Defining and Measuring Performance of Electricity Distributors
(EB-2010-0379)

Electricity Distributors Association

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September 25, 2013

Preface

The distributor rate-setting mechanism that the Board implements through this initiative will significantly impact ratepayers, distributors, and other stakeholders throughout the Province. It will be critical for promoting regulatory efficacy and efficiency, for stabilizing rate changes and for ensuring the sufficiency of funding of critical infrastructure.

This initiative comes at a difficult time for the sector. Irrespective of the broader societal benefits, the Province of Ontario's policy priorities of green energy, conservation and smart grid technologies put upward pressure on the electricity bill. These changes have also led to cost pressures for distributors which deliver many of these policies and programs. The Board, ratepayers, distributors, and other stakeholders share concern for minimizing electricity rates, including distribution rates.

To balance the full spectrum of interests it is essential that the forthcoming incentive rate mechanism be based on realistic and empirically supported assessments of costs in the distribution segment of the sector.

The analysis of productivity and performance can be of a highly technical nature. In order to contribute to the discussion, without sacrificing precision, we have attempted to describe the central threads of the analysis in the main document, and to relegate technical details to Appendices.

EXECUTIVE SUMMARY

Summary of Observations and Recommendations

A. We have estimated the productivity factor using two methodologies – an index based approach, and a cost based approach. The resulting estimates are both approximately -0.8%, indicating *significant upward cost pressures in the industry*. We emphasize that our estimates are based on all available data. The exclusion of the two largest distributors does not materially change our results.

B. In our view, the Pacific Economics Group (PEG) recommendation that the productivity factor be "no lower than zero" does not adequately take into account evolving cost patterns in the electricity distribution industry. As noted by the Pacific Economics Group, negative productivity factors are not unprecedented in other regulatory settings. Furthermore, as submitted by Power Systems Engineering on behalf of the Coalition of Large Distributors, the assignment of a zero productivity factor in circumstances where the estimated value is significantly and materially negative, implicitly builds in a positive stretch factor.

C. Ontario distributors have been under incentive regulation for many years during which there have been sustained efforts to drive out inefficiencies. We believe it is time to start rewarding efficiency, and that therefore stretch factors should range from -0.3% to +0.3%. Yardstick competition, which is a fundamental rationale for differentiated treatment of distributors, does not require positive 'stretch factors'.

D. Estimation of relative efficiencies is difficult and subject to considerable risk of misclassification. Even minor model variations can lead to migration of distributors from one efficiency cohort (or tranche) to another. There are also a number of unresolved data issues which could result in unfair penalization of certain distributors.

E. The allocation to efficiency cohorts proposed by the Pacific Economics Group places a disproportionate number of distributors in the two highest stretch factor groups (26 and 17 respectively) and very few in the two lowest groups (5 and 7). Furthermore, the demarcations between cohorts in some cases combine distributors with widely disparate efficiency ranking. For example, the cohort with the highest proposed stretch factor has distributors with 'actual minus predicted costs' ranging from 15% to 73%.

F. We propose demarcation lines between tranches as follows. This allocation mitigates risks of unfairly penalizing distributors due to modeling or data deficiencies.

Tranche	**Relative Cost Performance**	**Number of Distributors in Tranche**
One	Actual costs are at least 15% below predicted costs	13
Two	Actual costs are between 0% and 15% below predicted costs	21
Three	Actual costs are between 0% and 15% above predicted costs	24
Four	Actual costs are between 15% and 30% above predicted costs	9
Five	Actual costs are more than 30% above predicted costs	6

G. The Board initially considered an industry-specific inflation. However, because of the high capital intensity in the electricity distribution industry, even modest changes in interest rates could lead to a high degree of volatility. The Board is now proposing a 2-Factor Inflation Price Index (IPI), comprised of a labour price index, and a broad non-labour price index. We are supportive of the Board's move to a broader measure of inflation. Two concerns remain. First, since capital cost changes are no longer directly included, there may, in the future be a divergence between the proposed inflation measure and capital related cost pressures experienced by distributors. It will be important to ensure that, were this to occur, suitable measures so that distributor revenues are not unreasonably constrained. Second, the labour price index is weighted towards non-union labour, whereas electricity distribution in Ontario relies to a substantial degree on highly skilled unionized labour. It would seem reasonable therefore to implement a labour price sub-index that assigns a substantially higher weight to increases in costs associated with unionized labour.

H. In past submissions we have argued that peer group analysis, as implemented, is contentious and unlikely to contribute productively to the assignment of distributors to efficiency cohorts. We support the Board’s decision to set aside the use of Peer Group analysis at the present time.

I. The analyses and empirical work described in this report have been conducted within a relatively short time-frame. Even during the course of these proceedings, input data have been changing and a number of distributors have raised issues with the data that have been incorporated. Some data issues remain unresolved. We recognize that data development is an ongoing project, and in part for this reason we believe that differentiation of performance must be done cautiously.

Background

The Ontario Energy Board regulates approximately 75 electricity distributors. Over the course of several years, the Board has been engaged in a consultative process with the objective of renewing its regulatory framework and developing a 4th Generation Incentive Regulation Mechanism.

Since the 2008 '3GIRM' proceeding, the Board, stakeholders and distributors have implemented important steps to improve the efficacy and efficiency of the regulatory process. These include the development of detailed Ontario distributor data (previously, U.S. data were used to inform the selection of the productivity factor). The process has required a massive data development effort. The use of Ontario data is even more important now as Ontario's electricity policies (in particular, the implementation of FIT programs) diverge from those in the U.S. The data assembled through the Board's current process also permits total cost benchmarking, rather than benchmarking based on OM&A data, as was the case in the 2008 proceeding. There has been further development price indexes and the provision of multiple rate-setting options to distributors.

The present report focuses primarily on the methodology and empirical work in support of 4GIRM, on the empirical analyses conducted by the Pacific Economics Group (PEG), as well as on the Draft Report of the Board, September 6, 2013.

Productivity Analysis

There are two widely studied methods for measuring productivity growth. In broad terms these may be characterized as follows:

- Index based approaches, which compare rates of growth of inputs to rates of growth of outputs.

- Cost based approaches, which focus on the estimation of technology driven cost trends and scale effects.

Properly implemented with suitable data, the two should lead to similar results. Wide differences require reconciliation. The two approaches are related as follows:

Productivity Growth = Output Growth – Input Growth = Technology Effects + Scale Effects

The first approach is appealing in part because of its interpretation. For example, if inputs are growing at a rate of 2% and output is growing at 3%, then productivity is growing at 1%.

The second approach also affords an intuitive interpretation. For example, if real costs are trending downward at 0.8% and scale economies are generating an additional reduction of 0.2% per year, then productivity is again growing at 1%. The cost-based approach is also appealing because it permits the attribution of cost changes to specific causative factors.

One usually thinks of "technology effects" as inexorably leading to lower unit costs, but that is not necessarily the case, especially when new, evolving technologies are being introduced. For example, the adoption of renewable electricity and smart grid technologies has led to increases in electricity costs. Demand management programs which slow demand growth, may in turn reduce potential gains from scale economies, at least in the medium term. Over time, as technology and the policies and processes associated with it stabilize and mature, cost savings may be realized.

It has been argued that index modeling is 'more transparent' than cost modeling. The appropriateness and accuracy of index modeling relies on a host of assumptions that are critical to its validity. Furthermore, certain key coefficients estimated in the cost model are used to calibrate the index model. Therefore, one cannot be satisfied that the index model findings are valid without having faith in the underlying cost model upon which it relies.

We appreciate that the Board has settled on the index approach for calculating productivity. That determination does not specify the particular variant of the index approach that is to be implemented, which observations should be given greater or lesser weight, and which should simply be excluded from the analysis. Nor does the Board's determination preclude the Board from seeking to understand anomalies arising out of widely different results using each of the two approaches.

Productivity Estimates

We have estimated productivity growth using each of the above two methodologies. The index-based and cost-based calculations both yield values of approximately -0.8%. That is, unit costs have been *rising* at a rate of 0.8% per year in real terms.

The index-based approach proposed by PEG assigns weights to distributors that are roughly proportional to their size. The two largest distributors are excluded from the calculation, but the remaining large distributors are weighted much more heavily than medium or small distributors. We avoid these problems by assigning equal weights to all distributors. In particular, we calculate an individual productivity index for each distributor, then average across distributors. Our estimates lead to an average productivity factor of -0.8%.

Our cost-based estimates consist of two components: the technology effect is estimated to be 1.2% (this is the trend coefficient in the cost model); it indicates significant upward cost pressures. The effect is partly offset by a favorable scale effect which has been reducing unit costs at a rate of about -0.4% for the 'average' distributor.[1] Combining the two effects yields a productivity factor of -0.8%.

We note that, going forward, this scale effect may over-estimate future potential gains, particularly if growth in demand slows as a result of conservation.[2]

Benchmarking and Stretch Factor Assignments

The same cost model that is relied upon to calibrate the output index in the index modeling approach can be used to compare the relative efficiencies of distributors. Relative efficiencies are obtained by comparing costs predicted by the model for each distributor to their actual costs in recent years.

It is important to distinguish between the accuracy with which industry-wide productivity factors can be estimated, and the accuracy with which one can assess relative efficiencies of individual distributors. Though both can be obtained from the same model, the former is an average effect and can therefore be estimated with much greater precision than the latter, which involves a separate prediction for each individual distributor. This creates real potential for classification of a distributor into an incorrect efficiency cohort.

Our analysis of the data reveals that even modest variations in model specification can lead to substantial changes in distributor rankings and migration of individual distributors to other efficiency cohorts. Given the complexities of the distribution sector and its data limitations, such variations are plausible. This could result in incentives that are not aligned with the Board's objectives.

The Board has determined that distributors will be assigned to efficiency cohorts based on econometric total cost benchmarking. Given the Board's reliance on index based calculation of an industry-wide productivity factor, it may be worth also considering distributor-specific productivity growth factors in the assignment of distributors to efficiency cohorts.

We recommend that the Board use this opportunity to shift its approach to stretch factors by modifying the range to include rewards as well as penalties. PEG has proposed shifting the penalties such that they are generally less severe. We propose going a step further and introducing a reward for top tier efficiency, that is, stretch factors ranging from -0.3% to +0.3%. This reward/penalty mix is conceptually attractive and practical. It is

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[1] The effect of business condition variables used in this proceeding on industry-wide productivity growth has been small. These factors are, however, part of the cost model and can have material impacts when comparing performance of individual distributors.

