EDA
The Voice Of Ontario's Electricity Distributors

April 14, 2008

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

Via email to BoardSec@oeb.gov.on.ca and by courier

Dear Board Secretary:

Re: EDA Submission on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors EB-2007-0673

The Electricity Distributors Association (EDA) would like to provide the attached submission in response to the OEB staff "Discussion Paper on 3rd Generation Incentive Regulation for Ontario Distributors" dated February 28, 2008 and the report entitled "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" prepared by the Pacific Economics Group. The EDA's submission was prepared by Prof. Adonis Yatchew of the University of Toronto in consultation with members of the Association.

Yours truly,

"original signed"

Richard Zebrowski
Vice President, Policy & Corporate Affairs

Attach.

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3rd Generation Incentive Regulation for Ontario's Electricity Distributors EB-2007-0673

Submissions on behalf of the Electricity Distributors Association

Adonis Yatchew, Ph.D.

April 14, 2008

EXECUTIVE SUMMARY

Background

1. The Ontario Energy Board regulates over 80 electricity distributors. Since August 2007, the Board has been engaged in a consultative process with the objective of developing a 3rd Generation Incentive Regulation Mechanism.

2. In February 2008, the Board Staff issued two key documents: "Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario Distributors" and "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario" which was prepared by the Pacific Economics Group. The purpose of the present document is to provide commentary and analysis on behalf of the Electricity Distributors Association.

The Board Staff Discussion Paper

3. In developing its vision of a long-term framework for incentive regulation of Ontario distributors, the Board Staff Discussion Paper articulates four main criteria: sustainability, predictability, effectiveness and practicality. In addition it is indicated that an incremental approach towards the long term vision is appropriate.

4. Using the four evaluation criteria, three alternative regulatory models are assessed:

    a. comprehensive multi-year cost of service;
    b. a hybrid partial index approach under which OM&A costs would be regulated using an index, and capital costs would be regulated on a cost-of-service basis;
    c. a comprehensive price-cap index with added flexibility to recognize incremental capital investment needs.

    The Staff Discussion Paper finds that the comprehensive price-cap approach dominates the other two options.

5. A number of additional key elements of a "core plan" are identified and discussed including:

    a. a three to five year plan term to be determined by individual distributors;
    b. an inflation factor which is based on an industry specific input price index;
    c. continued migration to a common deemed capital structure of 60% debt and 40% equity;
    d. an incremental capital investment module similar to a Z-factor approach.

The Pacific Economics Group Calibration Report

6. The central purpose of the Pacific Economics Group Calibration Report is to recommend productivity factors which would be incorporated within a comprehensive price-cap index. The Report outlines alternative methodologies and recommends that an index-based approach be used. Index-based approaches rely on historical data to assess productivity trends by comparing growth rates of inputs to growth rates of outputs. For example, if inputs, (such as labour and capital) are growing at 2% per year and output is increasing at 3% per year, then productivity is growing at 1% per year.

7. The Pacific Economics Group proposes that the X-factor be defined as the sum of two components:

   a. a basic industry-wide productivity factor of 0.88%; this figure is estimated using U.S. utility data;
   b. a "stretch factor" ranging from 0% to 0.6%; assignment of individual stretch factors would be based on assessments of OM&A costs of individual Ontario distributors; utilities which are deemed to be relatively more efficient would be assigned lower stretch factors.

   The resulting X-factors would therefore lie in the range 0.88% to 1.48%. The Pacific Economics Group has calculated that the resulting industry-wide average X-factor would be 1.16%.

Recommendations

8. Given the alternatives, a comprehensive price-cap incentive regulation mechanism is the preferred approach for many utilities. It produces the strongest incentives for efficiency gains and it is the simplest from an administrative point of view. An optional three to five year term is appropriate. However, further refinement of the price-cap approach to incorporate variability in capital expenditures is highly desirable.

9. Capital investments, conducted in a timely and rational manner, are essential to the efficiency, effectiveness and reliability of a capital intensive industry such as electricity distribution. It is therefore recommended that:

   a. Multi-year capital plans should be allowed at the time of rebasing. This would reduce dependence on "off-ramps" and intra-term capital cost approval processes, and lead to better capital expenditure profiles.
   b. A capital investment module with a materiality threshold of 1%-2% of net fixed assets should also be available. The threshold should be applied to total incremental capital expenditures rather than on a project basis.

10. The development of a mechanism by which multi-year capital expenditures would be incorporated within the price-cap framework should be a central objective. The most appropriate approach would seem to be the direct inclusion of a utility-specific “K-factor” within the price-cap formula. Evaluation of this approach using the four criteria set out in the Staff Discussion Paper leads us to conclude that it is superior to the other options that have been proposed:

    Sustainability: The approach is more sustainable in that it can better handle varied circumstances and it achieves greater consistency among distributors.

    Predictability: Conventional price-caps set the price trajectory during the course of the plan. However, between plans there could be substantial variation as a result of rebasing which would need to reflect capital program and other changes. A K-factor is likely to reduce “between-plan” variability as forecast capital program changes would be incorporated on an ongoing basis. Reduced reliance on intra-term capital approval processes should also enhance predictability.

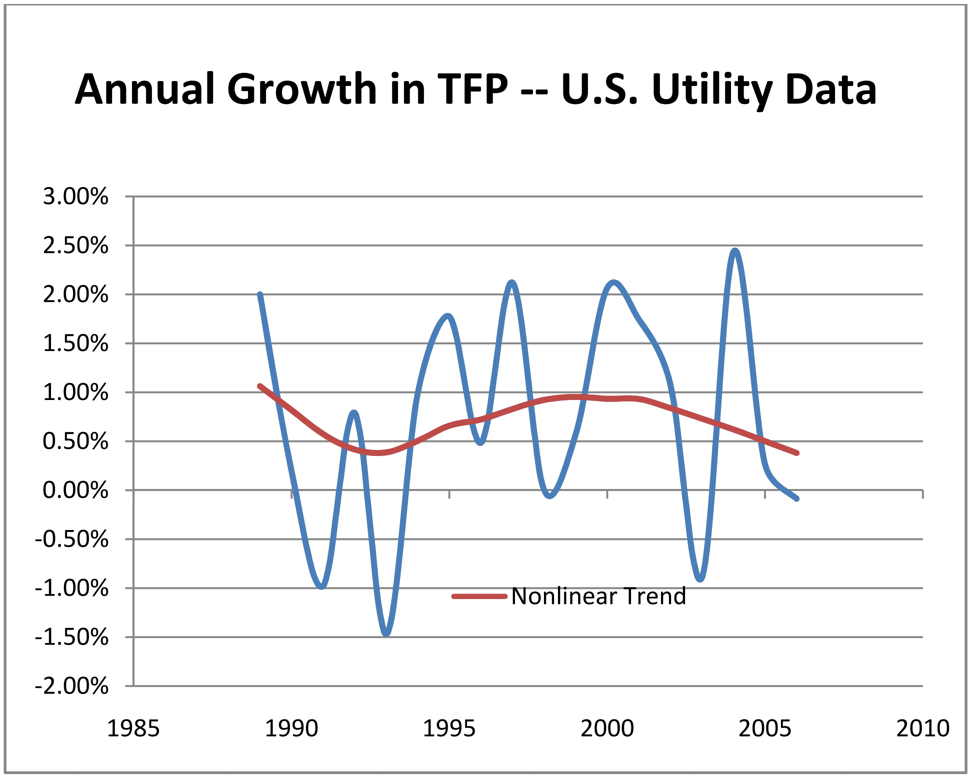
    Effectiveness: The approach improves the incentives for matching actual capital expenditures to the optimal time profile. For example, the incentives to delay expenditures until the next rebasing and to increase proposed test year outlays are reduced.

    Practicality: The degree of complexity in establishing the K-factor path is comparable to that involved in rebasing. Additional administrative costs should be modest relative to a conventional price-cap.

11. A few utilities, for example, those expecting significant declines in sales volumes (exclusive of conservation and demand management programs) or large variability in sales may be disadvantaged under a price-cap approach. As suggested in the Staff Discussion Paper, utilities should be able to apply to the Board to have their rates set according to an alternative plan such as a revenue-cap. We note that in the Ontario natural gas industry, price-cap and revenue-cap regulation are both presently in use.

12. In developing its position on productivity factors, the Pacific Economics Group has relied principally upon data on 69 U.S. utilities for the period 1988-2006. The following observations are made in relation to these data.

    a. The average annual productivity growth for this period is 0.72%.
    b. There is no statistical evidence of systematic acceleration in productivity growth which could justify higher expected productivity factors in the near term.
    c. Estimation of a nonlinear trend effect model suggests variation of productivity growth between 0.4% and just over 1% during the period 1988-2006, as illustrated in the figure below.
    d. The most recent years of data suggest a period of deceleration. Recessionary effects in the U.S. are likely to have an adverse impact on productivity trends.



13. Based on its analysis of the U.S. data, the Pacific Economics Group has suggested an industry average productivity factor of 1.16%. Our review of the statistical evidence indicates that this figure is substantially too high. Indeed, it is outside the range of average productivity growth rates observed in the U.S. during the entire 1988-2006 period.

