PRODUCTIVITY AND BENCHMARKING RESEARCH IN SUPPORT OF INCENTIVE RATE SETTING IN ONTARIO:

FINAL REPORT TO THE ONTARIO ENERGY BOARD

November 2013

(Issued on November 21, 2013 and as corrected on December 19, 2013 and January 24, 2014)

Pacific Economics Group Research, LLC

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Table of Contents

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1 Introduction and Executive Summary

Board Staff retained Pacific Economics Group Research LLC (PEG) to advise it on productivity and benchmarking research in support of incentive rate setting in Ontario. Research topics included measuring industry input price inflation, mitigating volatility in measured inflation, estimating TFP for the electricity distribution industry, and appropriate business conditions to consider when benchmarking Ontario distributors.

PEG was asked to develop recommendations for these elements and endeavored to base the recommendations on rigorous and objective empirical research that could be replicated, refined and extended in future IR applications. Some of PEG's current benchmarking research may also inform the Board's review of Custom IR applications. PEG's empirical research was guided by policy direction set out in the Ontario Energy Board's (the Board) October 18, 2012 Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Board Report). PEG's empirical analysis was also informed by the suggestions and recommendations of a stakeholder Working Group on Performance, Benchmarking and Ratemaking (PBR) as well as the principles for effective incentive regulation. [1]

The Board's Policy Direction

On October 18, 2012, the Board released the RRFE Board Report. The RRFE Board Report sets out three rate-setting options: 4th Generation Incentive Rate-setting (Price Cap IR), which the Board considers suitable for most distributors; Custom Incentive Rate-setting (Custom IR) for distributors with large or highly variable capital requirements; and an Annual Incentive Rate-setting Index (Annual IR) for distributors with limited incremental capital requirements. The Price Cap IR option will use rate adjustment formulas that are calibrated using estimates of Ontario-specific industry input price and total factor productivity (TFP)

[1] The PBR Working Group held nine meetings between January 11, 2013 and March 1, 2013. In addition to Board Staff and Dr. Kaufmann, the PBR Working Group had representatives from Hydro One Networks, Waterloo North Hydro, Canadian Niagara Power, Cornerstone Hydro Electric Concepts, the Association of Major Power Consumers in Ontario, the Consumers Council of Canada, the Vulnerable Energy Consumers Coalition, the Power Workers' Union, Toronto Hydro, Hydro Ottawa, the School Energy Coalition, and the Electricity Distributors' Asssociation.

trends, as well as benchmark-based information on each distributor's relative efficiency. The Price Cap IR builds on the 3rd Gen IR that has been in effect since 2008, but the existing IR regime is modified to better reflect input price and productivity trends in Ontario.[2]

In both Price Cap IR and 3rd Gen IR, the allowed change in regulated rates for distribution services is based on the growth in an inflation factor minus an X-factor. The Board has concluded that the inflation factor for the Price Cap IR will be a more industry-specific inflation factor designed to track inflation in the prices of inputs used by the Ontario electricity distribution sector.[3] The Board has found that any concerns regarding the volatility of an industry-specific inflation factor will be mitigated by the methodology it selects to measure inflation.

The basic architecture for the X-factor in the Price Cap IR formula is intended to be similar to that developed in 3rd Gen IR. In its July 14, 2008 EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, the Board described the components of the 3rd Gen IR X-factor as follows:

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.
>
> The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.[4]

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[2] The First Generation IR was implemented in 2000. This mechanism had a three-year intended term but, before the plan could run its course, the Provincial Government imposed a freeze on overall retail electricity prices. This cap effectively eliminated any further formula-based distribution price adjustments for distribution services and thus ended the plan. The Board implemented a second generation incentive regulation mechanism (2nd Generation IRM) in December 2006. The 2nd Generation IR was essentially a transitional mechanism that applied until rates were "rebased" to reflect each distributor's cost of service in a test year.

[3] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 16.

[4] *EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, p. 12.

The Board indicated in the RRFE Board Report that it will retain this basic approach for Price Cap IR but concluded that the productivity factor will be based on an estimate of industry Total Factor Productivity (TFP) growth in Ontario's electricity distribution sector. A single productivity factor will be set in advance and will apply to all distributors during the term of the Price Cap IR. The Board used an index-based approach for estimating the industry TFP trend in 3rd Gen IR and intends to use the same approach for Price Cap IR.[5]

The Board has also stated that its approach for assigning stretch factors will be modified to reflect distributors' *total* cost performance.[6] In 3rd Gen IR, each distributor is assigned to one of three efficiency cohorts based on two benchmarking evaluations of that distributor's operation, maintenance, and administrative (OM&A) costs.[7] Since 2008, these cohort assignments have been used to assign stretch factors. In Price Cap IR, the Board will make these assignments using total cost benchmarking evaluations and determine the

[5] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17.

[6] *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 17-18.

[7] The Board's decision on how to establish the three efficiency cohorts is presented in EB-2007-0673 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, July 14, 2008, pp. 20-23; the Board's decision on the empirical values for each of the three efficiency cohorts is presented in EB-2007-0673 *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, September 17, 2008, pp. 19-22. The first benchmarking evaluation compares a distributor's OM&A unit cost (i.e. OM&A cost divided by an index of the distributor's output) to the average OM&A cost for that distributor's designated peer group. The peer groups were based on PEG's analysis of the variables that drive OM&A costs across the Ontario electricity distribution industry.

The second benchmarking analysis is based on an econometric cost model. Using statistical methods, PEG developed an econometric model of each firm's OM&A cost. The parameters of the model were estimated using Ontario data. After these parameter estimates were obtained, data on the cost "driver" variables for each distributor were inserted into the model to develop an estimate of each firm's predicted (or expected) OM&A cost. Each year, the distributor's actual costs are compared to the predicted cost generated by the model plus or minus a confidence interval around the cost prediction. If actual cost is below predicted cost minus the lower bound of this interval, the difference between actual and predicted costs is statistically significant and the distributor is deemed to be a superior cost performer. On the other hand, if actual cost is above predicted cost plus the upper bound of the confidence interval, the difference between actual and predicted costs is statistically significant and the distributor is deemed to be an inferior cost performer. If the difference between actual and predicted cost is within the confidence interval, the distributor is deemed to be an average cost performer.

The efficiency cohorts in 3rd Gen IR are determined using both benchmarking evaluations. If a distributor is a superior cost performer and in the top quartile of the industry on the unit cost benchmark, it is in efficiency cohort I and assigned a stretch factor of 0.2 per cent. If a distributor is an inferior cost performer and in the bottom quartile of the industry on the unit cost benchmark, it is in efficiency cohort III and assigned a stretch factor of 0.6 per cent. All other distributors are in efficiency cohort II and assigned a stretch factor of 0.4 per cent. Larger stretch factors are assigned for relatively less efficient firms since they are deemed to have greater potential to achieve incremental productivity gains.

appropriate stretch factor values for the different efficiency cohorts in conjunction with its determination of the productivity factor.

Empirical Analysis Undertaken

Throughout the course of the Price Cap IR consultation, PEG has undertaken a host of empirical analyses. Some of PEG's earlier work has included supplementary empirical investigations, or recommendations on issues other than the productivity factor or final benchmarking model, that are not addressed in this Final Report. The main reports or memoranda that PEG has provided during this consultation include:

1. The May 3, 2013 report *Empirical Research in Support of Incentive Rate Setting in Ontario*. This report included PEG's recommendations for the inflation factor, productivity factor, and stretch factor assignments. The recommended stretch factor assignments were based on the results of two benchmarking models PEG developed and applied to Ontario electricity distributors: an econometric cost benchmarking model, and a unit cost, peer group benchmarking model. The May 3rd report also included TFP "backcasts" and statistical tests which showed that Hydro One and Toronto Hydro were having a statistically significant impact on the industry's TFP trend, thereby providing the empirical rationale for eliminating these companies from the sample used to set the productivity factor for the electricity distribution industry.

2. The May 31, 2013 report *Empirical Research in Support of Incentive Rate Setting in Ontario*. This report was identical to the May 3rd report but modified the data on Low Voltage (LV) charges paid by embedded distributors to host distributors. PEG provided both "clean" and "redlined" versions of this report, the latter of which showed precisely what changes had been made from the May 3rd report.

3. The June 14, 2013 memorandum *Supplementary Empirical Analyses*. This memorandum provided two empirical analyses that supplemented PEG's May 2013 reports: (1) an estimate of TFP growth for the Ontario electricity distribution industry using an average of each distributor's estimated TFP growth over the 2002-2011 period;

and (2) a re-estimate of the econometric model used to benchmark distributors' cost performance using a measure of total cost that excluded the LV charges that embedded distributors pay to host distributors.

4. The September 4, 2013 report *Empirical Research in Support of Incentive Rate-Setting: 2012 Update*. This report updated PEG's TFP and cost benchmarking analyses to include 2012 data. The report also included PEG's updated recommendations for the productivity factor and stretch factor assignments.

PEG's Recommendations

This report presents the final results of PEG's productivity and benchmarking research for the Ontario electricity distribution industry for the 2002-2012 period.

Productivity

PEG's estimate of the industry's TFP growth excludes Toronto Hydro and Hydro One because these firms directly and materially impact the industry's estimated TFP growth, and the measured TFP growth trend in an IR plan should be "external" to the utilities in the industry that are potentially subject to that plan. Using index-based methods, PEG estimated that TFP for the Ontario electricity distribution sector grew at an average rate of -0.33% per annum between 2002 and 2012.

Several factors lead PEG to conclude that a negative productivity factor would not be appropriate. One is that the Board is currently examining the application of revenue decoupling to electricity distribution. Not to prejudge the outcome of this Board examination, but a decoupling mechanism would largely address the impact of declining output on industry TFP and, by extension, industry revenue change. One of the main reasons electricity distributors' TFP has slowed and become negative in recent years is because of the decline in distributor output, and a revenue decoupling mechanism would counter this trend.

Another is that there may be concerns associated with the rate riders and related rate recovery mechanisms that exist in Ontario. Some costs transferred to the 2012 Trial Balance data may have been previously reflected in and recovered by a rate rider. If so, it would not be appropriate for costs previously recovered through rate riders to be reflected in the TFP trend, and therefore the rate adjustment mechanism, that will apply during an IR term. Doing so would mean increasing future customer rates to pay for costs that have already been recovered in previous customer rates.

Third, it is not clear that the negative 2002-2012 TFP trend is in fact industry-wide rather than the experience of a relatively small number of distributors. The RRFE will have multiple ratemaking options available to distributors. As previously noted, one of these options is designed to be "custom" to distributors with especially rapid capital investment needs. Although it is not clear which distributors will elect to file custom IR proposals, it is conceivable that distributors with historically high capital spending could depress industry-wide TFP trends, and thereby reduce the X factor in Price Cap IR, and later choose to opt out of this ratemaking approach precisely because of their atypical capital requirements. This would lead to higher price adjustments under Price Cap IR than are warranted for distributors with more typical capital requirements. Because of these concerns, PEG recommends that the productivity factor in Price Cap IR be set to zero.

Benchmarking

PEG developed an econometric model to benchmark distributors' total cost performance. PEG's recommended model finds that there is a statistically significant relationship between a distributor's total costs and five business condition variables: 1) the number of customers served; 2) kWh deliveries; 3) system peak capacity; 4) the average km of distribution over the sample period; and 5) the percent of customers added in the last 10 years.

PEG used the cost model to generate econometric evaluations of the cost performance of distributors by inserting values for each distributor's business condition variables into the cost model that is "fitted" with the estimated coefficients for the business condition variables. This process yields a value for the predicted (or expected) costs for each distributor in the sample given the exact business condition variables faced by that distributor. The model also generates confidence intervals around that cost prediction.

PEG believes that the empirical research used to develop its recommendations can provide a solid foundation for future incentive rate-setting in Ontario. PEG has estimated TFP trends and benchmarked the total costs of electricity distributors in Ontario. Our TFP and benchmarking studies can be updated and refined over time to accommodate new data from the industry or consider different business condition variables, including measures of service reliability such as SAIDI and SAIFI. Overall, PEG believes the methodologies used strike a reasonable balance between rigor, objectivity and feasibility (given the data constraints), while simultaneously developing empirical techniques that can provide a foundation for effective IR applications for Ontario in the future.

Overview of this Report

This report is structured as follows. After this introduction, Chapter Two details the basic indexing logic that underpins the calibration of X factors. Chapter Three presents PEG's input price research, which is necessary to estimate industry TFP trends. Chapter Four discusses data sources and issues associated with available data. Chapter Five estimates historical TFP growth for the Ontario electricity distribution industry for the 2002-2012 period. Chapter Six presents PEG's econometric research on the cost performance of Ontario electricity distributors. Chapter Seven presents concluding remarks.

There are also two appendices. Appendix One presents a mathematical decomposition of TFP growth into its various components. Appendix Two presents some technical details of PEG's econometric modeling.

2 Inflation and X Factors

This chapter will provide some background on developing inflation and X factors in index-based incentive regulation plans. We begin by presenting the indexing logic that illustrates the relationship between the parameters of indexing formulas and just and reasonable rate adjustments. We turn next to specific choices for inflation factors. We then discuss the X factor.

2.1 Indexing Logic

The Price Cap IR will use a price cap index (PCI) formula to restrict the change in electricity distribution prices. While PCIs vary from plan to plan, the PCI growth rate $(growthPCI)$ is typically given by the growth in an inflation factor (P) minus an X-factor (X) plus or minus a Z-factor (Z), as in the formula below:

$$growth\ PCI = P - X \pm Z. \qquad [1]$$

In North American regulation, the terms of the PCI are set so that the change in regulated prices mimics how prices change, in the long run, in competitive markets. This is a reasonable basis for calibrating utility prices since rate regulation is often viewed as a surrogate for the competitive pressures that would otherwise lead to "just and reasonable" rates. Economic theory has also established that competitive markets often create the maximum amount of benefits for society.[8] It follows that effective utility regulation should replicate, to the greatest extent possible, the operation and outcomes of competitive markets. A "competitive market paradigm" is therefore useful for establishing effective regulatory arrangements, and several features of competitive markets have implications for how to calibrate PCI formulas.

One important aspect of competitive markets is that prices are "external" to the costs or returns of any individual firm. By definition, firms in competitive markets are not able to affect the market price through their own actions. Rather, in the long run, the prices facing

[8] This is sometimes known as the "First Fundamental Welfare Theorem" of economics, but it should be noted that the theoretical finding that competition leads to efficient outcomes does not apply under all conditions (*e.g.* if there are externalities whose costs or benefits are not reflected in competitive market prices).

any competitive market firm will change at the same rate as the growth in the industry's unit cost.

