EMPIRICAL RESEARCH IN SUPPORT OF INCENTIVE RATE SETTING IN ONTARIO:

REPORT TO THE ONTARIO ENERGY BOARD

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Pacific Economics Group Research, LLC

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1. Introduction and Executive Summary

On October 18, 2012, the Ontario Energy Board (the Board) released a Report of the Board titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the RRFE Board Report). The RRFE Board Report sets out three rate-setting options: 4th Generation Incentive Rate-setting (4th Gen 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 4th Gen IR option will use rate adjustment formulas that are calibrated using estimates of Ontario-specific industry input price and total factor productivity (TFP) trends, as well as benchmark-based information on each distributor's relative efficiency. The 4th Gen 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.[1]

In both 4th Gen 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 4th Gen 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.[2] 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 4th Gen 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:

[1] 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.

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

> 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.[3]

The Board indicated in the RRFE Board Report that it will retain this basic approach for 4th Gen 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 4th Gen 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 4th Gen IR.[4]

The Board has stated that its basic approach for assigning stretch factors under the 3rd Gen IR will continue under 4th Gen IR, although it will be modified to reflect distributors' *total* cost performance.[5] Currently, 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.[6] Since 2008, these cohort assignments have been used to

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

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

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

[6] 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 assign stretch factors. In 4th Gen IR, the Board will make these assignments using total cost benchmarking evaluations and determine the appropriate stretch factor values for the different efficiency cohorts in conjunction with its determination of the productivity factor.

The Board Staff retained Pacific Economics Group Research LLC (PEG) to advise on the development of 4th Gen IR. We worked closely with Board Staff to help organize and conduct a series of stakeholder Working Group discussions on Performance, Benchmarking and Ratemaking (PBR) topics for the 4th Gen IR.[7] Among other things, the PBR Working Group discussed options for 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 also asked to develop specific, quantitative recommendations for three elements of the 4th Gen IR rate adjustment formula: 1) the inflation factor; 2) the productivity factor that applies to the entire industry; and 3) stretch factors that apply to different cohorts of distributors in the industry. PEG endeavored to base our recommendations on all three elements using rigorous and objective empirical research that could be replicated, refined and extended in future IR applications. Some of our current benchmarking research may also inform the Board's review of custom IR applications. Our empirical analysis was also informed by, and consistent with, the suggestions and recommendations of the PBR Working Group as well as the principles for effective incentive regulation.

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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.

[7] 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.

Our recommendations can be briefly summarized. PEG recommends that the inflation factor be constructed as a weighted average of inflation in three separate indices: 1) a capital service price that PEG has constructed using publicly available information; 2) average weekly earnings for workers in Ontario; and 3) the GDP-IPI. The weights that apply to each index are equal to the estimated shares of capital, labor, and non-labor OM&A expenses, respectively, in total distribution cost for the Ontario electricity distribution industry. This inflation factor can be updated and computed each year using publicly-available information on inflation in the selected indices and, when relevant, changes in the Board's approved rates of return.

We also recommend that, in each year, the inflation factor be measured as the average value of inflation in our recommended input price index (IPI) over the three most recent years. Measuring inflation as the three-year moving average in our recommended IPI substantially reduces the volatility of the inflation factor. Evidence over the 2002-2011 period suggests that the volatility of PEG's recommended IPI will be similar to the volatility of the inflation factor that is currently used in 3rd Gen IR.

PEG produced two estimates for TFP growth for Ontario electricity distributors over the 2002-2011 period. Both estimates excluded Toronto Hydro and Hydro One because of evidence showing that 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 annual rate of ~~0.05%~~ 0.1% per annum. PEG also used an econometric cost model to backcast TFP growth for the industry between 2002 and 2011. The backcast analysis predicted average TFP growth of ~~-0.03%~~ 0.07% over the sample period.

Given that the index-based and econometric-based TFP estimates are both close to ~~zero~~0.1%, PEG recommends that the productivity factor for 4th Gen IR be set equal to ~~zero~~0.1%. In addition to being consistent with the two empirical estimates, PEG believes a productivity factor of ~~zero~~ 0.1% is reasonable for several reasons. First, PEG's analysis shows that the industry's slower TFP growth stems primarily from a slowdown in output growth rather than an acceleration in distributors' spending. The slower output growth has been particularly pronounced since the introduction of CDM programs in 2006. PEG believes the continued emphasis on CDM policies in Ontario will continue to limit the potential for output quantity and TFP gains for the industry.

Second, we find the available evidence does not support a negative productivity factor. While TFP growth for the Ontario electricity distribution industry has been negative since 2007, much of this decline is attributable to the severe recession in 2008-09. This was a one-time event and is not anticipated to recur during the term of 4th Gen IR. PEG also concludes that the experience since 2007 is not long enough to be the basis for a productivity factor; TFP trends should be calculated over at least a nine-year period. We also do not favor treating sub-periods within a sample period differently (*e.g.* by placing more weight on one sub-period rather than another), since such an approach can give rise to “cherry picking” and artificial manipulation of the available data. The nine-year industry TFP trend is more consistent with a productivity factor of ~~zero~~0.1% than a substantially negative productivity factor.

Third, an IPI inflation factor combined with a productivity factor of ~~zero~~ 0.1% would mean electricity distributor prices grow at nearly the same rate as the industry’s input price inflation, if all else is held equal. PEG’s research shows that input price inflation for the electricity distribution industry has been slightly below GDP-IPI inflation. It is not unusual for price inflation in a particular sector (such as electricity distribution) to be similar to average price inflation in the economy. If the productivity factor was the only component of the X factor, a productivity factor equal to ~~zero~~ 0.1% would likely mean that electricity distribution prices grow at rates similar to the prices of other goods and services in the economy. Price inflation in a particular sector that is similar to aggregate, economy-wide inflation is not necessarily a sign of sub-par productivity performance in that sector.

However, the productivity factor is *not* the only component of the X factor, nor is it the component of the X factor that is designed to ensure that consumers benefit from incentive rate setting. Stretch factors are intended to reflect distributors’ incremental efficiency gains under incentive ratemaking. Adding a stretch factor to the productivity factor allows customers to share in these anticipated efficiency gains. PEG has recommended positive stretch factors for most distributors, which means that electricity distributor prices are ~~still~~ expected to fall in “real,” inflation-adjusted terms under the index-based rate adjustments allowed in 4th Gen IR. A productivity factor of 0.1% ~~zero~~ is therefore not incompatible with the Board's incentive rate-setting objectives of encouraging cost efficiency and ensuring that customers share in these efficiency gains.

PEG used econometric and unit cost/peer group models that we developed to benchmark distributors' total cost performance and inform stretch factor assignments. As in 3rd Gen IR, both benchmarking methods were used to identify efficiency cohorts in the industry, but we recommend expanding the number of these cohorts from three (in 3rd Gen IR) to five. This recommendation is designed to facilitate the movement of distributors into higher cohorts. Since distributors in higher cohorts are subject to lower recommended stretch factors, a larger number of cohorts strengthens distributors' incentives to pursue efficiency.

PEG recommends that distributors be assigned to efficiency cohort I if they are significantly superior cost performers at a 90% confidence level and if they are in the top quintile of distributors on the peer group/unit cost benchmarking analysis. ~~Six~~Eight distributors satisfy these criteria, and we recommend that the ~~six~~ eight distributors in cohort I be assigned a stretch factor of 0. Distributors will be assigned to efficiency cohort II if they are significantly superior cost performers at a 90% confidence level and if they are in the second quintile of distributors on the peer group/unit cost benchmarking analysis. Four~~One~~ distributors satisfy~~ies~~ these criteria, and we recommend that the~~is~~ four distributors in cohort II be assigned a stretch factor of 0.15%.

Conversely, PEG recommends that distributors be assigned to efficiency cohort V if they are significantly inferior cost performers at a 90% confidence level and if they are in the bottom quintile of distributors on the peer group/unit cost benchmarking analysis. ~~Eleven~~ Thirteen distributors satisfy these criteria, and we recommend that the 13~~1~~ distributors in cohort V be assigned a stretch factor of 0.6%. Distributors will be assigned to efficiency cohort IV if they are significantly inferior cost performers at a 90% confidence level and if they are in the fourth quintile of distributors on the peer group/unit cost benchmarking analysis. Four~~ive~~ distributors satisfy these criteria, and we recommend that the four~~ive~~ distributors in cohort IV be assigned a stretch factor of 0.45%. The remaining 44~~50~~ distributors are in cohort III and will be assigned a stretch factor of 0.3%.

By increasing the number of cohorts from three to five, this approach for assigning stretch factors makes it easier for distributors to migrate into higher cohorts by controlling costs. The recommended maximum stretch factor remains 0.6%, but PEG recommends that the minimum stretch factor be reduced to zero to encourage and reward efforts to reduce unit cost. PEG also recommends that the stretch factor for the largest group of distributors be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time. ~~Given that our recommended productivity factor is zero, the values of these stretch factors would set the value of the X factors that apply to each respective cohort of distributors in 4th Gen IR.~~

PEG believes that the empirical research used to develop these recommendations for 4th Gen IR 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 to determine the X factors in the 4th Generation IR 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.

Our 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 our recommended inflation factor. Chapter Four discusses data sources and issues associated with available data. Chapter Five presents our econometric research on the cost performance of Ontario electricity distributors. Chapter Six estimates historical TFP growth for the Ontario electricity distribution industry and uses the econometric cost model to "backcast" the industry's TFP growth for the 2002-2011 period. Chapter Seven presents information on unit cost and "cost driver" variables, identifies six peer groups of Ontario electricity distributors, develops unit cost comparisons for the peer groups, and makes recommendations for efficiency cohorts and stretch factors. Chapter Eight presents final recommendations and concluding remarks.

There are also three 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. Appendix Three presents technical details on some of the statistical tests undertaken in Chapter Five.

2. Inflation and X Factors

This chapter will provide some background on developing appropriate 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 4th Gen 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.

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

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:

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

Substituting [3] into [2] we obtain

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

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 4th Gen IR will be a measure of industry input price inflation, so the indexing logic presented in equations [1] through [4] is valid for 4th Gen IR.

While industry TFP and input price measures are used to calibrate X factors, 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 relationship between TFP growth and the various factors that can "drive" changes in productivity over the term of an incentive regulation plan.

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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.

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. The Inflation Factor

The inflation factor in the current 3rd Gen IR is the Gross Domestic Product Implicit Price Index for final domestic demand (GDP-IPI). The Board has concluded that a more industry-specific measure of input price inflation will be used as the inflation factor in 4th Gen IR.[13] In 3rd Gen IR, the Board considered using an industry input price index (IPI) for the inflation factor but decided against doing so because of the potential volatility of such an index. The Board has concluded that concerns regarding volatility in the IPI will be mitigated by the methodology it selects to measure inflation.

Electricity distributors procure three broad classes of inputs: 1) capital; 2) labor; and 3) non-labor, OM&A expenses. The main challenge in developing an IPI is identifying the best available subindices for measuring inflation in the prices of electricity distributors' capital, labor, and non-labor OM&A inputs, respectively. Once these are identified, overall inflation is easily computed as the weighted average of the inflation rates in each subindex, where the weights are equal to each input's associated share of the industry's total cost. The details of calculating industry total cost will be discussed in Chapter Four of this report.

The Board has said that it will be guided by the following criteria when deciding on appropriate input price subindices and an appropriate inflation factor:[14]

- the inflation factor must be constructed and updated using data that are readily available from public and objective sources such as Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada;
- to the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labor prices should be indexed by Ontario distribution industry-specific indices; and

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

- the component of the inflation factor designed to adjust for inflation in labor prices will be indexed by an appropriate generic and off-the-shelf labor price index (i.e., the labor price index will not be distribution industry-specific).

PEG has developed two alternative, inflation factors that we believe comply with the Board's criteria. The first is a "two-factor" IPI, where industry input price inflation is measured using separate input price subindices for capital and OM&A inputs. The second option is a "three-factor" IPI, where inflation is measured using separate input price subindices for capital, labor, and non-labor OM&A inputs, respectively.

This Chapter will summarize PEG's research on the inflation factor. We begin by discussing the choices for inflation subindices. We then discuss the issue of inflation volatility and options for mitigating volatility. Next we present our estimates of historical input price inflation for Ontario electricity distributors using the two-factor and three-factor IPI options. Finally, PEG presents its recommended inflation factor for 4th Gen IR.

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. A single inflation factor will apply to all distributors in the industry under 4th Gen IR, so it is appropriate for the weights in the IPI to be calculated using average cost shares for the industry as a whole. Developing an IPI with separate indices for capital, labor, and non-labor OM&A input prices therefore 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 applies to the capital input price index (described below) was 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 index 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). The input price index that PEG recommends as an inflation factor will therefore also be a component of the TFP analysis and therefore should be consistent with the cost measure used in this analysis.

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.[15] 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 Labor Prices

The RRFE Board Report finds that labor prices should be indexed by generic and off-the-shelf labor price indices (i.e. indices that are not distribution industry-specific). PEG believes the best generic and off-the-shelf labor price index to use in the 4th Gen IR inflation factor is average weekly earnings (AWE) for all workers in Ontario.[16] 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. PEG therefore recommends that the AWE for all Ontario workers be used to measure labor price inflation in the inflation factor used in 4th Gen IR.