14. Consistent with the U.S. results, Ontario data for the period 2002-2006 also indicate a slowdown in productivity growth. Growing emphasis on conservation and demand management, increasing regulatory requirements and aging infrastructure are likely contributory factors. Taking these various factors into consideration, it is our view that a reasonable target for the industry average productivity factor is in the range of 0.5% to 0.6%.

15. "Stretch factors" are rationalized on the basis that a utility should experience "accelerated productivity growth" as one transitions from cost-of-service to incentive regulation. However, Ontario distributors have been under a form of price-cap regulation for an extended period of time. Moreover, no statistical evidence has been presented to support the proposition that productivity growth is likely to accelerate materially in the near future. Thus, the inclusion of the proposed stretch factor is not justified.

16. Although the evidence does not support inclusion of a stretch factor, a "diversity factor" which reflects relative efficiencies of distributors is an appropriate part of the long-term vision for incentive regulation in Ontario. The diversity factor should be centered at the industry average productivity factor.

17. At the present time, there remain serious concerns about the validity of the benchmarking analysis that would underpin the assignment of "diversity factors". In particular, the analysis focuses on OM&A costs as Ontario distributor capital data of sufficient quality are not yet available. We recommend a sequence of two steps:

    Step 1: the exclusion of a "diversity factor" until significantly better benchmarking data become available; in the interim, a common X-factor between 0.5% and 0.6% would be assigned to all distributors;

    Step 2: after estimates of relative efficiencies of distributors are found to be sufficiently reliable, the inclusion of "diversity factors" ranging from say -0.3% to +0.3%; combining these with an industry average productivity factor of say 0.5% would result in X-factors which range from 0.2% to 0.8%.

18. The absence of consistent Ontario capital data limits further improvements to the calibration of an incentive mechanism in two important ways:

    a. It limits our ability to estimate long-term industry-wide productivity targets for Ontario.
    b. It limits our ability to calibrate diversity factors across Ontario utilities.

    Development of better historical Ontario data would substantially resolve these shortcomings and should be undertaken.

19. The long-term objective of replacing a broad measure of inflation with an industry specific input price index is appropriate. The ideas put forth by Board Staff are useful and provide important insights into the development of such an index. However, further work is required to ensure that the index tracks actual cost pressures experienced by utilities. It would also be useful to gather utility-specific wage data for Ontario distributors rather than relying exclusively on external labour cost databases.

20. Earnings sharing mechanisms have the undesirable feature that they reduce the power of incentives for efficiency improvements. In considering such mechanisms, one should be mindful that, upon rebasing, consumers capture the benefits of efficiency improvements in perpetuity. In the event that an earnings sharing mechanism is implemented, it should be symmetrical.

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1. INTRODUCTION AND BACKGROUND

In August 2007, the Ontario Energy Board began a consultative process on incentive regulation of Ontario's electricity distributors. Since two incentive-based regimes preceded the present process, the objective has been to develop a "3rd Generation Incentive Regulation Mechanism" (3GIRM). At the commencement of the consultation, Board Staff issued an initial document entitled *3rd Generation Incentive Regulation for Electricity Distributors, Staff Scoping Paper, EB-2007-0673*.

In the course of the intervening months, numerous stakeholder meetings were held with a view to developing a coherent framework which would be sufficiently flexible to accommodate the wide range of circumstances and operating environments within which Ontario's many distributors must function. In these proceedings Board Staff was assisted and supported by the Pacific Economics Group, LLC (PEG).

In February 2008, the Board issued two key documents:

> *Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario Distributors*, Ontario Energy Board, February 28, 2008;
>
> *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, prepared by the Pacific Economics Group, LLC, and authored by Lawrence Kaufmann, Ph.D., Dave Hovde, M.A., Lullit Getachew, Ph.D., Steve Fenrick, Kyle Haemig, M.S. and Amber Moren, February 2008.

Henceforth we will refer to these documents as the "Staff Discussion Paper" and the "PEG Calibration Report".

In addition, in March 2008, the Board issued *Benchmarking the Costs of Ontario Power Distributors*, Pacific Economics Group, (henceforth the "PEG Benchmarking Report"), authored by Mark Newton Lowry, Ph.D., Lullit Getachew, Ph.D., and Steve Fenrick, March 20, 2008. The relevance of the latter document to the present proceeding is that its main purpose is to assess the relative efficiencies of Ontario distributors.

Board Staff has requested that comments on the proposals that have been put forth in the first two of these reports be submitted by April 14, 2008. The purpose of the present document is to provide commentary and analysis on behalf of the Electricity Distributors Association.

2. INCENTIVE REGULATION OF DISTRIBUTION

A. CENTRAL CONSIDERATIONS

Objectives of incentive regulation.

Incentive regulation has often been ascribed a broad and ambitious range of objectives. Foremost among these have been the strengthening of incentives for cost minimization, efficient capital expenditures and innovation. In some cases, industry rationalization or restructuring has been seen as a potential by-product of the search for cost savings and service enhancements.

In addition, other longstanding regulatory objectives continue to be of central importance including the provision of appropriate levels of service quality and reliability, fair rates to customers, fair cost recovery and reasonable returns for utilities.

Incentive regulation does not necessarily reduce regulatory burden.

A stable incentive regulation regime should lead to improvements in the efficacy and efficiency of the regulatory process itself. In some instances one might expect reductions in total regulatory costs -- that is those incurred by the regulator and by utilities. However, this has not always been the case, particularly in the incipient and development stages of incentive regulation.

In developing its vision of a long-term framework for incentive regulation of Ontario distributors, the Staff Discussion Paper articulates four main criteria:[1]

Proposed criteria for evaluation of incentive regulation plans:

sustainability, predictability, effectiveness, practicality.

> **Sustainability**: "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."
>
> **Predictability:** "A predictable framework facilitates planning and decision-making by ratepayers and electricity distributors."
>
> **Effectiveness:** "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."

[1] Staff Discussion Paper, page 10.

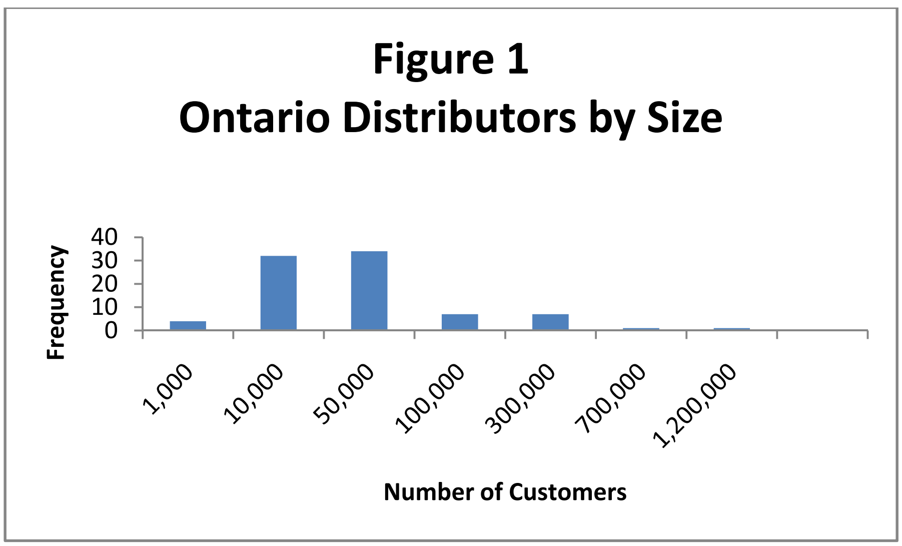
> **Practicality:** "Without sacrificing the other criteria, under a practical framework, the distributor's costs of administration should not exceed the benefits."

The document also recognized the importance of proceeding in an **incremental** fashion towards the long-term vision.

An incremental approach is appropriate.

B. ADVANTAGES AND CHALLENGES OF THE ONTARIO ENVIRONMENT

At present, the Ontario Energy Board regulates approximately 85 electricity distributors. The smallest distributors serve less than a thousand customers, while the largest, Hydro One Networks, serves over one million, (see Figure 1). Together these distributors provide service to over 4.5 million customers. Approximately two-thirds of Ontario customers are served by the eight largest distribution companies.



The regulatory challenge: over 80 distributors varying in size by three orders of magnitude.

In addition to differences in size, Ontario distributors exhibit variation in a number of other characteristics. Some serve densely populated urban areas, others serve less dense suburban or rural areas. Some utility service territories are comprised of a mixture of customer densities.

Costs of distribution vary for a variety of reasons including customer density, age of assets, and degree of under-grounding.

Substantial variation is also present in the age of utility assets, the rate of growth of customer bases, the range of voltage levels at which service is provided, the degree of undergrounding of distribution facilities, the topography, the customer mix and the level of sales per customer.

These, as well as historical factors and accounting conventions contribute to substantial variation in the costs of distribution per customer.

Some may consider that the presence of a multiplicity of utilities creates an unnecessary and avoidable regulatory burden and increases the costs for the industry as a whole. While further voluntary and mutually beneficial amalgamations will in all likelihood occur, driven by economies of scale and scope, the presence of multiple distributors can enhance the potential for efficacious regulation and a highly efficient distribution sector, for example, by providing a statistical basis for intra-jurisdictional comparisons.