Competitive market prices also depend on the *average* performance in the industry. Competitive markets are continually in a state of flux, with some firms earning more and others less than the "normal" rate of return on invested capital. Over time, the average performance exhibited in the industry is reflected in the market price.[9]

Taken together, these features have the important implication that in competitive markets, returns are commensurate with performance. A firm can improve its returns relative to its rivals by becoming more efficient than those firms. Companies are not disincented from improving efficiency by the prospect that such actions will be translated into lower prices because the prices facing any individual firm are external to its performance. Firms that attain average performance levels, as reflected in industry prices, would earn a normal return on their invested capital. Firms that are superior performers earn above average returns, while firms with inferior performance earn below average returns. Regulation that is designed to mimic the operation and outcomes of competitive markets should allow for this important result.

Another implication of the competitive market paradigm bears a direct relationship to the calibration of PCI formulas. As noted above, in the long run, competitive market prices grow at the same rate as the industry trend in unit cost. Industry unit cost trends can be decomposed into the trend in the industry's input prices minus the trend in industry total factor productivity (TFP). Thus if the selected inflation measure is approximately equal to the growth in the industry's input prices, the first step in implementing the competitive market paradigm is to calibrate the X factor using the industry's long-run TFP trend.

The mathematical logic underlying this result merits explanation. We begin by noting that if an industry earns a competitive rate of return in the long run, the growth in an index of the prices it charges (its output prices) will equal its growth in unit cost.

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[9] This point has also been made in the seminal 1986 article in the Yale Journal of Regulation, *Incentive Regulation for Electric Utilities* by P. Joskow and R. Schmalensee. They write "at any instant, some firms (in competitive markets) will earn more a competitive return, and others will earn less. An efficient competitive firm will expect on average to earn a normal return on its investments when they are made, and in the long run the average firm will earn a competitive rate of return"; *op cit*, p. 11.

$$\textit{trend Output Prices}^{\textit{Industry}} = \textit{trend Unit Cost}^{\textit{Industry}}. \quad [2]$$

As stated above, the trend in an industry's unit cost is the difference between trends in its input price index and its TFP index. The full logic behind this result is presented below:

$$\begin{aligned}
\text{trend Unit Cost}^{\text{Industry}} &= \text{trend Cost}^{\text{Industry}} - \text{trendOutput Quantities}^{\text{Industry}} \\
&= \left(\textit{trend}\ \text{Input Prices}^{\text{Industry}} + \textit{trend}\ \text{Input Quantities}^{\text{Industry}}\right) \\
&\quad - \textit{trend}\ \text{Output Quantities}^{\text{Industry}} \\
&= \textit{trend}\ \text{Input Prices}^{\text{Industry}} \\
&\quad - \left(\text{trend Output Quantities}^{\text{Industry}} - \textit{trend}\ \text{Input Quantities}^{\text{Industry}}\right) \\
&= \text{trend Input Prices}^{\text{Industry}} - \textit{trend}\ \text{TFP}^{\text{Industry}}.
\end{aligned} \quad [3]$$

Substituting [3] into [2] we obtain

$$\textit{trend Output Prices}^{\textit{Industry}} = \textit{trend Input Prices}^{\textit{Industry}} - \textit{trend TFP}^{\textit{Industry}} \quad [4]$$

Equation [4] demonstrates the relationship between the X factor and the industry TFP trend. If the selected inflation measure (*P* in equation [1]) is a good proxy for the industry's trend in input prices, then choosing an X factor equal to the industry's TFP trend causes output prices to grow at the rate that would be expected in a competitive industry in the long run. This is the fundamental rationale for using information on TFP trends to calibrate the X factor in index-based PBR plans.

It should be emphasized that both the input price and TFP indexes above correspond to those for the relevant utility *industry*. This is necessary for the allowed change in prices to conform with the competitive market paradigm. In competitive markets, prices change at the same rate as the industry's trend in unit costs and are not sensitive to the unit cost trend of any individual firm. This is equivalent to saying that competitive market prices are external to the performance of any given firm in the industry.

There are two main options for selecting inflation factors in index-based PBR plans. One general approach is to use a measure of economy-wide inflation such as those prepared by government agencies. Examples include the Gross Domestic Product Implicit Price Index (GDP-IPI) or the US Price Index for Gross Domestic Product (GDP-PI). An established alternative is to construct an index of external price trends for the inputs used to provide utility services. This approach is explicitly designed to measure input price inflation of the regulated industry.[10] The Board has found that the inflation factor in Price Cap IR will be closer to a measure of industry input price inflation, so the indexing logic presented in equations [1] through [4] is valid for Price Cap IR.

While industry TFP and input price measures are used to calibrate a PCI, in most index-based incentive regulation plans the X factor is greater than what is reflected in the utility industry's long-run TFP trend. This is because industry TFP trends are usually measured using historical data from utility companies. Utilities have historically not operated under the competitive market pressures that naturally create incentives to operate efficiently, and it is also widely believed that traditional, cost of service regulation does not promote efficient utility behavior.

Incentive regulation is designed to strengthen performance incentives, which should in turn encourage utilities to increase their efficiency and register more rapid TFP growth relative to historical norms. It is also reasonable for these performance gains to be shared with customers since incentive rate-setting is designed to produce "win-win" outcomes for customers and shareholders. For this reason, nearly all North American incentive regulation plans have also included what are called "consumer dividends" or productivity "stretch factors" as a component of the X factor. The stretch factor reflects the expected acceleration in TFP relative to historical TFP trends.[11]

2.2 X Factors and Productivity Measurement

2.2.1 TFP Basics

As discussed, the most common approach for setting X factors in North America is to calibrate productivity factors using measures of industry rather than individual company TFP growth. Since productivity plays an important role in North American incentive regulation, it is valuable to review some basics on TFP measurement. We will also briefly consider the

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[10] A less common approach is to set inflation measures using changes in *output* prices charged by peer utilities. It is important for any such peer-price inflation measure to be constructed carefully so that it reflects the circumstances of companies that are very similar to the utility subject to the incentive regulation plan.

[11] More precisely, the stretch factor is that portion of the expected acceleration of TFP growth that it passed through to the change in customer rates as a form of benefit-sharing under the plan.

relationship between TFP growth and the various factors that can "drive" changes in productivity over the term of an incentive regulation plan.

A TFP index is the ratio of an output quantity index to an input quantity index.

$$TFP = \frac{Output\ Quantities}{Input\ Quantities}. \qquad [5]$$

TFP therefore represents a comprehensive measure of the extent to which firms convert inputs into outputs. Comparisons can be made between firms at a point in time or for the same firm (or group of firms) at different points in time.

The growth trend in a TFP trend index is the difference between the trends in the component output quantity and input quantity indexes.

$$trend\ TFP = trend\ Output\ Quantities - trend\ Input\ Quantities. \qquad [6]$$

The trend in output quantity of an industry summarizes trends in the workload that it performs. If output is multidimensional, the growth in each output quantity dimension considered is measured by a subindex. The growth in the output quantity index depends on the growth in the quantity subindexes.

The trend in input quantity of an industry summarizes trends in the amounts of production inputs used. TFP grows when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index. TFP can rise or fall in a given year but in most industries typically trends upward over time.

As equation [3] shows, a TFP index will capture the effect of all developments that cause the unit cost of an industry to grow more slowly than its input prices. The sources of TFP growth are diverse. Appendix One of this report presents a technical, algebraic decomposition of TFP growth into its various components. This section provides a non-technical discussion of the sources of TFP growth.

One component is technical change. New technologies permit an industry to produce a given amount of output with fewer inputs. Economies of scale are a second source of TFP growth. Scale economies are realized when cost grows less rapidly than output. A third important source of TFP growth is the elimination of "X inefficiencies", or inefficiencies that arise when companies fail to operate at the maximum efficiency that technology allows. TFP will grow (decline) to the extent that X inefficiency diminishes (increases).

In most regulatory proceedings where TFP trends have been estimated using indexing methods, long-run TFP trends have been estimated using 10 or more years' worth of historical data. A 10 year period is generally considered to be sufficient for smoothing out short-term fluctuations in TFP that can arise because of changes in output (*e.g.* kWh deliveries that are sensitive to changes in weather and economic activity) and the timing of different types of expenditures. This long-run historical TFP trend is then assumed (either implicitly or explicitly) to be a reasonable proxy for the TFP growth that is expected over the term of the indexing plan.

This is not always an appropriate assumption. For example, it is often not warranted to assume that TFP growth measured for short historical periods will be a good proxy for future trends. Shorter sample periods are more likely to be distorted by factors such as the timing of expenditures or unusual output growth. There is accordingly less confidence that past TFP trends are a good proxy for the future trend if the available data only allows TFP to be calculated for a relatively short period. As discussed, a general rule of thumb in regulatory proceedings is that a minimum of 10 years of data are needed to calculate a generally reliable estimate of the industry's long-run TFP trend.

2.2.2 Econometric Estimation of TFP Trends

In addition to estimating historical TFP trends using indexing methods, econometric methods can be used to estimate TFP growth. The econometric approach essentially uses statistical methods to estimate the underlying "drivers" of TFP growth, such as technological change and the realization of scale economies. Statistical techniques can estimate the impact of each of these sources of TFP growth by using data from electricity distributors operating under a wide variety of business conditions. Once those underlying TFP "drivers" are estimated, they can be combined with data on the changes in the business condition variables that apply for either individual electricity distributors or for groups of distributors. This information can then be brought together using a methodological framework that draws on the decomposition of TFP outlined in Appendix One of this report.

The econometric approach to estimating TFP growth has a number of potential advantages. One is that it is rigorous and has a strong foundation in statistical methods and the economics literature. This approach can also be tailored to reflect the specific business conditions, and "TFP drivers," of the Ontario power distribution industry.

The main disadvantage of the econometric approach is its complexity. Econometrics often involves technically complex statistical methods. The TFP estimates that result from econometric modeling therefore tend to be less transparent and not as easy to understand as those resulting from indexing methods. While unnecessary complexity should be avoided in regulatory proceedings, it is not always practical or desirable to rely on simpler, index-based TFP estimates when calibrating the terms of PCI formulas. This would be the case, for example, if the available time series data was either too short, or distorted by transitory factors, and therefore did not yield reliable estimates of long-term TFP trends.

2.2.3 Stretch Factors

The final component of the X factor is the productivity "stretch factor" or consumer dividend. The stretch factor is designed to reflect incremental efficiency gains utilities are expected to achieve under incentive regulation. Adding a stretch factor to the productivity factor allows a share of these anticipated efficiency gains to be reflected in price adjustments under the incentive regulation plan. Because a positive stretch factor leads prices to grow less rapidly under an incentive regulation plan, stretch factors allow customers to share in the expected benefits of incentive regulation while the plan is in effect.

In practice, North American regulators have chosen the values for stretch factor almost entirely on the basis of judgment. This judgment has led to approved stretch factors in a relatively narrow range, between 0.25% and 1%, with an average value of approximately 0.5%. PEG presented evidence on these approved consumer dividends, and on approved X factors more generally, in our report for 2nd Generation IRM.[12]

[12] See M.N. Lowry *et al*, *Second Generation Incentive Regulation for Ontario Power Distributors*, June 13, 2006, Table 1 on p. 55. The average stretch factor in the 11 plans on this table for which there were acknowledged stretch factors was 0.54%.

3 Input Price Research

Input price research is a component of TFP analysis and total cost benchmarking. It is used to determine input quantities in the TFP calculation, and input prices are used as independent variables in the econometric benchmarking model. The main challenge when estimating input price inflation is identifying the best available subindices for measuring inflation in the prices of electricity distributors' capital, labor, and non-labor OM&A inputs, respectively.

This Chapter will summarize PEG's research on input price trends for Ontario electricity distributors. We begin by discussing the choices for inflation subindices. We then summarize overall input price inflation using these subindices and present our estimates of historical input price inflation for Ontario's electricity distribution industry.

3.1 Inflation Subindices

3.1.1 Subindex Weights

Industry-wide input price inflation is computed as the weighted average of inflation in price subindices for different inputs, where the weights are equal to each input's share of the industry's total cost. When estimating industry-wide input price and TFP trends, it is appropriate for the weights in the IPI to be calculated using average cost shares for the industry as a whole. This requires information on the share of each of these input categories in the total cost of the Ontario electricity distribution industry.

Industry total cost was computed as the sum of capital cost and distribution OM&A expenses. The weight that PEG applies to the capital input price index (described below) is calculated as the electricity distributors' capital cost divided by the total cost measure used in the TFP analysis. It is appropriate to use the cost measure used in the TFP analysis since the input price inflation plays a role in the computation of TFP growth *(e.g.* the change in OM&A inputs is calculated as the growth in OM&A expenses minus the growth in OM&A input prices).

Developing separate weights for labor and non-labor OM&A input prices requires information on labor's share of OM&A expenses. These data are confidential for specific distributors in Ontario. However, in its 3rd Gen IR inflation factor proposal, Staff estimated that labor expenses accounted for 70% of distributors' OM&A expenses.[13] PEG used this industry-wide, estimated ratio to obtain estimates of the industry's labor cost and non-labor OM&A costs. Cost shares for labor and non-labor OM&A inputs were then obtained by dividing these respective costs by the total cost of the electricity distribution industry.

3.1.2 Capital Input Prices

PEG has used a capital service price to measure capital input prices. In this report, we will use these terms synonymously. The formula for the capital service price index is:

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot r_t \qquad [7]$$

The two terms of the service price formula reflect the "return of" and the "return on" capital, respectively. The first term corresponds to depreciation, where *d* is the economic rate of depreciation on the capital stock. The second term corresponds to the rate of return on capital, where r_t is the opportunity cost of plant ownership per dollar of plant value. WKA_t is an element of both the first and second terms. It corresponds to a price index that reflects the cost of purchasing and installing distribution assets. Implementing this formula requires measures for the rate of depreciation *d*, the rate of return *r*, and the asset price index *WKA*.

In this study, PEG uses a "geometric" depreciation rate where capital decays at a constant rate each year. Academic studies that examine the prices paid for used capital assets in secondary markets lend support for this pattern of depreciation.[14] PEG also consulted on this issue with the PBR Working Group, and it supported a geometric depreciation rate. The geometric rate of depreciation *r* was estimated to be 4.59%.[15]

The rate of return r_t was computed as the weighted average cost of capital (WACC) for Ontario distributors. This is appropriate since the rate of return in equation [7] is designed to reflect a distributor's opportunity cost of capital, not its actual returns. The WACC was calculated using Board-approved values for long-term debt rates, short-term debt rates, and

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[13] *Staff Discussion Paper on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, February 28, 2008, pp. 52.

[14] Hulten and Wykoff (1981)

[15] This was equal to a weighted average of the declining balance rates estimated by Hulten and Wykoff *op cit* for equipment and structures, divided by the estimated lifetimes for different assets. Because depreciation factors more directly into our cost estimates, details of this calculation are provided in Chapter Four of this report.

return on equity since 2002. Before May 2008, the Board approved different long-term debt and equity rates for different size categories of distributors. PEG used the Board-approved values for medium-small companies in the years before 2008 (*i.e.* from 2002 through 2007) because this size category accounts for the largest number of distributors in the Province. In all years, we applied the Board's current, deemed capital structure when computing the WACC. The current capital structure assumes 40% equity, 56% long-term debt, and 4% short-term debt. PEG consulted on this issue with the PBR Working Group, and the Working Group supported PEG's recommended approach of using the Board-approved values for long-term debt rates, short-term debt rates, and return on equity and the capital structure to calculate the rate of return r_t.