3.1.3 Capital Input Prices

Unlike labor prices, the Board has found that non-labor prices should to the extent practicable be indexed by Ontario distribution industry-specific indices. There are two classes of non-labor inputs: capital and non-labor OM&A expenses. We deal with each of these non-labor input categories in turn.

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

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

16 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.

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.[17] 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%.[18]

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 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 WACC and the capital structure to calculate the rate of return r_t.

Our measure of the asset-price index WKA_t was 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.

[17] Hulten and Wykoff (1981)
[18] 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 4 of this report.

We believe a capital service price estimated using these data satisfies the Board's criteria for measuring non-labor prices in the inflation factor. The capital service price can be updated in a straightforward manner each year using two pieces of information: changes in the Board's approved WACC, and changes in the EUCPI. Both sets of data come from public and objective sources. The EUCPI series is updated in early April of each year. The Board-approved WACC is obviously specific to the Ontario electricity distribution industry. The EUCPI reflects trends in electricity distribution asset prices in Canada, rather than Ontario specifically. Nevertheless, this is the most practical, publicly-available index of electricity distribution asset prices for Ontario distributors since Stats Canada does not publish any comparable series that are specific to Ontario.

Table One presents information on this capital service price for Ontario distributors over the 2002-2011 period. This is the same sample period that will be used in this report's TFP analysis. 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 in the second to last column from the right (*i.e.* the "Capital Price Inflation" column), as well as a three-year moving average of capital service price inflation in the last column on the right.

It can be seen that capital service prices grew at an average annual rate of 1.00% per annum over the sample period. When measured on a three-year moving average basis, the capital service price grew somewhat more rapidly at 1.13% per annum. The EUCPI grew at an average rate of 2.27% per annum between 2002 and 2011, and the Board-approved WACC declined at an average rate of 1.77% over this period.

PEG's recommended capital service price is somewhat volatile, with annual inflation in the index ranging from -0.7% in 2006 to 2.4% in 2007 and 2008. The standard deviation in the annual capital service price index is 1.11%. However, when measured on a three-year moving average basis, the capital service price varies over a smaller range (from a high of 2.0% in 2009 to a low of 0.1% in 2006) and the standard deviation is reduced by about 40% to 0.69%. This analysis suggests that volatility in capital service prices can be mitigated by measuring their inflation as a three-year moving average rather than through annual changes in index values.

Table 1

Calculation of Capital Service Price Index

Year	EUCPI	Annual Growth	WACC	Annual Growth	Depreciation Rate	Capital Price Index	Capital Price Inflation	Three Year Moving Average
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%	0.5%
2006	142.4	6.4%	7.74%	-6.88%	4.59%	16.88	-0.7%	0.1%
2007	148.8	4.4%	7.35%	-5.22%	4.59%	17.30	2.4%	0.9%
2008	150.3	1.0%	7.27%	-1.11%	4.59%	17.72	2.4%	1.4%
2009	151.1	0.5%	7.32%	0.63%	4.59%	17.93	1.2%	2.0%
2010	155.1	2.6%	7.40%	1.14%	4.59%	18.30	2.0%	1.9%
2011	160.1	3.2%	7.08%	-4.46%	4.59%	18.32	0.1%	1.1%
Average		**2.27%**		**-1.77%**			**1.00%**	**1.13%**
Standard Deviation		**2.11%**		**2.95%**		`	**1.11%**	**0.69%**
Standard Deviation/ Average		**92.7%**		**-166.7%**			**110.4%**	**61.0%**

Notes: The weighted average cost of capital is computed using 40% equity, 56% long term debt and 4% short term debt and Board-approved allowed rates of return.

3.1.4 Non-Labor OM&A Input Prices

The other non-labor input for electricity distributors is non-labor OM&A expenditures. The Board has found that non-labor input inflation indices should be drawn from public and objective sources and be as specific as practicable to the Ontario electricity distribution industry. However, while private vendors like DRI have developed indices that specifically measure inflation in utilities' non-labor OM&A input prices, PEG is not aware of similar indices that are available from objective, public sources.

One difficulty is that "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 4th Gen IR.

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.[19] 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.

The practical difficulties of isolating such labor expenses, and in identifying publicly available indices that reflect the breadth of non-labor OM&A input prices, requires decisions on how best to satisfy the Board's criteria for establishing an inflation factor. One issue is what inflation subindex is the best practical choice for capturing the diverse array of inputs that will be reflected in distributors' non-labor, OM&A expenditures. A second issue is to what extent the best practical option for a non-labor, OM&A input price index should stress labor price pressures reflected in outsourcing contracts and recorded as non-labor OM&A expenditures. Selecting a broad-based price index that emphasizes the diversity of the input

[19] The cost of these outsourcing contracts is not separately categorized in the RRRs.

mix would necessarily rule out an index stressing labor price pressures, and there is no practical way to construct a non-labor OM&A input price measure that includes both since data are not available on the share of outsourced contract labor in OM&A expenses.

Because of these practical challenges, PEG's analysis considers two options for the price subindex for non-labor OM&A inputs. The first is AWE for all Ontario workers. This option obviously emphasizes the portion of labor cost implicit in non-labor OM&A expenses. Since the AWE is also used to measure labor input prices, having this index apply to non-labor OM&A inputs as well would effectively mean that two price subindices are used to measure inflation in the three input categories. We call this option the "two-factor" IPI.

The second option is to use the GDP-IPI to measure non-labor OM&A input prices. This option emphasizes the breadth and diversity of non-labor OM&A inputs. The GDP-IPI is a good index for reflecting the broad scope of these inputs, since it applies to all final domestic demand in Canada. In addition to being very broad, this index is currently used in 3rd Gen IR and therefore familiar to the Board, Staff, and stakeholders. The second option uses distinct input price subindices for each of the three input categories, and PEG accordingly calls this the "three-factor" IPI.

Table Two provides information on inflation in the AWE-All Employees and the GDP-IPI indices over the 2002-2011 period. It can be seen that average AWE inflation of 2.56% per annum has exceeded the 1.69% average annual growth in the GDP-IPI. The gap widens somewhat (2.61% vs. 1.69%) if the two indices are measured on a three-year moving average basis. The AWE is also more volatile, with a standard deviation of 1.01% (or about 39% of annual AWE inflation) compared with a standard deviation of 0.35% (or about 21% of annual inflation) for the GDP-IPI. In general, these data show that if the AWE rather than the GDP-IPI was used as the non-labor OM&A input price subindex, it would tend to lead to more rapid and more volatile changes in the inflation factor.

3.2 Mitigating Inflation Volatility

An important consideration in constructing the inflation factor for 4th Gen IR is volatility. Tables One and Two show PEG's capital service is the most volatile of our recommended input price subindices. These tables also show that measuring inflation on the basis of a three-year moving average substantially reduces volatility. Using standard

Table 2

Alternate Measures of Non-Labor OM&A Input Price Inflation

	AWE- All Employees			GDPIPI		
Year	Ontario	Annual Growth	Three Year Moving Average	Ontario	Annual Growth	Three Year Moving Average
2002	710.73			92.25		
2003	728.23	2.43%		93.54	1.39%	
2004	748.78	2.78%		95.11	1.66%	
2005	776.19	3.60%	2.94%	96.96	1.92%	1.66%
2006	788.62	1.59%	2.66%	98.43	1.51%	1.70%
2007	818.93	3.77%	2.99%	100.00	1.58%	1.67%
2008	838.14	2.32%	2.56%	102.30	2.27%	1.79%
2009	849.15	1.31%	2.47%	103.60	1.26%	1.71%
2010	882.21	3.82%	2.48%	105.10	1.44%	1.66%
2011	894.71	1.41%	2.18%	107.40	2.16%	1.62%
Average		**2.56%**	**2.61%**		**1.69%**	**1.69%**
Standard Deviation		**1.01%**	**0.28%**		**0.35%**	**0.05%**
Standard Deviation/Average		**39.33%**	**10.81%**		**20.94%**	**3.15%**

deviation as the volatility metric, relative volatility of the capital service price declines by 38% when inflation is measured as average inflation over the last three years rather than by the average annual change in the index. The comparable figures for the AWE and the GDP-IPI are 72% and 86%, respectively.[20]

These data suggest that a three-year moving average is an effective way to mitigate inflation volatility. We also consulted on this approach with the PBR Working Group, and it supported using a three-year moving average to mitigate inflation volatility. PEG therefore recommends that a three-year moving average be used to damp volatility of both the two-factor IPI and the three-factor IPI. This three-year moving average is calculated simply by computing annual inflation in the IPI for each of the three most recent years and then calculating the average of these inflation rates.

3.3 Historical Results on Industry Input Price Inflation

Overall input price indexes were constructed as a weighted average of the selected input price subindices. The weights were based on the share of the total cost measure used in the TFP analysis that is associated with the respective input. These cost shares were 62.4% for capital, 26.3% for labor, and 11.3% for non-labor OM&A expenses.

Table Three presents data on inflation in the two-factor IPI for the 2002-2011 period. Table Four presents data on inflation in the three-factor IPI for the same period. Table Five compares the inflation rates of the two IPIs.

In Table 3, it can be seen that the two-factor IPI grew at an average annual rate of 1.59% over the sample period. This average inflation rate rises somewhat to 1.68% if it is measured on a three-year moving average basis. The standard deviation of the two-factor IPI is 0.95% if inflation is measured annually but falls to 0.39% if inflation is measured as a three-year moving average. A three-year moving average therefore reduces volatility in this index by about 59% (*i.e.* ((0.95%-0.39%)/0.95% = 59%).

Table 4 shows that the three-factor IPI grew at an average annual rate of 1.49% between 2002 and 2011. This average inflation rate rises somewhat to 1.58% if it is

[20] For the capital service price, the standard deviations associated with annual and three year moving average inflation are 1.11% and 0.69%; the percentage decline in standard deviation, relative to value when inflation is measured annually, is ((1.11% - 0.19%)/1.11%)= 38%. The comparable calculations for the AWE and GDP-IPI are ((1.01%-0.28%)/1.01%) = 72%, and ((0.35%-0.05%)/0.36%) = 86%.

Table 3

Two-Factor Inflation Measure

Year	OM&A Input Price			Capital Service Price			Inflation Measure		
	AWE-All Employees-	Annual Growth	Weight	Index	Annual Growth	Weight	Index	Annual Growth	Three Year Moving Average
2002	710.73			16.74			100.00		
2003	728.23	2.43%	37.6%	16.82	0.47%	62.4%	101.22	1.21%	
2004	748.78	2.78%	37.6%	16.85	0.19%	62.4%	102.40	1.16%	
2005	776.19	3.60%	37.6%	17.01	0.92%	62.4%	104.39	1.93%	1.43%
2006	788.62	1.59%	37.6%	16.88	-0.74%	62.4%	104.53	0.13%	1.07%
2007	818.93	3.77%	37.6%	17.30	2.42%	62.4%	107.64	2.93%	1.66%
2008	838.14	2.32%	37.6%	17.72	2.39%	62.4%	110.22	2.37%	1.81%
2009	849.15	1.31%	37.6%	17.93	1.21%	62.4%	111.60	1.24%	2.18%
2010	882.21	3.82%	37.6%	18.30	2.04%	62.4%	114.66	2.71%	2.11%
2011	894.71	1.41%	37.6%	18.32	0.13%	62.4%	115.36	0.61%	1.52%
Average		**2.56%**			**1.00%**			**1.59%**	**1.68%**
Standard Deviation		**1.01%**			**1.11%**			**0.95%**	**0.39%**
Standard Deviation/ Average		**39.3%**			**110.4%**			**60.1%**	**23.0%**

Table 4

Three Factor Inflation Measure

Year	OM&A Input Price: GDPIPI-Ontario	OM&A Input Price: Annual Growth	OM&A Input Price: Weight	OM&A Input Price: AWE- All Employees-Ontario	OM&A Input Price: Annual Growth	OM&A Input Price: Weight	Capital Service Price: Index	Capital Service Price: Annual Growth	Capital Service Price: Weight	Inflation Measure: Index	Inflation Measure: Annual Growth	Inflation Measure: Three Year Moving Average
2002	92.25			710.73			16.74			100.00		
2003	93.54	1.39%	11.3%	728.23	2.43%	26.3%	16.82	0.47%	62.4%	101.10	1.09%	
2004	95.11	1.66%	11.3%	748.78	2.78%	26.3%	16.85	0.19%	62.4%	102.15	1.04%	
2005	96.96	1.92%	11.3%	776.19	3.60%	26.3%	17.01	0.92%	62.4%	103.94	1.74%	1.29%
2006	98.43	1.51%	11.3%	788.62	1.59%	26.3%	16.88	-0.74%	62.4%	104.07	0.12%	0.97%
2007	100.00	1.58%	11.3%	818.93	3.77%	26.3%	17.30	2.42%	62.4%	106.90	2.68%	1.52%
2008	102.30	2.27%	11.3%	838.14	2.32%	26.3%	17.72	2.39%	62.4%	109.45	2.36%	1.72%
2009	103.60	1.26%	11.3%	849.15	1.31%	26.3%	17.93	1.21%	62.4%	110.82	1.24%	2.09%
2010	105.10	1.44%	11.3%	882.21	3.82%	26.3%	18.30	2.04%	62.4%	113.55	2.44%	2.01%
2011	107.40	2.16%	11.3%	894.71	1.41%	26.3%	18.32	0.13%	62.4%	114.35	0.70%	1.46%
Average		**1.69%**			**2.56%**			**1.00%**			**1.49%**	**1.58%**
Standard Deviation		**0.35%**			**1.01%**			**1.11%**			**0.87%**	**0.40%**
Standard Deviation/ Average		**20.9%**			**39.3%**			**110.4%**			**58.4%**	**25.2%**