C. THREE ALTERNATIVES PROPOSED BY BOARD STAFF

As indicated earlier, the Staff Discussion Paper recommends implementation of an incremental approach that is sustainable, predictable, effective and practical. Using these criteria, Staff evaluated three alternative models:

Regulatory alternatives assessed by Staff.

1. Comprehensive multi-year cost of service.
2. A hybrid, partial index approach.
3. A comprehensive price-cap index approach.

Comprehensive Multi-Year Cost of Service

This approach would require the development of a detailed multi-year plan by each utility followed by regulatory review. The approach would be least risky from the point of view of the utility, but it would exact a significant regulatory burden and would create little in the way of new incentives for cost minimization and efficiency improvements.

On the other hand, since capital plans would also be reviewed as part of the process, it would provide for an orderly capital renewal process for those utilities in need of extensive refurbishment and capital expansion for those experiencing significant growth.

Furthermore, a number of additional issues in need of resolution, such as declining per-customer sales experienced by some utilities, treatment of conservation and demand management programs and smart meter programs could be integrated into the multi-year cost of service analysis.

Cost of service approach addresses a number of distributor diversity issues.

As has been widely recognized throughout the consultation, there is broad variation among distributors with respect to their characteristics, their operating environment, their capital needs and risks. To a large extent, cost-of-service regulation implicitly recognizes this distributor diversity by treating each utility according to its circumstances.

Hybrid Partial Index Approach

Under this approach, OM&A costs would be regulated using an index (such as a price-cap), and capital costs would be regulated using a cost of service approach. Benchmarking of OM&A costs for the purposes of setting appropriate price-caps requires detailed data not only on OM&A expenditures but also on capital.

This regulatory approach creates incentives for distributors to seek larger capital appropriations in order to reduce OM&A expenditures and thereby increase earnings.

The "hybrid approach" is likely the least desirable of the options considered.

In present circumstances, the approach would likely be inferior to "comprehensive multi-year cost of service" and to various other alternatives.

Comprehensive Price-Cap Index

This approach produces the strongest incentives for efficiency gains. In comparison to the other suggested approaches, it is the simplest from an administrative point of view. It also creates the greatest risks for utilities. Moreover, a uniformly applied price-cap rule does not account for diversity amongst distributors.

Some sources of diversity can, in principle, eventually be accounted for through benchmarking processes that adjust for differing characteristics and operating environments. However, there may also be substantial differences among utilities with respect to their capital requirements over the term of the regulatory rule.

The Staff Discussion Paper proposes that some provision be made for incremental capital expenditures, the exact nature and structure of which is yet to be established.

Summary

The Staff Discussion Paper assesses each of these approaches using its evaluation criteria and concludes that price-cap regulation should be a key element of the "core plan". In our view, a suitably designed price-cap mechanism, with proper treatment of future capital expenditures, (e.g., one that includes a K-factor) is the most appropriate alternative for many utilities.

A price-cap approach with proper treatment of capital costs is the preferred approach for many utilities.

Staff has suggested a flexible plan term of three to five years. As the length of the term increases, the utility faces greater risks as a result of unanticipated costs or lower than expected revenues. On the other hand, a longer term provides greater incentive for productivity improvements because the benefits flow to the utility and its shareholders for a longer period of time.

In our view, the proposed three to five year term provides an appropriate balance. Choice of term also provides utilities with a means of mitigating the risks that they face.

D. DISTRIBUTOR DIVERSITY AND THE REGULATORY APPROACH

The Staff Discussion Paper suggests that distributor diversity can be addressed through one or more mechanisms including productivity factors, stretch factors, inflation factors, capital investment mechanisms, earnings sharing mechanisms, off-ramps, menus and modules.[2] These can also be assessed using the four basic evaluation criteria: sustainability, predictability, effectiveness and practicality.

Most of these mechanisms are discussed at various points in this document. In this section we outline our views in relation to the issue of distributor diversity.

"Diversity factors" will contribute to addressing diversity issues.

1. Since expected productivity factors can vary across utilities it is convenient to divide the X-factor into two components: an industry average productivity factor (which is the same for all utilities), and a "diversity factor" which reflects the relative potential for efficiency improvements by individual utilities. In our view, the inclusion of a "diversity factor" of this type is an appropriate part of the long-term vision for incentive regulation in Ontario. [3]

Calibration of "diversity factors" is not yet sufficiently reliable.

2. Calibration of the "diversity factor", however, represents a challenging task. The Ontario Energy Board is presently engaged in a staged consultation process on the comparison and benchmarking of Ontario distributor costs (EB 2006-0268). However, the analyses that have been performed to date suffer from at least one critical deficiency. In particular, Ontario capital data are not yet available over a sufficient period of time to enable one to benchmark total costs. Thus, addressing diversity issues through a diversity factor at this time is problematic.

[2] Staff Discussion Paper, page 34.
[3] For further discussion, see the section 3B entitled "*'Stretch Factors' or 'Diversity Factors'?*".

3. The Staff Discussion paper and the PEG Calibration Report suggest the use of utility-specific "stretch factors". In our view, the inclusion of "stretch factors" is inappropriate. First, theoretical arguments in support of stretch factors advance the view that one should anticipate accelerated productivity growth as one moves from cost-of-service to incentive regulation. The premise however, is not satisfied in that Ontario distributors are now moving into the 3rd generation of incentive regulation. Second, the empirical evidence suggests that measured productivity growth is decelerating, both in Ontario and in the U.S. The deceleration in Ontario may have little to do with efficiency and is more likely driven by increasing conservation mandates, growing regulatory responsibilities and aging infrastructure.[4]

"Stretch factors" which would be added to an industry-wide productivity factor are not an appropriate mechanism for addressing distributor diversity in Ontario.

4. The Staff Discussion Paper proposes an industry-specific inflation factor as part of the price-cap formula. Once a suitable inflation index is developed and assessed, it would constitute an important improvement over the use of broader economy-wide measures of inflation.[5] One could argue further that inflation factors should vary across utilities in order to better reflect distributor diversity. For example, one might consider utility-specific weights for the capital, labour and materials sub-indexes that make up the inflation index. In our view, this level of refinement is premature and that there are more crucial elements of regulatory design that need to be focused upon.

Utility-specific inflation factors may be worthy of consideration in the future.

5. One of the most important of these is the diversity in capital requirements faced by utilities. The Staff Discussion Paper states that, at the time of rebasing, rates "will include provision for capital investment-related amounts as determined by the Board".[6] This will, to a degree, capture some of the diversity in utility capital needs. However, for some utilities, rates which are based upon a single test year may not adequately reflect forthcoming capital expenditures. We therefore recommend that utilities be permitted to submit multi-year plans at time of rebasing and that a K-factor be incorporated in the price-cap formula to accommodate their inclusion. In addition, a capital investment module should be available for incremental capital expenditures. Together, these mechanisms should help to address the capital aspect of the diversity issue.[7]

The inclusion of a utility-specific K-factor would address an important aspect of distributor diversity.

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[4] For further discussion of the proposed "stretch factor", see the section 3B "*'Stretch Factors' or 'Diversity Factors'?*".
[5] For further discussion, see section 3C, "The Inflation Factor".
[6] Staff Discussion Paper, page 17.
[7] For further discussion see section 4, "Capital Investment".

A "menu" approach, though it has some very desirable features, would be premature in Ontario.

6. The Staff Discussion Paper also suggests that menus of regulatory options can assist in addressing distributor diversity. This option was considered during the development of 1st generation incentive regulation in Ontario. Under this approach, utilities selecting more aggressive productivity factors would be allowed higher rate of return ceilings.[8] The "menu" approach to regulation is appealing not only because it can address certain aspects of distributor diversity, it is also potentially more effective, leading to superior societal outcomes. There is strong support for this approach in the theoretical literature.[9] In the U.K., the regulator has adopted this approach in the regulation of electricity distribution.[10] Despite the appeal of a menu approach, it is our view that it is premature to apply it in the Ontario setting.

Permitting the election of a revenue-cap or other regulatory mechanism would provide a useful way of addressing distributor diversity.

7. However, some choice should still be available to utilities. This is consistent with the view of Board Staff:

> "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."[11]

Some utilities, for example those at risk for significant declines in sales volumes (exclusive of conservation program effects) or those with volatile loads that are particularly sensitive to the business cycle, may be disadvantaged under a price-cap approach. Given the precedent that has been set in the regulation of Ontario natural gas distributors – Union Gas is regulated using a price-cap mechanism while Enbridge is regulated using revenue-caps – it would seem appropriate to provide an alternative mechanism, such as a revenue-cap to electricity distributors in certain instances.

Choice of plan term contributes to addressing the distributor diversity issue.

8. We note that providing utilities with a choice of the term of the regulatory plan, (whether it is a price-cap, a revenue-cap or some other mechanism) contributes to addressing the distributor diversity issue.

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[8] See Staff Discussion Paper, pages 36-37 and 63.

[9] See A Theory of Incentives in Regulation and Procurement, J.J. Laffont and J. Tirole, MIT Press, Cambridge, Massachussetts.