Our preferred measure of the asset-price index WKA_t is the Electric Utility Construction Price Index (EUCPI) for distribution assets. This index includes the costs of purchasing and installing distribution assets and therefore reflects the costs of construction labor. The EUCPI is calculated by Statistics Canada for distribution systems throughout Canada. Statistics Canada does not publish data on the EUCPI specifically for Ontario.

Table 1 presents information on this capital service price for Ontario distributors over the 2002-2012 period. The table presents information on annual inflation in each of the three components of the capital service price, although with a geometric rate of depreciation the depreciation rate is by definition constant in all sample years. We also compute annual changes in the overall capital service price index.[16]

It can be seen that capital service prices grew at an average annual rate of 0.38% per annum over the sample period. The EUCPI grew at an average rate of 2.14% per annum between 2002 and 2012. Measured WACC declined at an average rate of 2.86% over this period.

[16] PEG calculated the values for the WACC presented in Table 1 using month-weighted averages of the Board's determined values of the cost of capital parameters. The Board typically updates these values in May, but updates have taken place at different times within the course of a year.

Table 1

Calculation of Capital Service Price Index

Year	EUCPI	Annual Growth	WACC*	Annual Growth	Depreciation Rate	Capital Price Index	Capital Price Inflation
2002	130.5		8.30%		4.59%	16.74	
2003	130.6	0.1%	8.30%	0.00%	4.59%	16.82	0.5%
2004	131.1	0.4%	8.30%	0.00%	4.59%	16.85	0.2%
2005	133.6	1.9%	8.30%	0.00%	4.59%	17.01	0.9%
2006	142.4	6.4%	7.74%	-6.88%	4.59%	16.88	-0.7%
2007	148.8	4.4%	7.35%	-5.22%	4.59%	17.30	2.4%
2008	150.3	1.0%	7.27%	-1.11%	4.59%	17.72	2.4%
2009	151.1	0.5%	7.32%	0.63%	4.59%	17.93	1.2%
2010	155.1	2.6%	7.40%	1.14%	4.59%	18.30	2.0%
2011	160.1	3.2%	7.08%	-4.46%	4.59%	18.32	0.1%
2012	161.6	0.9%	6.23%	-12.69%	4.59%	17.40	-5.2%
Average		**2.14%**		**-2.86%**			**0.38%**

* The WACC used in these calculations is the average of the approved cost of capital for each month of the calendar year.

3.1.3 OM&A Input Prices

PEG believes the best generic and off-the-shelf labor price index to use in our input price and TFP research is average weekly earnings (AWE) for all workers in Ontario.[17] This index reflects labor price trends for both salaried and hourly workers. It also captures Province-wide labor price pressures, not specific developments or labor settlements for Ontario's electricity distribution sector.

"Non-labor OM&A" covers a wide and diverse set of expenditures. These inputs include insurance, fuel, office supplies, and some IT software. No single, publicly-available price index focuses solely on these inputs. Constructing such an index using highly disaggregated price subindices for the relevant input categories, and their associated shares of distributors' non-labor OM&A cost, would be laborious and non-transparent. Even if it was feasible to construct such an index using publicly available data, it would not be easy to update it annually during the term of the Price Cap IR.[18]

Because of these practical challenges, PEG prefers the GDP-IPI to measure non-labor OM&A input prices. This option reflects the breadth and diversity of non-labor OM&A inputs, since it applies to all final domestic demand in Canada.

Table 2 provides information on inflation in the AWE-All Employees and the GDP-IPI indices over the 2002-2012 period.[19] It can be seen AWE inflation has averaged 2.45% per annum, while the average annual growth in the GDP-IPI has been 1.90%. Overall OM&A input prices have grown at an average rate of 2.29% per annum over the 2002-2012 period.

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[17] Techncially, this is the Average Weekly Earnings for the industrial aggregate in Ontario, and the series providing these data on annual basis is series number 281-0027. It should be recognized, however, that the "industrial aggregate" in Ontario includes goods-making and non-goods making industries.

[18] Another complication is that at least some inflation in non-labor OM&A input prices will actually include inflation in *labor* prices. The reason is that distributors' contracts for outsourced, operational services are reported as non-labor OM&A expenses. The cost of these outsourcing contracts is not separately categorized in the RRRs. Labor is an important cost component of many outsourcing contracts. Consequently, factors impacting labor prices will be reflected, to some extent, in the amounts reported by distributors as non-labor, OM&A expenses.

[19] The GDP-IPI inflation reported in Table 2 is the average value for the relevant year. It differs from the GDP-IPI inflation rate the Board has used to determine the inflation factor for 3rd Gen IR. The Board's inflation factor is not calculated on a calendar-year basis.

Table 2

OM&A Input Price Inflation

	AWE- All Employees		GDPIPI		OM&A Price Index	
Year	Ontario	Annual Growth	Canada	Annual Growth	Level	Annual Growth
2002	710.73		90.23		100.00	
2003	728.23	2.43%	91.70	1.62%	102.21	2.19%
2004	748.78	2.78%	93.38	1.81%	104.79	2.49%
2005	776.19	3.60%	95.40	2.15%	108.16	3.16%
2006	788.62	1.59%	97.68	2.36%	110.14	1.82%
2007	818.93	3.77%	99.98	2.33%	113.88	3.34%
2008	838.14	2.32%	102.48	2.47%	116.60	2.36%
2009	849.15	1.31%	103.75	1.24%	118.11	1.28%
2010	882.21	3.82%	104.80	1.01%	121.68	2.98%
2011	894.71	1.41%	107.23	2.29%	123.73	1.67%
2012	908.00	1.47%	109.15	1.78%	125.68	1.57%
Average		**2.45%**		**1.90%**		**2.29%**

3.2 Historical Estimates of Industry Input Price Inflation

Overall input price inflation is estimated as a weighted average of the selected input price subindices. The weights are based on the share of the total cost measure used in the TFP analysis that is associated with the respective input. These cost shares are 61.9% for capital, 26.7% for labor, and 11.4% for non-labor OM&A expenses.

Table 3 presents data on input price inflation for the 2002-2012 period. It can be seen that inflation grew at an average annual rate of 1.11% over the sample period. Overall input prices declined in 2012 from the previous year due to a 5.2% decline in the capital service price. This decline reflects the decline in interest rates experienced in the market which is reflected in the Board's approved cost of capital parameters.

Table 3

Input Price Inflation

	OM&A Input Price						Capital Service Price			Input Price Inflation	
Year	GDPIPI-Canada	Annual Growth	Weight	AWE- All Employees-Ontario	Annual Growth	Weight	Index	Annual Growth	Weight	Index	Annual Growth
2002	90.23			710.73			16.74			100.00	
2003	91.70	1.62%	11.4%	728.23	2.43%	26.7%	16.82	0.47%	61.9%	101.13	1.13%
2004	93.38	1.81%	11.4%	748.78	2.78%	26.7%	16.85	0.19%	61.9%	102.21	1.06%
2005	95.40	2.15%	11.4%	776.19	3.60%	26.7%	17.01	0.92%	61.9%	104.04	1.77%
2006	97.68	2.36%	11.4%	788.62	1.59%	26.7%	16.88	-0.74%	61.9%	104.29	0.23%
2007	99.98	2.33%	11.4%	818.93	3.77%	26.7%	17.30	2.42%	61.9%	107.22	2.77%
2008	102.48	2.47%	11.4%	838.14	2.32%	26.7%	17.72	2.39%	61.9%	109.80	2.38%
2009	103.75	1.24%	11.4%	849.15	1.31%	26.7%	17.93	1.21%	61.9%	111.17	1.24%
2010	104.80	1.01%	11.4%	882.21	3.82%	26.7%	18.30	2.04%	61.9%	113.86	2.39%
2011	107.23	2.29%	11.4%	894.71	1.41%	26.7%	18.32	0.13%	61.9%	114.69	0.72%
2012	109.15	1.78%	11.4%	908.00	1.47%	26.7%	17.40	-5.19%	61.9%	111.72	-2.62%
Average		**1.90%**			**2.45%**			**0.38%**			**1.11%**

4 Data for Total Factor Productivity and Total Cost Analysis

As previously noted, the Board has found that the productivity factor is to be based on the estimated TFP trend for the Ontario electricity distribution industry and stretch factors assignments are to be be based on benchmarking of distributors' total costs. PEG was asked to provide recommendations for the productivity factor and benchmarking analysis so PEG's work included estimates of industry TFP growth and benchmarking comparisons of Ontario distributors' total cost. These analyses require estimates of Ontario distributors' capital stocks. PEG notes that capital typically accounts for more than half the costs of electricity distribution services. PEG developed these capital measures using data from several sources. In some instances, the Board requested additional information from distributors to support PEG's work.

This chapter discusses the data used in PEG's work, with an emphasis on capital measurement. We begin by discussing the primary data sources. We then discuss the calculation of capital additions, capital stocks and the Board's supplemental data request. Next we discuss the calculation of capital cost. Finally, we discuss the computation of total cost measures for our TFP and benchmarking work. It should be noted that all data used in PEG's analysis is posted on the Board's website[20].

4.1 Primary Data Sources

Extensive data are available on the operations of Ontario power distributors. Cost data are gathered chiefly under Section 2.1.7 of the Board's Electricity Reporting and Record Keeping Requirements ("RRR"). This Trial Balance information is filed annually. The trial balances include highly itemized data on gross plant value. The accumulated "amortization" (*i.e.* depreciation) on electric utility property plant and equipment is also reported, as well as the accumulated amortization on tangible and intangible plant.

[20] **Defining and Measuring Performance of Electricity Transmitters and Distributors (EB-2010-0379)**

An important supplemental source of Ontario electricity distributor data filed annually under Section 2.1.5 of the Board's RRR (i.e., the Performance Based Regulation ("PBR") information). The PBR filings provide data on plant value as well as plant additions, which are not reported in the trial balances.[21] The PBR data also include information on output, revenue, and utility characteristics. Data on billed kWh, billed kW, total revenue, and the number of customers served are currently available for nine customer classes: residential, general service < 50 kW, general service > 50 kW, large users, subtransmission customers, embedded distributors, street lighting, sentinel lighting, and unmetered scattered load.

The available RRR data have a number of strengths that support their use in TFP and total cost benchmarking research. The trial balance cost data are highly detailed. The PBR data also include detailed information on revenues and outputs, including data on peak distribution loads.

RRR data also have some limitations. The number of years of information on capital expenditures (i.e., 10 years) is insufficient to calculate accurate capital quantities for the purpose of TFP and total cost estimation. While 10 years of input and output quantity data is enough to compute a long-run TFP growth trend, more than 10 years of data is needed to calculate the capital quantities that are used when computing that trend. An extensive time series of capital data is valuable for developing capital cost measures, as we explain below.

4.2 Data on Capital and Capital Additions

Accurate and standardized capital cost measures require many years of consistent, detailed plant additions data. There is no rule of thumb in this regard, but more years of data is always better. RRR data on plant additions are available since 2002.[22] PEG advises that using 10 years of data on capital additions limits the reliability of the capital measures that can be computed using RRR data.

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[21] Some capital spending data are also provided on distributors' audited financial statements.

[22] Direct data on plant additions are available from 2002 through Section 2.1.5 of the RRRs; indirect measures of plant additions, using Trial Balance data on changes in gross asset values and asset retirements, would only be available from 2003. With respect to the Section 2.1.5 data, the PBR Working Group advised against relying on it and instead recommended that PEG use the Trial Balance data.

Measuring the quantity of capital begins with a *benchmark* capital stock, or (price deflated) value of net plant value in some base year. The base year for the capital quantity should be as distant from the present day as is practical. As the base year becomes more remote, all else equal the value of capital depends more on observed values for capital additions that are added to this benchmark value rather than the value of the benchmark capital stock itself.

Capital measures typically become more accurate when the measured capital values depend more on cumulative capital additions rather than the benchmark capital value. Capital additions between any two periods are measured more accurately when they are appropriately "deflated" by contemporaneous changes in capital asset prices. This, in turn, is equivalent to separating capital expenditures into a change in (gross) capital input quantities and a change in the prices paid for capital inputs. Since TFP growth is defined as the change in total output quantity minus the change in total input quantity, only the change in real capital inputs is used directly to measure TFP growth. Building up capital measures from the longest, practical time series of deflated capital additions therefore enables TFP measures to place greater emphasis on direct changes in capital input quantities. This leads to more accurate measures of capital input than relying on benchmark capital values, where there is more uncertainty about how to deflate reported net plant in a given, benchmark year.[23]

In order to make our capital benchmark year as remote from the present day as possible, the Board provided PEG with plant values from the Municipal Utility Databank (MUDBANK). MUDBANK is a dataset on municipal utilities that was compiled by Ontario Hydro under the previous electric utility industry structure. The MUDBANK data allowed PEG to use 1989 as the capital benchmark year in our TFP analysis.

PEG notes that the 1989 capital benchmark did not prove to be feasible for six distributors. One was Hydro One, which was part of the previous Ontario Hydro. MUDBANK contains data on the municipal utilities for which Ontario Hydro performed a regulatory-type function, but not on Ontario Hydro itself, so Hydro One data before 2002 are

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[23] If a full series of capital stock additions was available for each distributor in the industry since its inception, it would not be necessary to start with a benchmark capital stock, for actual data on capital additions could then be used to develop estimates of capital quantity in any given year. In practice, however, it is almost never possible to obtain the full historical series of capital stock changes for any distributor, so capital quantity measurement must begin with a benchmark value in a base year.

not available. Similarly, MUDBANK data are not available in all necessary years for Algoma Power, PUC Distribution, Canadian Niagara Power, Greater Sudbury Hydro, and Innisfil Hydro. For these companies and for Hydro One, we therefore used a 2002 benchmark capital stock value

MUDBANK data are available for all municipal utilities through 1997 and for some municipal utilities through 1998. RRR data are available from 2002 to the present for all distributors. Because there was a data "gap" between these data sources between 1997 and 2002, PEG had to interpolate capital additions data between 1997 and 2002.

In most cases, PEG was able to infer capital additions over this period using the differences in existing gross asset values between those years. This was done simply by calculating the difference between gross capital assets in 2002 and gross capital assets in 1997, dividing this difference by five, and adding in a measure of estimated capital retirements in these years. Based on RRR data for the distributors, we estimated annual retirements to be 0.5% of gross capital values.

In some cases, however, PEG noticed precipitous drops in gross assets between 1997 and 2002. These drops did not appear to be plausible. Discussions with the PBR Working Group revealed that, in some mergers over the 1997-2002 period, the gross capital stocks reported in 2002 for the merged company were in fact equal to *net* asset values in those years. The actual gross stocks were accordingly higher than what was reported by these distributors in 2002.