[2] Furthermore, this scale effect is not appropriate for addressing issues of potential efficiency gains that may arise from consolidations or mergers of distributors. A separate analysis would be required which is beyond the scope of the present proceeding.

reasonable to expect that lean distributors will use the incremental funds to sustain or advance their preferred ranking, thus establishing a sustainable framework for pursuing this objective.

Furthermore, the allocation to efficiency cohorts proposed by the Pacific Economics Group places a disproportionate number of distributors (43 out of 73) in the two least efficient groups. In our view, asymmetry in this direction is not justified, particularly when one takes into account the potential for misclassification. In order to reduce the risk of unfairly penalizing some distributors due to data or model deficiencies, we recommend that demarcation lines between efficiency tranches be set at regular intervals as detailed in the table near the beginning of this Executive Summary.

The Board has decided to move away from using Peer Group Analysis to assign individual distributors to stretch factor tranches. In general, we are supportive of this move. Our view has been that the use of peer group analysis, in its proposed form, would have been contentious and unlikely to contribute productively to the assignment of distributors to efficiency cohorts, largely because of the difficulty in determining appropriate peer groups.

Inflation Factor

Although an industry specific measure of inflation was initially explored by the Board, the Board has preliminarily indicated its intention to use a broader measure of inflation in its implementation of 4GIRM. Specifically, the Board proposes a 2-Factor Inflation Price Index (IPI), comprised of a labour price index, reflecting the average weekly earnings for workers in Ontario, and a non-labour price index, reflecting the Canada Gross Domestic Input Price Index for Final Domestic Demand (GDP-IPI FDD). This 2-Factor IPI would not include a specific capital sub-index.

We are, in principle, supportive of the Board's move to a broader measure of inflation. Such measures have several advantages. First, they are widely available and therefore easy to obtain. Second, they generally display less variability than industry-specific measures. Third, they are likely to be better understood and accepted by electricity users because they track more closely the inflationary pressures experienced by consumers.

However, we are concerned about the exclusion of a capital sub-index, though the proposed approach may be a reasonable solution to the volatility issue. Nevertheless, given the capital intensity of electricity distribution, it is important to ensure that in the result, distribution rates are not restricted inappropriately, as this could delay expenditures on vital infrastructure.

A second concern with the proposed inflation factor is that the labour price index is weighted towards non-union labour. There is a broad economic literature on the effect of unions on wages and it is generally supportive of the proposition that unions are able, through collective bargaining, to attain better wages and labour conditions for their workers. Recent increases in unionized wage rates in Ontario appear to be consistent with this proposition. While Ontario distributors are parties to such negotiations, and can therefore influence outcomes, they are not in a position to substantially affect broader measures of wage increases in other unionized industries. It would seem reasonable therefore to implement a labour index that assigns a substantially higher weight to increases in costs associated with unionized labour.

Recommendations on Allowable Rate Increases

The incentive regulation mechanism is given by

Allowable Rate Increase = Inflation Factor – Productivity Factor – Stretch Factor.

Based on the most recent updates available from the Pacific Economics Group and the Draft Report of the Board, the calibration for 2014 would appear to be as follows:

a. an inflation factor of 1.6%;
b. an industry-wide productivity factor of 0%;
c. a “stretch factor” ranging from 0.0% to +0.6%.

Allowable rate increases would therefore range from 1% to 1.6%.

In our view, this is insufficient at a time when there is clear evidence of upward pressure on distributor costs, aside from the usual inflationary effects. Such an arrangement may prove to be unsustainable and could even undermine the Board’s objective to “facilitate the maintenance of a financially viable electricity industry”. [3]

Our analyses indicate that a productivity factor of -0.8% is most consistent with the data. We recognize the political difficulties in implementing a negative productivity factor, even if it is fully justified. However, stretch factors that are centered at zero, and which therefore reward the more efficient utilities, are defensible.

Combining the most recent inflation figure of 1.6% (unadjusted for the union effect) with a zero productivity factor and stretch factors centered at zero would produce a median increase of 1.6% and allowable rate increases ranging from 1.3% to 1.9%.

[3] *Ontario Energy Board Act*, 1998, Part I.

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1. INTRODUCTION AND BACKGROUND

In December 2010, the Ontario Energy Board began a consultative process on incentive regulation of Ontario's electricity distributors as part of a broader renewal of the regulatory framework for electricity distribution. Since three incentive-based regimes preceded the present process, the objective has been to develop a "4th Generation Incentive Regulation Mechanism" (4GIRM).

In February 2011, an initial stakeholder consultation meeting was held, at which interested stakeholders had the opportunity to exchange ideas. 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).

On November 8, 2011, the Board issued its first set of key documents: *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper*, prepared by the Pacific Economics Group, LLC, and authored by Lawrence Kaufmann, Ph.D., April 2011; and *Staff Discussion Paper on Defining and Measuring Performance of Electricity Transmitters and Distributors*, Ontario Energy Board, November 8, 2011.

The purpose of these two papers was to assist in the Board's determination of its policies in relation to performance measures by identifying the issues for consideration, and describing the options available for 4GIRM.

At the end of 2012, these were followed by another paper entitled *Concept Paper on Empirical Analysis and Benchmarking to Be Used in the Renewed Regulatory Framework for Electricity*, prepared by the Pacific Economics Group, LLC, and authored by Lawrence Kaufmann, Ph.D., December 2012. This latter PEG concept paper provided a primer on the empirical methods that would form the core of PEG's recommendations to the Board.

In May 2013, the Board issued *Empirical Research in Support of Incentive Rate Setting In Ontario: Report to the Ontario Energy Board*, Pacific Economics Group, authored by Lawrence Kaufmann, Ph.D., Dave Hovde MA, John Kalfayan MA, and Kaja Rebane MA, henceforth the "PEG May 2013 Report".[4] In this report, the Pacific Economics Group presented its initial recommendations on the inflation, productivity and stretch factors to be used in 4GIRM, and on the benchmarking of electricity distributors.

On September 6, 2013, the Pacific Economics Group provided an additional report, henceforth the "PEG September 2013 Report", entitled *Empirical*

[4] Available at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_20130531.pdf.

Research in Support of Incentive Rate Setting In Ontario: Report to the Ontario Energy Board -- 2012 Update, which updated the analysis to include data from the year 2012.[5]

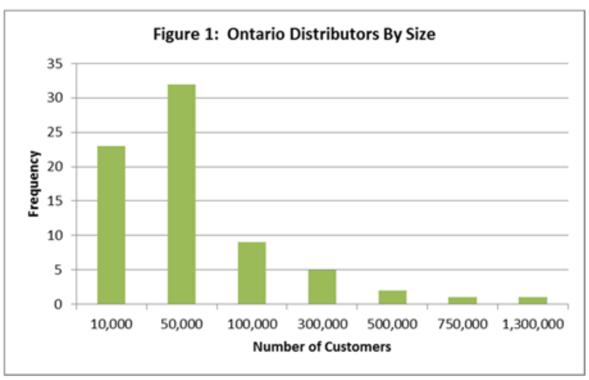
In tandem with PEG's updated report, the Board issued *EB-2010-0379: Draft Report of the Board on Empirical Research to Support Incentive Rate-setting for Ontario's Electricity Distributors*, which set out the Board's proposed policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance.

Board Staff has requested comments on the proposals that have been put forth in the "PEG Report" and the "Draft Report of the Board". The purpose of the present document is to provide commentary and analyses on behalf of the Electricity Distributors Association (EDA). It updates the earlier report submitted on behalf of the EDA on June 27, 2013

2. THE CURRENT POLICY SETTING

A. THE CHANGING POLICY ENVIRONMENT

At present, the Ontario Energy Board regulates over 70 electricity distributors, ranging in size from just over one thousand customers, to over one million. Together these distributors provide service to over 4.8 million customers. The ten largest distributors together serve over 70% of Ontario customers.



During the late 1990's there was a concerted effort to corporatize distributors and move the generation and retail elements of the industry towards a competitive model. This led to a major restructuring of the industry.

[5] Available at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379%202012_PEG_Report_on_Empirical_Work.pdf.

Starting in 2004, the Provincial Government began to shift to a centralized model in which the Ministry of Energy and Provincial agencies (e.g. Ontario Power Authority) began to play more active roles through directives, central planning, and Province-led initiatives. In 2009, the Provincial Government passed the Green Energy and Green Economy Act, the central purpose of which was to promote renewable electricity production, conservation and demand management programs and smart grid technologies. The Act established feed-in-tariff programs for renewable energy and required distribution and transmission entities to connect such facilities. Distributors were permitted to own small-scale renewable energy generating facilities. The Act also introduced new objectives for the OEB, including the promotion of renewable energy, conservation and demand management, and smart grid technologies. It also required distributors to achieve conservation and demand management targets to be set by the OEB.

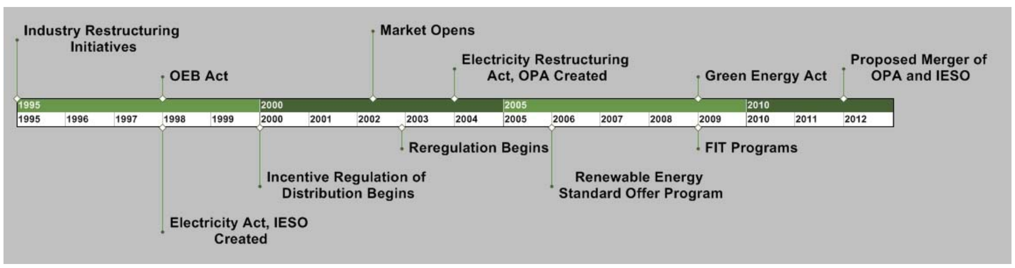


Figure 2: Timeline of Major Policy and Legislative Changes

Notably, the Act provided for more active Government involvement in the management of renewable energy, conservation and smart grid initiatives through Ministerial directives, which the Government has actively used.

Distributors are now permitted to own and operate distributed generation facilities. They are involved in the delivery of Conservation and Demand Management (CDM) programs, they have been required to install smart meters and many have investigated or implemented improved grid technologies. Distributors have also been charged with the implementation of government initiatives such as the Ontario Clean Energy Benefit (as amended) and other responsibilities. These expanded roles and accountabilities have not been realized without associated increases in costs.