[10] Office of Gas and Electricity Markets (2004b), "Electricity Distribution Price Control Review: Final Proposals", 265/04, London.

[11] Staff Discussion Paper, page 2.

E. CAPITAL ISSUES

Capital investments, conducted in a timely and rational manner, are essential to the efficiency, effectiveness and reliability of a capital intensive industry such as electricity distribution. These investments are required to maintain integrity and reliability, to accommodate system growth, to meet evolving environmental and technical standards, and to meet legal and regulatory obligations.

The Staff Discussion Paper has indicated that 3rd generation incentive regulation will incorporate capital investment based on a forward test year:

> "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. As amortization is not a good predictor of future capital expenditure needs, 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 changes in technology and standards)."[12]

Submission of multi-year capital plans at time of rebasing should be permitted.

For some utilities, however, capital expenditures beyond the test year may not be at levels similar to those in the test year. In such circumstances, the option to file a multi-year capital plan should be available.

Given the large number of utilities in Ontario and the substantial variation in their characteristics it would be surprising if the test year were reflective of capital expenditures over the plan term for each of them. The option to file multi-year plans would therefore contribute to addressing the diversity issue.

There are additional advantages to this approach. First, it would reduce dependence on intra-term capital cost approval processes and "off-ramps". Second, it would lead to better capital expenditure profiles and reduce the incentives for "front-end loading" of capital expenditures into test years.

It could be argued that the review of multi-year capital plans will substantially increase the regulatory burden.[13] However, this may not be the case. First,

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[12] Staff Discussion Paper, page 17.

[13] "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." Staff Discussion Paper, page 22.

some, perhaps many utilities will choose to rely on a test-year approach to capital expenditures. Second, the Board is experienced at evaluating capital plans for various segments of the electricity industry and will, in many cases, be conducting a detailed review as part of rebasing. Third, the option to file multi-year capital plans may induce some utilities to seek longer plan terms, reducing the frequency of future regulatory reviews.

A crucial and unresolved issue is the mechanism by which multi-year capital expenditures would be implemented within the price-cap framework. The most appropriate approach would seem to be the direct inclusion of a utility-specific "K-factor" within the price-cap formula.

This approach can be evaluated using the same criteria that have been used to assess other regulatory approaches. Table 1, (which is an augmented version of Table 1, page 43 of the Staff Discussion Paper), contains summary evaluations provided by Staff for the three regulatory options that it considered, along with an evaluation of a fourth option – a "Comprehensive Price-Cap Index With K-Factor". In their analysis, Staff found that the basic "Comprehensive Price-Cap Index Approach" dominated the other two options.

We have assessed the price-cap approach augmented with a K-factor and find this option to be preferable to all those considered by Staff:

According to the evaluation criteria proposed in the Staff Discussion Paper, a price-cap augmented with a K-factor is preferable to the alternatives that were considered.

> *Sustainability:* The K-factor approach is more sustainable in that it can better handle varied circumstances and it achieves greater consistency among distributors.
>
> *Predictability:* Conventional price-caps set the trajectory during the course of the plan. However, between plans, there could be substantial variation as a result of rebasing which would need to reflect changing capital expenditure patterns. The presence of a K-factor would reduce this source of variability because such changes, to the extent that they have been correctly anticipated in the multi-year capital plan, would be incorporated on an ongoing basis. Furthermore, reduced reliance on intra-term capital approval processes should also enhance predictability.
>
> *Effectiveness*: The K-factor approach improves incentives for matching actual capital expenditures to their optimal time profile; for example, the incentives to delay expenditures until the next rebasing and to increase proposed test year outlays are reduced.
>
> *Practicality*: The degree of complexity in establishing the K-factor path is comparable to that involved in rebasing. Utilities could choose to file a test year plan, or a multi-year plan. Additional administrative costs, if a multi-year plan is reviewed, should be modest relative to a conventional price-cap rebasing.

We note that a price-cap mechanism augmented by a K-factor is not equivalent to the "Hybrid Approach" considered by Staff. The most important distinguishing feature is that the capital component of costs is not regulated on a cost-of-service basis as it would be in the Hybrid Approach. Though multi-year capital plans would be reviewed, required efficiency improvements would apply to all costs not just the OM&A component.

Inclusion of an "incremental capital investment module" is appropriate.

However, even with the availability of a K-factor, some utilities may experience the need for unanticipated and substantial capital expenditures during the term of the plan. The Staff Discussion Paper proposes an "incremental capital investment module" which would be treated much like a Z-factor with a materiality threshold of 3% to 5% of net fixed assets.[14] Inclusion of this module is appropriate; however, in our view the materiality threshold should be reduced to 1%-2%. The threshold should be applied to total incremental capital expenditures rather than on a project basis.

[14] Staff DiscussionPaper, page 65.

	Table 1: Summary Evaluation of Four Alternatives[15]			
	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
Comprehensive Price Cap Index Approach With K-Factor	Higher – better able to handle varied circumstances and achieves greater consistency among distributors	Higher – reduced variability between plans and reduced reliance on intra-term capital approval processes and off-ramps	Higher – reduced incentive to delay capital expenditures until rebasing and to increase proposed test year outlays; improved capital expenditure profiles	Medium – similar to that under the "Comprehensive Price Cap Index Approach"

[15] All but the last row of cells in the table are obtained from the Staff Discussion Paper, Table 1, page 43.

3. CALIBRATION OF A PRICE CAP RULE

A. THE X-FACTOR:

Two general classes of methodologies were considered for calibrating the X-factor for Ontario electricity distributors: econometric approaches which estimate a cost function and rely upon the estimated time trend coefficient to calibrate the X-factor; and, indexing approaches which aggregate inputs and outputs across utilities and determine rates of productivity growth from the growth rates of outputs relative to inputs. Each of these two general classes encompasses numerous variants. To a large extent, the most appropriate approach in any given circumstance is dependent upon the nature and quality of the data that are available.

Productivity can be calibrated using econometric or index-based methodologies.

After considering various options, the Pacific Economics Group has proposed that the X-factor be calibrated using an index-based approach. It has further suggested that the X-factor be comprised of two components: an industry productivity factor estimated using U.S. data, and a "stretch factor" based on Ontario data.

The Pacific Economics Group proposes the use of an index-based approach.

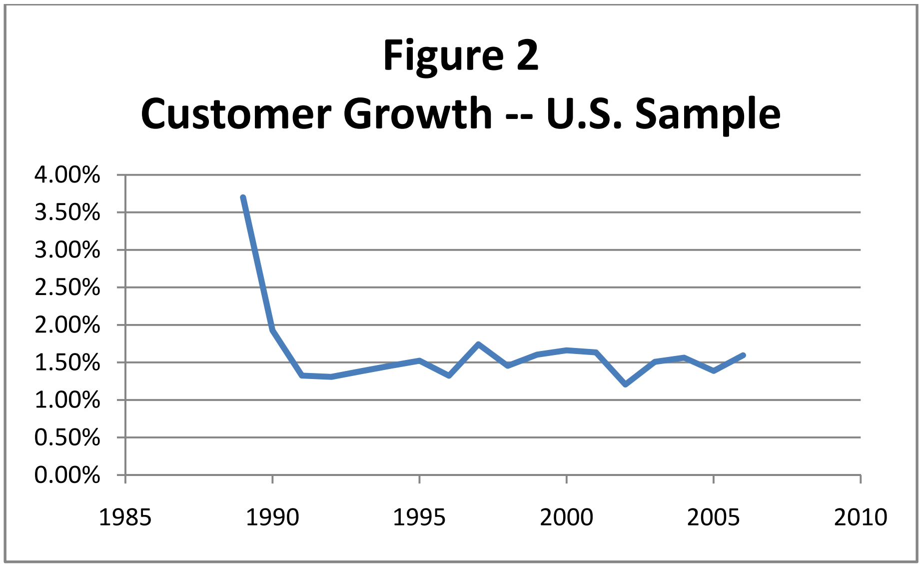
The Pacific Economics Group analysis focuses on two output measures – the number of customers and volume of deliveries. It is important to note that a third output measure – a capacity-related measure – is also relevant since the distributor must stand ready to meet and reliably deliver electricity volumes that vary by time of day, day of week and season. The analysis contained in the PEG Calibration Report is therefore limited to the extent that capacity is not included as part of its aggregate measure of output.

The proposed output measure consists of "number of customers" and "delivery volumes".