In light of this fact, for those distributors with precipitous drops in gross capital values between 1997 and 2002, PEG inferred capital expenditures between these years in the following way:

1. First, we assumed that what was reported as gross plant in 2002 was actually *net* plant in 2002.

2. PEG estimated each distributor's (Accumulated Depreciation/Gross Asset) (i.e. (AD/G)) ratio for 1997 using the MUDBANK data; we assumed that this estimate was accurate and that this ratio did not change between 1997 and 2002.

3. Given those two pieces of information, we inferred a measure of gross plant for each of the necessary companies in 2002 by recognizing that:
    a. Net plant = Gross plant (G) – Accumulated Depreciation (AD), which implies:
    b. Net plant/Gross plant = 1 – AD/G, and therefore:
    c. Gross plant = Net plant/(1-AD/G)

4. PEG inserted net plant for 2002 (as assumed in Step 1) and the estimate AD/G (computed in step 2) into the equation in Step 3c to derive an estimate of Gross plant in 2002. PEG obtained estimates of 2002 gross plant in this way for each of the distributors with precipitous drops in gross plant between 1997 and 2002.

5. Given the estimate for 2002 gross plant from Step 4, capital additions for the relevant group of distributors was estimated in each year between 1997 and 2002 as (Gross plant 2002 – Gross plant 1997)/5, plus the estimate of capital retirements in each year.

PEG also used the MUDBANK and RRR data to estimate capital additions in other years after the 1989 benchmark year. We used differences in MUDBANK gross capital values between 1989 and 1997 (and, where the data were available, 1998) to estimate gross capital additions over this period. Although capital additions data were available directly from the PBR Section of the RRRs, the PBR Working Group advised against relying on the PBR data and instead recommended that PEG use the Trial Balance data. [24]

Capital additions for smart meters in the 2006-2012 were an important component of capital additions during these years. Many distributors booked these additions to a deferral account while the smart meter rollout was in progress and analog meters were still on distributors' books. A full series of annual changes in smart meter capital additions was accordingly not available from RRR data sources.

PEG obtained data on annual capital additions for smart meters through a supplementary data request from the Board.[25] In addition, the Board's supplemental data request asked distributors to provide additional information on two sources of costs for the 2002-2011 period: 1) ownership of high-voltage (HV) transmission substations, and whether account 1815 of the RRRs included amounts that were not related to ownership of HV equipment or capital contributions related to HV equipment; and 2) charges for low voltage (LV) services provided by "host" distributors to other distributors embedded within their

[24] It should also be noted that data were available from various sources in 2000 and 2001, although not for all distributors. Many stakeholders who took part in the PBR Working Group discussions had concerns with the accuracy of the data that were available. The PBR Working Group therefore recommended that the available 2000-01 data not be used in PEG's TFP or benchmarking analyses.

[25] On February, 26, 2013, the Board issued a letter to electricity distributors asking them to file certain information with the Board in order to support the Board's further empirical work on the electricity distribution sector (Letter).

systems. All three of these cost components were important for developing appropriate cost measures for the purposes of total cost benchmarking, as we explain in Section 4.4.

4.3 2012 Data Issues

PEG's empirical analysis was impacted by two issues with distributors' 2012 data: 1) a number of distributors cleared balance sheet deferral accounts in 2012 and moved the associated costs to their Trial Balance OM&A accounts; and 2) at least 13 distributors adopted international financial reporting standards in 2012. We address these issues in turn below.

From 2006 through 2011, distributors recorded income from rate adders, capital amortization and incremental OM&A in smart meter deferral accounts. In 2012, many distributors applied for and were granted Board approval to move booked assets to meter account number 1860 and the other income and expense items to the relevant Trial Balance accounts. This caused a step increase in reported costs in 2012. These are one-time expenditures that are not consistent with the industry's long-run TFP experience and which will not be repeated during the term of the Price Cap IR. Therefore, the Board determined that incremental OM&A associated with smart meters, as well as smart meter capital expenditures, should not be reflected in the productivity factor to be used in Price Cap IR.

The relevant deferral account (account 1556) includes incremental OM&A as well as amortization (i.e. depreciation) associated with smart meter investments. PEG does not use amortization data in our TFP analysis, but the amortization expenses were not separately itemized for each distributor in account 1556. It was accordingly necessary to estimate the depreciation booked to account 1556 on smart meter investments. PEG estimated these values by applying our 4.59% composite depreciation rate to each distributor's annual smart meter expenditures, as reported on the supplemental data request. These estimated depreciation expenses were then netted out of the account 1556 balances that were "cleared" to the RRR Trial Balance accounts in the year that they were cleared. The resulting net figure was the estimate of incremental OM&A associated with smart meters, and those incremental OM&A costs were subtracted from PEG's cost measure used for the TFP analysis. However, both the smart meter capital expenditures and the incremental OM&A associated with smart meters were included in PEG's computation of each distributor's benchmarking cost measure, since smart meters are part of the capital stock that distributors use to provide service to customers.

PEG also had to adjust its approach to estimating capital additions for some distributors in 2012. For the 2002-2011 period, capital expenditures were estimated each year using differences in each distributor's gross asset value plus an assumed rate of annual asset replacement. These capital expenditures, in turn, entered into the formula used to estimate annual changes in capital input. In 2012, however, this method would have led to implausibly negative estimates of capital expenditures for 15 distributors. One of the main factors contributing to these implausible capital expenditure estimates was the switch to IFRS accounting; eight of the 15 identified distributors adopted IFRS accounting in 2012. For all 15 distributors where using differences in gross plant values would have led to implausibly negative capital expenditures, PEG used the distributors' reported capital additions (from the PBR section of the RRRs) in place of our previous method.[26]

The switch to IFRS also impacted reporting on contributions in aid of construction (CIAC). Under IFRS, the previously reported values for CIAC are reported as deferred revenue and appear on the liability side of the balance sheet in Account 2440. To determine the CIAC for 2012, for all distributors, PEG added the CIAC balances in account 1995 (Contributions and Grants – Credit) at the end of the year and the deferred revenue booked in account 2440 (Deferred Revenues) to determine a total CIAC balance at the end of 2012. The CIAC balance in 2011 was then subtracted from this sum. If this difference was positive, it was taken to be 2012 CIAC for that distributor. If the difference was negative, PEG used zero as the value for CIAC.

[26] Staff has confirmed that 13 distributors adopted IFRS accounting in 2012 (as noted on Page 2 of the 2012 Electricity Distributor Yearbook): Atikokan Hydro Inc., Enersource Hydro Mississauga Inc., EnWin Utilities Ltd., Grimsby Power Incorporated, Guelph Hydro Electric Systems Inc., Halton Hills Hydro Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, Lakefront Utilities Inc., Norfolk Power Distribution Inc., Oshawa PUC Networks Inc., PowerStream Inc. and Rideau St. Lawrence Distribution Inc. Five of these distributors – Halton Hills, Lakefront Utilities, Norfolk Power Distribution, Oshawa PUC Networks and Rideau St. Lawrence – did not have large, negative estimated capital expenditures using PEG's previous method for estimating capital expenditures, and accordingly we did not adjust our capital expenditures calculation for these distributors in 2012. Seven other distributors where PEG relied on reported 2012 capital additions from the PBR section of the RRRs were Brantford Power, E.L.K. Energy, Hydro Hawkesbury, Niagara Peninsula, Orangeville Hydro, Parry Sound Power, and Whitby Hydro.

4.4 Computing Capital Cost

PEG estimated the cost of utility plant in a given year t (CK_t) as the product of the capital service price index (WKS_t) discussed in Chapter Three and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_t = WKS_t \cdot XK_{t-1}. \qquad [7]$$

The formula for the capital service price index is

$$WKS_t = d \cdot WKA_t + WKA_{t-1} \cdot r_t \qquad [8]$$

This is the capital service price presented in Chapter Three. The first term in the expression corresponds to the cost of depreciation. The second term corresponds to the rate of return on capital. The values for WKA_t and r_t are described in Chapter Three.

PEG calculated the value of the economic, "geometric" depreciation rate for the Ontario electricity distribution industry to be 4.59% based on: 1) the estimated declining balance parameters for structures and equipment (0.91 and 1.65 respectively) in Hulten and Wykoff's seminal depreciation study; 2) OEB data on average asset lives in Ontario for different categories of assets, as estimated by Kinetrics Inc. in its July 8, 2010 report *Asset Depreciation Study for the Ontario Energy Board*; and 3) the share of each asset category in the Ontario electricity distribution industry's total gross capital stock in 2011, as calculated from RRR data. PEG did not update this calculation when the 2012 data became available because in our experience the shares of the asset categories in overall gross capital stock do not vary materially from year to year. Table 4 shows the details of this calculation.

It should be noted that PEG's capital cost and capital service price measures do not include tax costs. This decision reflected the institutional and policy environment in Ontario. It was recognized that tax rates for electricity distributors fell over the 2002-2012 period, and this development is unlikely to persist. Including tax changes over 2002-2012 could provide a misleading estimate of the TFP and input price trends that could be expected over the next five years, so we did not include tax costs in our analysis. The decision to exclude taxes from PEG's measures of total cost was supported by the PBR Working Group.

Regarding capital stocks, as previously discussed, measuring the quantity of capital begins with a benchmark capital stock, or price-deflated value of capital in some base year.

Table 4

CALCULATION OF THE ECONOMIC DEPRECIATION RATE

	Distribution Substations	Poles and Wires	Line Transformers	Services and Meters	General Plant	Equipment	Information Technology	Total Plant
Industry Total (2011)	$ 1,106,968,267	$ 12,984,407,954	$ 3,852,700,174	$ 1,816,079,550	$ 530,943,619	$ 998,075,226	$ 818,062,952	$ 22,107,237,742
Percent of Total	5.0%	58.7%	17.4%	8.2%	2.4%	4.5%	3.7%	100.0%
Hulten-Wykoff Parameter [A]	1.65	0.91	1.65	1.65	0.91	1.65	1.65	
Life [B]	45	50	45	35	50	10	4	
Rate [A/B]	3.67%	1.82%	3.67%	4.71%	1.82%	16.50%	41.25%	4.59%

The benchmark year for the capital stock in PEG's study is 1989 (except for the six previously noted distributors). We deflated the benchmark capital stocks by a "triangularized weighted average" of capital asset prices over a multi-year period preceding the 1989 benchmark capital value.[27]

PEG used the following perpetual inventory equation to compute subsequent values of the capital quantity index *XK* (*i.e.* the capital stock) after the benchmark year:

$$XK_t = (1 - d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad [9]$$

Here, the parameter d is the economic depreciation rate, VI_t is the value of gross additions to the distributor's plant, and WKA_t is an index of distributor plant asset prices. The value of *WKA* is the electric utility construction price index that is used in equation [8] and in the estimation of the industry input price inflation. The depreciation rate is identical to what is derived on Table 1. PEG's estimates of gross capital additions VI_t were described in Section 4.2.

4.5 Total Cost Measures for TFP and Benchmarking Analysis

The TFP and the benchmarking analyses both require estimates of total cost. For TFP, an estimate of industry total cost is necessary to derive the shares of capital and OM&A expenses in total costs. These cost share weights are then used to weight the growth in capital and OM&A inputs, respectively, when computing the overall growth in input quantity. PEG computed total costs for the industry over 2002-2012 as the sum of distribution OM&A expenses from the RRRs and the industry's total capital costs, as discussed in Section 4.2 and 4.4.

Capital costs for the TFP analysis were computed using equations [7] and [8] and gross capital additions net of capital contributions in aid of construction (CIAC). CIAC payments were excluded from the TFP cost measure because CIAC should not be included in PEG's estimate of TFP growth. The reason is that estimated TFP growth will be part of the

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[27] The triangularized weighted average approach is a method of deflating the (unobserved) series of capital expenditures that will be reflected in a benchmark value of gross capital, so that this gross capital value is expressed in real, inflation-adjusted terms. See Stevenson (1980) for a discussion of this approach.

PCI formula used to adjust regulated distribution rates. CIAC payments are not part of distributors' rate base and therefore not subject to this rate adjustment formula. Including CIAC in our TFP analysis would therefore create a mismatch between the costs used as inputs for IR-based rate adjustments and the costs that are actually subject to that IR mechanism.

PEG's benchmarking analysis requires total cost measures for every Ontario distributor. The starting point for the benchmarking cost measure was the total cost used in our TFP analysis. However, PEG undertook several cost adjustments in order to make the costs more comparable across distributors.[28]

One cost adjustment was made to make the costs of high-voltage (HV) transformation services (*i.e.* transmission substations greater than 50 kV) more comparable. If this was not done, the costs of the distributors that own HV equipment would be higher (all else equal) than the costs of the distributors who do not own high voltage equipment. PEG therefore excluded plant values explicitly identified by distributors as HV assets (in account 1815) and the OM&A accounts directly associated with HV transformation (accounts 5014, 5015, and 5112) from the total cost calculation.

These adjustments isolate most of the costs of HV ownership, but some costs cannot be readily distinguished in the Uniform System of Accounts. HV equipment capital is isolated in account 1815, but associated land and buildings capital is not categorized separately. Also, while HV-related O&M costs are booked in accounts 5014, 5015, and 5112, O&M for associated buildings are blended with other expenditures in accounts 5012 or 5110. Other HV-related costs are spread across multiple other accounts. Extracting these costs is problematic and not practical.

One other adjustment was made to make costs more comparable across distributors. PEG included some charges for low voltage (LV) services that were paid by distributors to their "host" distributors. These charges are regulated separately by the OEB but not included in the RRRs. The necessary data were obtained from two sources: (a) Hydro One provided a

[28] These adjustments make the capital and OM&A cost shares for benchmarking somewhat different than the cost shares used in our TFP and input price analysis. The cost shares described in Chapter Three are derived from the cost measure used in PEG's TFP work and are the appropriate ones to use in those analyses.

summary of LV Charges to distributors from 2002 to 2012, and (b) the Board's supplementary data request described in Section 4.2.[29]

PEG also included contributions in aid of construction (CIAC) and smart meter capital additions in the capital cost measure, as well as incremental OM&A associated with smart meters in the OM&A used in each distributor's benchmarking cost measure. While CIAC payments are outside of the Board's IR rate adjustment formula, they are part of the capital stock that distributors use to provide service to their customers. Similarly, smart meters are part of this capital stock.

Table 5 summarizes the differences between the cost measures that PEG used to estimate TFP and to benchmark distributors' total costs. The adjustments to PEG's TFP cost measure are necessary to reflect the costs that will be subject to the PCI adjustment. Because PEG's TFP study is to designed to inform the Board's decision on an appropriate productivity factor that will be an element of the PCI, the cost measure used in that study is appropriate for that purpose.