During this period, through legislative and regulatory processes, distributors have also become responsible for implementing a number of policies with societal objectives that differed from the traditional obligations. Among these were low income customer programs, prescriptive customer service processes, and energy consumer protection.

B. FEED-IN-TARIFF PROGRAMS AND THE DECARBONIZATION AGENDA

Over the past twenty years, many countries have expanded their renewables programs as part of a broader decarbonization agenda. Some have introduced feed-in tariff (FIT) programs which fix prices paid for renewable energy, thereby providing for assurance of a long term revenue stream to the generator. Others have introduced programs which fix the quantity of renewable energy to be procured. These can take various forms, among them renewable portfolio standards (RPS) and tradable green certificate (TGC) schemes.[6]

Insight into the effectiveness in promoting renewable energy can be gleaned by examining the experience of various countries with FIT, RPS and TGC programs. For example, Denmark, Germany and Spain have relied primarily on evolving and aggressive FIT programs, while Great Britain and the U.S. (for example, the State of Texas) have instituted TGC and RPS programs. We note that the design of the Ontario FIT program was influenced by those in Germany, Denmark and Spain.[7]

Figure 3 below graphs the market share of renewables in a number of these jurisdictions over the course of the last two decades. Figure 4 graphs residential electricity prices over the same period.[8] The dollar amounts in Figure 4 are for bundled electricity services. The International Energy Agency, which is the source of these data, does not separate out distribution services.

In both graphs, jurisdictions with FIT programs are represented by solid lines; those with TGC or RPS programs have dashed lines.

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[6] Government renewable support policies can be grouped into three broad categories. The first group of policies consists of fiscal incentives, such as various forms of subsidies and tax incentives. The second group, public financing, includes public investments, loans and grants. The third group, and that most relevant to the electricity industry, consists of policies, such as FITs, RPS and TGCs, that require electricity consumers or companies to pay for renewable power. For further discussion, see Green, R. and Yatchew, A. (2012). "Support Schemes for Renewable Energy: An Economic Analysis." Economics of Energy & Environmental Policy, vol. 1(2), pages 83-98.

[7] See e.g., http://fit.powerauthority.on.ca/background/fit-program-benefits.

[8] Sources: National data on market shares are obtained from Renewables Information 2011, page 57, Table 3. National data on residential electricity prices are obtained from Electricity Information 2011, International Energy Agency, Table 3.7. The figures for Spain are adjusted to include the 'tariff deficit'. For Texas data see the US Energy Information Administration Electric Power Annual 2009, State Data Tables, http://www.eia.gov/cneaf/electricity/epa/epa_sprdshts.htm.

FIT programs are highly effective in stimulating market penetration by renewable suppliers. However, jurisdictions that have implemented such programs have also experienced substantial rate increases.[9] It is not necessarily the case that the rate increases were caused exclusively by the FIT programs themselves (one would need to do an analysis assessing what rates would have been in the absence of such programs).

Nor does this constitute an argument against renewables programs in general, and FIT programs in particular. Nevertheless, politicians, ratepayers and other stakeholders need to be realistic about what to expect. The long-term success of decarbonization programs is critically dependent on their public acceptability. Unexpected consequences can lead to policy reversals, often causing havoc in nascent local renewables industries.

Increasing the market share of renewable electricity will – until such technologies achieve grid parity – drive up electricity rates, primarily through commodity rates.

Furthermore, there are also cost and therefore rate impacts within the wires segments of the industry, both at the transmission and distribution levels. The integration of intermittent technologies (such as wind and solar) require investment in new technologies at the wires level.

It is important to ensure that, in the result, distribution rates are not restricted inappropriately as this could delay expenditures on vital infrastructure investments which would serve both new renewable generation and traditional load customers. Delaying expenditures in the short term can lead to higher overall costs in the longer term. Ensuring the timely planning of network investment and co-ordinating those investments on a regional basis with a view to the long term is an expressed priority for the Board's renewed regulatory framework.

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9 For example, between 1990 and 2010 the largest increase in renewable market share of any OECD country is exhibited by Denmark. Over the same period, Denmark also experienced the largest increase in electricity prices of this group.

Figure 3: Market Share of Renewables

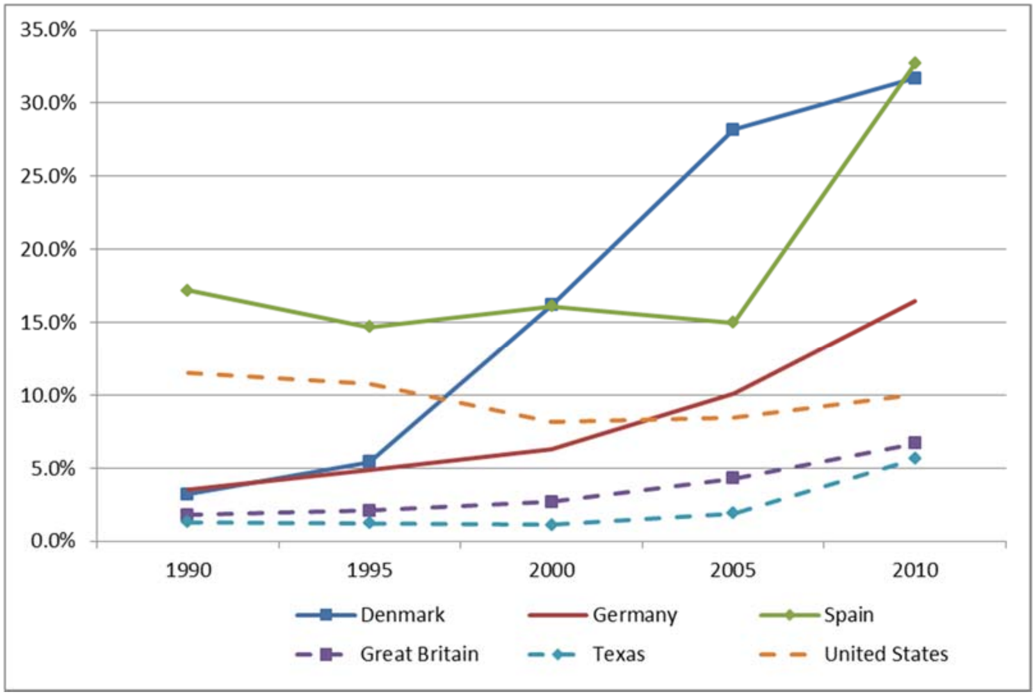
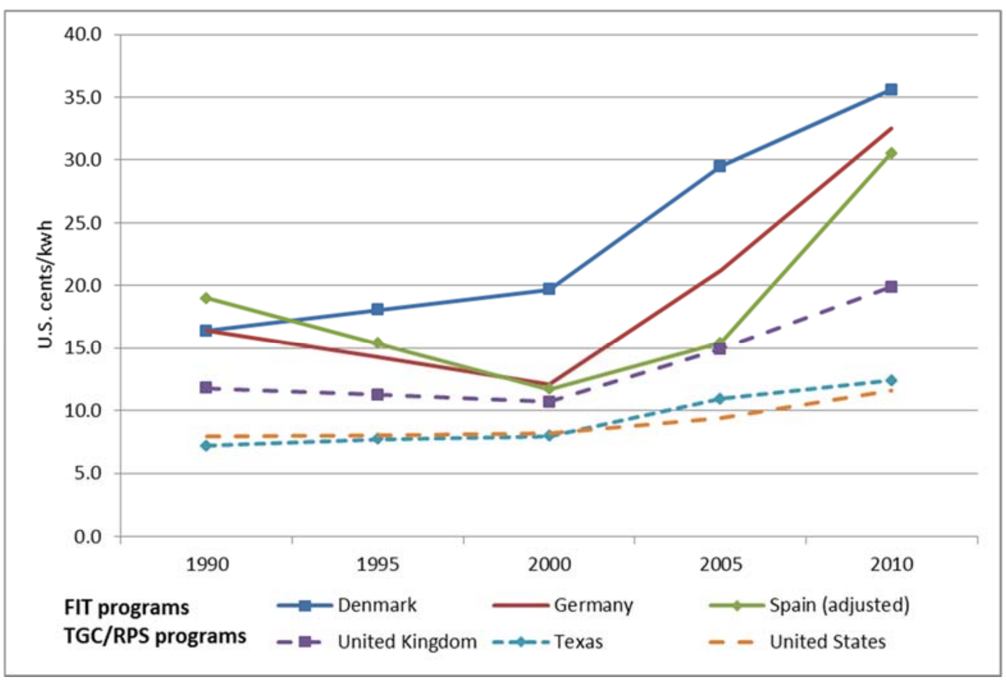


Figure 4: Residential Electricity Prices



C. THE CHALLENGES FACING DISTRIBUTION

The electricity distribution industry has faced a series of challenges over the past decade. Among these are the following.[10]

Infrastructure Refurbishment. In recent years, infrastructure investment in distribution has been driven by the need for replacement, expansion and upgrades. Such investments must be undertaken on a continuous basis if long-term costs are to be minimized and reliability is to be ensured. Major portions of distribution infrastructure were put in place many years ago and are approaching the end of their useful lifetime. Replacement of these assets at current prices puts significant upward pressure on rates. Furthermore, aging assets that remain in service require greater OM&A expenditures, which adds further pressure to costs.

New and Emerging Technologies. The Ontario distribution industry has been among the leaders in deployment of new technologies, including smart meter and smart grid devices. These have put upward pressure on costs.

Conservation and Demand Management. Distributors are required to meet CDM targets set by the Ontario Energy Board. The OPA has developed a series of Province-wide programs and distributors have relied upon these programs to achieve their conservation and demand management objectives. In some cases, larger distributors have proposed additional programs.

Renewable and Distributed Generation. Policies and legislation towards renewable and distributed generation passed by the Ontario Government have dramatically increased the role that renewable technologies will play in forthcoming years. As the share of renewable energy resources increases, the challenges of balancing the system also increase, mainly because of the variability and difficulty in predicting supply from these sources. Distribution systems originally conceived and engineered to deliver electricity will need to be modified to incorporate distributed generation.

Costs Pressures. Recent projections indicate that Ontario electricity prices will grow very significantly over the coming years. This realization has put pressure on cost structures throughout the industry. The commodity price of electricity is likely to increase more quickly than distribution rates in the province.