Table 5

Inflation Measure Summary

Year	Option One: Two Factor Inflation Measure			Option Two: Three Factor Inflation Measure		
	Index	Annual Growth	Three Year Moving Average	Index	Annual Growth	Three Year Moving Average
2002	100.00			100.00		
2003	101.22	1.21%		101.10	1.09%	
2004	102.40	1.16%		102.15	1.04%	
2005	104.39	1.93%	1.43%	103.94	1.74%	1.29%
2006	104.53	0.13%	1.07%	104.07	0.12%	0.97%
2007	107.64	2.93%	1.66%	106.90	2.68%	1.52%
2008	110.22	2.37%	1.81%	109.45	2.36%	1.72%
2009	111.60	1.24%	2.18%	110.82	1.24%	2.09%
2010	114.66	2.71%	2.11%	113.55	2.44%	2.01%
2011	115.36	0.61%	1.52%	114.35	0.70%	1.46%
Average		**1.59%**	**1.68%**		**1.49%**	**1.58%**
Standard Deviation		**0.95%**	**0.39%**		**0.87%**	**0.40%**
Standard Deviation/ Average		**60.1%**	**23.0%**		**58.4%**	**25.2%**

measured on a three-year moving average basis. The standard deviation of the three-factor IPI is 0.87% if inflation is measured annually but falls to 0.40% if inflation is measured as a three-year moving average. A three-year moving average therefore reduces volatility of this IPI by about 54% (*i.e.* ((0.87%-0.40%)/0.87% = 54%). The two-factor and the three-factor IPIs therefore have nearly identical standard deviations when measured on a three-year moving average basis (*i.e.* 0.39% and 0.40%, respectively). This implies that a three-year moving average application of either IPI option can be expected to mitigate volatility in the inflation factor by similar amounts.

Table Four also shows that a three-year moving average application of either IPI is likely to generate volatility in measured inflation that is similar to what has been experienced under 3rd Gen IR. Currently, inflation in 3rd Gen IR is measured by annual changes in the GDP-IPI. Table Four shows that the standard deviation of the GDP-IPI, when measured by annual changes in the index, is 0.35%. As discussed, the standard deviations for the two-factor and three-factor IPIs, when measured on a three-year moving average basis, are 0.39% and 0.40%, respectively. Past experience therefore suggests that the volatility of either the two- or three-factor IPI would be expected to be similar to the inflation volatility that customers have experienced under 3rd Gen IR. PEG therefore concludes that a three-year moving average of either IPI would effectively mitigate volatility in the inflation factor.

3.4 Recommended Inflation Factor

The empirical results for the two-factor IPI and three-factor IPI are similar. The options are nearly indistinguishable in terms of volatility. The three-factor IPI will likely lead to lower inflation than the two-factor IPI because GDP-IPI inflation is almost always below inflation in the AWE. Our historical data show that three-factor IPI leads to roughly 0.1% less inflation each year compared with the two-factor IPI.

Notwithstanding these similarities, PEG believes the three-factor IPI better satisfies the Board's criteria for an inflation factor in 4th Gen IR. The Board has established separate criteria for the labor- and non-labor input price subindices to be used in the inflation factor. The subindex designed to adjust for inflation in non-labor prices should be Ontario distribution industry-specific, while the subindex designed to adjust for inflation in labor prices should be a generic and off-the-shelf labor price index and therefore not distribution industry-specific. Since the Board has established different criteria for labor and non-labor input price subindices, it would be more difficult to satisfy these distinct criteria if the generic, off the shelf index used to measure labor price inflation was also used to measure a portion of non-labor input price inflation. However, that is what the two-factor IPI does, since it uses the AWE to measure both labor price inflation and non-labor OM&A input price inflation. The two-factor IPI option therefore blurs the criteria that the Board has established for selecting separate labor and non-labor price indices for the inflation factor.

The three-factor IPI will also be a more accurate measure of the underlying input price pressures that electricity distributors face. The two-factor IPI measures inflation in capital and labor prices only and makes no allowance for the miscellaneous other inputs that electricity distributors procure. The three-factor IPI is more disaggregated and includes what is likely to be a more precise measure of non-labor OM&A input price inflation.

Because both options are similar in terms of mitigating volatility and the three-factor IPI is superior to the two-factor IPI with respect to satisfying the Board's criteria and on conceptual grounds, PEG recommends that the three-factor IPI be used as the inflation factor in 4th Gen IR. Moreover, we recommend that this inflation factor be calculated each year as a three-year moving average of the three-factor IPI. This is equivalent to setting updated values for the inflation factor that are equal to the average inflation rate of the three-factor IPI over the three, most recent years preceding the year of the update.

4. Data for Total Factor Productivity and Total Cost Analysis

In 4th Gen IR, the Board has found that the productivity factor will be based on the estimated TFP trend for the Ontario electricity distribution industry and stretch factors will be based on benchmarking analyses of distributors' total costs. PEG was asked to provide recommendations for the productivity factor and stretch factors, so our work required estimates of industry TFP growth and benchmarking comparisons of Ontario distributors' total cost. These analyses require estimates of Ontario distributors' capital stocks, since 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, PEG needed to supplement the publicly available data with Board requests for additional information.

This chapter discusses data issues, 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.

4.1 Primary Data Sources

Extensive data are available on the operations of Ontario power distributors. Cost data are gathered chiefly from the Trial Balance reports. These reports are filed annually by distributors, as provided for under Section 2.1.7 of the Board's Electricity Reporting and Record Keeping Requirements ("RRRs"). 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.

An important supplemental source of Ontario cost data is the Performance Based Regulation ("PBR") reports. These are prepared annually by distributors as provided for under Section 2.1.5 of the Board's RRRs. The PBR data 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 most serious problem for TFP and total cost estimation is the number of years of available information. An extensive time series of capital data is particularly 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 years of consistent, detailed plant additions data. RRR data on plant additions are, at best, only available since 2002.[22] The lack of extensive time series data on capital additions limits the reliability of the capital measures that can be computed using RRR data.

In practical terms, measuring the quantity of capital typically 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 benchmark capital stock itself.

Capital measures typically become more accurate as measured capital values depend on cumulative capital additions rather than the benchmark capital value. Capital additions

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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.

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, PEG supplemented the RRR data on utility plant with plant values from the Municipal Utility Databank (MUDBANK). MUDBANK was 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.

However, 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 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.

[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.

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 additions 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. We also used differences in gross capital from the Trial Balance data to estimate gross capital additions between 2002 and 2011. Although capital additions data were available directly from the PBR Section of the RRRs, the Working Group advised against relying on the PBR data and instead recommended that PEG use the Trial Balance data.[24]

Finally, PEG included distributor capital additions for smart meters in the 2006-2011 period in our measured capital additions. 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. 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 systems. Both 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 Computing Capital Cost

PEG estimated the cost of utility plant in a given year t (CK_t) as the product of a 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}).

[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 Working Group therefore recommended that the available 2000-01 data not be used in PEG's TFP or benchmarking analyses.

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

The formula for the capital service price index is

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

This is identical to the capital service price used 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 identical to those described and used 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. Table Six 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 2002-2011 period, and this development is unlikely to persist. Including tax changes over 2002-2011 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 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. 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.[25]

[25] See Stevenson (1980) for a discussion of this approach.

Table 6

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 following perpetual inventory equation is used 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 and is identical to what is used in equation [8] and in the construction of the inflation factor. The depreciation rate is identical to what is derived on Table Six. PEG's estimates of gross capital additions VI_t were described in Section 4.2.

4.4 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 2002-2011 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 4.3.

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 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, the Working Group undertook extensive discussions on whether, and how, total cost should be adjusted in order to make “apples to apples” benchmarking comparisons across distributors.[26] The Working Group supported three cost adjustments.

One was to eliminate the costs of high-voltage (HV) transformation services (*i.e.* transmission substations greater than 50 kV) from the cost measures. 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 eliminated 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 our total cost calculation.

These adjustments will 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.

PEG also added in two cost items to make costs more comparable across distributors. First, we included 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. We obtained these data through the Board’s supplementary data request described in Section 4.2. PEG excluded the costs of regulatory asset recovery from the Hydro One LV charges because they include more than payment for LV services.

PEG also included contributions in aid of construction (CIAC) in the capital 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. If these CIAC were not included in distributors’ cost measures used for benchmarking, these costs

[26] 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.

would differ across distributors simply because of differences in the relative amounts of capital financed by CIAC.

Table Seven summarizes the differences between the cost measures that PEG used to estimate TFP and to benchmark distributors' total costs. Again, the three adjustments to our TFP cost measure were necessary to promote apples-to-apples cost comparisons across Ontario's electricity distributors. However, if these cost adjustments were made to the TFP cost measure, they would have either eliminated cost items (*e.g.* HV assets that are deemed to be distribution assets for some distributors) that will be subject to the PCI adjustment, or added in cost items (*e.g.* CIAC and LV charges to embedded distributors) that will not be subject to the PCI adjustment. Because our 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 out TFP study was appropriate for that purpose.

PEG developed total cost measures for 73 distributors in Ontario. These distributors are listed in Table Eight.[27] 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 Nine.

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

Table 7

Cost Measures for Empirical Analysis

Industry TFP Growth	Included in Study?	Distribution Cost Benchmarking	Included in Study?
Candidate Capital Costs:		**Candidate Capital Costs:**	
Capital Benchmark Year: 1989*		Capital Benchmark Year: 1989*	
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	Yes	Smart Meter Expenditures	Yes
Candidate OM&A Costs:		**Candidate OM&A Costs:**	
Distribution OM&A	Yes	Distribution OM&A	Yes
High Voltage OM&A***	Yes	High Voltage OM&A***	No
Low Voltage Charges to Embedded Distributors****	No	LV Charges to Embedded Distributors****	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

Table 8

SAMPLED POWER DISTRIBUTORS
(2011 Utility Names)

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.

Total Companies: 73

Table 9

SUMMARY OF DATA ADJUSTMENTS

Company Name	Year	Data Changed by PEG
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
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
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
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. Econometric Research on Cost Performance

PEG was asked to benchmark the total cost of Ontario's electricity distributors. We did this using two benchmarking methods: 1) a total cost econometric model; and 2) total unit cost comparisons across selected peer groups of distributors. This Chapter discusses our econometric work, while Chapter Seven will discuss the unit cost benchmarking.

5.1 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.[28] 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

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

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.

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.

5.2 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 extensively on the choices for outputs and business condition variables in our 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 allowed to participate. This webinar generated substantial comment on the merits of a variety of "cost driver" variables that PEG considered during its econometric work. In addition to outputs, the business condition variables we 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
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 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.

5.3 Estimation Results and Econometric Benchmarking

5.3.1 Full Sample Econometric Results

Estimation results for our electricity distribution cost model are reported in Table 10. 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. The table shades results for these terms for reader convenience.

Table 10 also reports the t values generated by the estimation program. The t 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 10, 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 scattered unmetered customers. 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 demand measure reported by the distributor, and this value is therefore also recorded as the

Table 10

Econometric Coefficients: Full Sample

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 = 2011 Service Territory
	L = Average Line Length (km)
	NG = % of 2011 Customers added in the last 10 years
	Trend = Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.624	88.183
N*	0.398	7.094
C*	0.220	4.346
D*	0.102	3.314
WKxWK	0.060	1.392
NxN	-0.480	-1.777
CxC	0.142	0.572
DxD*	0.189	2.558
WKxN*	0.026	1.372
WKxC	0.028	1.582
WKxD	0.000	-0.009
NxC	0.227	0.929
NxD	0.054	0.527
CxD*	-0.210	-2.335
A	0.018	1.552
L*	0.246	8.651
NG*	0.022	3.143
Trend*	0.012	8.578
Constant*	12.818	353.823
System Rbar-Squared	0.983	
Sample Period	2002-2011	
Number of Observations	729	

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

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 .~~27~~40%. A 1% hike in kWh deliveries raised cost by about .10~~7~~%. A 1% increase in system capacity increased distribution cost by 0.~~34~~22%. ~~Peak demand~~ Customer numbers was therefore the dominant output-related cost driver, followed by ~~customer numbers~~peak demand, followed by kWh deliveries.

Two~~hree~~ other business condition variables are also identified as statistically significant cost drivers on Table 10. One is a distributor's average circuit km of line over the 2002-2011 period. It can be seen that a 1% increase in average circuit km raised distribution cost by 0.~~1~~25%. 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 2002-2011 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.

~~Two~~One other business condition variable~~s~~ in Table 10 ~~are~~ is statistically significant. ~~One is the total km² of service territory in 2011. All else equal, a 1% increase in service territory raised distribution cost by 0.06%. This variable is also correlated with the extensiveness of distribution systems, customer location, and customer density within service territories. This finding is important, because a number of distributors serve vast amounts of largely unpopulated territory, and PEG's results show that there are costs associated with serving extensive service areas even after controlling for distributors' km of line.~~

~~The other statistically significant business condition variable was~~ It is the share of a distributor's customers that was added over the last 10 years. This 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 0.0~~3~~22%.