PEG developed total cost measures for 73 distributors in Ontario. These distributors are listed in Table 6.[30] PEG relied on RRR data reported by the distributors for our TFP and benchmarking research. PEG did not adjust these reported RRR data, except for a few instances where there appeared to be clear data recording errors. A complete list of these data adjustments is provided in Table 7.

[29] An Industry Workshop was held on October 7, 2013 to obtain guidance from the sector on which LV charges to include in total cost benchmarking. The Workshop Summary is posted on the Board's website (Summary of Hydro One Low Voltage Charges to Distributors 2002–2012 (07Oct13).xlsx).

[30] Two distributors were excluded from our analysis: Five Nations Energy and Hydro One Remote Communities.

Table 5

Cost Measures for Empirical Analysis

Industry TFP Growth		Distribution Cost Benchmarking	
Candidate Capital Costs:	Included in Study?	**Candidate Capital Costs:**	Included in Study?
Capital Benchmark Year: 1989*		Capital Benchmark Year: 1989*	
Taxes	No	Taxes	No
Transmission Substations > 50 KV Assets**	Yes	Transmission Substations > 50 KV Assets**	No
Gross Capital Expenditures	Yes	Gross Capital Expenditures	Yes
CIAC	No	CIAC	Yes
Smart Meter Expenditures	No	Smart Meter Expenditures	Yes
Candidate OM&A Costs:		**Candidate OM&A Costs:**	
Distribution OM&A (excluding bad debt expenses)	Yes	Distribution OM&A (excluding bad debt expenses)	Yes
High Voltage OM&A***	Yes	High Voltage OM&A***	No
Low Voltage Charges to Embedded Distributors****	No	LV Charges to Embedded Distributors****	Yes
Smart Meter Incremental OM&A*****	No	Smart Meter Incremental OM&A*****	Yes

Notes:

* Exceptions are Hydro One, Algoma Power, Canadian Niagara Power, Greater Sudbury Power, Innisfill Hydro and PUC Distribution, where data before 2002 were not available.

** Account Number 1815

*** Proxy High Voltage OM&A costs were calculated as the sum of OM&A in accounts 5014, 5015, and 5112

**** Excludes Regulatory Asset Recovery Charges

***** Account Number 1556, net of estimated amortization of smart meter expenditures

Table 6

Companies Included in the Study

Algoma Power Inc.
Atikokan Hydro Inc.
Bluewater Power Distribution Corporation
Brant County Power Inc.
Brantford Power Inc.
Burlington Hydro Inc.
Cambridge And North Dumfries Hydro Inc.
Canadian Niagara Power Inc.
Centre Wellington Hydro Ltd.
Chapleau Public Utilities Corporation
Collus Power Corporation
Cooperative Hydro Embrun Inc.
E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.
Entegrus Powerlines
Enwin Utilities Ltd.
Erie Thames Powerlines Corporation
Espanola Regional Hydro Distribution Corporation
Essex Powerlines Corporation
Festival Hydro Inc.
Fort Frances Power Corporation
Greater Sudbury Hydro Inc.
Grimsby Power Incorporated
Guelph Hydro Electric Systems Inc.
Haldimand County Hydro Inc.
Halton Hills Hydro Inc.
Hearst Power Distribution Company Limited
Horizon Utilities Corporation
Hydro 2000 Inc.
Hydro Hawkesbury Inc.
Hydro One Brampton Networks Inc.
Hydro One Networks Inc.
Hydro Ottawa Limited
Innisfil Hydro Distribution Systems Limited
Kenora Hydro Electric Corporation Ltd.
Kingston Hydro Corporation
Kitchener-Wilmot Hydro Inc.
Lakefront Utilities Inc.
Lakeland Power Distribution Ltd.
London Hydro Inc.
Midland Power Utility Corporation
Milton Hydro Distribution Inc.
Newmarket-Tay Power Distribution Ltd.
Niagara Peninsula Energy Inc.
Niagara-On-The-Lake Hydro Inc.
Norfolk Power Distribution Inc.
North Bay Hydro Distribution Limited
Northern Ontario Wires Inc.
Oakville Hydro Electricity Distribution Inc.
Orangeville Hydro Limited
Orillia Power Distribution Corporation
Oshawa Puc Networks Inc.
Ottawa River Power Corporation
Parry Sound Power Corporation
Peterborough Distribution Incorporated
Powerstream Inc.
Puc Distribution Inc.
Renfrew Hydro Inc.
Rideau St. Lawrence Distribution Inc.
Sioux Lookout Hydro Inc.
St. Thomas Energy Inc.
Thunder Bay Hydro Electricity Distribution Inc.
Tillsonburg Hydro Inc.
Toronto Hydro-Electric System Limited
Veridian Connections Inc.
Wasaga Distribution Inc.
Waterloo North Hydro Inc.
Welland Hydro-Electric System Corp.
Wellington North Power Inc.
West Coast Huron Energy Inc.
Westario Power Inc.
Whitby Hydro Electric Corporation
Woodstock Hydro Services Inc.

Table 7

SUMMARY OF CHANGES TO DATA

Company Name	Year	Data Adjustments
ALGOMA POWER INC.	2005	kW and kWh data are transposed for non-residential. They were reversed and totals recalculated
ATIKOKAN HYDRO INC.	2006	KWh are shifted from 2006 to 2007. Average values by customer class for 2006-2007 were substituted. Residential inferred from total and other categories.
ATIKOKAN HYDRO INC.	2007	KWh are shifted from 2006 to 2007. Average values by customer class for 2006-2007 were substituted. Residential inferred from total and other categories.
BLUEWATER POWER DISTRIBUTION CORPORATION	2005	75% drop in System Peak; estimated using previous and subsequent years
CANADIAN NIAGARA POWER INC.	2002	Reversal of OH and UG reporting for Fort Erie; Switched such that OH is dominant
CANADIAN NIAGARA POWER INC.	2003	Reversal of OH and UG reporting for Fort Erie; Switched such that OH is dominant
CANADIAN NIAGARA POWER INC.	2004	Reversal of OH and UG reporting for Fort Erie; Switched such that OH is dominant
E.L.K. ENERGY INC.	2002	System peak units problem, multiply reported data by 1000
E.L.K. ENERGY INC.	2003	System peak units problem, multiply reported data by 1000
ENWIN UTILITIES LTD.	2002	System peak units problem, multiply reported data by 1000
ENWIN UTILITIES LTD.	2003	System peak units problem, multiply reported data by 1000
ENWIN UTILITIES LTD.	2004	System peak units problem, multiply reported data by 1000
ERIE-THAMES	2008	Includes 511,638 of missing OM&A data for Clinton as per company request.
FORT FRANCES POWER CORPORATION	2005	kWh data were transposed for non-residential. They were reversed and totals recalculated
HALTON HILLS HYDRO INC.	2005	Missing system peak values; estimate based on 2004 and 2007 values
HALTON HILLS HYDRO INC.	2006	Missing system peak values; estimate based on 2004 and 2007 values
HYDRO ONE BRAMPTON NETWORKS INC.	2008	System peak units problem, multiply reported data by 1000
HYDRO ONE NETWORKS INC.	2003	99% drop in system peak, impute using 2002 and 2005 data
HYDRO ONE NETWORKS INC.	2004	99% drop in system peak, impute using 2002 and 2005 data
NIAGARA PENINSULA	2008	OM&A reduced by 324,286 as per company request to correct for the classification of bad debt expenses.
PARRY SOUND POWER CORPORATION	2005	System peak units problem, multiply reported data by 1000
PUC DISTRIBUTION INC.	2002	System peak units problem, multiply reported data by 1000
PUC DISTRIBUTION INC.	2003	System peak units problem, multiply reported data by 1000
PUC DISTRIBUTION INC.	2004	System peak units problem, multiply reported data by 1000
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	2002	Units problem; multiply km of line by 10
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	2005	System peak units problem, multiply reported data by 1000
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	2011	OM&A revised upward by 184,997 as per company request to reflect the companies amended RRR
WEST COAST HURON ENERGY INC.	2002	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2003	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2004	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2005	System peak units problem, multiply reported data by 1000
WEST COAST HURON ENERGY INC.	2006	System peak units problem, multiply reported data by 1000
WESTARIO POWER INC.	2002	Missing system peak values; impute based on corrected 2003 values
WESTARIO POWER INC.	2003	Units problem for summer and winter peak, divide by reported values by 10, 100

5 Estimating Total Factor Productivity Growth

This Chapter presents PEG's estimates of TFP growth for the Ontario electricity distribution industry over the 2002-2012 period. We begin by briefly discussing our index-based methods of estimating TFP. The following two sections discuss the Ontario distributors' output quantity and input quantity indexes, respectively. We then present our index-based estimates of industry output quantity, input quantity, and TFP growth.

5.1 Indexing Methods

PEG calculated TFP indexes in Ontario using the Törnqvist index form. With this index, the annual growth rate of the input quantity index is determined by the formula:

$$\ln\left(\frac{\textit{Input Quantities}_t}{\textit{Input Quantities}_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \qquad [10]$$

Here in each year *t*,

$\textit{Input Quantities}_t$ = Input quantity index

$X_{j,t}$ = Input quantity subindex for input category *j*

$S_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of the quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. For the input quantity indexes, weights are equal to the average shares of each input in total distribution cost. With the Tornqvist form, the annual growth rate of the output quantity index is determined by the formula:

$$\ln\left(\frac{\textit{Output Quantities}_t}{\textit{Output Quantities}_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{k,t} + S_{k,t-1} \right) \cdot \ln\left(\frac{Y_{k,t}}{Y_{k,t-1}} \right). \qquad [11]$$

Here in each year *t*,

$\textit{Output Quantities}_t$ = Output quantity index

$Y_{k,t}$ = Output quantity subindex for output category *k*

$S_{k,t}$ = Cost elasticity share for output category *k*.

Again the growth rate of the index is a weighted average of the growth rates of the quantity subindexes. For the output quantity index, weights are cost elasticity shares *i.e.* the cost elasticity for each quantity subindex divided by the sum of the cost elasticities for all outputs.

The annual growth rate in the TFP index is given by the formula

$$\ln\left(\frac{TFP_t}{TFP_{t-}} \right) = \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}} \right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right). \qquad [12]$$

We estimated TFP trends for the Ontario electricity distribution industry for the 2002-2012 period. The trend in this TFP index was computed using the formula:

$$trend\ TFP_t = \frac{\sum_t {}_{2002}^{2012} \ln\left(\frac{TFP_t}{TFP_{t-1}} \right)}{10} = \frac{\ln\left(\frac{TFP_{2012}}{TFP_{2002}} \right)}{10} \qquad [13]$$

The trend is the average annual growth rate during the years of the sample period. The reported trends in other indexes that appear in this report are computed analogously.

5.2 Output Quantity Variables

The output quantity subindexes are customer numbers (other than street lighting, sentinel lighting, and unmetered scattered loads), total kWh deliveries, and system capacity peak demand. Output quantity growth is a weighted average of the growth in these subindexes, with weights equal to each output's cost elasticity share.

These cost elasticities are equal to the coefficients on the first order terms of associated outputs in the cost model presented in Table 8. These cost elasticities were 0.408 for customer numbers, 0.071 for kWh, and 0.194 for system capacity. The associated cost

Table 8

Econometric Coefficients Used to Determine Output Weights

VARIABLE KEY

Input Price:	WK =	Capital Price Index
Outputs:	N =	Number of Customers
	C =	System Capacity Peak Demand
	D =	Retail Deliveries
Other Business Conditions:	A =	2012 Service Territory
	U =	Percent Lines Underground
	L =	Average Line Length (km)
	NG =	% of 2012 Customers added in the last 10 years
	Trend =	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.5978	90.0060
N*	0.4077	8.8770
C*	0.1942	4.1640
D*	0.0712	2.4960
WKxWK*	0.3075	11.2480
NxN*	-1.2366	-6.3740
CxC	-0.2488	-1.2890
DxD*	0.1596	2.0540
WKxN*	0.0299	1.9900
WKxC*	0.0297	2.1890
WKxD	0.0091	1.5720
NxC*	0.7869	4.6440
NxD*	0.1830	1.9880
CxD*	-0.3186	-3.3980
A	0.0063	0.3890
U	0.0206	1.3190
L*	0.3090	8.5940
NG	0.0079	0.6440
Trend*	0.0081	5.8210
Constant*	12.219	489.950
System Rbar-Squared	0.980	
Sample Period	2002-2012	
Number of Observations	780	

***Variable is significant at 95% confidence level**

elasticity shares, which must necessarily sum to one, are 0.606, 0.106, and 0.289 for customer numbers, kWh, and system capacity peak demand, respectively.[31]

5.3 Input Prices and Quantities

PEG developed measures of input quantities for two input quantity subindexes: capital and OM&A inputs. The growth in the overall input quantity index was a weighted average of the growth in these two input quantity subindexes. The weight that applied to each subindex was its share of electricity distribution cost.

Our measures of capital inputs and capital costs used for TFP research were discussed in Chapter Four. The quantity subindex for OM&A was estimated as the ratio of distribution OM&A expenses to an index of OM&A prices. The OM&A price index is comprised of the labor and non-labor OM&A components of the input price inflation that is estimated in Chapter Three. We estimated the change in OM&A inputs using the theoretical result that the growth rate in the cost of any class of input *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class. This implies that

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j. \qquad [14]$$

5.4 Index-Based Results

For the 2002-2012 period, PEG's index-based TFP results for the Ontario electricity distribution industry excluding Toronto Hydro and Hydro One are presented in Tables 9 through 13. Table 9 presents details on the output quantity index. Table 10 shows the computation of OM&A input quantity. Table 11 presents the calculation of capital costs and capital input quantity. Table 12 brings the results of Tables 10 and 11 together and shows the growth in total input quantity. Finally, Table 13 displays the calculation of the TFP indexes.

[31] The coefficients used to establish cost elasticity-based weights for the output quantity and TFP indexes are derived from an econometric cost model where the dependent variable is the cost measure used in our TFP analysis. Recall from Chapter Four report that this cost measure differs from the costs used to benchmark distributors' cost performance. It is more accurate for cost elasticities used in TFP analysis to be derived from a cost model that uses the same cost measure that is used in the TFP analysis than to use a different, benchmarking cost measure. The former approach is unambiguously superior because it uses internally consistent cost measures in the TFP analysis and the econometric estimates used directly in that TFP analysis. We explain the econometric analysis PEG uses to benchmark distributors' costs in Chapter Six.