Regulation and Government Policy. The Green Energy Act has created new obligations for wires companies, such as the requirement to connect renewable resources. The increased direct role of Government, through the

[10] A more detailed description may be found in "The Power to Deliver. Recommendations for the Future of Electricity Distribution in Ontario" EDA submissions to the Ontario Distribution Sector Review Panel, August 2012.

issuance of directives, is also likely to increase the uncertainty of the policy environment within which distributors operate.

3. TFP ANALYSIS – A SIMPLE EXPOSITION

A. THE MAIN IDEA

The measurement of productivity growth using total factor productivity (TFP) has been studied extensively and applied widely.[11] Broadly speaking, there are two methodologies for its implementation.

> The first is the index approach which is motivated by a simple, intuitively appealing idea. It compares the rate of growth of inputs into a production process to the rate of growth of output.
>
> The second is the cost function approach which attempts to determine the sources and drivers of productivity growth. Usually, the most important drivers are technological change and scale effects.

How are the two related?

For the purposes of the analysis here, productivity growth, as measured by the index model should be approximately equal to the combined effects of technology and scale.[12] That is,

Productivity Growth = Output Growth – Input Growth = Technology Effect + Scale Effect

The index model calculation estimates the first part: "Output Growth – Input Growth". The cost model approach estimates the second part: "Technology Effect + Scale Effect".[13]

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[11] The term "factor" refers to the inputs into the production process, such as capital and labour; and, "total" signifies that the measure is intended to capture the collective productivity of all inputs.

[12] The idea of relating and combining the two approaches was first put forth in a paper by Michael Denny, Melvyn Fuss, and Leonard Waverman in1981, "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, With An Application To Canadian Telecommunications"; in Productivity Measurement In Regulated Industries, ed. T. Cowing and R. Stevenson, 179–218. New York: Academic Press.

[13] Business conditions can also affect productivity growth. In the analyses conducted for this proceeding, their effect has been small.

The above equation provides a simple template for framing a number of the issues at hand:

- PEG bases its recommendations on the index model formulation, that is, the first part of the equation. In its earlier report, PEG estimated productivity growth to be about 0.1% per year. [14] The updated report concludes that inputs grew faster than outputs so that measured productivity *declined* by 0.33% per year over the 2002-2012 period. Nevertheless, PEG concludes that a negative productivity factor is not appropriate for the forthcoming incentive regulation period and recommends that the productivity factor be "no lower than zero".[15]

- To address the second part of the equation we first consider the "Technology Effect" which is estimated using the "trend coefficient".

    - In its earlier report, PEG estimated the effect to be +1.2%, suggesting that cost pressures were *increasing* real costs at a rate of about 1.2% per year.[16]

    - The current PEG estimates range from +0.8% to 2.0% depending on which model and data are used.[17]

    - Such a broad discrepancy is troublesome and warrants further analysis.

- The "Technology Effect" is offset in part by the "Scale Effect" but the magnitude and range of the trend coefficient and the discrepancies between index-based and cost-based approaches are concerning.[18]

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[14] PEG May 2013 Report, Table 18, page 67.

[15] PEG September 2013 Report, page 29.

[16] PEG May 2013 Report, Table 10, page 37 and Table 12, page 55. The "Trend" coefficient is 0.012.

[17] PEG September 2013 Report, Table 1, page 5 reports a trend coefficient of 0.0079. Table 13, page 19 reports a trend coefficient of 0.0198 which is more than twice as large.

[18] PEG's earlier calculation of the combined technology and scale effects yielded a value of 0.07%. PEG May 2013 Report Tables 19-20 pages 71-72. The effect of business conditions was minimal. Calculations provided by PSE on behalf of the Coalition of Large Distributors (CLD) dispute PEG's calculation and this conclusion."Research and Recommendations on 4th Generation Incentive Regulation," authored by Steve Fenrick, Lullit Getachew, and David Williams of Power Systems Engineering Inc., on behalf of The Coalition of Large Distributors, June 13, 2013.

Before addressing these points and providing our own estimates of TFP growth, we provide some further background and elaboration.

B. MULTIPLE INPUTS, OUTPUTS AND BUSINESS CONDITIONS

In order to implement the index model approach, the following steps are required. First one needs to determine the quantities of each input into production (usually labour and capital). Even this step is challenging. To estimate the 'quantity' of labour one might be inclined to count the number of employees, or labour-hours. But how does one aggregate line workers, administrative, management and other staff? A common approach is to first construct a price index for labour, then divide expenditures on labour by this index to determine a quantity index for labour. This just moves the problem back one step -- now one must find a sensible way to construct a labour price index that aggregates various kinds of employees.

If there are multiple outputs (in our case, the number of customers, capacity and deliveries) then a separate methodology is required for aggregating them. The approach taken by PEG is to import coefficient estimates from the cost model to construct weights for the three components of the output index.

Once all these steps are completed, then one can compare output growth to input growth in order to estimate productivity growth. The interpretation is appealing, but the result is only as reliable as the series of steps and assumptions that underpin it.

Calculation of TFP growth using the cost model actually requires fewer steps. Once the cost model has been estimated, the technology effect is simply the trend coefficient. Scale effects can be calculated directly from the estimated coefficients without the calculation of input indexes.

The cost model separately identifies the technological and scale effects, and it permits incorporation and evaluation of the effects of changing business conditions on costs and productivity.[19]

The index-based approach, as put forth in this proceeding, does not provide for such a decomposition. This shortcoming is especially important at a time

http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/CLD_Submission_20130614.pdf

[19] For simplicity, we have omitted the latter from the discussion to this point, but they can be readily incorporated into the calculation. We note that the calculations provided by PEG indicate that the impact of business conditions included in their model on productivity has been very small.

when the policy and technological environment is changing, as has been the case in Ontario.

A further advantage of the cost model is that once it has been estimated, it can be used to compare efficiencies amongst distributors.

Figure 5 provides an overview of the steps involved in the estimation of TFP using each of the two methodologies outlined above. Two observations are worthy of attention and reiteration:

- First, the 'cost model' is estimated whether one is going to calculate TFP by comparing output growth to input growth, or whether one does so by calculating technology and scale effects.

- Second, the cost model approach permits the identification of the components of productivity changes (technology, scale and even business condition effects).

In view of these points it could be argued that the index model is only as transparent as the indexes upon which it is based. On the other hand, the ability of the cost model to distinguish between factors causing productivity change would seem to *increase* rather than reduce transparency – one can assess the plausibility of estimates by examining the contribution of each factor.

An analogy with medical diagnostics may be helpful. Allow for the moment that the index approach is akin to an X-ray, and the cost modeling approach is like an MRI. The X-ray is widely used and provides useful information of certain types. However, suppose one has back pain. The cause of the pain can usually be identified more clearly using an MRI. The X-ray may not even identify the problem until there is skeletal damage arising, for example, from the failure of a disc to provide a buffer between vertebrae.

In the present case, the use of the cost model to calibrate the index model[20] is akin to undergoing an MRI, then using the MRI results to implement the X-ray procedure. It would seem that if the results of the two were dissonant, one would not want to ignore those contained in the MRI report. Rather, one would want to give it careful consideration.

Why then are index models used so widely? A key contributory factor is that the data required for implementing cost models are not widely available, (just as X-rays are often used because MRIs are much more expensive or simply not available). However, given that we have the capability to perform an MRI, it would seem imprudent to rely solely on X-ray results.

[20] See Figure 5.

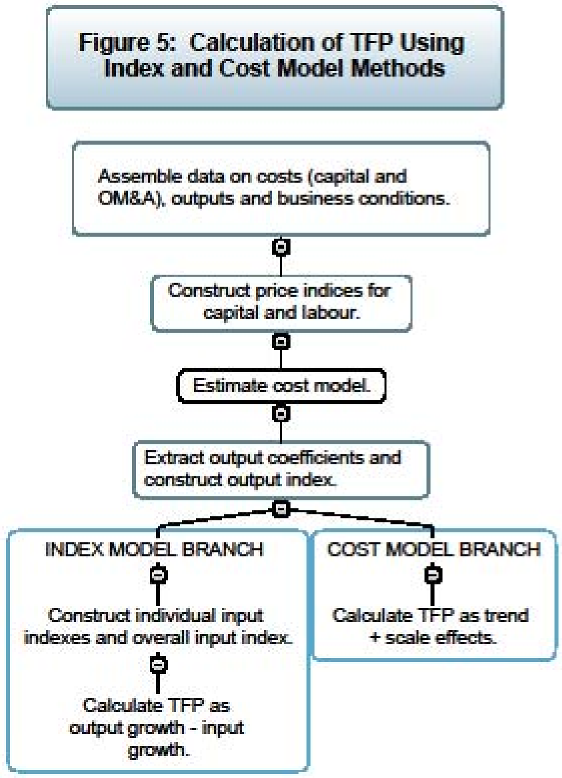
Figure 5: Calculation of TFP Using Index and Cost Model Methods
Assemble data on costs (capital and OM&A), outputs and business conditions.
Construct price indices for capital and labour.
Estimate cost model.
Extract output coefficients and construct output index.
INDEX MODEL BRANCH
Construct individual input indexes and overall input index.
Calculate TFP as output growth - input growth.
COST MODEL BRANCH
Calculate TFP as trend + scale effects.

4. PRODUCTIVITY ESTIMATES

A. THE COST MODEL

In conventional economic theory, a cost function maps the relationship between a firm's costs of production and the various conditions faced by the firm. Total costs depend on the prices of the inputs used in production, the scale of production, the various business conditions faced by the firm, the technology used for production, as well as the progression of this technology.

Given historical data on costs, inputs prices, output quantities and business conditions, statistical methods can be used to measure the cost structure of firms in an industry. The estimated cost function can, in turn, be used for industry analyses, for example, to study the pattern of changes in total factor productivity, or to evaluate the relative efficiency of different firms in the industry.

For electricity distributors, the key input prices are those that drive its capital costs, and the various labour and material resources required to operate, maintain and administer the enterprise (OM&A costs). Production scale can be inferred based on the total number of customers served, the kWh of electricity delivered, as well as the system capacity of the distributor, the latter reflecting peak demand.

Various other business conditions may also be important in electricity distribution, including: the density and spatial distribution of the customer base, the physical environment of the service territory, the percent of electricity lines buried underground, and the rate of growth of the distributor's customer base. We test the statistical significance of these factors in arriving at our model.