INDEX BASED ANALYSIS OF U.S. DATA

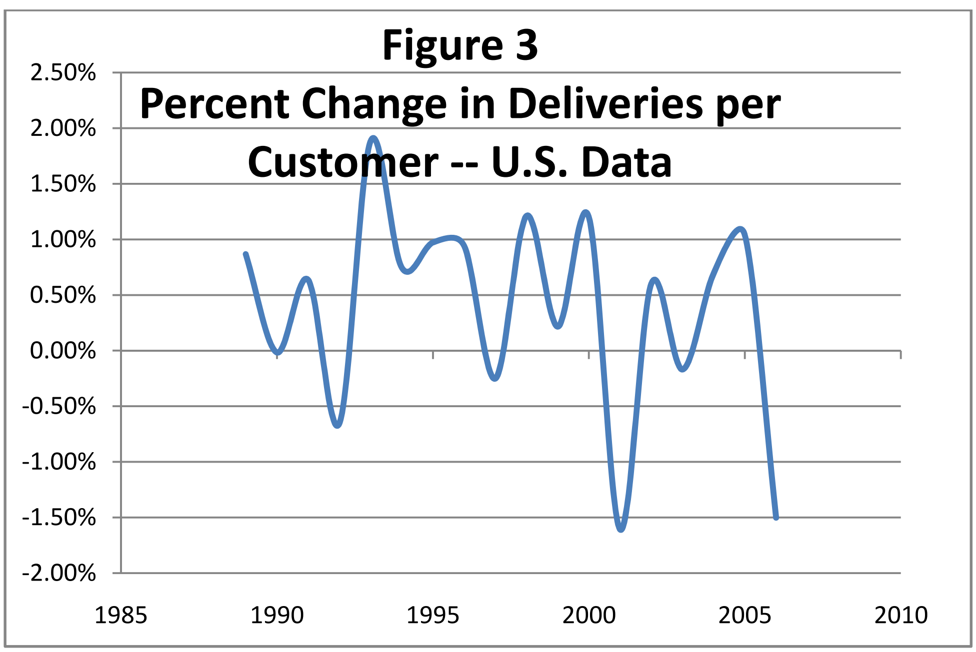
Extensive analysis of data on the distribution operations of 69 U.S. electrical utilities for the period 1988-2006 has been performed by the Pacific Economics Group. During the earliest part of the sample period, customer growth exceeded 3% per year. Following the initial decline in customer growth during the late 1980s and early 1990s, customer growth stabilized at about 1.5% per year. Average growth over the entire period has been 1.61% per year. (See Figure 2.[16])

[16] Source: PEG Calibration Report, page 50, Table 8.



U.S. customer growth steady at 1.5% per year.

Over the same period, deliveries per customer (i.e., kwh/customer) display considerable volatility, largely as a result of economic and weather effects. (See Figure 3.[17]) On average, per customer sales have grown at a rate of 0.37% over the period 1988-2006. The total volume of sales has grown at about 2% per year over the same period.



U.S. deliveries per customer are volatile.

[17] Calculations based on PEG Calibration Report, page 50, Table 8.

A substantial negative growth rate of -1.61% was experienced in 2001, probably as a result of the September 11, 2001 terrorist attacks. However, there was also strong negative growth in 2006 of -1.5%. Over the most recent period, 2002-2006, growth in per customer deliveries has averaged 0.01% per year.

To calculate the aggregated measure of output, PEG applies a weight of 0.63 to "customer numbers" and 0.37 to "kwh deliveries".[18] Figure 4 displays growth in this measure of output. After an initial decline in the late 1980s, the output index grows at an average annual rate of approximately 1.6% per year.

During the sample period labour inputs decline at 1.26% per year, while capital inputs grow at 1.18% annually. At the same time, materials and services grow at about 2.56 % per year. These figures suggest a trend towards greater capital intensity. The decline in labour intensity may be in part as a result of increased reliance on out-sourcing. [19]

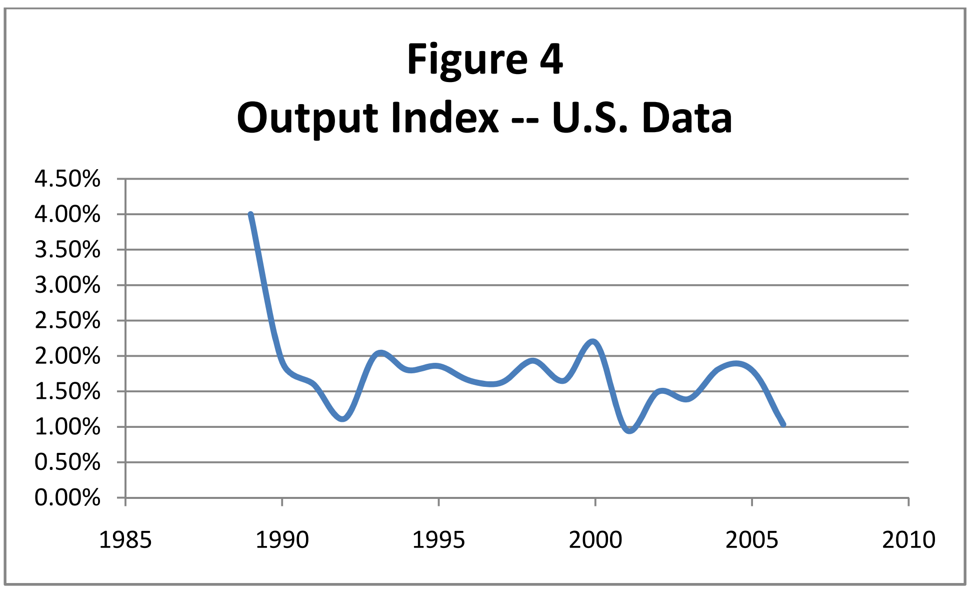


Figure 5 depicts annual total factor productivity (TFP) growth rates in the U.S. sample. Annual growth rates are negative and positive varying in these data in the range -1.5% to close to 2.5%. Average annual TFP growth is 0.72% over the entire period 1988-2006. Moreover, visual inspection suggests no systematic trend in TFP growth.

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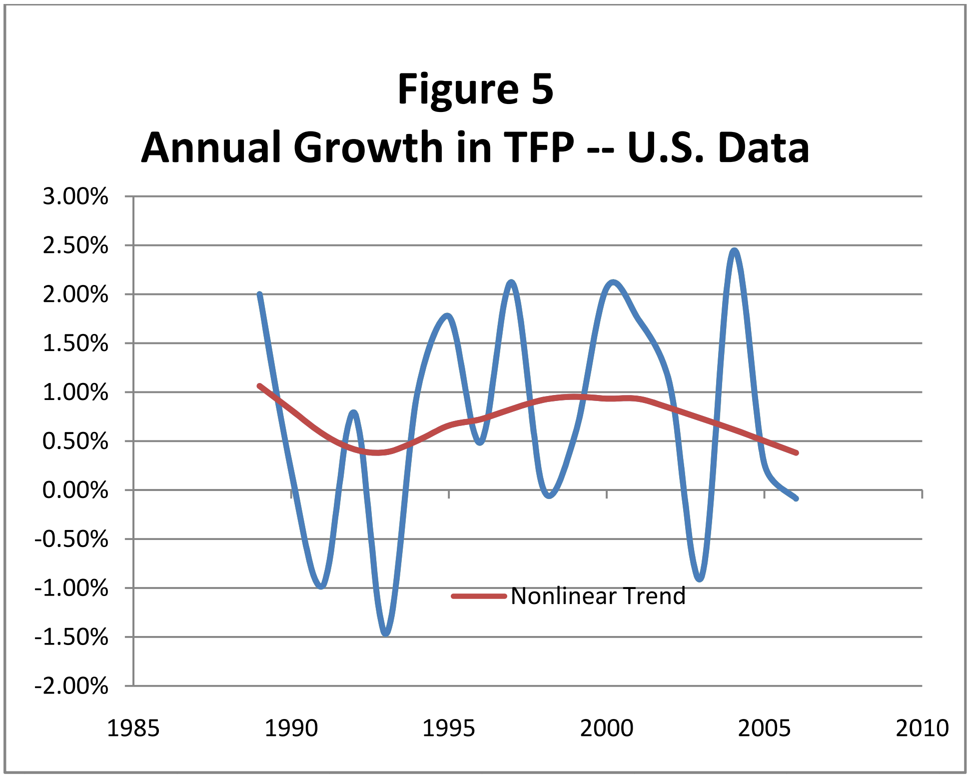
[18] PEG Calibration Report, page 54.
[19] PEG Calibration Report, page 51, Table 9.

Four important features of the U.S. sample data:

1. *Average productivity growth is 0.72%.*
2. *There is no evidence of a linear trend effect.*
3. *There is evidence of a nonlinear trend effect which varies between 0.4% and about 1%.*
4. *The most recent data suggest a period of deceleration.*



A simple regression of annual productivity growth rates for 1988-2006 on a time trend term yielded a coefficient that is statistically insignificant suggesting no systematic linear drift in productivity.[20] Indeed, the proportion of variation explained by a linear trend term (i.e., the R^2) is negligible.

However, the absence of a linear trend effect does not preclude the possibility that more recent data have greater relevance for short-term forecasting because there may be a nonlinear trend, cyclical or other effects present in the data.

Figure 5 displays the results of a flexible estimation procedure designed to give greater weight to data that are proximate in time when estimating expected levels of TFP growth. During the earliest years of the sample period, expected productivity growth is close to 1% per year. This

[20] For the model $\%TFP\ growth = \beta_0 + \beta_1 Year + \varepsilon$, the estimates were as follows:

Coefficients:	Value	Std. Error	t value	Pr(>|t|)
Intercept	-38.481	107.667	-0.357	0.725
Year	0.020	0.054	0.364	0.721

Multiple R-Squared: 0.00822

decreases to less than 0.5% during the early 1990s then increases to about 1% around the turn of the century. It then declines to a value of about 0.4% in 2006.[21] One of the possible reasons for this recent decline in the U.S. data is increased pension contributions.[22]

The nonlinear trend effect model that was estimated captures about 18% of the total variation in annual TFP growth over the period (in comparison to the linear time trend model which captures less than one percent of the variation).