Table 9

Output Quantity Trends for Ontario Power Distributors, 2002-2012

Year	Total Customers		Peak Demand (KW)		Delivery Volume (KWh)		Output Quantity Index	
	Level	Growth	Level	Growth	Level	Growth	Index	Growth
2002	2,528,664		14,953,754		65,523,878,635		100.00	
2003	2,590,817	2.43%	15,124,270	1.13%	67,480,321,397	2.94%	102.13	2.11%
2004	2,647,118	2.15%	15,282,376	1.04%	68,588,997,365	1.63%	103.96	1.77%
2005	2,703,821	2.12%	15,710,004	2.76%	72,989,180,570	6.22%	106.85	2.74%
2006	2,748,114	1.62%	16,004,095	1.85%	71,323,881,577	-2.31%	108.22	1.28%
2007	2,781,589	1.21%	16,030,411	0.16%	75,581,326,413	5.80%	109.74	1.39%
2008	2,823,654	1.50%	16,040,362	0.06%	74,626,460,193	-1.27%	110.61	0.79%
2009	2,864,567	1.44%	16,095,983	0.35%	71,454,871,565	-4.34%	111.18	0.51%
2010	2,885,251	0.72%	16,172,034	0.47%	71,603,206,532	0.21%	111.84	0.59%
2011	2,919,186	1.17%	16,287,524	0.71%	71,223,956,582	-0.53%	112.80	0.86%
2012	2,954,040	1.19%	16,391,549	0.64%	71,808,750,725	0.82%	113.92	0.99%
Average Annual Growth Rate 2002-2012		**1.55%**		**0.92%**		**0.92%**		**1.30%**

Table 10

OM&A Quantity Trends for Ontario Electric Distributors, 2002-2012

	OM&A Cost		OM&A Price Index		OM&A Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.000		100.000		100.000	
2003	104.040	3.96%	102.213	2.19%	101.787	1.77%
2004	105.063	0.98%	104.791	2.49%	100.259	-1.51%
2005	107.207	2.02%	108.156	3.16%	99.122	-1.14%
2006	110.827	3.32%	110.142	1.82%	100.622	1.50%
2007	119.051	7.16%	113.880	3.34%	104.541	3.82%
2008	123.955	4.04%	116.605	2.36%	106.303	1.67%
2009	126.116	1.73%	118.112	1.28%	106.777	0.44%
2010	126.854	0.58%	121.680	2.98%	104.253	-2.39%
2011	133.297	4.95%	123.730	1.67%	107.732	3.28%
2012	149.012	11.14%	125.683	1.57%	118.562	9.58%
Average Annual Growth Rate 2002-2012		**3.99%**		**2.29%**		**1.70%**

Table 11

Capital Quantity and Cost Trends for Ontario Power Distributors, 2002-2012

	Capital Cost		Capital Price Index		Capital Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.50	1.48%	100.47	0.47%	101.02	1.01%
2004	103.39	1.85%	100.66	0.19%	102.71	1.66%
2005	106.08	2.57%	101.59	0.92%	104.42	1.65%
2006	106.14	0.06%	100.84	-0.74%	105.26	0.80%
2007	111.43	4.86%	103.31	2.42%	107.85	2.44%
2008	115.45	3.55%	105.82	2.39%	109.11	1.16%
2009	117.08	1.40%	107.10	1.21%	109.32	0.19%
2010	121.66	3.83%	109.31	2.04%	111.30	1.80%
2011	123.45	1.46%	109.45	0.13%	112.76	1.30%
2012	121.49	-1.60%	103.92	-5.19%	116.87	3.58%
Average Annual Growth Rate 2002-2012		**1.95%**		**0.38%**		**1.56%**

Table 12

Input Quantity Trends for Ontario Electric Distributors, 2002-2012

	Input Quantity Index		Capital Quantity		O&M Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.30	1.29%	101.02	1.01%	101.79	1.77%
2004	101.79	0.48%	102.71	1.66%	100.26	-1.51%
2005	102.42	0.61%	104.42	1.65%	99.12	-1.14%
2006	103.51	1.06%	105.26	0.80%	100.62	1.50%
2007	106.62	2.96%	107.85	2.44%	104.54	3.82%
2008	108.08	1.36%	109.11	1.16%	106.30	1.67%
2009	108.39	0.29%	109.32	0.19%	106.78	0.44%
2010	108.61	0.20%	111.30	1.80%	104.25	-2.39%
2011	110.87	2.06%	112.76	1.30%	107.73	3.28%
2012	117.71	5.99%	116.87	3.58%	118.56	9.58%
Average Annual Growth Rate 2002-2012		**1.63%**		**1.56%**		**1.70%**

Table 13

TFP Index Calculation for Ontario Power Distributors, 2002-2012

	Output Quantity Index		Input Quantity Index		TFP Index	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	102.13	2.11%	101.30	1.29%	100.82	0.82%
2004	103.96	1.77%	101.79	0.48%	102.13	1.29%
2005	106.85	2.74%	102.42	0.61%	104.32	2.12%
2006	108.22	1.28%	103.51	1.06%	104.55	0.21%
2007	109.74	1.39%	106.62	2.96%	102.92	-1.57%
2008	110.61	0.79%	108.08	1.36%	102.34	-0.56%
2009	111.18	0.51%	108.39	0.29%	102.57	0.22%
2010	111.84	0.59%	108.61	0.20%	102.97	0.39%
2011	112.80	0.86%	110.87	2.06%	101.75	-1.20%
2012	113.92	0.99%	117.71	5.99%	96.79	-5.00%
Average Annual Growth Rate 2002-2012		**1.30%**		**1.63%**		**-0.33%**

Turning first to the output quantity results, it can be seen that overall output quantity grew at an annual rate of 1.30% per annum. Customers grew by an average of 1.55% annually. In contrast, kWh deliveries and system capacity demand grew more slowly, with each growing by 0.92% per annum. The fact that customers grew more rapidly than either deliveries or peak demand means that volumes per customer and peak demand per customer have declined, on average, over the sample period. Some of these declines clearly result from the severe recession that took place in 2008-09; for example, kWh deliveries fell by 1.3% and 4.3% in these respective years. However, some of the decline in volumes and demand per customer may be attributed to energy conservation policies that have been pursued in Ontario over the sample period.[32] Output declines appear to be especially pronounced after 2006.

In Table 10, it can be seen that OM&A inputs grew at an average rate of 1.70% over the sample period. In 2012, OM&A input quantity grew by 9.58%. This is nearly three times the 3.28% growth in OM&A input quantity in 2011 and is by far the most rapid annual change in OM&A input in any of the sample years. This increase is due to an 11.14% increase in OM&A expenses in 2012.

Table 11 shows that capital input quantity grew at an average rate of 1.56% between 2002 and 2012. Capital investment grew by 3.58% in 2012 as compared to 1.30% in 2011. The 2012 increase in capital input is more rapid than the trend in previous years.

Table 12 shows the change in overall input quantity. Overall inputs grew at an average rate of 1.63% between 2002 and 2012. The 5.99% increase in input quantity in 2012 is more than twice as large as the annual change in input quantity in any year in the 2002-2011 period.

[32] On May 31, 2004, the Minister of Energy granted approval to all electricity distributors in Ontario to apply to the Board for an increase in their 2005 rates by way of the third instalment of their incremental market adjusted revenue requirement ("MARR"). This approval was conditional upon a commitment to reinvest in CDM an equivalent of that amount. Consequently, in 2005 distributors brought forward, and the Board approved, $163 million in CDM funding for distributors, an amount related to the third tranche of their MARR. Subsequently, electricity distributors were permitted to apply for CDM funding as part of 2006 and 2007 rates. Beginning in 2008 CDM funding was available to distributors through the OPA. In 2010, in accordance with a directive from the Minister of Energy and Infrastructure, dated March 31, 2010, the Board was required to take certain steps to establish targets for the reduction of electricity consumption and peak provincial electricity demand to be met by certain licensed electricity distributors, as a condition of licence. Currently, to facilitate achievement of those targets, distributors may access funding from the OPA and through distribution rates.

Table 13 shows that Ontario distributors' TFP declined at a 0.33% average rate over the 2002-2012 period. This negative trend was strongly impacted by the industry's experience in 2012, when TFP declined by 5.00% from the previous year. The average growth in industry TFP was 0.19% per annum over the 2002-2011 period.

The 2012 TFP results are anomalous when compared with the industry's annual TFP changes between 2002 and 2011. TFP declined dramatically in 2012 primarily because of the 11.14% surge in reported OM&A in that year. Output growth, in contrast, was somewhat greater than in recent years, which all else equal would tend to bolster TFP growth.

As explained in Chapter Four, the 2012 TFP results were impacted by two issues with the 2012 data: 1) 15 distributors adopted international financial reporting standards (IFRS) for the first time in 2012; and 2) a number of distributors cleared balance sheet deferral accounts in 2012 and moved the associated costs to their Trial Balance OM&A expense accounts. PEG's TFP results were most affected by the clearing of the deferral accounts to expense.

The Board asked PEG to test the sensitivity of long-run TFP growth to Province-wide conservation programs. We were provided data on net energy savings (in GWh) reported by OPA on these programs for each year between 2006 and 2011. Since PEG did not have 2012 data on these energy savings, we assumed they were unchanged from 2011. We also multiplied the OPA net energy savings in each year by 0.6, since Hydro One and Toronto Hydro together account for about 40% of energy deliveries in the Province but neither company is included in the sample PEG uses to measure the industry's output quantity or TFP growth.

This sensitivity test is illustrated in Tables 14 and 15. Table 14 shows output quantity growth when the annual conservation savings from the OPA programs are added back into industry kWh deliveries in 2006 through 2012 (assuming 2012 net energy savings are equal to 2011 net energy savings). This scenario effectively shows what kWh deliveries would have been over this period in the absence of OPA programs. It can be seen that output quantity growth under this scenario would have averaged 1.36% per annum in the 2002-2012 period. This is six basis points higher than the 1.30% output quantity growth measured for the same period in Table 9.

Table 14

Output Quantity Trends for Ontario Power Distributors with Net Energy Savings Adjustment, 2002-2012

	Total Customers		Peak Demand (KW)		Delivery Volume (KWh)		Output Quantity Index	
Year	**Level**	**Growth**	**Level**	**Growth**	**Level**	**Growth**	**Index**	**Growth**
2002	2,528,664		14,953,754		65,523,878,635		100.00	
2003	2,590,817	2.43%	15,124,270	1.13%	67,480,321,397	2.94%	102.13	2.11%
2004	2,647,118	2.15%	15,282,376	1.04%	68,588,997,365	1.63%	103.96	1.77%
2005	2,703,821	2.12%	15,710,004	2.76%	72,989,180,570	6.22%	106.85	2.74%
2006	2,748,114	1.62%	16,004,095	1.85%	72,296,481,577	-0.95%	108.37	1.42%
2007	2,781,589	1.21%	16,030,411	0.16%	77,681,926,413	7.18%	110.05	1.54%
2008	2,823,654	1.50%	16,040,362	0.06%	77,048,660,193	-0.82%	110.98	0.84%
2009	2,864,567	1.44%	16,095,983	0.35%	74,370,271,565	-3.54%	111.65	0.60%
2010	2,885,251	0.72%	16,172,034	0.47%	74,866,606,532	0.67%	112.37	0.64%
2011	2,919,186	1.17%	16,287,524	0.71%	75,150,956,582	0.38%	113.44	0.95%
2012	2,954,040	1.19%	16,391,549	0.64%	75,735,750,725	0.78%	114.57	0.98%
Average Annual Growth Rate 2002-2012		**1.55%**		**0.92%**		**1.45%**		**1.36%**

Table 15

TFP Index Calculation for Ontario Power Distributors with Net Energy Savings Adjustment, 2002-2012

	Output Quantity Index		Input Quantity Index		TFP Index	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	102.13	2.11%	101.30	1.29%	100.82	0.82%
2004	103.96	1.77%	101.79	0.48%	102.13	1.29%
2005	106.85	2.74%	102.42	0.61%	104.32	2.12%
2006	108.37	1.42%	103.51	1.06%	104.70	0.35%
2007	110.05	1.54%	106.62	2.96%	103.22	-1.42%
2008	110.98	0.84%	108.08	1.36%	102.69	-0.51%
2009	111.65	0.60%	108.39	0.29%	103.00	0.31%
2010	112.37	0.64%	108.61	0.20%	103.46	0.44%
2011	113.44	0.95%	110.87	2.06%	102.33	-1.10%
2012	114.57	0.98%	117.71	5.99%	97.33	-5.00%
Average Annual Growth Rate 2002-2012		**1.36%**		**1.63%**		**-0.27%**

Table 15 shows the TFP implications of this scenario. Input quantity growth is unchanged when the OPA program savings are added to the industry's kWh deliveries. Output quantity growth increases by six basis points when net energy savings are added to industry kWh deliveries. TFP growth is equal to the growth in output quantity minus the growth in input quantity, so the 2002-2012 industry TFP trend also rises by six basis points under this scenario, from -0.33% per annum to -0.27% per annum.

5.5 Recommended Productivity Factor

The 2012 TFP results reduce the industry's estimated TFP trend from 0.19% (the 2002-2011 TFP trend) to -0.33%, or -0.27% if savings from OPA conservation programs are added back into output growth.

There are precedents for negative X factors in energy utility regulation. For example, a number of indexing plans approved for transmission utilities in Australia early in the previous decade had large negative X factors. These utilities were subject to a "building block" approach to incentive regulation, and all were undertaking extensive capital investment programs. Capital spending for transmission service is especially lumpy, and these utilities were entering a phase of their investment cycles that required large increases in capital spending just as their incentive regulation plans were being approved.

More recently, some electricity distributors in the UK now have negative X factors in their RPI-X rate adjustment plans. It must be recognized, however, that before these negative X factors were approved, the UK distributors had experienced very large price reductions (via very large X factors) during the preceding 10 or 15 years of their price controls. Some distributors' prices declined by more than 50% during this period in "real," inflation-adjusted terms. These price reductions reflected the substantial cost efficiencies these distributors had achieved under incentive regulation, and over the course of multiple price control reviews the UK distributors have still experienced X factors that are far larger, on average, than those that have been applied to distributors in Ontario.

In principle, it can be appropriate to have a negative X factor *if* industry-wide input quantity is systematically growing more rapidly than industry-wide output quantity and that trend is expected to persist. Recall from PEG's 2010 concept paper that TFP is not identical to efficiency, since efficiency change is a component of TFP change. It is never appropriate to assume that efficiency would decline, but TFP could still decline because of changes in other factors identified in PEG's TFP decomposition formula.

Notwithstanding the theoretical possibility that negative X factors may be appropriate in some circumstances, there are several reasons why PEG finds a negative productivity factor would not be appropriate in Price Cap IR. First, the Board is currently examining the application of revenue decoupling to electricity distribution. Not to prejudge the outcome of this Board examination, but it should be noted that a decoupling mechanism would largely address the impact of declining output on industry TFP and, by extension, industry revenue change. Furthermore, as discussed in PEG's May 2013 report, the main reason electricity distributors' TFP has slowed and become negative in recent years is because of the decline in distributor output, and a revenue decoupling mechanism would counter this trend.