Configuration and ownership of transformation and other facilities may differ across distributors, leading to different types of charges to distributors. Considerable effort has been expended at this proceeding to attempt to assess which charges should be included and which excluded in order to provide for a fair comparison.

There remain questions about which low-voltage and high-voltage charges (LVHV) should remain in the cost data.[21] Furthermore, costs incurred by a

[21] Indeed, PEG uses different measures of total costs in their index and cost models. In addition, there is insufficient clarity on the LV charges provided by Hydro One. Distributors have not yet successfully related this information to their annual LV costs. In order to validate the accuracy of data distributors should be accorded the opportunity to complete their review of the data prior to finalization.

distributor are affected by the magnitude of capital contributions in aid of construction (CIAC).[22] [23]

One of the methods for dealing with such variables is to include them as business condition variables, the impacts of which are estimated by the model.

Whether to include or exclude LVHV costs from the cost measure has been the subject of much discussion in this proceeding.[24] It would not be surprising if LVHV costs proved to be a significant cost driver in a model where the total cost measure includes LVHV costs. It would perhaps be surprising if LVHV costs were a significant cost driver in models which *exclude* these costs from the total cost measure because it would suggest that the presence of substantial LVHV expenditures can influence non-LVHV costs of the firm.

The cost model we estimate is in great degree similar to that estimated in the PEG Report. The main differences are in the inclusion of two additional business condition variables just described, the use of a consistent definition of total costs across our analysis, and in the specification of the unexplained (random) component of the model. Technical details are provided in an appendix.

B. COST MODEL ESTIMATES

Estimates of our cost model (based on the 73 distributors for which data are available) are presented in Table 1. The estimated coefficients of input prices, business conditions and the "first order" terms of the output variables can be interpreted as cost elasticities for the 'average' distributor in the sample.

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[22] The use of gross capital expenditures (including CIAC) in the performance benchmarking process could disadvantage distributors that have experienced proportionately more capital spending related to system expansions and road relocations, if such expenditures are uneconomic but mandatory.

[23] There is a need to ensure that capital costs associated with the smart meter program are incorporated into distributor data in a way that minimizes the potential for distortions of relative efficiencies. In addition, there is the potential for distortion arising from the treatment of 'bad debt', payments in lieu of taxes, and other costs. (It is our understanding that PEG has not included such costs.)

[24] The PEG Report includes LVHV expenditures in estimating the cost model, but excludes them for the index-based TFP analysis. Neither would seem to adequately reflect the network intricacies of these and related costs. For example, the methodology assigns LV line costs to embedded distributors, but does not make corresponding adjustments through business conditions driving these costs (such as circuit length of host facilities). Furthermore, in some cases, host LV line assets are located outside of the service area of the embedded distributor without a corresponding business condition adjustment.

The estimate on the capital input price (WK) implies that a 10% increase in the price of capital will result in approximately a 6% increase in the costs of a distributor. Since OM&A costs constitute the other major component of total costs, this implies that a 10% increase in the price of OM&A will result in approximately a 4% increase in total costs.

The estimates on the output variables are all of the expected sign and statistically significant. By adding the coefficients together,[25] we obtain the implied scale elasticity for the average firm of approximately 0.6. That is, for the 'average firm' if output increases by 10%, costs will increase by 6%, the remainder of the increase being absorbed by improvements in scale economies.

Our estimate of the time trend implies that there have been significant cost pressures in the distribution industry between 2002 and 2012, leading to higher costs for distributors, on the order of 1.28% per year.[26]

It is notable that CIAC is a significant cost driver in the model, even though the total cost measure does not include this component.

C. ESTIMATES OF TFP USING THE COST MODEL

The cost model may now be used directly to estimate TFP:

- Technology Effect: Since costs are trending upwards, the impact on TFP is -1.28% (the trend coefficient in Table 1).

[25] 0.273 + 0.194 + 0.125 = 0.592.

[26] An argument has been made that the trend coefficient is biased upwards because distributors are engaging in incremental activities or producing outputs that are not captured by the model. See Supplementary Empirical Analysis, Pacific Economics Group, June 14, 2013, http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Supplementary_Empirical_Analysis.pdf.

The trend coefficient cannot be viewed in isolation. For example, suppose that the decarbonization agenda discussed earlier in this paper, is leading to increasing activities and costs that can be captured by say a business condition variable. Then its effect would need to enter into the calculation of total factor productivity. The net effect would likely not lead to dramatic changes in estimated TFP.

In short, the positive trend coefficient reflects growing cost pressures that need to be addressed in the regulatory rule. Model elaborations do not alter the validity of the calculation above, which are based on the data available.

- Scale Effect: The output scale elasticity is 0.59. Furthermore, our estimates imply that during the 2002-2012 period, the output index has been growing at 1.10% per year. Combining these one obtains the scale effect to be $(1-0.59)\times 1.10\% = 0.45\%$.

- Cost Based TFP: The growth rate of TFP as calculated using the cost model is just the sum of the technology and scale effect, yielding a value of -0.83%.

The incorporation of business conditions within the calculation does not materially alter these results.

D. ESTIMATES OF TFP USING THE INDEX MODEL

The index-based approach implemented by PEG assigns weights to distributors that are roughly proportional to their size. The two largest distributors are excluded from the calculation, but the remaining large distributors are weighted much more heavily than medium or small distributors.

For example, the seven largest distributors remaining in the sample (those with more than 100,000 customers) are accorded approximately the same weight as all the other 64 distributors combined. This seems odd given that the objective is to estimate an average productivity factor that is to apply to each individual distributor.

We avoid these problems by assigning equal weights to all distributors. For the analyses in this section, we calculate an individual productivity index for each distributor, then average across distributors.

A second important issue relates to the cost measure, in particular the treatment of LVHV and CIAC cost components. As noted earlier, the PEG May 2013 Report argues for the exclusion of LVHV and CIAC cost components when calculating index-based TFP. Given that at least one of these variables is statistically significant[27] even when the corresponding cost components are excluded from the total cost measure, it would appear that the effects of these variables as drivers of total costs have not been fully eliminated.

We therefore took the additional step of eliminating any residual effects of the LVHV and CIAC variables from OM&A and capital costs prior to conducting the

[27] See Table 1.

index-based TFP analysis.[28] The resulting firm-specific TFP factors varied from about -5.5% to +3.5%. The range is not surprising given different operating environments, customer growth rates, and capital cost variation. The average was -0.84% (the median was -0.73%).

In summary, our index-based TFP estimate of -0.84% was quite similar to our cost-based TFP of -0.83%.

[28] Details are in Appendix C.

Table 1

Cost Function Coefficients

VARIABLE KEY

Dependent Variable:	Total costs excluding LVHV and CIAC
Input Price:	WK = Capital Price Index
Outputs:	N = Number of Customers
	C = System Capacity Peak Demand
	D = Retail Deliveries
Other Business Conditions:	L =Average Line Length (km)
	CIAC = % of Capital Costs In Aid of Construction
	LVHV = % of Net LV-HV Charges
	TREND = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK	0.5911	50.0971
N	0.2730	4.4029
C	0.1935	3.1863
D	0.1246	3.2568
WKxWK	0.2844	17.0390
NxN	-0.6040	-3.0176
CC	0.0461	0.2632
DxD	0.1906	2.4621
WKxN	0.0012	0.0843
WKxC	0.0221	1.6787
WKxD	0.0203	3.3372
NxC	0.3317	1.9846
NxD	0.1241	1.5188
CxD	-0.2667	-3.3161
L	0.4392	14.7500
CIAC	-0.0174	-10.0224
LVHV	0.0019	1.2775
Trend	0.0128	12.9668
Constant	12.9940	410.0358
Sample Period	2002-2012	
Number of Observations	803	

5. BENCHMARKING AND THE ASSIGNMENT OF STRETCH FACTORS

A. YARDSTICK COMPETITION[29]

Consider for the moment a common form of the incentive regulation mechanism:

Allowable Rate Increase = Inflation Factor – Productivity Factor.

Incentive regulation theory suggests that this rule is sufficient for creating efficiency-improving incentives that are superior to those under conventional cost of service regulation.

In Ontario, there is an additional component to the regulatory mechanism referred to as the 'stretch factor'.[30] Whereas the inflation and productivity factors are common to all, the 'stretch factor' can vary across distributors. Its presence fundamentally strengthens the incentive creation mechanism in Ontario. A distributor (and its board of directors) compares its performance and position in the rankings to that of other distributors. Any changes in rankings are scrutinized.

This form of regulation is called yardstick competition. The presence of many distributors within the regulator's jurisdiction strengthens this form of competition and improves the efficacy of regulation.

B. THE CHALLENGES IN DETERMINING RELATIVE EFFICIENCIES

In the present proceeding, the same cost model that is relied upon to calibrate the index modeling approach can be used to compare the relative efficiencies of distributors. Relative efficiencies are obtained by comparing costs predicted by the model for each distributor to their actual costs in recent years.

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[29] A classic paper on the subject is "A Theory of Yardstick Competition", Andrei Shleifer, The RAND Journal of Economics, Vol. 16, No. 3. (Autumn, 1985), pp. 319-327. That paper contains a number of the elements that have been implemented in Ontario. Among them, the use of cost models to incorporate differences amongst distributors and the prediction of costs for a given distributor using data on *other* distributors.

[30] The original motivation of stretch factors was linked to a *transition* from cost-of-service regulation to incentive regulation. Given that Ontario distributors have been under some form of incentive regulation for many years, the rationale for stretch factors that recognize the potential for accelerated productivity growth disappears. A more appropriate terminology might be a 'diversity factor' to reflect differences amongst distributors.

It is important to distinguish between the accuracy with which industry-wide productivity factors can be estimated, and the accuracy with which one can assess **relative efficiencies** of individual distributors. Though both can be obtained from the same model, the former is an average effect and can therefore be estimated with much greater precision than the latter, which involves predictions for each individual distributor. This creates real potential for classification of a distributor into the incorrect efficiency cohort.[31]

Our analysis of the data reveals that even modest variations in model specification can lead to substantial changes in distributor rankings and migration of individual distributors to other efficiency cohorts. Table 2 contains our evaluations of relative efficiency using the cost model in Table 1.