A surprising finding of our cost model was the coefficient on the trend variable. This coefficient was estimated to be 0.0124%. 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.~~4~~2% per annum between 2002 and 2011. 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

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- The share of service territory that is urban
- Municipal population divided by km^2 of urban territory
- The percentage of circuit km that are underground

5.3.2 Full Sample Econometric Benchmarking

PEG used the cost model presented in Table 10 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 10. 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 generated confidence intervals around that cost prediction.

PEG then compared each distributor's actual total cost to the model's cost prediction plus or minus the confidence intervals. This comparison was made for each distributor's average value of cost in 2009-2011. These are the three most recent years of the sample period, as well as being the three years that 3rd Gen IR has been in effect. By focusing the cost evaluations on these years, the analysis assesses distributors' relative cost performance under the current, incentive-based regulatory regime rather than their performance under previous regulatory arrangements that are no longer in effect.

A distributor is deemed to be a significantly superior cost performer if its costs are below the model's prediction minus the confidence interval. A distributor is deemed to be a significantly inferior cost performer if its costs are above the model's prediction plus the confidence interval. A distributor is considered an average cost performer if is costs are within the confidence intervals.

Table 11 presents these cost evaluations for both 95% and 90% levels of confidence. The first column presents the difference between each distributor's actual and predicted cost in percentage terms. Distributor names have been suppressed in this table (as well as in Tables 13~~, 24, 25~~ and 26 that follow) and replaced with a number that is used consistently throughout the report. The second column reflects the "p value," or level of statistical significance associated with the hypothesis that this difference between actual and predicted costs is equal to zero.

Table 11

Difference Between Actual and Predicted Cost: Full Sample

	Actual minus Predicted Cost	P-Value	
Distributor Number 73	-56.4%	0.000	
Distributor Number 5	-44.1%	0.002	
Distributor Number 15	-37.7%	0.000	95% Confidence
Distributor Number 24	-27.8%	0.010	
Distributor Number 69	-22.9%	0.022	
Distributor Number 35	-22.1%	0.024	
Distributor Number 44	-19.1%	0.047	
Distributor Number 14	-19.0%	0.043	
Distributor Number 25	-18.9%	0.064	
Distributor Number 11	-16.6%	0.069	
Distributor Number 10	-16.3%	0.073	90% Confidence
Distributor Number 54	-15.4%	0.083	
Distributor Number 38	-15.1%	0.086	
Distributor Number 21	-13.0%	0.124	
Distributor Number 2	-9.4%	0.200	
Distributor Number 57	-8.5%	0.225	
Distributor Number 43	-8.3%	0.230	
Distributor Number 17	-8.0%	0.247	
Distributor Number 65	-7.8%	0.243	
Distributor Number 27	-6.7%	0.345	
Distributor Number 39	-6.6%	0.281	
Distributor Number 19	-6.4%	0.286	
Distributor Number 59	-5.5%	0.311	
Distributor Number 23	-5.3%	0.317	
Distributor Number 58	-5.0%	0.330	
Distributor Number 31	-4.9%	0.333	
Distributor Number 4	-4.7%	0.338	
Distributor Number 63	-4.7%	0.346	
Distributor Number 52	-3.1%	0.396	
Distributor Number 29	-2.6%	0.410	
Distributor Number 62	-2.5%	0.412	
Distributor Number 7	-2.4%	0.415	
Distributor Number 28	-2.0%	0.432	
Distributor Number 60	-1.8%	0.435	
Distributor Number 22	-0.2%	0.494	

Table 11 (continued)

Difference Between Actual and Predicted Cost: Full Sample

	Actual minus Predicted Cost	P-Value	
Distributor Number 67	0.7%	0.474	
Distributor Number 50	1.1%	0.462	
Distributor Number 41	1.3%	0.453	
Distributor Number 56	3.1%	0.392	
Distributor Number 12	4.0%	0.361	
Distributor Number 8	4.0%	0.360	
Distributor Number 6	4.2%	0.354	
Distributor Number 30	4.6%	0.339	
Distributor Number 32	5.7%	0.309	
Distributor Number 20	7.7%	0.245	
Distributor Number 64	8.1%	0.236	
Distributor Number 71	8.6%	0.221	
Distributor Number 16	8.6%	0.222	
Distributor Number 33	8.8%	0.215	
Distributor Number 1	9.2%	0.211	
Distributor Number 18	10.6%	0.197	
Distributor Number 37	12.0%	0.164	
Distributor Number 13	12.1%	0.137	
Distributor Number 70	13.3%	0.116	
Distributor Number 40	13.6%	0.114	
Distributor Number 51	14.2%	0.098	
Distributor Number 46	14.4%	0.102	
Distributor Number 53	14.5%	0.104	
Distributor Number 3	14.9%	0.096	
Distributor Number 42	16.9%	0.067	90% Confidence
Distributor Number 72	17.8%	0.055	
Distributor Number 55	19.4%	0.041	
Distributor Number 45	19.6%	0.062	
Distributor Number 34	20.0%	0.042	
Distributor Number 47	20.5%	0.044	
Distributor Number 66	21.2%	0.028	
Distributor Number 61	21.7%	0.030	
Distributor Number 36	22.2%	0.024	95% Confidence
Distributor Number 48	25.8%	0.012	
Distributor Number 9	38.3%	0.000	
Distributor Number 68	48.6%	0.000	
Distributor Number 49	65.9%	0.000	
Distributor Number 26	73.1%	0.000	

Note: Light shading implies result is within 95% confidence interval. Darker shading implies result is within 90% confidence interval.

It can be seen that ~~seven~~ eight distributors are identified as superior cost performers at the 95% level, and ~~eight~~ five additional distributors are superior cost performers at the 90% confidence level. The bulk of the industry – 44~~0~~ distributors –is identified as being average cost performers. ~~Eighteen~~ Sixteen distributors are seen to be inferior cost performers at the 90% level, and 11~~2~~ of these distributors are also inferior cost performers at the 95% level.

Although they are not specifically identified on Table 11, the Hydro One and Toronto Hydro econometric results raise concerns regarding the productivity factor that applies to the entire industry. Hydro One and Toronto Hydro are the two largest electricity distributors in the Province and could be exerting a disproportionate impact on econometric estimates for the industry. There are at least two ways that Hydro One and Toronto Hydro could be distorting the industry's measured TFP trend.

First, the estimated cost elasticities for the output variables are used to construct the industry's output quantity index. If Hydro One and Toronto Hydro's presence in the econometric sample leads to a statistically significant change in these cost elasticities, this will be translated directly into a change in the cost elasticities that are used to weight the growth in output quantity subindexes. Unless all output quantity subindexes are growing at the same rate, this will in turn change the industry's measured growth in output quantity and therefore its measured TFP growth.

Second, Hydro One and Toronto Hydro could be having a disproportionate impact on the estimated trend coefficient in the econometric model. Systematic, upward cost pressures that are specific to these distributors, but not reflected in the model's business condition variables, could contribute to the positive trend coefficient. All else equal, a positive upward trend in cost is also reflected in lower, measured TFP growth.

If Hydro One and Toronto Hydro are materially impacting TFP growth for the Ontario electricity distribution industry, there is a strong case for excluding them when estimating the industry's TFP trend. Recall from Chapter Two that North American incentive regulation uses "a competitive market paradigm" to set the terms of rate indexing formulas. Chapter Two also emphasizes (p. 8) that "one important aspect of competitive markets is that prices are external to the costs or returns of any individual firm." The TFP trends used in rate indexing formulas should therefore be "external" to regulated utilities and reflect the average trend of the entire industry, not be unduly influenced by a small number of companies. This is central to the conceptual foundation for incentive regulation. If Toronto Hydro and Hydro One exert a disproportionate impact on the industry's measured TFP trend (by either directly impacting measured cost elasticities for outputs or indirectly impacting cost trends), then one of the foundational principles of incentive regulation is violated. In this instance, PEG would advise the Board to remove Toronto Hydro and Hydro One from the sample used to estimate TFP in order to obtain a TFP trend that is "external" for the entire industry.[29]

5.3.3 Restricted Sample Econometric Results

To explore the potential impact of Hydro One and Toronto Hydro on the econometric and TFP results, PEG re-estimated the econometric model presented in Table 10 for a sample that excluded Hydro One and Toronto Hydro. Other than eliminating these distributors from the sample, the econometric model is identical to what was previously presented. Results for this model are presented in Table 12.

In general terms, the results are similar, although there are notable differences. The cost elasticities for customer numbers, system peak capacity, and kWh deliveries are now 0.444~~295~~, 0.215~~366~~, and 0.050~~93~~, respectively. This compares with previous estimates of 0.400~~271~~, 0.220~~341~~. and 0.102~~67~~ for these variables. By reducing the coefficient on kWh but correspondingly increasing the cost elasticity~~ies~~ for ~~system peak capacity and~~ customer numbers, the updated cost model strengthens the finding that the main output-based drivers of power distribution cost are ~~peak demand and~~ customer numbers and peak demand, with kWh having less quantitative impact.

The coefficient on circuit km of line is also reduced somewhat, from a previous estimate of 0.246~~119~~ to a current estimate of 0.~~09~~241. The coefficient on the trend variable is also lower. In the updated model, the estimated cost trend (independent of all other cost drivers) is 1.18% per annum, compared with 1.24% in the previous model. All else equal, this lower cost trend implies a 0.~~3~~06% increase in the industry's TFP trend. ~~It is also worth noting that the~~

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29 Clearly, a sample that excludes Toronto Hydro and Hydro One would remain external to those companies; an estimated TFP trend cannot be dominated by a company that has been excluded from the sample. A sample excluding Hydro One and Toronto Hydro would also almost certainly remain external to the 71 Ontario distributors that are still in the sample since each of those companies would be relatively small compared with the industry aggregate.

Table 12

Econometric Coefficients: Restricted Sample

VARIABLE KEY

Outputs:	N =	Number of Customers
	C =	System Capacity
	D =	Retail Deliveries
Other Business Conditions:	A =	2011 Service Territory
	U =	% of Lines Underground
	L =	Average Line Length (km)
	NG =	% of 2011 Customers added in the last 10 years
Input Price:	WK =	Capital Price Index
	Trend =	Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
WK*	0.602	90.121
N*	0.444	8.338
C*	0.215	4.175
D*	0.050	1.822
WKxWK	0.058	1.322
NxN*	-0.490	-1.739
C*C	0.324	1.245
DxD*	0.123	1.723
WKxN*	0.033	1.690
WKxC	0.029	1.610
WKxD	0.000	-0.019
NxC	0.111	0.435
NxD	0.152	1.434
CxD*	-0.256	-2.829
A	0.019	1.624
U	0.014	0.869
L*	0.241	8.662
NG*	0.021	2.897
Trend*	0.012	8.311
Constant*	12.141	546.199
System Rbar-Squared	0.980	
Sample Period	2002-2011	
Number of Observations	709	

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

~~share of lines that is underground is now a statistically significant cost driver, although that was not the case in the previous model.~~[30]

The difference between the coefficients in Tables 10 and 12 are suggestive, and PEG undertook several statistical tests on whether Hydro One and Toronto Hydro have a statistically significant impact on the four parameter estimates that, directly or indirectly, can be manifested in the industry's TFP trend. These are the estimates on the number of customers, peak demand, kWh, and trend parameters. These statistical tests are presented in Appendix Three of this report.

These tests show that the hypothesis that Hydro One Networks and Toronto Hydro do not have a statistically significant impact on these four parameter estimates can be rejected with 99% confidence. PEG therefore concludes that Toronto Hydro and Hydro One are likely to have a significant impact on the estimated TFP trend for the Ontario electricity distribution industry. Sound incentive regulation should utilize external measures of industry TFP trends, not estimates that may be impacted by one or two dominant firms in an industry. We have accordingly removed Toronto Hydro and Hydro One from both the econometric model as well as the sample used to estimate TFP growth for the Ontario electricity distribution industry. If both distributors were not removed from the econometric sample, they would impact the cost elasticities used to weight outputs and therefore directly impact estimated TFP growth for the industry.

5.3.4 Restricted Sample Econometric Benchmarking

Given the decision to remove Toronto Hydro and Hydro One from the cost model, PEG used the cost model presented in Table 12 to generate econometric evaluations of the cost performance of Ontario electricity distributors. The process for generating these cost evaluations was identical to that discussed for the full sample. Table 13 presents these cost evaluations for both 95% and 90% levels of confidence.