Table 2 provides more detailed information on the input and output indexes as well as the TFP index over the sample period. As indicated earlier, the productivity factor over the longest period for which U.S. data have been available, averages 0.72% per year. Absent consistent Ontario data, this figure would seem to be an appropriate long term target at this time.

DECELERATING PRODUCTIVITY GROWTH

Ontario distributor data suggest decelerating productivity growth in recent years.

Consistent with productivity growth patterns in the U.S. electricity distribution data, TFP growth in Ontario during recent years has also been slow. For the period 2002-2006, productivity growth amongst Ontario distributors has been 0.01% per year.[23]

[21] The estimator that was implemented was the "super-smoother" which is a refinement of a "moving average estimator". However, rather than fitting a mean involving say "k" adjacent observations, one performs least squares. For more details see "A variable-span smoother, "Friedman, J.H. & Stuetzle, W. (1984), Technical Report No. 5, Department of Statistics, Stanford University. The estimator can be implemented directly in S-Plus software using the function "supsmu". Similar results were obtained using a "local polynomial" estimator. See *Local Polynomial Modelling and Its Applications*, J. Fan and I. Gijbels, Chapman & Hall, 1996.

[22] "I can say one thing, though, about 2002 through 2006. One thing that's definitely happening for utilities in the US, maybe in Canada, too, is pension contributions. Companies -- because of the stock-market boom in the '90s, a lot of companies conserved on pension contributions. They weren't making them, because they didn't have to. That obviously changed in early 2000. So there has been a big increase in pension contributions. That's a cost that companies are kind of catching up on. They under-funded pensions in the '90s. Now they're catching up on that. And that's the sort of thing that you would pick up in a multi-year or ten-year plan, but if you just looked at, say, a four- or five-year period, it may not be reflected."Dr. Kaufman, Transcripts of Stakeholder Meeting, Ontario Energy Board, March 25, 2008, pages 73-74.

[23] PEG Calibration Report, page 54.

There are a variety of possible reasons for these low recent productivity growth rates in Ontario. They include changing and expanding service mandates for distributors, aging infrastructure, and expanding regulatory requirements.

Are the factors contributing to decelerating productivity growth likely to abate or to reverse themselves?

A central question is whether these factors are likely to abate or reverse themselves over the upcoming regulatory period. In Ontario, Provincial Government policy is driving the expansion of conservation and demand management programs requiring additional capital expenditures, as well as additional labour and materials resources. At present it is anticipated that these policy directions will continue on course and perhaps increase in momentum as global warming issues become more prominent in policy agendas. For many distributors, refurbishment of aging infrastructure is expected to continue, particularly after many years of underfunding. In addition, distributors face increasing retirements which will put upward pressure on training and apprenticeship program costs.

The Pacific Economics Group has proposed a figure of 0.88% per year basic productivity factor for Ontario distributors. In arriving at this conclusion, PEG analysed various sub-periods illustrated in Table 3 and concluded that the period 1995-2006 is the most appropriate for estimating long-term TFP trends. The statistical methodology that was employed was designed to "select a start date where economic and weather conditions are as similar as possible to those that prevailed in 2006". [24]

One of the considerations in coming to a determination on the productivity growth rate is to select a sample period that does not include data so distant in the past to bear little relevance to present circumstances. In particular, the PEG Calibration Report states at page 60:

> "As previously discussed, when selecting an appropriate time period for measuring long-run TFP trends, it is important for TFP to be estimated over a period that is long enough to balance the year-to-year fluctuations in TFP change. At the same time, the sample should not be so long that it includes information that is "stale" i.e. conditions in the distant past rather than recent TFP developments. In most regulatory proceedings, a sample period of about 10 years has been viewed as providing a reasonable balance of these two considerations."

[24] PEG Calibration Report, pages 61-63.

TABLE 2. PRODUCTIVITY RESULTS: U.S. SAMPLE				
Year	**Output Quantity Index**	**Input Quantity Index**	**TFP Index**	**Annual Growth in TFP**
1988	1	1	1	
1989	1.040	1.020	1.020	2.00%
1990	1.060	1.037	1.022	0.20%
1991	1.077	1.064	1.012	-0.98%
1992	1.089	1.068	1.020	0.79%
1993	1.111	1.106	1.005	-1.47%
1994	1.131	1.114	1.015	1.00%
1995	1.152	1.115	1.033	1.77%
1996	1.171	1.128	1.038	0.48%
1997	1.190	1.123	1.060	2.12%
1998	1.213	1.145	1.060	0.00%
1999	1.233	1.157	1.066	0.57%
2000	1.260	1.158	1.088	2.06%
2001	1.272	1.150	1.107	1.75%
2002	1.291	1.153	1.119	1.08%
2003	1.309	1.181	1.109	-0.89%
2004	1.333	1.173	1.136	2.43%
2005	1.357	1.191	1.139	0.26%
2006	1.371	1.205	1.138	-0.09%
Average Annual Growth Rate	**1.75%**	**1.04%**	**0.72%**	

TABLE 3: Average Annual Growth Rate			
	Output Quantity Index	**Input Quantity Index**	**Annual Growth in TFP**
1988-2006	1.77%	1.04%	0.73%
1989-2006	1.64%	0.99%	0.65%
1990-2006	1.62%	0.94%	0.68%
1991-2006	1.62%	0.83%	0.79%
1992-2006	1.66%	0.87%	0.79%
1993-2006	1.63%	0.66%	0.97%
1994-2006	1.62%	0.66%	0.96%
1995-2006	1.59%	0.71%	0.88%
1996-2006	1.59%	0.66%	0.93%
1997-2006	1.59%	0.79%	0.80%
1998-2006	1.54%	0.64%	0.90%
1999-2006	1.53%	0.58%	0.94%
2000-2006	1.42%	0.67%	0.75%
2001-2006	1.51%	0.94%	0.57%
2002-2006	1.51%	1.11%	0.41%
2003-2006	1.55%	0.67%	0.88%
2004-2006	1.42%	1.35%	0.06%
2005-2006	1.03%	1.18%	-0.14%

As illustrated in Figure 5, our analysis of the U.S. data suggests that there is evidence of slowing productivity growth in recent years. If, as PEG argues, data in the distant past are less relevant for predicting forthcoming productivity growth rates, then more recent data should be more relevant. Given that growth has been decelerating and well below long term averages, then the 0.88% figure proposed by PEG, and even the long term 0.72% U.S. productivity growth rate is too high as a forecast of forthcoming rates in the near-term.

We note that the Ontario Energy Board, in its 1st Generation IRM decision, placed additional weight on the most recent Ontario experience. In setting the productivity factor, the Board used the 10 year growth rate of 0.86% for the period 1988 to 1997, but gave additional weight to the 1993-1997 sub-period, during which time distributor productivity grew at 2.05%. The assigned productivity factor of 1.25% was calculated as follows: 1.25% ≈ ⅔ 0.86% + ⅓ 2.05%.

Board determined in 1st Generation IRM that most recent productivity growth patterns should receive additional weight.

Applying similar reasoning to present data, that is, assigning greater weight to the most recent experience, yields an expected productivity factor materially below the proposed level of 0.88%. For example, if one takes 0.72% as the best estimate of long term productivity growth and combines it with the Ontario figure of 0.01% over the period 2002-2006 then the resulting productivity factor would be 0.49% ≈ ⅔ 0.72% + ⅓ 0.01%, a figure that is consistent with the most recent expected productivity growth rate in the U.S., (see Figure 5). Even using the long-term figure proposed by the Pacific Economics Group of 0.88% and recent Ontario growth, one obtains 0.59% ≈ ⅔ 0.88% + ⅓ 0.01%.

In summary, our review of the statistical evidence indicates that the base productivity factor of 0.88% suggested by the Pacific Economics Group is an overestimate of the productivity growth that we can expect in Ontario during the forthcoming regulatory window. U.S. data indicate a productivity slowdown in electricity distribution in recent years.[25] Recessionary affects are not likely to ameliorate this trend.

In Ontario, increasing emphasis on conservation and demand management and aging infrastructure effects are likely to continue. Nor is Ontario immune to the effects of a U.S. recession. Taking these various factors into consideration it is our view that a reasonable target for industry average productivity factor is in the 0.5% to 0.6% range.

A reasonable range for the industry average productivity factor is 0.5% to 0.6%.

[25] The productivity slowdown in the U.S. data during the early 1990s was in part related to recessionary effects. See Figure 4.

B. "STRETCH FACTORS" OR "DIVERSITY FACTORS"?

ABSENCE OF RATIONALE FOR A STRETCH FACTOR

Stretch factors and acceleration in productivity growth.

"Stretch factors" have been rationalized on the basis that a utility should experience "accelerated productivity growth" as one transitions from cost-of-service to incentive regulation. This point is made several times in submissions by the Pacific Economics Group: For example,

> "The other major component of the X-factor is the consumer dividend (also called the productivity "stretch factor"). Incentive regulation is designed to create stronger performance incentives compared with traditional cost of service regulation, and these enhanced incentives should lead to more rapid TFP growth."[26]

In each case the "stretch factor" is linked to a transition from cost-of-service regulation to incentive regulation.