C. MOST VALUABLE PLAYER OR MOST IMPROVED PLAYER?

Given the Board's reliance on index based calculation of an industry-wide productivity factor, it may be worth considering distributor-specific productivity growth factors in the process of determining stretch factors.

Distributors often make the point that their individual circumstances cannot be captured effectively by a model common to the industry as a whole. Differentiating variables such as reliability, urban core effects and system configuration have been among those that have emerged in discussions. Some distributors have suggested that one should examine a distributor's performance over time to see whether its unit costs are declining or increasing.

This approach is worthy of consideration. In sports (and in educational settings) considerable emphasis is placed on top performance (for example the most valuable player, or MVP award). However, additional incentives can be created by rewarding improvement, not just absolute performance. Reward systems have therefore also evolved in this direction. For example, the National Basketball Association (NBA), has had a "Most Improved Player Award" for over 25 years. An illustration of how such a regime could work in practice incorporating both relative cost performance and productivity growth is provided in Appendix D.

[31] The problem bears some similarity to competitions of various kinds. For example, predicting the average time for horses running the Kentucky Derby can be done accurately -- roughly 2 minutes ("the fastest 2 minutes in sports"). However, predicting the order of the finishers is subject to great uncertainty (and attracts a great deal of betting), even though every horse has been observed previously on multiple occasions. For distributors, the problem is complicated by numerous differences in characteristics, (at least the horses are all about the same age).

Table 2: Relative Efficiency Results

Report ID	Actual Minus Predicted Cost	Report ID	Actual Minus Predicted Cost
73	-49.2%	22	0.5%
69	-44.9%	57	0.6%
15	-43.0%	53	0.9%
44	-38.0%	29	1.0%
17	-31.0%	20	1.1%
10	-29.2%	60	1.3%
59	-27.2%	21	1.6%
24	-24.3%	25	2.3%
5	-22.3%	6	3.3%
18	-22.0%	64	4.0%
39	-17.7%	12	5.1%
35	-16.6%	16	5.5%
63	-15.2%	67	6.1%
38	-14.1%	8	7.4%
54	-12.8%	4	8.6%
30	-11.2%	37	9.0%
19	-11.0%	50	10.7%
43	-11.0%	70	11.5%
58	-10.0%	36	11.5%
11	-10.0%	33	13.4%
62	-8.7%	41	13.7%
52	-7.5%	31	13.8%
28	-6.4%	51	14.0%
1	-6.1%	46	14.3%
23	-5.9%	72	15.5%
65	-5.0%	40	17.2%
14	-4.5%	45	17.8%
32	-4.3%	3	18.2%
71	-4.3%	13	19.5%
7	-3.1%	48	19.7%
42	-2.3%	55	19.8%
56	-2.0%	47	21.4%
27	-0.7%	66	27.8%
2	0.0%	68	31.5%
		34	34.7%
		26	35.9%
		61	37.7%
		49	37.9%
		9	41.8%

D. 'STRETCH FACTORS' NEED NOT BE POSITIVE

We also recommend that the Board use this opportunity to shift its approach to stretch factors by modifying the range to include rewards as well as penalties. Under the 3GIRM approach, every distributor was presented with an incentive to become more efficient through positive stretch factors of 0.2%, 0.4%, and 0.6%. Inherent in this approach is an assumption of additional inefficiency beyond that which the productivity factor is designed to address.

However, yardstick competition, which we have argued is a fundamental rationale for differentiated treatment of distributors, does not require positive 'stretch factors'. Furthermore, the Board has indicated, as part of its renewed regulatory framework, that it would consider the "[d]evelopment of incentives to … reward superior performance.[32]

We therefore propose going a step beyond the initial PEG proposal and introducing *rewards* for strong efficiency performance, that is, stretch factors that range from -0.3% to +0.3%.

This reward/penalty mix is conceptually attractive and practical. It is reasonable to expect that lean distributors will use the incremental funds to sustain their preferred ranking, thus establishing a sustainable framework for pursuing this objective.

Conceptually, it presents a balanced approach following a sustained period of efforts to drive out inefficiencies in the industry.

E. DEMARCATION LINES BETWEEN EFFICIENCY COHORTS

The allocations as proposed by the Pacific Economics Group place a disproportionate number of distributors in the two highest stretch factor groups -- 26 and 17 respectively. Indeed 43 of 73 distributors fall in these two categories. Very few -- 5 and 7 respectively –- are assigned to the two lowest groups.

In our view, asymmetry in this direction is not justified, particularly when one takes into account the potential for misclassification.

Furthermore, the demarcations between cohorts in some cases combine distributors with widely disparate efficiency ranking. For example, the cohort

[32] *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* Ontario Energy Board, October 18, 2012.

with the highest proposed stretch factor has distributors with 'actual minus predicted costs' ranging from 15% to 73%.[33]

In order to reduce the risk of unfairly penalizing some distributors due to data or model deficiencies, we recommend that demarcation lines between efficiency tranches be set at regular intervals as indicated below.

Table 3: Efficiency Cohorts/Tranches

Tranche	Relative Cost Performance	Number of Distributors in Tranche
One	Actual costs are at least 15% below predicted costs	13
Two	Actual costs are between 0% and 15% below predicted costs	21
Three	Actual costs are between 0% and 15% above predicted costs	24
Four	Actual costs are between 15% and 30% above predicted costs	9
Five	Actual costs are more than 30% above predicted costs	6

F. PEER GROUP ANALYSIS

In response to concerns raised by stakeholders during the consultation process, the Board is evidently deciding to move away from Peer Group Analysis.

We are supportive of this change.

Our view has been that the use of peer group analysis, in its proposed form, would have been contentious and unlikely to contribute productively in the assignment of distributors to efficiency cohorts.

A peer group approach is problematic, largely because of the difficulty in determining appropriate peer groups. There are too many variables that can affect distributor costs to give one confidence in the allocation to peer groups.

[33] PEG September 2013 Report, Tables 14 and 15, pages 22-24.

Furthermore, peer group analysis does not use information efficiently, a problem that is avoided through the use of statistical benchmarking.[34]

6. THE INFLATION FACTOR

The PEG May 2013 Report proposes to use industry specific measures and to implement a three year moving average to smooth the series, thereby reducing volatility. Because monetary policies such as quantitative easing, have led to declines in interest rates, the current value, based on the three year period 2010-2012, would be 0.5%.

However, rising interest rates could push the industry-specific inflation factor to levels of 4% or even higher. In periods of volatile interest rates, increases and decreases could follow in quick succession. Such changes could result in confusion and resistance from ratepayers.

Although an industry specific measure of inflation was initially explored by the Board, the Board has preliminary indicated its intention to use a broader measure of inflation in its implementation of the 4GIRM. Specifically, the Board proposes a 2-Factor Inflation Price Index (IPI), comprised of a labour price index, reflecting the average weekly earnings for workers in Ontario, and a non-labour price index, reflecting the Canada Gross Domestic Input Price Index for Final Domestic Demand (GDP-IPI FDD). This 2-Factor IPI would exclude a specific capital sub-index.

We are, in principle, supportive of the Board's move to a broader measure of inflation. Such measures have several advantages. First, they are widely available and therefore easy to obtain. Second, they generally display less variability than industry-specific measures. Third, they are likely to be better understood and accepted by electricity users because they track more closely the inflationary pressures experienced by consumers.

However, we are concerned about the exclusion of a capital sub-index, though the proposed approach may be a reasonable solution to the volatility issue. Nevertheless, given the capital intensity of electricity distribution, it is important to ensure that, in the result, distribution rates are not restricted inappropriately, as this could delay expenditures on vital infrastructure.

A second concern with the proposed inflation factor is that the labour price index is weighted towards non-union labour. There is a broad economic literature on the effect of unions on wages and it is generally supportive of the proposition that unions are able, through collective bargaining, to attain better wages and labour conditions for their workers. Recent increases in unionized wage rates in Ontario appear to be consistent with this proposition. While

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[34] See for example, Shleifer, *op. cit.* page 324, "Sorting firms into identical or even similar groups to apply yardstick competition is a very inefficient use of information."

Ontario distributors are parties to such negotiations, and can therefore influence outcomes, they are not in a position to substantially affect broader measures of wage increases in other unionized industries. It would seem reasonable therefore to implement a labour index that assigns a substantially stronger weight to increases in costs associated with unionized labour.

Data on unionized labour earnings for Ontario (and for Canada) are available through Statistics Canada, Labour Force Survey Estimate.[35]

7. CONCLUSIONS AND RECOMMENDATIONS

We have entered a period where productivity growth in the Ontario electricity industry -- as assessed using conventional measures -- may appear to be negative. This is likely because conventional measures do not fully reflect the broader range of activities that distributors are now undertaking as agents of Provincial energy and social policies. (Economic turmoil in recent years is also a contributory factor.) There is every reason to expect that this period will last for the duration of 4GIRM or longer.

A greener industry will, for the foreseeable future, mean a costlier industry, not only for generation but also for the wires companies that connect and serve renewable distributed generators. This is consistent with cost increases in other jurisdictions that have implemented ambitious conservation and FIT programs.

Thus, while a distributor's productivity growth in relation to conventional activities may be positive, the rapid and substantial introduction of new activities may offset those advances and, from an aggregate view, result in apparent negative productivity.

We have estimated the productivity factor two ways using, in effect, the same cost measure in each case by incorporating relevant business condition variables.[36] [37] It is somewhat reassuring that our estimates of TFP are similar, regardless of which method we use. The increasing cost trends in the industry

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[35] See, for example, Statistics Canada, Table 282-0073 -- Labour Force Survey Estimates (LFS), Wages of Employees by Job Permanence, Union Coverage, Sex and Age Group, Unadjusted for Seasonality. Geography = Ontario, Wages = Median Weekly Wage Rate, Job Performance = Total Employees, Union Coverage = Union Coverage, Sexes = Both Sexes, Age Group = 15 Years and Over, Frequency = Annual (Average).

[36] In particular, the LVHV and CIAC variables.

[37] Consultant to the Board attaches some importance to the use of the same cost measure when comparing TFP analyses. See Supplementary Empirical Analysis, Pacific Economics Group, June 14, 2013, page 4, http://www.ontarioenergyboard.ca/OEB/ Documents/EB-2010-0379/PEG_Supplementary_Empirical_Analysis.pdf.

-- as captured by a strongly significant trend coefficient – are consistent with the index-based results and, in our view, cannot be ignored.