~~[30] This undergrounding variable was actually also included in the previous econometric model, but it was not statistically significant. Table 10 reports coefficients only on the statistically significant drivers of electricity distribution cost, and this explains why undergrounding was not reported in Table 10. The change in parameter estimates between Tables 10 and 12 therefore result entirely from excluding Hydro One and Toronto Hydro from the sample, not from adding a new variable to the model.~~

Table 13

Difference Between Actual and Predicted Cost: Restricted Sample

Distibutor Number	**Actual minus Predicted Cost**	**P-Value**	
Distributors Number 73	-56.1%	0.000	
Distributors Number 5	-45.6%	0.001	
Distributors Number 15	-38.1%	0.000	
Distributors Number 24	-30.0%	0.005	95% Confidence
Distributors Number 35	-24.4%	0.011	
Distributors Number 25	-22.6%	0.030	
Distributors Number 69	-22.0%	0.021	
Distributors Number 44	-21.1%	0.026	
Distributors Number 11	-20.1%	0.030	
Distributors Number 54	-16.7%	0.057	
Distributors Number 14	-16.6%	0.060	
Distributors Number 10	-16.3%	0.064	90% Confidence
Distributors Number 21	-15.0%	0.082	
Distributors Number 38	-14.2%	0.091	
Distributors Number 27	-12.5%	0.225	
Distributors Number 65	-11.0%	0.154	
Distributors Number 2	-9.7%	0.182	
Distributors Number 57	-8.3%	0.217	
Distributors Number 39	-7.9%	0.233	
Distributors Number 4	-7.1%	0.254	
Distributors Number 59	-6.9%	0.258	
Distributors Number 29	-6.7%	0.269	
Distributors Number 17	-6.1%	0.294	
Distributors Number 31	-6.1%	0.284	
Distributors Number 58	-5.3%	0.310	
Distributors Number 23	-5.1%	0.317	
Distributors Number 62	-4.8%	0.325	
Distributors Number 28	-4.5%	0.338	
Distributors Number 43	-3.9%	0.357	
Distributors Number 41	-1.8%	0.433	
Distributors Number 67	-1.4%	0.446	
Distributors Number 63	-1.0%	0.465	
Distributors Number 19	-1.0%	0.464	
Distributors Number 22	-0.8%	0.471	

Note: Light shading implies result is within 95% confidence interval. Darker shading implies result is within 90% confidence interval.

Table 13 (continued)

Difference Between Actual and Predicted Cost: Restricted Sample

	Actual minus Predicted Cost	P-Value	
Distributor Number 7	0.2%	0.494	
Distributor Number 50	2.0%	0.427	
Distributor Number 8	2.1%	0.422	
Distributor Number 60	2.6%	0.404	
Distributor Number 56	2.6%	0.403	
Distributor Number 12	2.9%	0.393	
Distributor Number 6	3.2%	0.381	
Distributor Number 30	3.7%	0.363	
Distributor Number 16	6.3%	0.278	
Distributor Number 52	7.0%	0.269	
Distributor Number 20	7.0%	0.254	
Distributor Number 33	7.3%	0.247	
Distributor Number 71	7.6%	0.237	
Distributor Number 64	9.5%	0.186	
Distributor Number 18	9.9%	0.206	
Distributor Number 3	10.7%	0.162	
Distributor Number 13	11.3%	0.145	
Distributor Number 1	11.4%	0.151	
Distributor Number 46	13.4%	0.107	
Distributor Number 40	14.0%	0.098	
Distributor Number 51	14.2%	0.088	
Distributor Number 70	14.5%	0.085	
Distributor Number 53	14.5%	0.093	
Distributor Number 45	16.0%	0.096	90% Confidence
Distributor Number 37	16.6%	0.081	
Distributor Number 55	17.2%	0.054	
Distributor Number 72	17.2%	0.054	
Distributor Number 32	17.3%	0.060	
Distributor Number 42	18.1%	0.046	
Distributor Number 66	18.9%	0.038	
Distributor Number 61	19.8%	0.038	
Distributor Number 36	20.7%	0.028	95% Confidence
Distributor Number 34	20.7%	0.030	
Distributor Number 47	24.9%	0.014	
Distributor Number 48	25.4%	0.009	
Distributor Number 9	35.9%	0.000	
Distributor Number 49	66.6%	0.000	

Note: Light shading implies result is within 95% confidence interval. Darker shading implies result is within 90% confidence interval.

It can be seen that ~~five~~ nine distributors are identified as superior cost performers at the 95% level, and ~~four~~ five additional distributors are superior cost performers at the 90% confidence level. Forty ~~five~~one distributors are average cost performers. A total of 18~~7~~ distributors are seen to be inferior cost performers at the 90% level, and ~~twelve~~ nine of these distributors are also inferior cost performers at the 95% level.

5.4 Implications for TFP and Unit Cost Analysis

PEG's econometric results have implications for the analysis that underpins our productivity factor and stretch factor recommendations. Most importantly, the econometric results show that Hydro One and Toronto Hydro should be eliminated from the industry aggregate that is used to estimate industry TFP trends for 4th Gen IR. Including Hydro One and Toronto Hydro will likely produce an estimate of industry TFP growth in which the experience of these distributors has a disproportionate impact on the industry's estimated TFP trend. Such a TFP trend would not be an industry-wide TFP trend that is appropriate to use in the PCI. In the following Chapter, PEG's TFP analysis will therefore exclude Hydro One and Toronto Hydro from our industry sample.

The econometric results also have implications for our unit cost/peer group benchmarking. The econometric cost model identified five ~~seven~~ statistically significant drivers of electricity distribution cost in Ontario: 1) customer numbers; 2) kWh deliveries; 3) system capacity peak demand; 4) average circuit km of lines; and 5) ~~total km^2 of service territory; 6)~~ share of customers added in the last 10 years.~~; and 7) percent of lines that are underground~~. In Chapter Seven, PEG will use these cost driver variables directly to select the peer groups that are used to benchmark unit costs.

6. Estimating Total Factor Productivity Growth

This Chapter presents PEG's estimates of TFP growth for the Ontario electricity distribution industry over the 2002-2011 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. Finally, we use the cost model developed in Chapter Five to develop a "backcast" of TFP growth over the 2002-2011 period.

6.1 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:

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

Here in each year t,

$Input\ Quantities_t$ = 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 the total distribution cost. With the Tornqvist form, the annual growth rate of the output quantity index is determined by the formula:

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

Here in each year t,

$Output\ Quantities_t$ = 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. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. 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. Cost elasticity shares were estimated using the total cost function and econometric research presented in Section 5.3.3.

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

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

We estimated TFP trends for the Ontario electricity distribution industry for the 2002-2011 period. The trend in this TFP index was computed using the formula:

$$trend\ TFP_t = \frac{\sum_t {}_{2002}^{2011} \ln\left(\frac{TFP_t}{TFP_{t-1}} \right)}{9}$$

$$= \frac{\ln\left(\frac{TFP_{2011}}{TFP_{2002}} \right)}{9} \qquad [13]$$

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

6.2 Output Quantity Variables

As discussed in Chapter Five, the output quantity subindexes are customer numbers (other than street lighting, sentinel lighting, and scattered unmetered customers), 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 12. These cost elasticities were 0.444~~295~~ for customer numbers, 0.050~~93~~ for kWh, and 0.215~~366~~ for system capacity. The associated cost elasticity shares, which must necessarily sum to one, are 0.636~~3913~~, 0.071~~1233~~, and 0.303~~4854~~ for customer numbers, kWh, and system capacity peak demand, respectively.~~[31]~~

6.3 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 extensively 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 was identical to the labor and non-labor OM&A component of the three-factor IPI that was constructed 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

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

6.4 Index-Based Results

PEG's index-based TFP results for the Ontario electricity distribution industry excluding Toronto Hydro and Hydro One are presented in Tables 14 through 18. Table 14 presents details on the output quantity index. Table 15 presents the calculation of capital costs and capital input quantity. Table 16 shows the computation of OM&A input quantity. Table 17 brings the results of Tables 15 and 16 together and shows the growth in total input quantity. Finally, Table 18 displays the calculation of the TFP indexes. For all tables, the sample period was 2002-2011.

~~[31] If these cost elasticity shares were rounded off to two or three decimal points, they would sum to 0.99; we accordingly have expressed them to four decimal points.~~

Table 14

Output Quantity Trends for Ontario Power Distributors, 2002-2011

Year	Total Customers		Peak Demand (KW)		Delivery Volume (KWh)		Output Quantity Index	
	Level	Growth	Level	Growth	Level	Growth	Index	Growth
2002	2,525,210		14,953,754		65,523,878,635		100.00	
2003	2,590,817	2.6%	15,124,270	1.1%	67,480,321,397	2.9%	102.18	2.2%
2004	2,647,118	2.1%	15,282,376	1.0%	68,588,997,365	1.6%	104.01	1.8%
2005	2,703,821	2.1%	15,710,004	2.8%	72,989,180,570	6.2%	106.76	2.6%
2006	2,748,114	1.6%	16,004,095	1.9%	71,323,881,577	-2.3%	108.28	1.4%
2007	2,781,589	1.2%	16,030,411	0.2%	75,581,326,413	5.8%	109.61	1.2%
2008	2,823,654	1.5%	16,040,362	0.1%	74,626,460,193	-1.3%	110.56	0.9%
2009	2,864,567	1.4%	16,095,983	0.3%	71,454,871,565	-4.3%	111.34	0.7%
2010	2,885,251	0.7%	16,172,034	0.5%	71,603,206,532	0.2%	112.02	0.6%
2011	2,919,186	1.2%	16,287,524	0.7%	71,223,956,582	-0.5%	113.04	0.9%
Average Annual Growth Rate 2002-2011		**1.61%**		**0.95%**		**0.93%**		**1.36%**

Table 15

Capital Quantity and Cost Trends for Ontario Power Distributors, 2002-2011

	Capital Cost		Capital Price Index		Capital Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.44	1.4%	100.47	0.5%	100.97	1.0%
2004	103.28	1.8%	100.66	0.2%	102.60	1.6%
2005	105.91	2.5%	101.59	0.9%	104.25	1.6%
2006	105.93	0.0%	100.84	-0.7%	105.05	0.8%
2007	111.44	5.1%	103.31	2.4%	107.87	2.6%
2008	115.69	3.7%	105.82	2.4%	109.33	1.3%
2009	117.22	1.3%	107.10	1.2%	109.45	0.1%
2010	121.02	3.2%	109.31	2.0%	110.71	1.2%
2011	123.06	1.7%	109.45	0.1%	112.41	1.5%
Average Annual Growth Rate 2002-2011		**2.31%**		**1.00%**		**1.30%**

Table 16

OM&A Quantity Trends for Ontario Electric Distributors, 2002-2011

	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	4.0%	102.142	2.1%	101.858	1.8%
2004	105.063	1.0%	104.672	2.4%	100.373	-1.5%
2005	107.207	2.0%	107.961	3.1%	99.302	-1.1%
2006	110.827	3.3%	109.664	1.6%	101.061	1.8%
2007	119.077	7.2%	113.133	3.1%	105.254	4.1%
2008	123.993	4.0%	115.771	2.3%	107.102	1.7%
2009	126.377	1.9%	117.277	1.3%	107.759	0.6%
2010	127.286	0.7%	120.975	3.1%	105.217	-2.4%
2011	136.679	7.1%	122.969	1.6%	111.150	5.5%
Average Annual Growth Rate 2002-2011		**3.47%**		**2.30%**		**1.17%**

Table 17

Input Quantity Trends for Ontario Electric Distributors, 2002-2011

	Input Quantity Index		Capital Quantity		O&M Quantity	
Year	**Index**	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	101.29	1.3%	100.97	1.0%	101.86	1.8%
2004	101.77	0.5%	102.60	1.6%	100.37	-1.5%
2005	102.39	0.6%	104.25	1.6%	99.30	-1.1%
2006	103.56	1.1%	105.05	0.8%	101.06	1.8%
2007	106.91	3.2%	107.87	2.6%	105.25	4.1%
2008	108.52	1.5%	109.33	1.3%	107.10	1.7%
2009	108.85	0.3%	109.45	0.1%	107.76	0.6%
2010	108.64	-0.2%	110.71	1.2%	105.22	-2.4%
2011	111.99	3.0%	112.41	1.5%	111.15	5.5%
Average Annual Growth Rate 2002-2011		**1.26%**		**1.30%**		**1.17%**

Table 18

TFP Index Calculation for Ontario Power Distributors, 2002-2011

Year	Output Quantity Index		Input Quantity Index		TFP Index	
	Index	**Growth**	**Index**	**Growth**	**Index**	**Growth**
2002	100.00		100.00		100.00	
2003	102.18	2.2%	101.29	1.3%	100.88	0.87%
2004	104.01	1.8%	101.77	0.5%	102.20	1.31%
2005	106.76	2.6%	102.39	0.6%	104.26	1.99%
2006	108.28	1.4%	103.56	1.1%	104.56	0.28%
2007	109.61	1.2%	106.91	3.2%	102.52	-1.96%
2008	110.56	0.9%	108.52	1.5%	101.88	-0.63%
2009	111.34	0.7%	108.85	0.3%	102.29	0.40%
2010	112.02	0.6%	108.64	-0.2%	103.11	0.80%
2011	113.04	0.9%	111.99	3.0%	100.94	-2.13%
Average Annual Growth Rate 2002-2011		**1.36%**		**1.26%**		**0.10%**

Turning first to the output quantity results, it can be seen that overall output quantity grew at a modest annual rate of 1.~~21~~36% per annum. Customers grew by an average of 1.61% annually. In contrast, kWh deliveries and system capacity demand grew more slowly, at 0.93% and 0.95% per annum, respectively. The fact that customers grew more rapidly than either deliveries or peak demand means that volumes per customer and peak demands 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 can likely be attributed to energy conservation policies that have been pursued in Ontario over the sample period. Output declines appear to be especially pronounced after the introduction of CDM programs in 2006.

Table 15 shows that capital input quantity grew at an average rate of 1.3% between 2002 and 2011. There is no evidence that capital investment has been accelerating over this period. In fact, capital input grew at an average rate of 1% in the approximately second half of the sample (*i.e.* from 2007 through 2011), compared with average growth of 1.5% per annum in the first half of the period (*i.e.* from 2002 through 2007).