However, Ontario distributors have been under a form of price-cap regulation for an extended period of time. Thus, the rationale for its inclusion is not present.

Nevertheless, the Pacific Economics Group has recommended that a stretch factor be added to the base productivity factor of 0.88%. The proposal is to calibrate the stretch factor using Ontario data where each utility would be assigned a value ranging from 0 to 0.6% depending on an assessment of its relative efficiency. The resulting productivity factors would therefore lie in the range 0.88% to 1.48%. The weighted average X-factor would be 1.16%.[27]

Pacific Economics Group is proposing an industry average X-factor of 1.16%.

We note that an industry X-factor of 1.16% over a multi-year period is outside the range of expected productivity growth rates observed in the U.S. during the entire 1988-2006 period. As can be seen in Figure 5, expected productivity growth fluctuated in the range 0.4% to just over 1.0%.

[26]PEG Calibration Report, page 5. Similar positions are expressed at page 12-13 and in footnote 10 at page 19. See also "Econometric Benchmarking of Cost Performance: The Case of U.S. Power Distributors", by Mark Lowry, Lullitt Getachew and David Hovde, The Energy Journal, Vol. 26, 2005, pages 75-92. The following statement appears at page 88: "The X factor reflects industry productivity growth plus a stretch factor that is intended to reflect a company's potential for accelerated productivity growth."

[27] PEG Calibration Report, Table 20, page 81-82.

Before proceeding, some comments on the notion of a "consumer dividend" are appropriate. As one moves from cost-of-service regulation to incentive regulation, it is reasonable to expect acceleration in productivity improvements. Fairness in regulation requires that the resulting benefits be shared by consumers and producers alike, hence the incorporation of a "stretch factor".

Consumer dividends and stretch factors.

However, even if a stretch factor is not justified and therefore not included, the benefits of incentive regulation continue to flow. First, the presence of an X-factor implies that cost savings from not-yet-realized efficiency improvements will be shared with consumers during the regulatory window. That is, cost savings are shared on a *prospective* basis. Second, upon rebasing, consumers gain the benefits of the realized cost savings in perpetuity.

Finally, "consumer dividends" could also take the form of an earnings sharing mechanism, though these have the undesirable feature that they tend to reduce the power of incentives for efficiency improvements. However, in the event that one is implemented, it should be symmetrical.

Earnings sharing mechanisms are another form of consumer dividends.

THE "DIVERSITY FACTOR"

Although the evidence does not support inclusion of a stretch factor, it may be appropriate to incorporate a "diversity factor" as part of assigned productivity improvements. Given a population of over 80 electricity distributors, there is likely some degree of variation in their relative productivities and therefore also in their potential for cost savings. Ideally one would like to assign individual productivity factors, or alternatively to adjust the industry average X-factor with positive and negative diversity factors reflecting each utility's potential for productivity improvements.

Ontario distributors vary widely in terms of their characteristics, their operating environments and the business conditions which they face. These need to be taken into account in order that fair comparisons of relative efficiency can be made. Indeed, this has been the central objective of the PEG Benchmarking Report.

Although the March 2008 PEG Benchmarking Report contains some important and useful improvements relative to the April 2007 version, the benchmarking analysis continues to have major shortcomings which limit its usefulness in the assignment of individual productivity factors. Most important of these is the absence of capital from the model.

Benchmarking analysis is not yet sufficiently reliable to justify its use in assigning diversity factors.

As a result, the benchmarking work analyzes OM&A costs rather than total costs. However, without capital data, calibration of OM&A costs is problematic since utilities may have higher OM&A costs as a result of the levels or characteristics of their capital inputs, rather than lower efficiency.[28]

We note also that utilities cannot verify the statistical analyses upon which they are judged because of confidentiality issues.

We therefore recommend a sequence of two steps:

> Step 1: the exclusion of a "diversity factor" until significantly better benchmarking data become available; in the interim, a common X-factor between 0.5% and 0.6% would be assigned to all distributors.
>
> Step 2: after estimates of relative efficiencies of distributors are found to be sufficiently reliable, the inclusion of "diversity factors" ranging from say -0.3% to +0.3%. Combining these with an industry average productivity factor of say 0.5% would result in X-factors which range from 0.2% to 0.8%.

In summary, though the evidence does not support inclusion of a stretch factor, a "diversity factor" which reflects relative efficiencies of distributors is an appropriate part of the long-term vision for incentive regulation in Ontario. However, their inclusion at the present time would be premature.

C. THE INFLATION FACTOR

The 2nd generation incentive regulation mechanism relied upon a broad measure of inflation, the "Gross Domestic Product Implicit Price Index", (GDP-IPI-FDD). This series enjoys at least two important advantages: it is directly accessible, not requiring computation or judgment on the part of the regulator; and, it is relatively stable, varying in a narrow range around 2% since the year 2000. [29]

[28] For further discussion, see, for example, Review of "Benchmarking The Costs of Ontario Power Distributors Pacific Economics Group, April 25 2007", prepared for the Electricity Distributors Association, A. Yatchew, June 26, 2007, http://www.oeb.gov.on.ca/documents/cases/EB-2006-0268/eda_peg-comments_20070704.pdf .
[29] See Staff Discussion Paper, Table 3, page 57.

However, it also has the important limitation that it may not reasonably reflect the cost pressures experienced by distribution utilities. The distribution business is very capital intensive with the most recent estimates provided by the Pacific Economics Group suggesting that 63% of costs are capital related, 26% are labour related and 11% are for materials.[30] Thus, as interest rates rise, cost pressures increase at a faster rate than in other less capital intensive industries. Even a modest increase in interest rates from 4% to 5% will eventually lead to a 25% increase in the interest cost of debt.

Broad measures of inflation may not track cost pressures of a capital intensive industry such as electricity distribution.

As a result, consideration is being given to an industry-specific inflation factor. Staff has put forth an approach to implementing such an index as follows:

$$IPI = \left(w_k \times P_k\right) + \left(w_l \times P_l\right) + \left(w_m \times P_m\right)$$

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 capital weight in the index; w_l is the labour weight in the index; and w_m is the materials weight in the index. The Capital Price Sub-Index at time t is calculated as:

$$PK_t = \left(r_t + d\right) \times CAP_t$$

where r_t is an average risk-free interest rate; d is the depreciation rate (assumed to be 5.67% per year); and CAP_t is the price of capital. Staff has suggested specific data series which permit implementation of the three sub-indexes.[31]

Figure 6 illustrates the growth rates of each of the three component sub-indexes since the late 1980s. By far the most volatile – and the one which comprises the largest share of costs – is the Capital Price Sub-Index which varies between -7% and +12% over the period. This is a result of substantial variation in both interest rates and the distribution capital construction price index.

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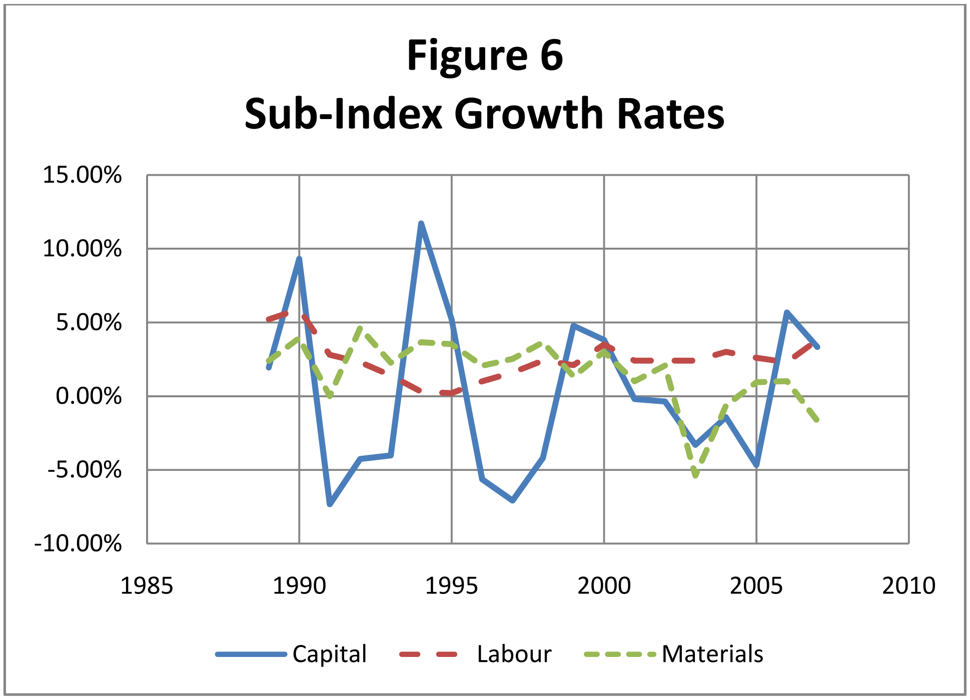
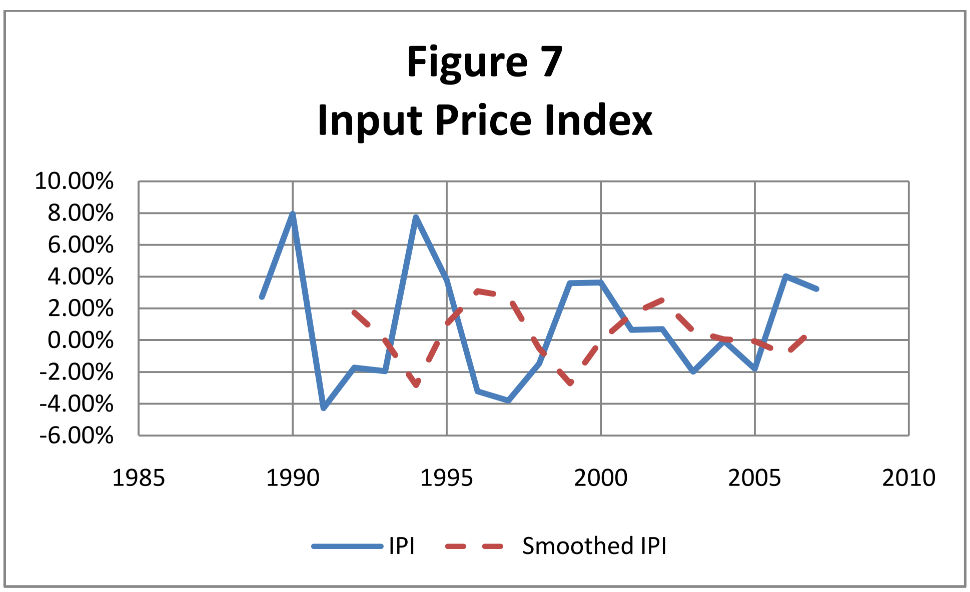
[30] Staff Discussion Paper, Table 2, page 52.
[31] Staff Discussion Paper, pages 46-59.