It is important to reflect the actual productivity experience and reasonable expectations for productivity in the rate-setting process. Just as in situations where productivity is expected to improve in aggregate, distributors are pressed with reductions, where costs are expected to increase in aggregate, distributors should be permitted their due increases. Failure to strike this balance will result in underfunding of distributors.

Where there is underfunding, less investment can be expected. This would perpetuate the "rate step" pattern that occurs in cost of service years. In order to provide ratepayers with steady, predictable rates, the incentive regulation rate-setting mechanism needs to reflect real cost pressures.

The incentive regulation mechanism is given by

> **Allowable Rate Increase = Inflation Factor – Productivity Factor – Stretch Factor.**

Based on the most recent updates available from the Pacific Economics Group and the Draft Report of the Board, the calibration for 2014 would appear to be as follows:

a. an inflation factor of 1.6%;
b. an industry-wide productivity factor of 0%;
c. a "stretch factor" ranging from 0.0% to +0.6%.

Allowable rate increases would therefore range from 1% to 1.6%.

In our view, this is insufficient at a time when there is clear evidence of upward pressure on distributor costs, aside from the usual inflationary effects. Such an arrangement may prove to be unsustainable and could even undermine the Board's objective to "facilitate the maintenance of a financially viable electricity industry".[38]

Our analyses indicate that a productivity factor of -0.8% is most consistent with the data. We recognize the political difficulties in implementing a negative productivity factor, even if it is fully justified. However, stretch factors that are centered at zero, and which therefore reward the more efficient distributors, are defensible.

Combining the most recent inflation figure of 1.6% (unadjusted for the union effect) with a zero productivity factor and stretch factors centered at zero would produce a median increase of 1.6% and allowable rate increases ranging from 1.3% to 1.9%. Incorporating wages that reflect union labour increases in other industries could raise these figures.

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[38] *Ontario Energy Board Act*, 1998, Part I.

APPENDIX A – NOTES ON TFP MEASUREMENT

The measurement of productivity growth[1] can be motivated by a simple, intuitively appealing idea which compares the rate of growth of inputs into a production process to the rate of growth of output.

Total factor productivity (TFP) is a commonly used term where

- "factor" refers to the inputs into the production process (such as capital and labour),
- "total" signifies that the measure is intended to capture the collective productivity of all inputs.

To illustrate the idea, assume for the moment that there is a single input X , and a single output Y . Then the growth in total factor productivity is given by

$$\dot{TFP} = \dot{Y} - \dot{X}$$

Productivity Growth = Output Growth – Input Growth (A.1)

where (as is customary in the literature) we use an elevated dot to denote the percentage rate of growth of a variable.

For example, if the input is growing at 2% and the output is growing at 3% then productivity is growing at 1%. Long run productivity growth is most importantly attributed to technological innovations but also to other effects, such as scale economies.

[1] The ideas in this section may be found in a paper by Michael Denny, Melvyn Fuss, and Leonard Waverman, 1981 entitled "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, With an Application To Canadian Telecommunications"; in Productivity Measurement In Regulated Industries, ed. T. Cowing and R. Stevenson, 179–218. New York: Academic Press.

Of course, managers, accountants and regulators scrutinize costs. In the one-factor setting, total costs (TC) are simply the price of the input times its quantity. Thus the rate of growth of total costs equals the rate of growth of prices plus the rate of growth of inputs. That is,

$$\dot{TC} = \dot{P} + \dot{X}$$

Total Cost Growth = Inflation + Input Growth

Using this expression, TFP growth in (1) can also be written as

$$\dot{TFP} = \dot{Y} - \left(\dot{TC} - \dot{P}\right)$$

Productivity Growth = Output Growth – Total Cost Growth Adjusted for Inflation

Alternatively, we may think of cost increases as being driven by inflation and increases in the level of output, offset in part by technological innovation and improved economies of scale. That is,

$$\dot{TC} = \dot{P} + \dot{Y} - \dot{T} - \dot{SE}$$

Total Cost Growth = Inflation + Output Growth – Technology Effects – Scale Effects

This decomposition of growth in total costs can be substituted into the immediately preceding equation to obtain

$$\dot{TFP} = \dot{T} + \dot{SE} \qquad \text{(A.2)}$$

Productivity Growth = Technology Effects + Scale Effects

Equations (A.1) and (A.2) are fundamental to understanding the present discussion (and disagreements) in the measurement of productivity growth.

- Equation (A.1) summarizes the index model approach. It expresses productivity growth as the difference between the output growth and input growth.
- Equation (A.2) summarizes the cost model (econometric benchmarking) approach. It expresses growth in terms of driving factors (technology and scale effects).

Equations (A.1) and (A.2) may now be combined to obtain:

$$\dot{TFP} \quad = \quad \dot{Y} - \dot{X} \quad = \quad \dot{T} + \dot{SE}$$

Productivity Growth = Output Growth – Input Growth = Technology Effects + Scale Effects

Economists scrutinize the causes of productivity growth and so the latter is attractive because it provides an explanation of the sources of growth.

Properly implemented, the two approaches should yield similar values.

APPENDIX B – THE COST MODEL

Specification

We use a translog specification for our cost model that takes into account the panel structure of the data. For distributor $i = 1, \ldots, N$ at time $t = 1, \ldots, T$ the total cost function is given by

$$\begin{aligned}\ln TC_{it} = \quad & \beta_0 + \sum_j \beta_j \ln Q_{j_{it}} + \sum_m \beta_m \ln \mathrm{W}_{m_{it}} \\ & + \frac{1}{2}\left(\sum_j \sum_l \gamma_{jl} \ln Q_{j_{it}} \ln Q_{l_{it}} + \sum_m \sum_n \gamma_{mn} \ln \mathrm{W}_{m_{it}} \ln \mathrm{W}_{n_{it}} \right) + \sum_j \sum_m \gamma_{jl} \ln Q_{j_{it}} \ln W_{m_{it}} \\ & + \sum_p \delta_p z_{p_{it}} + \delta_t t + \left(u_i + \varepsilon_{it}\right)\end{aligned} \tag{B.1}$$

where TC_{it} is total costs; $Q_{j_{it}}$ is the quantity of output j for $j = 1, \ldots, J$; $W_{m_{it}}$ is the price of input factor m for $m = 1, \ldots, \mathrm{M}$; $z_{p_{it}}$ is business condition variable p for $p = 1, \ldots, P$; t is time trend; and the composite error $u_i + \varepsilon_{it}$ consists of a time-invariant firm-specific effect combined with a transitory effect.

Most right-hand-side variables are first divided by their mean value. The approximation is therefore centered at a notional 'average firm'. This is important as one generally expects approximations to deteriorate as one moves further away from the point of expansion.

While estimation of the parameters is possible via Equation (B.1), this approach would not utilize all available information. A more efficient estimate may be obtained by augmenting the total cost equation with the set of share equations implied by Shepard's Lemma

$$S_{m_{it}} = \quad \beta_l + \sum_j \gamma_{jm} \ln Q_{j_{it}} + \sum_n \gamma_{mn} \ln \mathrm{W}_{n_{it}} + (v_{m_i} + \eta_{m_{it}}) \tag{B.2}$$

where the composite error of each share equation again consists of a time-invariant firm-specific effect combined with a transitory effect.

Since, by definition, the factor shares sum to unity, one cost share equation is redundant and thus can be excluded from the model. Since there are two factors (capital and OM&A), we include only the capital factor share.

Let lower case variable names denote logarithms. The system of equation implied by our model now becomes

$$\begin{aligned} tc_{it} = \quad & \beta_0 + \sum_j \beta_j q_{j_{it}} + \beta_k wk_{it} + \frac{1}{2}\left(\sum_j \sum_l \gamma_{jl} q_{j_{it}} q_{l_{it}} + \gamma_{kk} wk_{it}^{\ 2} \right) + \sum_j \gamma_{jk} q_{j_{it}} wk_{it} \\ & + \sum_p \delta_p z_{p_{it}} + \delta_t t + \left(u_i + \varepsilon_{it} \right) \end{aligned} \tag{B.3}$$

$$SK_{it} = \quad \beta_k + \sum_j \gamma_{jk} q_{j_{it}} + \gamma_{kk} wk_{it} + (v_i + \eta_{it}) \tag{B.4}$$

where total costs and the price of capital have been divided by the price index for OM&A.

Formally, the equations in (B.3) and (B.4) comprise a "seemingly unrelated regression" model. Fix distributor i and consider the structure of second order moments of the errors. Within equations, we have

$$\begin{aligned} &Var\left(u_i + \varepsilon_{it}\right) = \sigma_u^2 + \sigma_\varepsilon^2 \quad \textit{and} \quad Cov\left(u_i + \varepsilon_{is}, u_i + \varepsilon_{it}\right) = \sigma_u^2 \ \ \textit{if } s \neq t \\ &Var\left(v_i + \eta_{it}\right) = \sigma_v^2 + \sigma_\eta^2 \quad \textit{and} \quad Cov\left(v_i + \eta_{is}, v_i + \eta_{it}\right) = \sigma_v^2 \ \ \textit{if } s \neq t \end{aligned} \tag{B.5}$$

and between equations, we have

$$\begin{aligned} Cov\left(u_i + \varepsilon_{is}, v_i + \eta_{it}\right) &= \sigma_{uv} + \sigma_{\varepsilon\eta} \quad \textit{if } s = t \\ Cov\left(u_i + \varepsilon_{is}, v_i + \eta_{it}\right) &= \sigma_{uv} \qquad\quad \textit{if } s \neq t. \end{aligned} \tag{B.6}$$

This implies the following matrix Ω_i for the covariance structure of the composite error terms of distributor i :

$$\begin{bmatrix} \sigma_u^2 + \sigma_\varepsilon^2 & \sigma_u^2 & \cdots & \sigma_u^2 & \sigma_{uv} + \sigma_{\varepsilon\eta} & \sigma_{uv} & \cdots & \sigma_{uv} \\ \sigma_u^2 & \sigma_u^2 + \sigma_\varepsilon^2 & \cdots & \sigma_u^2 & \sigma_{uv} & \sigma_{uv} + \sigma_{\varepsilon\eta} & \cdots & \sigma_{uv} \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ \sigma_u^2 & \sigma_u^2 & \cdots & \sigma_u^2 + \sigma_\varepsilon^2 & \sigma_{uv} & \sigma_{uv} & \cdots & \sigma_{uv} + \sigma_{\varepsilon\eta} \\ \sigma_{uv} + \sigma_{\varepsilon\eta} & \sigma_{uv} & \cdots & \sigma_{uv} & \sigma_v^2 + \sigma_\eta^2 & \sigma_v^2 & \cdots & \sigma_v^2 \\ \sigma_{uv} & \sigma_{uv} + \sigma_{\varepsilon\eta} & \cdots & \sigma_{uv} & \sigma_v^2 & \sigma_v^2 + \sigma_\eta^2 & \cdots & \sigma_v^2 \\ \vdots & \vdots & \ddots & \vdots & \vdots & \vdots & \ddots & \vdots \\ \sigma_{uv} & \sigma_{uv} & \cdots & \sigma_{uv} + \sigma_{\varepsilon\eta} & \sigma_v^2 & \sigma_v^2 & \cdots & \sigma_v^2 + \sigma_\eta^2 \end{bmatrix}. \tag{B.7}$$

The independence between firms yields:

$$\Omega = \begin{bmatrix} \Omega_1 & 0 & \dots & 0 \\ 0 & \Omega_2 & \dots & 0 \\ \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & \dots & \Omega_N \end{bmatrix}.$$

The basic formulation of our cost model is identical to that of PEG's, except for the specification of the covariance structure of the error term. We explicitly take into consideration the panel structure of the data, and model a composite error that consists of a firm-specific time-invariant effect combined with a random transitory effect.