In Table 16, it can be seen that OM&A inputs grew at an average rate of 1.17% over the sample period. This is somewhat slower than the growth in capital input, although OM&A is more variable from year-to-year than capital. For example, OM&A inputs fell by 2.4% in 2010, but then rose by 5.5% in 2011. OM&A input growth has accelerated slightly between the first and second halves of the sample period. OM&A inputs grew at an average annual rate of 1.03% between 2002 and 2007, and at an average rate of 1.36% between 2007 and 2011.

Table 17 shows the change in overall input quantity. Overall inputs grew at an average rate of 1.26% between 2002 and 2011. Input growth has decelerated slightly to 1.16% per annum over the 2007-2011 period compared with average annual growth of 1.34% between 2002 and 2007. The year-to-year volatility in total input quantity mirrors the volatility in OM&A input.

Table 18 shows that Ontario distributors' TFP has been generally flat over the 2002-2011 period, growing at only a ~~-~~0.1~~05~~% average rate. TFP trends have also diverged markedly between the first half (0.~~4~~50% average TFP growth) and second half (-0.39~~68~~%

average TFP growth) of this period. This decline in the industry's TFP trend is due entirely to slowing output quantity growth in more recent years. Output quantity grew at an average rate of 1.~~7~~83% per annum between 2002 and 2007. For the 2007-2011 period, output quantity grew by only 0.77~~48~~% per annum. This 1.~~3~~06% slowdown in output growth was only partially offset by the 0.18% decline in input quantity growth between the first and second halves of the sample period.

As discussed, Tables 14 and 18 exclude Hydro One and Toronto Hydro because we believe that including these companies would lead to a distorted estimate of the industry TFP trend for 4th Gen IR. If these companies had been included, however, average TFP growth for the industry over the 2002-2011 period would have been -1.10~~24~~%. Because of the importance of using remote "benchmark" capital values in TFP studies, it could also be argued that the distributors for which it was necessary to use a 2002 capital benchmark year, rather than a 1989 benchmark year, should also be excluded from the industry's estimated TFP trend. If these five additional companies (Algoma Power, Canadian Niagara Power, Greater Sudbury Hydro, Innisfil Hydro, and PUC Distribution) are also excluded from the sample, the industry's average TFP growth rate rises slightly from ~~-~~0.10~~05~~% to 0.~~04~~21%.

6.5 Econometric "Backcast" of Industry TFP Growth

A "backcast" is analogous to a forecast except that it generates counterfactual scenarios for the past rather than hypothetical scenarios for the future. In this instance, our objective was to use our cost model to predict what the TFP growth the Ontario electricity distribution industry, excluding Hydro One and Toronto Hydro, would have been over the 2002-2011 period. This provides another piece of evidence on TFP growth for the Ontario industry that may inform the Board's choice for a productivity factor.

PEG generated backcast TFP predictions for the Ontario electricity distribution industry in the following way. First, we used our estimated econometric model of electricity distribution cost for the Ontario electricity distribution industry (excluding Hydro One and Toronto Hydro) to estimate the various drivers of electricity distribution cost. The coefficients for this model are presented in Table 12 in Chapter Five. Next, we inserted the industry's values (excluding Hydro One and Toronto Hydro) for the relevant cost driver variables into the fitted econometric model, for each of the 2002-2011 years. This generated a series of predictions for the industry's predicted costs of electricity distribution services for 2002-2011.

The first step in turning these predictions into a series of TFP growth rates for the 2002-2011 period was to transform the industry's 2002-2011 predicted costs into a cost index with a base year of 2002. We then divided each value of these cost indices by the respective (three input) industry input price index for the year, as presented in Chapter Three of this report. Using the indexing logic presented in Chapter Two, a cost index divided by an input price index is equal to an input quantity index. This process therefore yielded a notional input quantity index for the industry in 2002-2011. We computed the annual changes in this notional input quantity index and subtracted these input quantity growth rates from the respective industry's actual growth in output quantity in that year, as presented in Table 14.

This process yields a TFP growth measure that is identical in every respect but one to what PEG previously developed and presented in Table 18 using indexing methods. The one difference is that we substituted an econometric projection of the industry's electricity distribution costs, in each sample year, for the industry's actual, measured costs in that year. The resulting "backcast" TFP growth estimate therefore represents a benchmark level of TFP growth for the industry.

The TFP backcast calculations are presented in Tables 19 and 20. Table 19 shows the projected change in total cost over the 2002-2011 period, using PEG's econometric model (for the sample excluding Hydro One and Toronto Hydro) and values for average changes in the cost driver variables over this period. It can be seen that PEG's model predicts total cost growth for the Ontario electricity distribution industry of 2.78~~3~~% per annum over the sample period.

Table 20 combines this change in predicted cost with other, observed information over 2002-2011 to generate a TFP prediction for the Ontario electricity distribution industry. It can be seen that the econometric backcast of TFP growth for Ontario distributors over the 2002-2011 period was --0.07~~3~~% per annum. This is quite similar to the --0.1~~05~~% TFP trend that PEG estimated using index-based methods.

Table 19

COST GROWTH BACKCAST FROM ECONOMETRIC RESEARCH

Sample Years	Industry Average 2002-2011
Econometric Coefficient Estimates	
Customers [A]	0.44
System Capacity [B]	0.22
Total Deliveries [C]	0.05
Service Territory Size [D]	0.02
Percentage of Lines Underground [E]	0.01
Average Line Length [F]	0.24
Customer Additions in Previous 10 years [G]	0.02
Capital Input Price [H]	0.60
Sum of Output Elasticities [I=A+B+C+F]	0.950
Output Index Weights	
Customers [J=A/I]	46.74%
System Capacity [K=B/I]	22.64%
Total Deliveries [L=C/I]	5.29%
Average Line Length [M=F/I]	25.33%
Subindex Growth	
Customers [N]	1.61%
System Capacity [O]	0.95%
Total Deliveries [P]	0.93%
Service Territory Size [Q]	0.00%
Percentage of Lines Undergrounded [R]	1.93%
Average Line Length [S]	0.00%
Customer Additions in Previous 10 years [T]	0.00%
Capital Input Price [U]	1.01%
Subindex Growth * Econometric Coefficients	
Customers [V=A*N]	0.72%
System Capacity [W=B*O]	0.20%
Total Deliveries [X=C*P]	0.05%
Service Territory Area [Y=D*Q]	0.00%
Percentage of Lines Undergrounded [Z=E*R]	0.03%
Average Line Length [AA=F*S]	0.00%
Customer Additions in Previous 10 years [BB=G*T]	0.00%
Capital Input Price [CC=H*U]	0.61%
Trend [DD]	**1.18%**
Change in Projected Cost [V+W+X+Y+Z+AA+BB+CC+DD]	**2.78%**

Table 20

TFP Backcasts for the Ontario Electricity Distribution Industry, 2002-2011

Change in Predicted Cost [A]	2.78%
Change in Input Price Index [B]	1.49%
Change in Predicted Input Quantity Index [C] = [A] - [B]	1.29%
Change in Output Quantity Index [D]	1.36%
Change in Predicted TFP [E] = [D] - [C]	0.07%

6.6 Recommended Productivity Factor

Given that the index-based and econometric-based TFP estimates are both close to 0.1%~~zero~~, PEG recommends that the productivity factor for 4th Gen IR be set equal to ~~zero~~0.1%. In addition to being consistent with the two empirical estimates, PEG believes a productivity factor of ~~zero~~ 0.1% is reasonable for several reasons. First, PEG's analysis shows that the industry's slower TFP growth stems primarily from a slowdown in output growth rather than an acceleration in distributors' spending. The slower output growth has been particularly pronounced since the introduction of CDM programs in 2006. PEG believes the continued emphasis on CDM policies in Ontario will continue to limit the potential for output quantity and TFP gains for the industry.

Second, we find the available evidence does not support a negative productivity factor. While TFP growth for the Ontario electricity distribution industry has been negative since 2007, much of this decline is attributable to the severe recession in 2008-09. This was a one-time event and is not anticipated to recur during the term of 4th Gen IR. PEG also concludes that the experience since 2007 is not long enough to be the basis for a productivity factor; TFP trends should be calculated over at least a nine-year period. We also do not favor treating sub-periods within a sample period differently (*e.g.* by placing more weight on one sub-period rather than another), since such an approach can give rise to "cherry picking" and artificial manipulation of the available data. The nine-year industry TFP trend is more consistent with a productivity factor of ~~zero~~0.1% than a substantially negative productivity factor.

Third, an IPI inflation factor combined with a productivity factor of 0.1%~~zero~~ would mean electricity distributor prices grow at nearly the same rate as the industry's input price inflation, if all else is held equal. PEG's research shows that input price inflation for the electricity distribution industry has been slightly below GDP-IPI inflation. It is not unusual for price inflation in a particular sector (such as electricity distribution) to be similar to average price inflation in the economy. If the productivity factor was the only component of the X factor, a productivity factor equal to ~~zero~~ 0.1% would likely mean that electricity distribution prices grow at rates similar to the prices of other goods and services in the economy. Price inflation in a particular sector that is similar to aggregate, economy-wide inflation is not necessarily a sign of sub-par productivity performance in that sector.

However, the productivity factor is *not* the only component of the X factor, nor is it the component of the X factor that is designed to ensure that consumers benefit from incentive rate setting. Stretch factors are intended to reflect distributors' incremental efficiency gains under incentive ratemaking. Adding a stretch factor to the productivity factor would allow customers to share in these anticipated efficiency gains. A productivity factor of 0.1%~~zero~~ is therefore not incompatible with the Board's incentive rate-setting objectives of encouraging cost efficiency and ensuring that customers share in these efficiency gains.[32]

[32] Although PEG's recommended productivity factor is based on an analysis of the evidence and circumstances in the Ontario electricity distribution industry, it may also be instructive to consider recent precedents on X factors and productivity factors that are based explicitly on productivity evidence. PEG is aware of eight such plans (or in some cases, sets of plans) that are currently in effect outside of Ontario: for Central Maine Power (in ME, USA); Central Vermont Public Service and Green Mountain Power (both in VT, USA); ENMAX in Alberta; the other electricity distributors in Alberta; the gas distributors in Alberta; the electricity distributors in New Zealand; and the gas distributors in New Zealand. In the six electricity distribution plans, the approved X factors, industry produtivity factors (PF) and stretch factors (SFs) (where there were explicit findings on these distinct elements) are:

Company	PF	SF	X Factor
Central Maine Power	NA	NA	1.0%
Central Vermont Public Service	NA	NA	1.0%
Green Mountain Power	NA	NA	1.0%
ENMAX	0.8%	0.4%	1.2%
Other Alberta LDCs	0.96%	0.2%	1.16%
New Zealand LDCs	1.10%	NA	0

For the two gas distribution plans, the analogous factors are:

Company	PF	SF	X Factor
Other Alberta LDCs	0.96%	0.2%	1.16%
New Zealand LDCs	NA	NA	0

It should be noted that the same empirical evidence was used to establish all elements of the X factors for gas and electricity distributors in Alberta, but separate TFP studies were performed for gas and electricity distributors in New Zealand. The reason there was a positive productivity factor for the New Zealand electricity distribution industry but a zero X factor is the formula for the X factor in New Zealand includes the difference between industry and economy-wide TFP growth, not just industry TFP growth.

It can be seen that the average value of the X factor in the electricity distribution plans is about 0.90%, and approved productivity factors (where there have been explicit findings on industry TFP growth) have been between 0.8% and 1.16%. Although PEG is not recommending a zero X factor, ~~when stretch factors are included,~~ a zero X factor would not be unprecedented among current plans. However, no index-based plans that are currently in effect have approved a negative productivity factor.

7. Unit Cost Benchmarking and Stretch Factors

7.1 Methodological Approach

PEG was asked to benchmark distributors' total unit costs for 4th Gen IR. This task builds on PEG's OM&A unit cost benchmarking work in 2007-08, which was applied in 3rd Gen IR. Our unit cost metric is calculated by dividing each distributor's total distribution cost (rather than OM&A cost, as in 3rd Gen IR) by a comprehensive index of its output. As discussed in Chapter Four, the relevant unit cost measure for benchmarking excludes the capital and O&M costs of HV transformation but includes CIAC as well as LV charges paid by embedded distributors to host distributors.

Each distributor's unit cost was benchmarked relative to the unit cost of a designated "peer group" of Ontario distributors. These peer groups were determined directly on the basis of PEG's cost function research discussed in Chapter Five. As with the econometric benchmarking, unit cost comparisons were undertaken for the last three years, 2009-2011, since these years generally coincided with distributors' performance under the current regulatory regime. This was done by averaging each distributor's unit cost over these years, and using these average unit cost measures as the basis for benchmark comparisons.

This Chapter discusses PEG's unit cost benchmarking. We begin by describing how the peer groups were determined. Next, we present the unit cost calculations for each distributor and the unit cost comparisons. Finally, using both the econometric and unit cost benchmarking evidence, PEG makes recommendations for efficiency cohorts and stretch factors for the Ontario electricity distribution industry.