Capital sub-index is highly volatile.

Using the cost shares estimated by the Pacific Economics Group, Staff has calculated an Industry Specific Input Price Index (IPI) which is illustrated in Figure 7.



As a result, the industry-specific input price index is also highly volatile.

Not surprisingly, this index inherits the volatility of the capital price index, which is its largest component. In an effort to reduce the volatility of this index, Board Staff have calculated a "smoothed" version which first takes a three-year moving average of the Capital Sub-Index. The resulting "Smoothed Input Price Index" (Smoothed IPI) displays significantly less volatility as may be seen in Figure 7. In addition the "troughs" and "peaks" of the smoothed series are shifted forward relative to the original IPI.

One might ask whether smoothing of the series is necessary or desirable. On the one hand, reductions in volatility lead to better predictability of the inflation factor. On the other hand, smoothing can delay recovery of costs or cause higher electricity rates than are justified based on inflationary pressures.

More important than the smoothing issue is whether the component sub-indexes are reflective of actual cost pressures. In this regard, the Capital Price Sub-Index, in particular, is the most problematic.

> First, it relies on current capital acquisition costs. The physical capital in the electricity distribution industry is long-lived, as reflected by the low depreciation rate, and its cost is therefore a function of a relatively long time-series of capital acquisition costs.
>
> Second, the index implicitly assumes that debt is being refinanced every year. In fact, utilities typically hold a substantial quantity of long-term debt obligations and only a relatively small portion of the portfolio turns over in any given year.
>
> Third, the volatility itself suggests that the index is not reflective of the cost pressures faced by utilities. Our experience with utilities suggests that they do not face the kinds of *year-to-year fluctuations* in cost pressures that are inherent in this index.

It would seem appropriate, therefore that further investigation be conducted.

Finally, in our view, it would be useful to gather utility-specific wage data for Ontario distributors rather than relying exclusively on external databases. This would provide not only an indication of the actual labour cost pressures faced by utilities, but could also be incorporated in the "diversity factor" if there is material variation in distribution industry wages and salaries across the Province.

4. CONCLUDING REMARKS

The Staff Discussion Paper and the PEG Calibration Report together represent an important milestone in the development of a sustainable, predictable, effective and practical approach to 3rd generation of incentive regulation of Ontario distributors. Both documents contain much thoughtful analysis and useful empirical results that inform the present consultative process. Reliance on careful empirical analyses is essential to an objective approach to regulation.

The Executive Summary at the commencement of these submissions on behalf of the Electricity Distributors Association outlines our observations and recommendations in detail. In the present concluding section we will focus on a few of the most essential recommendations.

A core regulatory model based on a price-cap formula is sensible and it provides the strongest incentives of the models that were considered. It is predictable, effective and practical. If properly calibrated it is sustainable. A three to five year term is appropriate. We note that the term of the plan may be altered if a utility acquires or merges with another.

One of the important ways in which individual Ontario utilities differ from each other is in their forthcoming capital requirements. In order to better take account of these we believe that utilities should be able to file multi-year financial and capital plans at the time of rebasing. In our view, the most appropriate way to incorporate multi-year capital plans within the price-cap rule is through a K-factor.

In addition, during the course of the plan term, utilities should be able to apply for relief in the event that they require additional capital investments beyond what was anticipated at time of rebasing. The application should be subject to a materiality threshold.

However, even a price-cap approach, augmented by a K-factor, may not be suitable for every utility. In such cases, a utility (or a group of utilities) should have the option of applying to the Board to have its rates set according to an alternative plan, such as a revenue-cap.

Calibration of the price-cap rule should be based on the best available data and empirical analysis. The PEG Calibration Report recommends an average industry-wide X-factor of 1.16%. This is outside the range of expected productivity factors for the entire period upon which the empirical analysis is based. The empirical evidence that has been adduced supports an average industry productivity factor in the range of 0.5% to 0.6%.

Part of the reason that the Pacific Economics Group is recommending the higher value is that it proposes to include within the X-factor a stretch component which is intended to capture acceleration in productivity growth as one moves from cost of service regulation to incentive regulation. Ontario distributors have been under incentive regulation for an extended period of time, so that a stretch factor is not justified. Moreover, productivity growth has been decelerating in both Ontario and the U.S. in recent years. Thus, neither theoretical arguments nor empirical evidence supports the inclusion of a stretch factor.

There may be a temptation to include a stretch factor because it is being added elsewhere or, in its absence, to "pump up" the productivity factor. **The determination of a productivity factor should not be prejudiced by those that have been *imposed* elsewhere, but rather informed by productivity factors that have been actually *observed*.** Average productivity factors based on the observed U.S. data have been in the range 0.4% to about 1.0%. In recent years, they have been at the lower end of this range, hence our earlier recommendation of an X-factor between 0.5% and 0.6%.

Although the evidence does not support the inclusion of a stretch factor, a utility-specific "diversity factor" is an appropriate part of the long-term vision for incentive regulation in Ontario. The diversity factor should be centered at the industry average productivity factor.

The benchmarking analysis that is being performed by the Pacific Economics Group is valuable and should be continued. As a result of that analysis, we now have a much better understanding of the deficiencies in the data and how they should be remedied. However, the absence of capital data limits the usefulness of the resulting efficiency rankings for purposes of establishing diversity factors for individual utilities.

This deficiency in Ontario distributor capital data also limits our ability to estimate long-term industry-wide productivity targets for Ontario. Development of better historical Ontario data would substantially ameliorate these shortcomings and should be undertaken.

Finally, an industry-specific inflation factor could provide an improvement over the broader measures of inflation. However, additional analysis needs to be performed to determine an appropriate implementation methodology and to assess its effectiveness in tracking the actual cost pressures experienced by utilities.

APPENDIX –AUTHOR QUALIFICATIONS

PROFESSOR ADONIS J. YATCHEW, B.A., M.A., PH.D.

Since receiving his Ph.D. from Harvard University in 1980, Adonis Yatchew has been a member of the Economics Department at the University of Toronto. He has also taught at the University of Chicago and a Visiting Fellow at Trinity College, Cambridge. He has received the social science undergraduate teaching award at the University of Toronto.

His principal areas of research are theoretical and applied econometrics and energy and regulatory economics. From 1995-2005 he was Joint Editor of *The Energy Journal*. Since 2005, he has been Editor-in-Chief of *The Energy Journal.*

Professor Yatchew has prepared numerous analyses and studies of the electricity industry. He has prepared short term market assessments and forecasts of the cellular telephone industry; coauthored studies on oil pipeline cost allocation; and been involved in studies or analyses of the natural gas, gasoline and airline industries, among others.

His publications include:

Yatchew, A., 1995, "The Distribution of Electricity on Ontario: Restructuring Issues, Costs and Regulation", *Ontario Hydro at the Millennium*, University of Toronto Press, 327-342,353-354.

Waverman, L. and A. Yatchew, (1996), "The Regulation of Electricity in Canada", in *International Comparisons of Electricity Regulation*, R. Gilbert and E. Kahn, editors, Cambridge University Press, 366-405.

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Hall, Peter and A. Yatchew, 2007, “Nonparametric Estimation When Data on Derivatives are Available”, *Annals of Statistics*, 35:1, 300-323.

His recent book entitled *Semiparametric Regression for the Applied Econometrician*, Cambridge University Press, 2003, contains a number of applications to energy economics.