y$ = IPPI as of December $_Y$ / IPPI as of December $_{1992}$

[32] Due to the absence of the IPPI for December 2007, the material sub index shown in section 4.3 was calculated with the IPPI as of November, rather than December.

Data Revisions

The following table shows the proposed approach based on the index series with a revision to the prior year's results (using hypothetical data):

Publication Date		2000	2001	2002	2003	2004	2005	2006	2007	
28/02/2007	Sub Index	102.3	103.9	105.3	106.3	108.1	110.4	113.1		
(For 2007 rates)	Annual change		1.56%	1.35%	0.95%	1.69%	2.13%	2.45%		<= Used for setting 2007 rates
28/02/2008	Sub Index	102.3	103.9	105.3	106.3	108.1	110.4	112.7	114.5	<= 2006 data now revised
	Annual change		1.56%	1.35%	0.95%	1.69%	2.13%	2.08%	1.60%	
Series used for 2008 rate setting	Sub Index	102.3	103.9	105.3	106.3	108.1	110.4	113.1	114.5	<= Uses most recent data for 2007 only. Annual change of 2007 over 2006 incorporates both actual change and data revisions
	Annual change		1.56%	1.35%	0.95%	1.69%	2.13%	2.45%	1.24%	

If only the annual percent change published each year is used, then the effect of historical data revisions would be that the series would differ from, and probably diverge over time from, what it should be.

The above example considers the most likely scenario, where the most recent year's data is revised. Revisions beyond one year are more problematic, but are generally infrequent and small in magnitude. Ignoring changes beyond the prior year may be the easiest approach.

Rebasing

In the event that Statistics Canada changes the base of one of the selected indices, standard techniques for linking the old and new series together should be used. The following shows a hypothetical example of how such linking occurs:

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Old series	102.3	103.9	105.3	106.3	108.1	110.4	112.7	114.5		
New Series							100	101.6	103.8	105.4
Linked series	102.3	103.9	105.3	106.3	108.1	110.4	112.7	114.5	116.98	118.79

In this example the linked series for 2008 was calculated as the index for the year that is now the base year (in this case 2006) times the index for 2008 as available on the new series divided by 100. In other words 116.98= (112.7 * 103.8) / 100.

Appendix D: Z-Factors

(Replicated from December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors)

A Z-factor has been incorporated into the incentive regulation mechanism for well-defined and well-justified cases only – specifically, Z-factors will be limited to changes in tax rules and to natural disasters. These events are generally not within management's control. However, options are sometimes available for how management responds, each with various tradeoffs between cost and effectiveness. The distributor will be required to supply the details of management's plans for addressing these events in support of the distributor's request for special cost recovery. The Board may limit the recovery of certain amounts associated with activities.

A distributor may record amounts which meet the eligibility criteria presented below for Z-factor events.

A distributor must follow the requirements listed below to be eligible to apply to the Board to claim any amounts into rates which the distributor has recorded.

Eligibility Criteria for Z-factor Amounts

In order for amounts to be considered for recovery in the Z-factor, the amounts must satisfy all three tests set out in the following table.

Table 9: Z-Factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

The above three criteria will be applied to determine the eligibility of amounts for recovery through Z-factors, or any other approach deemed appropriate as a result of Board review. It should be noted that when an electricity distributor does apply for disposition of these amounts, it will be expected to submit evidence that the costs/revenues which were incurred/received meet the three standards outlined below in its annual application.

Causation

For Z-factor amounts, the revenue or expense must be clearly outside of the base upon which rates were derived.

Materiality

Recovery is reserved for amounts which have a significant influence on the operation of the distributor. As a guideline, an expense will be considered material if it involves 0.2% of total distribution expenses before taxes; and a capital cost will be considered material if it involves 0.2% of net fixed assets. Therefore, materiality will differ depending on the size of the distributor. Further, in both cases, the materiality threshold must be met on an individual event basis in order to be eligible for potential recovery.

Prudence

In supporting the prudence of the expense, the distributor will need to justify the reasonableness of the amount relative to other options that the distributor may have had. For example, if the distributor must incur costs to deal with a natural disaster the amount incurred must be justified.

Board Review

The Board may review and adjust the amounts claimed under Z-factor treatment at any time during the term of the incentive regulation plan.

Balancing Account

Those amounts that pass the three-part test outlined above should be included in account 1572, "Extraordinary Event Costs" of the Board's Uniform System of Accounts contained in the Accounting Procedures Handbook.

Interest on these deferral accounts shall be separately recorded within these accounts. The interest shall be calculated on the monthly opening balances in these accounts at the rate set in accordance with the Board-approved method for accounting interest rates (i.e., short-term carrying cost treatment) for variance and deferral accounts.

In support of a rate adjustment related to Z-factor amounts, the distributor must indicate the amounts booked to these accounts in the previous year and provide evidence that these amounts satisfy the three criteria listed above. Distributors must also propose a disposition amount for these accounts. The distributor must also provide the basis upon which the disposition amount should be allocated to each rate class, including a discussion of the merits of alternative allocations considered. The disposition amounts allocated to each rate class from the deferral account should then be tallied, and a rate class specific revenue requirement adjustment determined.

Disposition Account

The size of the prospective rate adjustment will not be subject to a predefined limit. The absence of a predefined disposition limit will give individual distributors the flexibility to propose the rate rider with due consideration to other rate-related customer impacts.

The Board may either, adjust the class-specific rate adjustments directly based on the information provided, or may seek additional information from the distributor and/or may request a review and report from the Board's Chief Regulatory Auditor on cost eligibility and the derivation of the rate rider.