7.2 Cost Drivers and Determining Peer Groups

In addition to capital input prices and the trend variable, Table 12 identified five~~seven~~ different drivers of distribution cost in Ontario: 1) customer numbers; 2) system peak capacity; 3) kWh deliveries; 4) circuit km of distribution line; and 5) ~~total km^2 of service territory; 6)~~ share of customers added in last 10 years.~~; and 7) share of lines that are underground.~~ PEG used direct information on these cost drivers, as well as total service territory and share of lines that are underground (which were previously found to be significant cost drivers) ~~~~to determine each distributor's "peers." Using similarities in cost drivers is clearly sensible for determining peer groups, because "apples to apples" cost comparisons are more likely when a distributor is compared to other distributors facing similar business conditions. PEG has endeavored to make the process of selecting peer groups based on similarities in cost drivers as transparent as possible.

We began by noting that four of the ~~seven~~ cost driver variables were related to distribution output: customer numbers; system peak demand; kWh deliveries; and circuit km of line. For each distributor, these four output variables can be aggregated into a comprehensive output quantity index using the cost elasticity shares presented in Table 12. This approach weights each of the four outputs by its respective, estimated impact on distribution cost. Each distributor's weighted outputs are then summed and expressed relative to the average aggregate output for the Ontario electricity distribution industry. This is known as a bilateral output index. Distributors with above average output will have a bilateral output index value that is above one, while distributors with below average output will have a bilateral output index that is less than one. The calculated, bilateral index values for every Ontario distributor are presented in Table 21.

The three remaining ~~cost driver~~ variables are total service territory area, percent of lines that are underground, and customer growth. For the purpose of identifying distributors with similar levels of business conditions, PEG began by examining a two dimensional graph where the bilateral output index for each distributor (vertical axis) was plotted against its service territory (horizontal axis). We then divided this chart up into four different quadrants, depending on whether the bilateral output index was above or below its mean value and the service area was above or below its median level.[33]

This graph is presented in Chart One for all distributors except Algoma Power, Hydro One and Toronto Hydro. These distributors are not included because their service territories and output are so large compared with other distributors that including them would compress every other sample observation into a very small space, making it impossible to distinguish

[33] We used the "median" rather than "mean" values to distinguish firms based on service territory because the territories for two distributors – Algoma Power and Hydro One Networks – were so much larger than every other Ontario distributor that they produce a distorted measure of "average" service territory in the Province. In fact, when the sample mean service territory is calculated, every firm but Hydro One and Algoma Power would have territories below the mean.

different output-service territory combinations within the Ontario electricity distribution sector. The horizontal line in Chart One reflects the mean value for output; all distributors

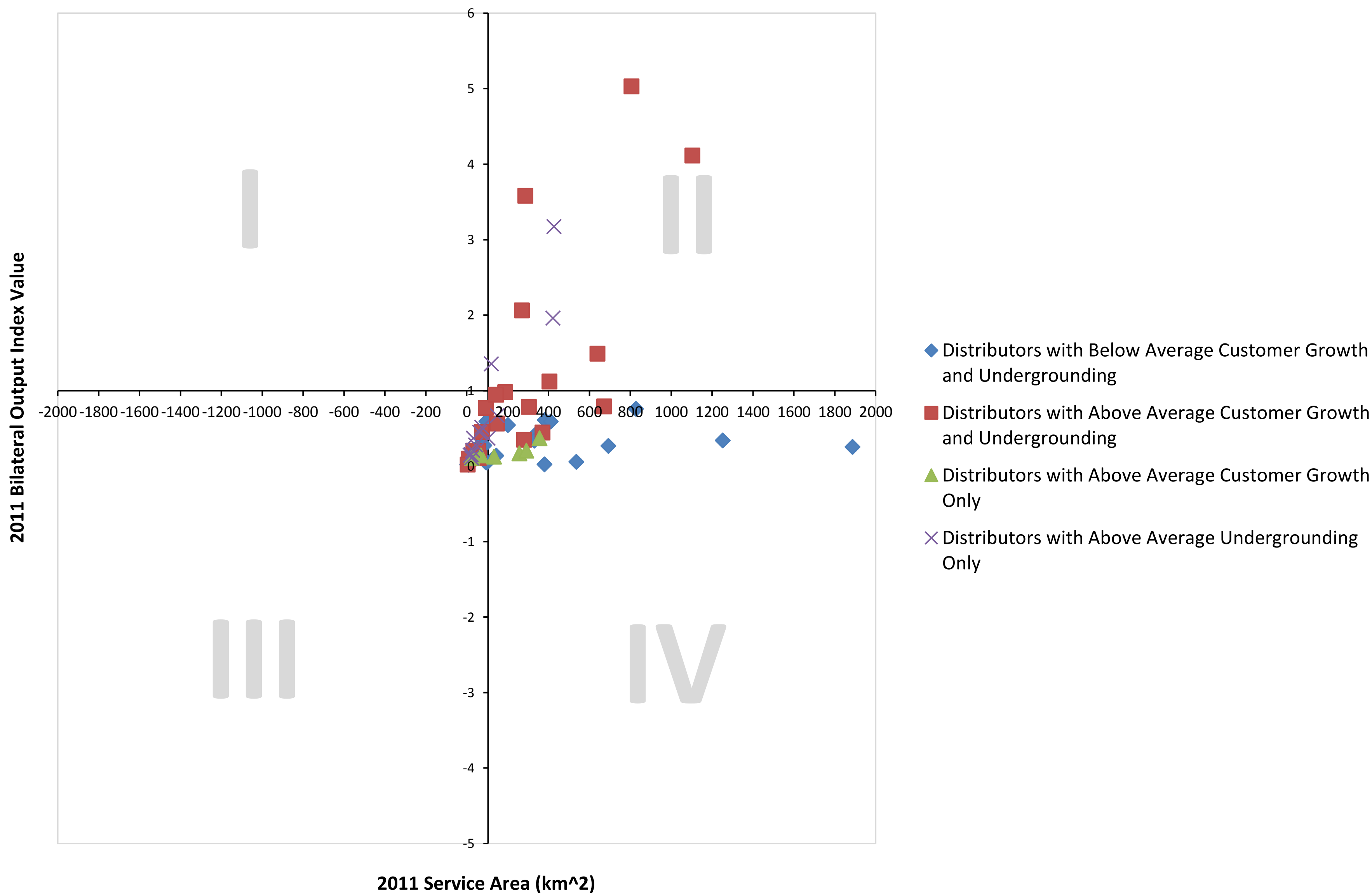
Table 21

2009-2011 Bilateral Output Index

Company Name	2009 Bilateral Output Index	2010 Bilateral Output Index	2011 Bilateral Output Index	2009-2011 Bilateral Output Index Average
ALGOMA POWER INC.	0.231	0.229	0.228	0.229
ATIKOKAN HYDRO INC.	0.027	0.026	0.026	0.026
BLUEWATER POWER DISTRIBUTION CORPORATION	0.479	0.478	0.480	0.479
BRANT COUNTY POWER INC.	0.151	0.151	0.152	0.151
BRANTFORD POWER INC.	0.440	0.430	0.458	0.443
BURLINGTON HYDRO INC.	0.900	0.902	0.897	0.900
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	0.685	0.687	0.691	0.688
CANADIAN NIAGARA POWER INC.	0.389	0.388	0.388	0.388
CENTRE WELLINGTON HYDRO LTD.	0.087	0.087	0.089	0.088
CHAPLEAU PUBLIC UTILITIES CORPORATION	0.018	0.017	0.017	0.018
COLLUS POWER CORPORATION	0.189	0.193	0.192	0.192
COOPERATIVE HYDRO EMBRUN INC.	0.020	0.020	0.020	0.020
E.L.K. ENERGY INC.	0.128	0.128	0.130	0.129
ENERSOURCE HYDRO MISSISSAUGA INC.	3.006	2.991	2.998	2.998
ENTEGRUS POWERLINES	0.541	0.548	0.540	0.543
ENWIN UTILITIES LTD.	1.065	1.074	1.070	1.070
ERIE THAMES POWERLINES CORPORATION	0.225	0.225	0.224	0.225
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	0.049	0.048	0.048	0.049
ESSEX POWERLINES CORPORATION	0.333	0.336	0.331	0.333
FESTIVAL HYDRO INC.	0.233	0.233	0.234	0.234
FORT FRANCES POWER CORPORATION	0.048	0.048	0.046	0.048
GREATER SUDBURY HYDRO INC.	0.566	0.563	0.564	0.565
GRIMSBY POWER INCORPORATED	0.121	0.134	0.134	0.130
GUELPH HYDRO ELECTRIC SYSTEMS INC.	0.660	0.666	0.678	0.668
HALDIMAND COUNTY HYDRO INC.	0.376	0.374	0.379	0.376
HALTON HILLS HYDRO INC.	0.369	0.367	0.373	0.369
HEARST POWER DISTRIBUTION COMPANY LIMITED	0.041	0.041	0.041	0.041
HORIZON UTILITIES CORPORATION	2.771	2.752	2.743	2.755
HYDRO 2000 INC.	0.015	0.015	0.015	0.015
HYDRO HAWKESBURY INC.	0.067	0.066	0.066	0.066
HYDRO ONE BRAMPTON NETWORKS INC.	1.755	1.780	1.821	1.785
HYDRO ONE NETWORKS INC.	20.781	20.742	20.677	20.733
HYDRO OTTAWA LIMITED	3.666	3.672	3.721	3.686
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	0.223	0.224	0.224	0.223
KENORA HYDRO ELECTRIC CORPORATION LTD.	0.064	0.064	0.064	0.064
KINGSTON HYDRO CORPORATION	0.314	0.312	0.311	0.312
KITCHENER-WILMOT HYDRO INC.	1.068	1.068	1.073	1.070
LAKEFRONT UTILITIES INC.	0.108	0.107	0.108	0.108
LAKELAND POWER DISTRIBUTION LTD.	0.139	0.139	0.137	0.138
LONDON HYDRO INC.	1.787	1.795	1.803	1.795
MIDLAND POWER UTILITY CORPORATION	0.087	0.092	0.107	0.095
MILTON HYDRO DISTRIBUTION INC.	0.386	0.412	0.431	0.410
NEWMARKET-TAY POWER DISTRIBUTION LTD.	0.461	0.461	0.433	0.452
NIAGARA PENINSULA ENERGY INC.	0.760	0.758	0.759	0.759
NIAGARA-ON-THE-LAKE HYDRO INC.	0.123	0.123	0.125	0.124
NORFOLK POWER DISTRIBUTION INC.	0.279	0.278	0.278	0.278
NORTH BAY HYDRO DISTRIBUTION LIMITED	0.320	0.318	0.318	0.319
NORTHERN ONTARIO WIRES INC.	0.097	0.096	0.096	0.097
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	0.844	0.841	0.853	0.846
ORANGEVILLE HYDRO LIMITED	0.129	0.130	0.130	0.130
ORILLIA POWER DISTRIBUTION CORPORATION	0.175	0.175	0.175	0.175
OSHAWA PUC NETWORKS INC.	0.622	0.620	0.626	0.623
OTTAWA RIVER POWER CORPORATION	0.113	0.113	0.113	0.113
PARRY SOUND POWER CORPORATION	0.052	0.052	0.052	0.052
PETERBOROUGH DISTRIBUTION INCORPORATED	0.405	0.403	0.404	0.404
POWERSTREAM INC.	4.472	4.433	4.476	4.460
PUC DISTRIBUTION INC.	0.417	0.414	0.414	0.415
RENFREW HYDRO INC.	0.047	0.046	0.046	0.046
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	0.073	0.073	0.073	0.073
SIOUX LOOKOUT HYDRO INC.	0.055	0.054	0.058	0.056
ST. THOMAS ENERGY INC.	0.185	0.185	0.185	0.185
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	0.615	0.607	0.608	0.610
TILLSONBURG HYDRO INC.	0.096	0.095	0.095	0.096
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	8.831	8.886	8.929	8.882
VERIDIAN CONNECTIONS INC.	1.363	1.377	1.406	1.382
WASAGA DISTRIBUTION INC.	0.117	0.120	0.123	0.120
WATERLOO NORTH HYDRO INC.	0.723	0.736	0.745	0.735
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	0.269	0.265	0.242	0.259
WELLINGTON NORTH POWER INC.	0.045	0.046	0.045	0.045
WEST COAST HURON ENERGY INC.	0.051	0.050	0.051	0.050
WESTARIO POWER INC.	0.264	0.275	0.274	0.271
WHITBY HYDRO ELECTRIC CORPORATION	0.525	0.525	0.539	0.530
WOODSTOCK HYDRO SERVICES INC.	0.181	0.183	0.183	0.182

Chart 1

Cost Drivers and Ontario Peer Groups



plotted above this line have overall output levels that exceed the industry average, and all distributors plotted below this line have output levels below the industry average. The vertical line in Chart One shows the median level of service territory in the Province. All distributors to the right of this vertical line have above median service territories, while all distributors plotted to the left of the vertical line have below median service territories.

The vertical and horizontal lines on Chart One divide the Ontario electricity distribution industry into four quadrants. These quadrants are distinguished by relative differences in overall output and service territories among distributors in the Province. Quadrant I contains distributors with above average output but below median service territories; quadrant II has distributors with above average output and above-median service territories; quadrant III has distributors with below average output and below median service territories; and quadrant IV has distributors with below average output but above median service territories. It can be seen that quadrant I is empty, which means that no distributors in Ontario have higher than average output levels but a service territory of below median size. We can therefore confine our attention to quadrants II, III, and IV.