PEG Residual Structure

PEG uses a heteroskedastic first-order vector autoregressive model for the residual. In the notation of equations (B.3) and (B.4) the PEG specification sets u_{it} and v_i equal to zero, but introduces additional structure on the remaining residuals as follows:

$$Var(\varepsilon_{it}) = \sigma_{\varepsilon i}^2 \qquad Var(\eta_{it}) = \sigma_{\eta i}^2 \qquad Cov(\varepsilon_{it}, \eta_{it}) = \sigma_{\varepsilon\eta i} \ .$$

$$Cov(\varepsilon_{it}, \varepsilon_{it-s}) = \rho_\varepsilon^s \sigma_{\varepsilon i}^2 \qquad Cov(\eta_{it}, \eta_{it-s}) = \rho_\eta^s \sigma_{\eta i}^2 \ .$$

There are also non-contemporaneous covariances between equations of the form:

$$Cov(\varepsilon_{it}, \eta_{it-s}) = \rho_\varepsilon^s \sigma_{\varepsilon\eta i} \quad for \ s = 1, \dots, T-1$$
$$Cov(\eta_{it}, \varepsilon_{it-s}) = \rho_\eta^s \sigma_{\varepsilon\eta i} \quad for \ s = 1, \dots, T-1.$$

Estimation

We use generalized least squares (GLS) to estimate our model.[1] Equations (B.3) and (B.4) are first jointly estimated using ordinary least squares while imposing cross-equation constraints on common parameters. The residuals are used to compute their associated

[1] "Chapter 7: Estimating Systems of Equations by OLS and GLS," in Wooldridge, J.M. (2002). *Econometric Analysis of Cross Section and Panel Data*. MIT Press.

second-order moments, and an estimate of the covariance matrix Ω which is then inserted in the GLS estimator.

Data

We use data developed by the Pacific Economics Group Research LLP (PEG) for their report to the Ontario Energy Board. Two minor adjustments are made to the data prior to estimation:

1. The 2004 observation for Erie Thames Powerlines Corporation contains an anomaly in its record of retail deliveries. PEG deal with this observation by dropping it from the sample altogether. Instead, we replace the recorded 2004 deliveries with the average of 2003 and 2005 deliveries.

2. The 2002 observation for Canadian Niagara Power Inc. appears to contain an anomaly: although there are apparently no LV-HV charges, the recorded OM&A costs net of LV-HV charges differ from the recorded OM&A costs gross of LV-HV charges. We use the OM&A costs gross of LV-HV charges for this observation.

APPENDIX C – ESTIMATION ALGORITHMS

Algorithm A: Estimation of Cost Model (Table 1)[1]

1. Import data.
2. Define, de-mean and transform the variables to be used in the analysis.
3. Jointly estimate equations B.3 and B.4 by ordinary least squares (OLS).
4. Using OLS residuals, estimate second-order moments of error terms in equations B.3 and B.4, and construct the covariance matrix in equation B.7.
5. Jointly estimate equations B.3 and B.4 by generalized least squares (GLS) using the estimated covariance matrix from step 4.

Algorithm B: Estimation of Relative Efficiencies (Table 2)

1. One-by-one, beginning with Distributor #1 and ending with Distributor #73, select each Distributor individually and rename it "Distributor *i*".
2. Drop "Distributor *i*" from the sample.
3. Re-estimate equations B.3 and B.4, using Algorithm A.
4. Use the estimate of equation B.3 to predict the costs of "Distributor *i*" for each of the last 10 years.
5. For each year, calculate the difference between predicted (log) costs of "Distributor *i*" and observed (log) costs.
6. Average this differential over the last three sample years.

Algorithm C: Estimation of Index-Based TFP (Section 4.D)

1. Estimate the parameters of equations B.3 and B.4 using Algorithm A.
2. Use the estimated parameter from Step 1 to construct the weighting factors for the individual components of the output index (number of consumers (N), capacity (C) and deliveries (D)).

[1] All equation numbers refer to equations in Appendix B.

3. For each distributor, compute the yearly growth rates of N, C, D. Using the weights from Step 2, calculate the weighted average to construct the growth rate of the distributor's Output Index.
4. For each distributor, use the estimated parameters from Step 1 to compute, and then net out, the yearly residual Capital in Aid of Construction (CIAC) effects and Low Voltage-High Voltage Charge (LV-HV) effects from the yearly Costs of Capital (CK) and Costs of OM&A (COMA), respectively.
5. For each distributor, compute the yearly CK and COMA shares of total costs (TC), where total costs are defined as the sum of Capital and OM&A costs.
6. For each distributor, compute the yearly input quantities of Capital (K) by dividing the yearly Costs of Capital by their respective yearly Rental Prices of Capital. Similarly, compute the yearly input quantities of OM&A (OMA).
7. For each distributor, compute the yearly growth rates of K and OMA. Using the cost shares from Step 5 as weights, average these together to construct the growth rates of the distributor's Input Index.
8. For each distributor, compute the yearly growth rate of Total Factor Productivity (TFP) by subtracting the yearly growth rates of the distributor's Input Index from the yearly growth rates of the distributor's Output Index
9. For each distributor, calculate the average 10-year growth rate of TFP.
10. Average these firm-specific TFP growth rates to obtain the index-based industry TFP growth rate.

APPENDIX D – AN ILLUSTRATION OF STRETCH FACTOR ASSIGNMENTS

The illustration in this appendix expands on the intuition of rewarding not only the 'Most Valuable Player', but also the 'Most Improved Player'. Under this approach, stretch factor assignments would be based on relative cost performance *and* growth in productivity. Firms which have demonstrated recent productivity improvements (relative to other firms) would be viewed favourably, even if their costs may appear to be high relative to other firms.

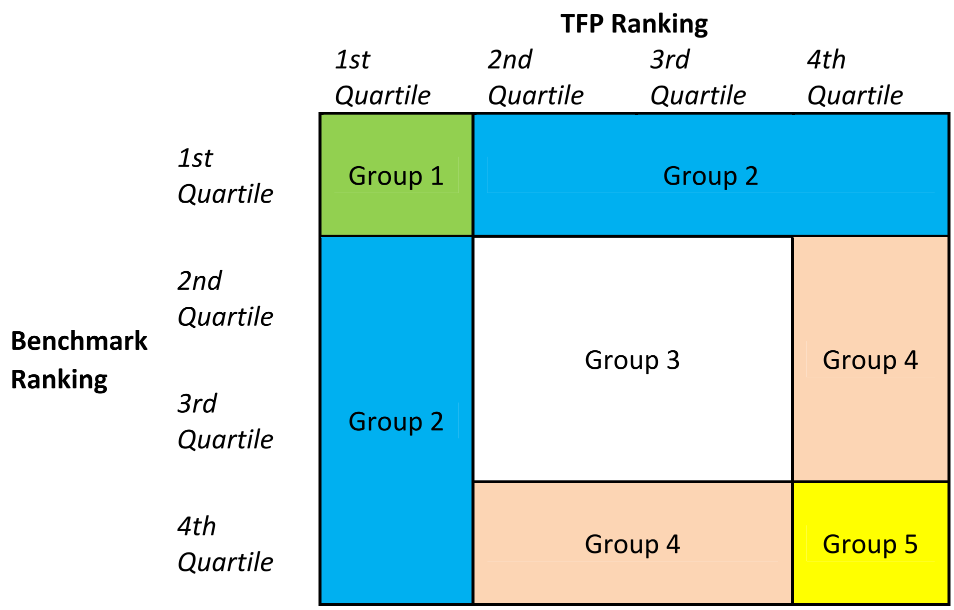
Details of Allocation Algorithm

1. Rank distributors according to their relative efficiency during the last three sample years.

2. Similarly, rank distributors according to their productivity growth over the last three sample years.

3. Assign distributors to one of five groups as follows:
    - Group 1 - Distributors which are in the first quartile in terms of **both** cost efficiency and productivity growth are assigned a stretch factor of -0.30%.
    - Group 2 - Distributors which are in the first quartile in terms of **either** cost efficiency or productivity growth, are assigned a stretch factor of -0.15%.
    - Group 3 - Distributors which are in the second or third quartile in terms of **both** cost efficiency and productivity growth are assigned a stretch factor of 0.0%.
    - Group 4 - Distributors which are in the fourth quartile in terms of **either** cost efficiency or productivity growth are assigned a stretch factor of +0.15%
    - Group 5 - Distributors which are in the fourth quartile in terms of **both** cost efficiency and productivity growth are assigned a stretch factor equal to +0.30%.

The allocation rule is illustrated in the table below.


TFP Ranking
1st Quartile
2nd Quartile
3rd Quartile
4th Quartile
Benchmark Ranking
1st Quartile
2nd Quartile
3rd Quartile
4th Quartile
Group 1
Group 2
Group 2
Group 3
Group 4
Group 4
Group 5