A decoupling mechanism effectively breaks the link between distributors' revenues and the kWh volumes that are delivered to customers. Under current regulation, all else equal, distributor revenues fall when kWh deliveries decline. Revenue decoupling would sever (or at least greatly weaken) this relationship, so that revenue would remain constant when distributors' kWh output declines. Recall that revenue is, by definition, equal to price multiplied by output. Because decoupling allows revenues to remain constant even when output falls, decoupling effectively raises prices on distribution services to recover the revenues that would be lost when kWh decline.[33]

Second, there may also be concerns associated with the rate riders and related rate recovery mechanisms that exist in Ontario. Some costs transferred to the 2012 Trial Balance data may have been previously reflected in and recovered by a rate rider. If this is true, it

[33] Although it is almost never interpreted in this way, revenue decoupling creates a kind of partial, "negative X factor" price adjustment when certain outputs fall. A revenue decoupling mechanism leads to price increases when designated outputs decline. A negative productivity factor leads to price increases (relative to inflation) when overall output declines and TFP growth becomes negative. Although a revenue decoupling mechanism is more narrow and targeted in scope, it effectively allows distributors to raise prices when their output declines.

Moreover, the same kWh (and perhaps kW) outputs that are targeted by the decoupling mechanism will also be included in the measure of industry TFP growth. Having two price adjustment mechanisms potentially impacted by the same underlying issue of declining output growth creates the potential for double counting. If a negative productivity factor is approved, it will allow distributors to increase prices relative to inflation largely because of increasingly slow and declining growth in kWh per distribution customer. If revenue decoupling is approved, it will allow distributors to raise prices as long as this existing, trend decline in kWh per customer *persists* while the revenue decoupling and IR mechanisms are in effect.

would not be appropriate for costs previously recovered through rate riders to be reflected in the TFP trend, and therefore the rate adjustment mechanism, that will apply during the term of Price Cap IR. Doing so would mean increasing future customer rates to pay for costs that have already been recovered in previous customer rates.

Finally, it is not clear that the negative 2002-2012 TFP trend is in fact industry-wide rather than the experience of a relatively small number of distributors. As previously noted, the Board's Renewed Regulatory Framework for Electricity (RRF) provides multiple ratemaking options to distributors. One of these options is designed to be "custom" to distributors with especially rapid capital investment needs. Although it is not clear which distributors will elect to file custom IR proposals, it is conceivable that distributors with historically high capital spending could depress industry-wide TFP trends, and thereby reduce the X factor in Price Cap IR, and later choose to opt out of this ratemaking approach precisely because of their atypical capital requirements. This would lead to higher price adjustments under Price Cap IR than are warranted for distributors with more typical capital requirements.[34]

In sum, the implications of a negative productivity factor are troubling given the Ontario regulatory environment. The possibility of revenue decoupling, the potential concerns associated with rate riders, and the multiple ratemaking options in the RRF create a significant probability that a negative productivity factor would either double-count costs that are being recovered elsewhere, or reflect the experience of a small number of distributors with atypical investment needs who elect to opt out of Price Cap IR altogether. The latter result would be counter to the Board's intended purpose of Price Cap IR, which is to be appropriate for most distributors in the Province who do not have high or variable capital requirements. Because of these concerns, PEG recommends that the productivity factor in Price Cap IR be set at zero.

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[34] It should be noted that neither the Australian transmission utilities nor the UK power distributors had the option of choosing among different regulatory mechanisms.

6 Econometric Research on Cost Performance

6.1 Total Cost Econometric Model

PEG benchmarked the total cost of Ontario's electricity distributors using a total cost econometric model. An econometric cost function is a mathematical relationship between the cost of service and business conditions. Business conditions are aspects of a company's operating environment that may influence its costs but are largely beyond management control. Economic theory can guide the selection of business condition variables in cost function models.

According to theory, the total cost of an enterprise depends on the amount of work it performs - the scale of its output - and the prices it pays for capital goods, labor services, and other inputs to its production process.[35] Theory also provides some guidance regarding the nature of the relationship between outputs, input prices, and cost. For example, cost is likely to rise if there is inflation in input prices or more work is performed.

For electricity distribution, total customers served and total kWh delivered are commonly used for output variables. Peak demand is another potential output variable. Peak demand is a billing determinant for some customers, but peak demand will also be an important cost driver for smaller customers whose peak demands are not metered. The reason is that delivery systems must be sized to accommodate peak demands, so there is a direct relationship between customers' peak demands and the costs of the necessary power delivery infrastructure.

In addition to output quantities and input prices, electricity distributors confront other operating conditions due to their special circumstances. Unlike firms in competitive industries, electricity distributors are obligated to provide service to customers within a given service territory. Distribution services are delivered directly into the homes, offices and businesses of end-users in this territory. Distributor cost is therefore sensitive to the circumstances of the territories in which they provide delivery service.

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[35] Labor prices are usually determined in local markets, while prices for capital goods and materials are often determined in national or even international markets.

One important factor affecting cost is customer location. This follows from the fact that distribution services are delivered over networks that are linked directly to customers. The location of customers throughout the territory directly affects the assets that utilities must put in place to provide service. The spatial distribution of customers will therefore have implications for network cost.

The spatial distribution of customers is sometimes proxied by the total circuit km of distribution line, or the total square km of territory served. Provided customer numbers is also used as a cost measure, these variables will together reflect the impact of different levels of customer density within a territory on electricity distribution costs.

Cost can also be sensitive to the mix of customers served. The assets needed to provide delivery service will differ somewhat for residential, commercial, and industrial customers. Different types of customers also have different levels and temporal patterns of demand and different load factors.

In addition to customer characteristics, cost can be sensitive to the physical environment of the service territory. The cost of constructing, operating and maintaining a network will depend on the terrain over which the network extends. These costs will also be influenced by weather and related factors. For example, costs will likely be higher in areas with a propensity for ice storms or other severe weather that can damage equipment and disrupt service. Operating costs will also be influenced by the type and density of vegetation in the territory, which will be at least partly correlated with precipitation and other weather variables.

Econometric cost functions require that a functional form be specified that relates cost to outputs, input prices, and other business conditions. The parameter associated with a given variable reflects its impact on the dependent cost variable. Econometric methods are used to estimate the parameters of cost function models. Econometric estimates of cost function parameters are obtained using historical data on the costs incurred by distributors and measurable business condition variables that are included in the cost model.

6.2 Econometric Research on Electricity Distribution Cost

Economic theory says that the cost of an enterprise depends on input prices and the scale of output. PEG's cost function included input prices, as defined and measured in Chapter Three of this report. PEG investigated a number of different choices for output variables, including customer numbers, kWh deliveries, different measures of peak demand, and total km of line. We also investigated the impact of other business condition variables that are largely beyond management control but can still impact distribution cost. Data on both the output and business condition variables were drawn from Section 2.1.5 of the RRRs.

PEG consulted with stakeholders extensively on the choices for outputs and business condition variables in the econometric work. This included discussions with the PBR Working Group, as well as a March 1, 2013 webinar on the topic in which the entire industry and other stakeholders were invited to participate. These consultations examined the merits of a variety of "cost driver" variables that PEG considered during its econometric work. In addition to outputs, the business condition variables explored could be categorized as belonging to one of five sets of cost drivers:

1) The mix of customers served *e.g.* serving a more industrialized customer base, load factor;
2) Variables correlated with urbanization and urban density, such as municipal population per square km of urban territory, the percent of urban territory in total territory, or the share of lines that are underground ;
3) Geography, such as total area served, the share of territory that is on the Canadian shield, and whether a distributor's territory is in Northern Ontario;
4) The age of assets, as proxied by accumulated depreciation relative to gross plant value or the share of total customers that were added in the last 10 years; or
5) High-voltage intensiveness, such as the share of transmission substation assets (greater than 50 kV) in total distribution plant. This variable was designed to reflect costs associated with high voltage assets that could not be specifically identified and eliminated from our cost measure.

The total cost benchmarking model also contains a trend variable. This variable captures systematic changes in costs over time that are not explained by the specified business conditions. It may also reflect the failure of the included business condition variables to measure the trends in relevant cost drivers properly. The model may, for instance, exclude an important cost driver or measure such a cost driver imperfectly. The trend variable might then capture the impact on cost of the trend in the driver variable.

6.3 Estimation Results and Econometric Benchmarking

6.3.1 Econometric Results

Estimation results for our electricity distribution cost model are reported in Table 16. The estimated coefficients for the business conditions and the "first order" terms of the output variables are elasticities of cost for the sample mean firm with respect to the variable. The first order terms do not involve squared values of business condition variables or interactions between different variables.

Table 16 also reports the t-statistic values generated by the estimation program. The t-statistic values were used to assess the statistical significance of the estimated cost function parameters. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected at a 5% significance level (*i.e.* a 95% confidence level). Each statistically significant parameter estimate is identified with an asterisk.

Examining the results in Table 16, it can be seen that there are three statistically significant output variables: customer numbers; kWh deliveries; and system capacity peak demand. Our measure of customer numbers is equal to total customers minus street lighting, sentinel lighting, and unmetered scattered load. The kWh deliveries measure is billed kWh deliveries (before loss adjustment) to all customers.

The system capacity peak demand measure was equal to the highest annual peak demand measure for a distributor up to the year in question. For example, in 2002 (the first sample year), the system capacity measure for each distributor was its annual peak demand for 2002. In 2003, if the distributor's reported annual peak exceeded its 2002 peak, the system capacity peak was equal to the annual peak demand in 2003. If the annual peak in 2003 was below the annual peak in 2002, the annual peak in 2002 was the highest peak

Table 16

Econometric Coefficients: Cost Benchmarking

VARIABLE KEY

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)
	NG =	% of 2012 Customers added in the last 10 years
	Trend =	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.6271	85.5530
N*	0.4444	8.0730
C*	0.1612	3.2140
D*	0.1047	3.4010
WKxWK*	0.1253	4.5320
NxN	-0.3776	-1.6160
CxC	0.1904	0.9340
DxD*	0.1646	2.1660
WKxN*	0.0536	3.4540
WKxC	0.0100	0.7200
WKxD	-0.0001	-0.0100
NxC	0.1415	0.7040
NxD	0.0674	0.6790
CxD*	-0.1990	-2.3070
L*	0.2853	13.9090
NG*	0.0165	2.4110
Trend*	0.0171	12.5700
Constant*	12.815	683.362
System Rbar-Squared	0.983	
Sample Period	2002-2012	
Number of Observations	802	

***Variable is significant at 95% confidence level**

demand measure reported by the distributor, and this value is therefore also recorded as the system capacity peak for 2003. Values in subsequent years were calculated in the same manner. The system capacity variable is intended to reflect distribution infrastructure sized to meet peak demands. Even if those demands fall over time, the distributor's infrastructure and its associated costs will (in nearly all cases) remain. The system capacity peak variable was suggested in the PBR Working Group discussions and largely supported by the Group.

The output parameter estimates, as well as the parameter estimate for capital input prices, were plausible as to sign and magnitude. Cost was found to increase for higher values of capital service prices and output quantities. At the sample mean, a 1% increase in the number of customers raised cost by .44%. A 1% increase in kWh deliveries raised cost by about .10%. A 1% increase in system capacity increased distribution cost by 0.16%. Customer numbers is therefore the dominant output-related cost driver, followed by peak demand, followed by kWh deliveries.

Two other business condition variables are also identified as statistically significant cost drivers on Table 16: average circuit km of line; and share of customers added over the last 10 years.

With respect to a distributor's average circuit km of line over the 2002-2012 period, it can be seen that a 1% increase in average circuit km raised distribution cost by 0.29%. PEG used average km over the sample period, rather than each distributor's reported time series of km, because of anomalous trends in circuit km data for some distributors. The circuit km coefficient therefore reflects the cost impact of cross-sectional differences in circuit km across distributors, but not the impact of *changes* in km of line (all else equal) over the 2002-2012 period, on distribution cost.

The circuit km variable clearly has an output-related dimension, because it reflects customers' location in space and distributors' concomitant need to construct delivery systems that transport electrons directly to the premises of end-users. The average circuit km variable can be considered a legitimate output when examining cross-sectional differences in costs across Ontario distributors. Circuit km could, for example, play an important role in identifying appropriate peer groups for unit cost comparisons, since this benchmarking exercise compares unit costs across Ontario distributors at a given point in time. However, it would not be appropriate for the average circuit km variable to be used as an output variable in the current TFP study. This study is designed to estimate *trends* in TFP for the Ontario electricity distribution industry, but the current average km variable only reflects cross sectional, and not trend, impacts on distribution cost.

With respect to the share of a distributor's customers that was added over the last 10 years, the variable is designed to proxy recent growth and the age of distribution systems. All else equal, serving a relatively fast-growing territory requires a greater amount of more current capital additions. These investment pressures could put upward pressure on costs. Our model shows that a 1% increase in this variable increases distribution costs by 0.017%.

A surprising finding of our cost model was the coefficient on the trend variable. This coefficient was estimated to be 0.017%. This implies that, even when input prices, outputs, and other business condition variables remain unchanged, costs for the Ontario electricity distribution industry still increased by an average of 1.7% per annum between 2002 and 2012. This is counter to the usual finding in cost research, where the coefficient on the trend variable is negative. One factor that could be contributing to these upward cost pressures is government policy implemented over the sample period. Another possibility is that there are cost pressures for a sizeable portion of the industry due to company-specific factors, rather than industry-wide policies, but it is difficult to capture these company-specific cost pressures in measurable business condition variables.

PEG did examine a wide range of other business condition variables in our cost research. These other variables were either not statistically significant or did not have sensible signs. These variables included:

- The percent of distribution territory on the Canadian shield;
- A dummy variable for whether or not a distributor was located in Northern Ontario;
- The share of transmission substation plant (greater than 50 kV) in total gross plant;
- The share of deliveries to residential customers;
- Load factor;
- The share of service territory that is urban;
- Municipal population divided by km^2 of urban territory; and
- The percentage of circuit km that are underground.

6.3.2 Econometric Benchmarking

PEG used its recommended cost model presented in Table 16 to generate econometric evaluations of the cost performance of Ontario electricity distributors. This was done by inserting values for each distributor's output and business condition variables into a cost model that is "fitted" with the coefficients presented in Table 16. This process yields a value for the predicted (or expected) costs for each distributor in the sample given the exact business condition variables faced by that distributor.

PEG then compared each distributor's actual total cost to the model's cost prediction. This comparison was made for each distributor's average value of cost in 2010-2012. These are the three most recent years of the sample period. Table 17 presents these cost evaluations.

Table 17

(as corrected December 19, 2013 and January 24, 2014)

Difference Between Actual and Predicted Cost: Cost Benchmarking Model

Distibutor	Ranking	Actual minus Predicted Cost
HYDRO HAWKESBURY INC.	1	-59.0%
WASAGA DISTRIBUTION INC.	2	-43.6%
NORTHERN ONTARIO WIRES INC.	3	-33.3%
HEARST POWER DISTRIBUTION COMPANY LIMITED	4	-28.3%
E.L.K. ENERGY INC.	5	-26.6%
HALTON HILLS HYDRO INC.	6	-26.5%
HALDIMAND COUNTY HYDRO INC.	7	-23.5%
KITCHENER	8	-22.2%
COOPERATIVE HYDRO EMBRUN INC.	9	-20.9%
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	10	-20.0%
NEWMARKET	11	-18.3%
OSHAWA PUC NETWORKS INC.	12	-18.1%
GRIMSBY POWER INCORPORATED	13	-17.1%
ESSEX POWERLINES CORPORATION	14	-15.5%
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	15	-15.4%
MILTON HYDRO DISTRIBUTION INC.	16	-14.9%
LAKEFRONT UTILITIES INC.	17	-15.3%
Entegrus Powerlines	18	-12.5%
LONDON HYDRO INC.	19	-12.7%
ENERSOURCE HYDRO MISSISSAUGA INC.	20	-11.7%
HORIZON UTILITIES CORPORATION	21	-11.2%
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	22	-10.4%
LAKELAND POWER DISTRIBUTION LTD.	23	-10.4%
HYDRO 2000 INC.	24	-9.3%
HYDRO ONE BRAMPTON NETWORKS INC.	25	-7.4%
KENORA HYDRO ELECTRIC CORPORATION LTD.	26	-7.1%
BURLINGTON HYDRO INC.	27	-7.9%
CAMBRIDGE and NORTH DUMFRIES HYDRO INC.	28	-7.0%
COLLUS POWER CORPORATION	29	-6.3%
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	30	-5.2%
CENTRE WELLINGTON HYDRO LTD.	31	-4.4%
POWERSTREAM INC.	32	-4.2%
WHITBY HYDRO ELECTRIC CORPORATION	33	-3.2%
ORILLIA POWER DISTRIBUTION CORPORATION	34	-3.1%
VERIDIAN CONNECTIONS INC.	35	-2.3%
WESTARIO POWER INC.	36	-1.5%

Table 17 (continued)

(as corrected December 19, 2013 and January 24, 2014)

Difference Between Actual and Predicted Cost: Cost Benchmarking Model

Distributor	Ranking	Actual minus Predicted Cost
PUC DISTRIBUTION INC.	40	0.9%
NORFOLK POWER DISTRIBUTION INC.	41	1.0%
BRANTFORD POWER INC.	42	1.0%
BLUEWATER POWER DISTRIBUTION CORPORATION	43	1.3%
KINGSTON HYDRO CORPORATION	44	1.6%
HYDRO OTTAWA LIMITED	45	1.7%
SIOUX LOOKOUT HYDRO INC.	46	2.7%
WATERLOO NORTH HYDRO INC.	47	3.4%
PARRY SOUND POWER CORPORATION	48	3.9%
NORTH BAY HYDRO DISTRIBUTION LIMITED	49	5.0%
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	50	5.9%
NIAGARA-ON-THE-LAKE HYDRO INC.	51	6.6%
NIAGARA PENINSULA ENERGY INC.	52	6.9%
GUELPH HYDRO ELECTRIC SYSTEMS INC.	53	9.4%
GREATER SUDBURY HYDRO INC.	54	9.5%
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	55	11.0%
ERIE THAMES POWERLINES CORPORATION	56	11.1%
TILLSONBURG HYDRO INC.	57	12.2%
FORT FRANCES POWER CORPORATION	58	13.0%
WELLINGTON NORTH POWER INC.	59	13.0%
CANADIAN NIAGARA POWER INC.	60	14.1%
PETERBOROUGH DISTRIBUTION INCORPORATED	61	15.4%
BRANT COUNTY POWER INC.	62	17.1%
RENFREW HYDRO INC.	63	17.3%
ATIKOKAN HYDRO INC.	64	18.5%
MIDLAND POWER UTILITY CORPORATION	65	18.6%
ENWIN UTILITIES LTD.	66	19.5%
CHAPLEAU PUBLIC UTILITIES CORPORATION	67	20.4%
FESTIVAL HYDRO INC.	68	20.6%
WEST COAST HURON ENERGY INC.	69	21.8%
WOODSTOCK HYDRO SERVICES INC.	70	31.8%
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	71	44.8%
HYDRO ONE NETWORKS INC.	72	58.3%
ALGOMA POWER INC.	73	65.5%

7 Concluding Remarks

Board Staff retained Pacific Economics Group Research LLC (PEG) to advise it on productivity and benchmarking research in support of incentive rate setting in Ontario. Research topics included measuring industry input price inflation, mitigating volatility in measured inflation, estimating TFP for the electricity distribution industry, and appropriate business conditions to consider when benchmarking Ontario distributors.

PEG was asked to develop recommendations for these elements and endeavored to base our recommendations on rigorous and objective empirical research that could be replicated, refined and extended in future IR applications. PEG's recommendations were also informed by, and consistent with, the principles for effective incentive regulation and salient regulatory precedents from around the world.

Drawing on our index-based research and knowledge of the broader regulatory environment in Ontario, PEG recommends that the productivity factor for Price Cap IR be set to zero. PEG also developed and recommends an econometric cost model to benchmark the cost performance of Ontario electricity distributors. This econometric cost model includes several adjustments to the cost measure used in the TFP analysis that were intended to make costs more comparable across Ontario electricity distributors. PEG recommends that the Board rely on the benchmarking measures from this econometric model to set stretch factors for distributors in the industry.

PEG believes that the methods used to develop its X factor recommendations can provide a solid foundation for future incentive regulation proceedings in Ontario. PEG's approach brings together a wealth of techniques and data sources that can be useful in future IR applications. At the same time, our methodology is flexible enough to allow the techniques used to estimate productivity and stretch factors to evolve and/or be refined as new or additional information becomes available in Ontario.

Appendix One: Econometric Decomposition of TFP Growth

There are rigorous ways to set X factors so that they are tailored to utility circumstances that differ materially from industry norms (either historically or at a given point in time). This can be done by developing information on the sources of TFP growth and adjusting the X factor to reflect the impact on TFP resulting from differences between a utility's particular circumstances and what is reflected in historical TFP trends. To provide a conceptual foundation for such adjustments, below we consider how the broad TFP aggregate discussed above can be decomposed into various sources of productivity change.

Our analysis begins by assuming a firm's cost level is the product of the minimum attainable cost level C^* and a term η that may be called the inefficiency factor.

$$C = C^* \cdot \eta . \qquad \text{[A1.1]}$$

The inefficiency factor takes a value greater than or equal to 1 and indicates how high the firm's actual costs are above the minimum attainable level.[36]

Minimum attainable cost is a function of the firm's output levels, the prices paid for production inputs, and business conditions beyond the control of management. Let the vectors of input prices facing a utility, output quantities and business conditions be given by $\boldsymbol{W}$ (= $W_1, W_2 \ldots W_J$), $\boldsymbol{Y}$ (= $Y_1, Y_2 \ldots Y_I$), and $\boldsymbol{Z}$ (= $Z_1, Z_2 \ldots Z_N$), respectively. We also include a trend variable (T) that allows the cost function to shift over time due to technological change. The cost function can then be represented mathematically as

$$C^* = g(\boldsymbol{W}, \boldsymbol{Y}, \boldsymbol{Z}, T). \qquad \text{[A1.2]}$$

Taking logarithms and totally differentiating Equation [A1.2] with respect to time yields

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g}. \qquad \text{[A1.3]}$$

---

[36] A firm that has attained the minimum possible cost has no inefficiency and an inefficiency factor equal to 1. The natural logarithm of 1 is zero, so if a firm is operating at minimum cost, the inefficiency factor drops out of the analysis that follows.

Equations [A1.1] and [A1.3] imply that the growth rate of *actual* (not minimum) cost is given by

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g} + \dot{\eta}. \qquad \text{[A1.4]}$$

The term ε_{Y_i} in equation [A1.4] is the elasticity of cost with respect to output i. It measures the percentage change in cost due to a small percentage change in the output. The other ε terms have analogous definitions. The growth rate of each output quantity i is denoted by $\dot{Y}$. The growth rates of input prices and the other business condition variables are denoted analogously.

Shephard's lemma holds that the derivative of minimum cost with respect to the price of an input is the optimal input quantity. The elasticity of minimum cost with respect to the price of each input *j* can then be shown to equal the optimal share of that input in minimum cost (SC_j^*). Equation [A1.4] may therefore be rewritten as

$$\begin{aligned} \dot{C} &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j SC_j^* \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}. \\ &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \dot{W}^* + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}. \end{aligned} \qquad \text{[A1.5]}$$

The W^* term above is the growth rate of an input price index, computed as a weighted average of the growth rates in the price subindexes for each input category. The *optimal* (cost-minimizing) cost shares serve as weights. We will call W^* the optimal input price index.

Recall from the indexing logic presented earlier that

$$T\dot{F}P = \dot{Y} - \dot{X} \qquad \text{[A1.6]}$$

And

$$\dot{X} = \dot{C} - \dot{W} \qquad \text{[A1.7]}$$

The input price index above is weighted using actual rather than optimal cost shares. Substituting equations [A1.6] and [A1.7] into [A1.4], it follows that

$$
\begin{aligned}
T\dot{F}P &= \dot{Y} - \left(\dot{C} - \dot{W}\right) \\
&= \dot{Y} - \left[\left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_n \varepsilon_{Z_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right) - \dot{W}\right] \\
&= \dot{Y} - \left[\left\{\left[\left(1 - \frac{1}{\sum \varepsilon_{Y_i}}\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_i \frac{\varepsilon_{Y_i}}{\sum_i \varepsilon_{Y_i}} \cdot \dot{Y}_i\right] + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right\} - \dot{W}\right] \\
&= \dot{Y} - \left\{\left[\left(\frac{1}{\sum \varepsilon_{Y_i}} - 1\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \dot{Y}^{\varepsilon} + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right] - \dot{W}\right\} \\
&= \cdot\left(1 - \sum \varepsilon_{Y_i}\right) \cdot \dot{Y}_i + \left(\dot{Y} - \dot{Y}^{\varepsilon}\right) - \left(W^* - \dot{W}\right) - \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n - \dot{g} - \dot{\eta}
\end{aligned}
$$

[A1.8]

The expression above shows that growth rate in TFP has been decomposed into six terms. The first is the **scale economy effect**. Economies of scale are realized if, when all other variables are held constant, changes in output quantities lead to reductions in the unit cost of production. This will be the case if the sum of the cost elasticities with respect to the output variables is less than one.

The second term is the **nonmarginal cost pricing effect**. This is equal to the difference between the growth rates of two output quantity indexes. One is the index used to compute TFP growth. The other output quantity index, denoted by $\dot{Y}^{\varepsilon}$, is constructed using cost elasticity weights. The Tornqvist index that we use to measure TFP should theoretically be constructed by weighting outputs by their shares of revenues. It can be shown that using cost elasticities to weight outputs is appropriate if the firm's output prices are proportional to its marginal costs, but revenue-based weights will differ from cost elasticity shares if prices are not proportional to marginal costs. Accordingly, this term is interpreted as the effect on TFP growth resulting from departures from marginal cost pricing.[37]

The third term is the **cost share effect**. This measures the impact on TFP growth of differences in the growth of input price indexes based on optimal and actual cost shares. This term will have a non-zero value if the firm utilizes inputs in non-optimal proportions.

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[37] See Denny, Fuss and Waverman *op cit*, p. 197.

The fourth term is the **Z variable effect.** It reflects the impact on TFP growth of changes in the values of the Z variables that are beyond management control.

The fifth term is **technological change**. It measures the effect on productivity growth of a proportional shift in the cost function. A downward shift in the cost function due to technological change will increase TFP growth.

The sixth term is the **inefficiency effect**. This measures the effect on productivity growth of a change in the firm’s inefficiency factor. A decrease in a firm’s inefficiency will reduce cost and accelerate TFP growth. Firms decrease their inefficiency as they approach the cost frontier, which represents the lowest cost attainable for given values of output quantities, input prices, and other business conditions.

Appendix Two: Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog.[38] This very flexible function is the most frequently used in econometric cost research, and by some account the most reliable of several available alternatives.[39] The general form of the translog cost function is:

$$\ln C = \alpha_0 + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j + \frac{1}{2}\left(\sum_h \sum_k \gamma_{h,k} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{j,n} \ln W_j \ln W_n \right) + \sum_h \sum_j \gamma_{i,j} \ln Y_i \ln W_j \qquad [A2.1]$$

where Y_h denotes one of K variables that quantify output and the W_j denotes one of N input prices.

One aspect of the flexibility of this function is its ability to allow the elasticity of cost with respect to each business condition variable to vary with the value of that variable. The elasticity of cost with respect to an output quantity, for instance, may be greater at smaller values of the variable than at larger values. This type of relationship between cost and quantity is often found in cost research.

Business conditions other than input prices and output quantities can contribute to differences in the costs of LDCs. To help control for other business conditions the logged values of some additional explanatory variables were added to the model in Equation [A2.1] above.

The econometric model of cost we wish to estimate can then be written as:

[38] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[39] See Guilkey (1983), et. al.

$$
\begin{aligned}
\ln C \;=\; & \alpha_o + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j \\
+ \; & \frac{1}{2}\left[\sum_h \sum_k \gamma_{hk} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n\right] \\
+ \; & \sum_h \sum_j \gamma_{ij} \ln Y_h \ln W_j + \sum_h \alpha_h \ln Z_h + \alpha_t T + \varepsilon
\end{aligned}
\qquad \text{[A2.2]}
$$

Here the Z_h's denote the additional business conditions, T is a trend variable, and ε denotes the error term of the regression.

Cost theory requires a well-behaved cost function to be homogeneous in input prices. This implies the following three sets of restrictions:

$$\sum_{h=1}^{N} \frac{\partial \ln C}{\partial \ln W_h} = 1 \qquad \text{[A2.3]}$$

$$\sum_{h=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots, N \qquad \text{[A2.4]}$$

$$\sum_{h}^{N} \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \qquad \forall j = 1,\ldots, K \qquad \text{[A2.5]}$$

Imposing the above $(1+N+K)$ restrictions implied above allow us to reduce the number of parameters that need be estimated by the same amount. Estimation of the parameters is now possible but this approach does not utilize all information available in helping to explain the factors that determine cost. More efficient estimates can be obtained by augmenting the cost equation with the set of cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, *j*, can be written as:

$$S_j = \alpha_j + \sum_i \gamma_{h,j} \ln Y_h + \sum_n \gamma_{jn} \ln W_n \qquad \text{[A2.6]}$$

We note that the parameters in this equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come as no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself.

A.2.2 Estimation Procedure

We estimated this system of equations using a procedure first proposed by Zellner (1962).[40] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve even a better estimator, PEG iterates this procedure to convergence.[41] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[42]

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[43] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

[40] See Zellner, A. (1962).

[41] That is, we iterate the procedure until the determinant of the difference between any two consecutive estimated disturbance matrices are approximately zero.

[42] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[43] This equation can be estimated indirectly from the estimates of the parameters left remaining in the model.

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