The two remaining ~~statistically significant cost drivers~~ variables that are not reflected on the vertical or horizontal axes of Chart One are customer growth and percent of lines that are underground. Within each quadrant, however, distributors can be categorized according to their similarity on these cost drivers by considering whether each distributor registers above or below average values for the ~~cost driver~~ variable in question. There are four possibilities for how distributors compare on these two ~~cost driver~~ variables within each quadrant:

1. A distributor has above average customer growth, but below average undergrounding
2. A distributor has above average undergrounding, but below average customer growth
3. A distributor has above average customer growth and above average undergrounding
4. A distributor has *below* average customer growth and *below* average undergrounding

These four possibilities are depicted on Chart One using four different symbols. Distributors with above average undergrounding only are graphed using an “X” symbol. Distributors with above average customer growth only are graphed with a triangle. Distributors with above average customer growth and undergrounding are graphed with a square. Distributors with *below* average customer growth and undergrounding are graphed with a diamond.

In summary, Chart One presents a visual depiction of Ontario electricity distributors based on similarities in values of the seven statistically significant drivers of electricity distribution cost. Distributors are placed into one of the three quadrants based on similarities in overall output (an aggregation of four output variables) and service territory. Within each quadrant, firms are further categorized based on similarities in their customer growth and undergrounding.

Because there are four different categories of firms within each of the three quadrants, a total of 12 potential peer groups can be identified based on similarities in the seven cost drivers. These potential peer groups are:

1. Above average output, above median area, above average undergrounding
2. Above average output, above median area, above average customer growth
3. Above average output, above median area, above average undergrounding and customer growth
4. Above average output, above median area, *below* average undergrounding and customer growth
5. Below average output, above median area, above average undergrounding
6. Below average output, above median area, above average customer growth
7. Below average output, above median area, above average undergrounding and customer growth
8. Below average output, above median area, *below* average undergrounding and customer growth
9. Below average output, below median area, above average undergrounding
10. Below average output, below median area, above average customer growth

11. Below average output, below median area, above average undergrounding and customer growth
12. Below average output, below median area, *below* average undergrounding and customer growth

These potential peer groups, and the distributors in each of them, are presented in Table 22. It can be seen that one of these potential peer groups – number 2 (above average output, above median area, above average customer growth only) – is empty. Two other potential peer groups – number 4 (above average output, above median area, below average undergrounding and customer growth) and number 5 (below average output, above median area, above average undergrounding only) – have only one distributor in the group. Because it is impossible to have "peer" comparisons with only a single firm in a group, the distributors in these two other groups need to be moved to one of the other potential peer groups if they are to be part of the peer group benchmarking exercise. Eliminating the one empty peer group and re-assigning these two distributors (Hydro One and Oshawa PUC) would therefore reduce the number of potential peer groups from 12 to nine.

Three of the remaining potential peer groups have four or fewer distributors in the group. These are group number 1 (above average output, above median area, above average undergrounding only), group number 6 (below average output, above median area, above average customer growth only), and group number 10 (below average output, below median area, above average customer growth only). One of the criticisms of the benchmarking study used in 3rd Gen IR is that some peer group benchmarking assessments relied on too small a number of peers. It was argued that, if there are too few peers in a group, comparing unit costs to the peer group's average unit cost is more likely to be distorted by outliers within the peer group. This critique has merit. Accordingly, PEG concluded that groups 1, 6 and 10 have too few firms to be stand-alone peer groups, and distributors in these three groups should be combined into other peer groups. This eliminates groups 1, 6, and 10 from consideration and thereby reduces the number of peer groups from nine to six.

PEG's six recommended peer groups are presented in Table 23. It can be seen that all of the distributors with above average output have now been grouped together into Peer Group A (Large Output, Extensive Area). Groups 6 and 7 have been consolidated into Peer Group B (Small Output, Extensive Area, Above Average Customer Growth). Group 8 is Peer

Group C (Small Output, Extensive Area, Below Average Undergrounding and Growth). Groups 10 and 11 have been combined into Peer Group D (Small Output, Small Area, Above

Table 22

Potential Ontario Distibutor Peer Groups

Quadrant	Group 1: Above average output, above median area, above average undergrounding	Group 2: Above average output, above median area, above average customer growth	Group 3: Above average output, above median area, above average undergrounding and customer growth	Group 4: Above average output, above median area, below average undergrounding and customer growth
II	ENWIN UTILITIES LTD. LONDON HYDRO INC. HORIZON UTILITIES CORPORATION TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	None	KITCHENER-WILMOT HYDRO INC. VERIDIAN CONNECTIONS INC. HYDRO OTTAWA LIMITED ENERSOURCE HYDRO MISSISSAUGA INC. POWERSTREAM INC. HYDRO ONE BRAMPTON NETWORKS INC.	HYDRO ONE NETWORKS INC.
	Group 5: Below average output, above median area, above average undergrounding	**Group 6: Below average output, above median area, above average customer growth**	**Group 7: Below average output, above median area, above average undergrounding and customer growth**	**Group 8: Below average output, above median area, below average undergrounding and customer growth**
III	OSHAWA PUC NETWORKS INC.	CANADIAN NIAGARA POWER INC. BRANT COUNTY POWER INC. INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMI NIAGARA-ON-THE-LAKE HYDRO INC.	WATERLOO NORTH HYDRO INC. CAMBRIDGE AND NORTH DUMFRIES HYDRO INC. HALTON HILLS HYDRO INC. MILTON HYDRO DISTRIBUTION INC. BURLINGTON HYDRO INC. WHITBY HYDRO ELECTRIC CORPORATION OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	ATIKOKAN HYDRO INC. ALGOMA POWER INC. SIOUX LOOKOUT HYDRO INC. HALDIMAND COUNTY HYDRO INC. NORFOLK POWER DISTRIBUTION INC. PUC DISTRIBUTION INC. NORTH BAY HYDRO DISTRIBUTION LIMITED THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. ERIE THAMES POWERLINES CORPORATION LAKELAND POWER DISTRIBUTION LTD. GREATER SUDBURY HYDRO INC. NIAGARA PENINSULA ENERGY INC. BLUEWATER POWER DISTRIBUTION CORPORATION
	Group 9: Below average output, below median area, above average undergrounding	**Group 10: Below average output, below median area, above average customer growth**	**Group 11: Below average output, below median area, above average undergrounding and customer growth**	**Group 12: Below average output, below median area, below average undergrounding and customer growth**
IV	PETERBOROUGH DISTRIBUTION INCORPORATED FESTIVAL HYDRO INC. TILLSONBURG HYDRO INC. KINGSTON HYDRO CORPORATION WOODSTOCK HYDRO SERVICES INC. BRANTFORD POWER INC. E.L.K. ENERGY INC. ORANGEVILLE HYDRO LIMITED ESSEX POWERLINES CORPORATION	LAKEFRONT UTILITIES INC. MIDLAND POWER UTILITY CORPORATION GRIMSBY POWER INCORPORATED	ST. THOMAS ENERGY INC. COLLUS POWER CORPORATION CENTRE WELLINGTON HYDRO LTD. COOPERATIVE HYDRO EMBRUN INC. WASAGA DISTRIBUTION INC. NEWMARKET-TAY POWER DISTRIBUTION LTD. GUELPH HYDRO ELECTRIC SYSTEMS INC.	NORTHERN ONTARIO WIRES INC. RENFREW HYDRO INC. CHAPLEAU PUBLIC UTILITIES CORPORATION ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION PARRY SOUND POWER CORPORATION KENORA HYDRO ELECTRIC CORPORATION LTD. RIDEAU ST. LAWRENCE DISTRIBUTION INC. FORT FRANCES POWER CORPORATION OTTAWA RIVER POWER CORPORATION WELLINGTON NORTH POWER INC. HYDRO 2000 INC. HYDRO HAWKESBURY INC. HEARST POWER DISTRIBUTION COMPANY LIMITED ORILLIA POWER DISTRIBUTION CORPORATION WEST COAST HURON ENERGY INC. WESTARIO POWER INC. ENTEGRUS POWERLINES WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Table 23

Peer Groups for Ontario Distributors

Group A- Large Output, Extensive Area	Group B- Small Output, Extensive Area, Above Average Customer Growth	Group C- Small Output, Extensive Area, Below Average Undergrounding and Growth
ENERSOURCE HYDRO MISSISSAUGA INC.	BRANT COUNTY POWER INC.	ALGOMA POWER INC.
ENWIN UTILITIES LTD.	BURLINGTON HYDRO INC.	ATIKOKAN HYDRO INC.
HORIZON UTILITIES CORPORATION	CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	BLUEWATER POWER DISTRIBUTION CORPORATION
HYDRO ONE BRAMPTON NETWORKS INC.	CANADIAN NIAGARA POWER INC.	ERIE THAMES POWERLINES CORPORATION
HYDRO ONE NETWORKS INC.	HALTON HILLS HYDRO INC.	GREATER SUDBURY HYDRO INC.
HYDRO OTTAWA LIMITED	INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	HALDIMAND COUNTY HYDRO INC.
KITCHENER-WILMOT HYDRO INC.	MILTON HYDRO DISTRIBUTION INC.	LAKELAND POWER DISTRIBUTION LTD.
LONDON HYDRO INC.	NIAGARA-ON-THE-LAKE HYDRO INC.	NIAGARA PENINSULA ENERGY INC.
POWERSTREAM INC.	OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	NORFOLK POWER DISTRIBUTION INC.
TORONTO HYDRO-ELECTRIC SYSTEM	WATERLOO NORTH HYDRO INC.	NORTH BAY HYDRO DISTRIBUTION LIMITED
VERIDIAN CONNECTIONS INC.	WHITBY HYDRO ELECTRIC CORPORATION	PUC DISTRIBUTION INC.
		SIOUX LOOKOUT HYDRO INC.
		THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

Group D- Small Output, Small Area, Above Average Customer Growth	Group E- Small Output, Small Area, Below Average Customer Growth	Group F- Small Output, Above Average Undergrounding, Below Average Customer Growth
CENTRE WELLINGTON HYDRO LTD.	CHAPLEAU PUBLIC UTILITIES CORPORATION	BRANTFORD POWER INC.
COLLUS POWER CORPORATION	ENTEGRUS POWERLINES	E.L.K. ENERGY INC.
COOPERATIVE HYDRO EMBRUN INC.	ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	ESSEX POWERLINES CORPORATION
GRIMSBY POWER INCORPORATED	FORT FRANCES POWER CORPORATION	FESTIVAL HYDRO INC.
GUELPH HYDRO ELECTRIC SYSTEMS INC.	HEARST POWER DISTRIBUTION COMPANY LIMITED	KINGSTON HYDRO CORPORATION
LAKEFRONT UTILITIES INC.	HYDRO 2000 INC.	ORANGEVILLE HYDRO LIMITED
MIDLAND POWER UTILITY CORPORATION	HYDRO HAWKESBURY INC.	OSHAWA PUC NETWORKS INC.
NEWMARKET-TAY POWER DISTRIBUTION	KENORA HYDRO ELECTRIC CORPORATION LTD.	PETERBOROUGH DISTRIBUTION INCORPORATED
ST. THOMAS ENERGY INC.	NORTHERN ONTARIO WIRES INC.	TILLSONBURG HYDRO INC.
WASAGA DISTRIBUTION INC.	ORILLIA POWER DISTRIBUTION CORPORATION	WOODSTOCK HYDRO SERVICES INC.
	OTTAWA RIVER POWER CORPORATION	
	PARRY SOUND POWER CORPORATION	
	RENFREW HYDRO INC.	
	RIDEAU ST. LAWRENCE DISTRIBUTION INC.	
	WELLAND HYDRO-ELECTRIC SYSTEM CORP.	
	WELLINGTON NORTH POWER INC.	
	WEST COAST HURON ENERGY INC.	
	WESTARIO POWER INC.	

Average Customer Growth). Group 12 becomes Peer Group E (Small Output, Small Area, Below Average Customer Growth). Finally, groups 5 and 9 are consolidated into Peer Group F (Small Output, Above Average Undergrounding, Below Average Customer Growth).

PEG believes that these are reasonable peer groups for the purposes of undertaking unit cost comparisons. The composition of the peer groups depends ~~directly~~ primarily on similarity in the cost drivers identified in the econometric analysis. Each peer group contains at least 10 distributors, which addresses the concern that some peer groups used in 3rd Gen IR were too small and apt to be distorted by outliers. PEG also endeavored to make the process for winnowing the groups to the six that are recommended as transparent as possible.

7.3 Unit Cost Comparisons

The unit cost benchmarking evaluations for each of the six peer groups are presented in Table 24. This table has two columns. The first is the 2009-2011 unit cost average. This column presents the average unit cost for each distributor in the peer group. At the bottom of this column, in bold, is the average unit cost measure for the entire peer group. The second column is the "Benchmark Unit Cost Comparison." The values in this column are equal to each distributor's unit cost minus the group average unit cost (*i.e.* "the benchmark" unit cost), with this difference then divided by the group average unit cost.

Table 25 arrays the benchmark unit cost comparisons from lowest (*i.e.* distributors registering the largest *negative* difference between their actual unit costs and the peer group benchmark unit costs) to highest (distributors with the largest *positive* difference between their actual unit costs and the peer group benchmark unit costs). Distributors with more negative differences between their actual and benchmark unit costs would be viewed as relatively more efficient, all else equal. ~~As in Tables 11 and 13, distributor names are suppressed in Tables 24 and 25.~~

It can be seen that only one~~the~~ top performer~~s~~ on the unit cost benchmarking analysis has~~ve~~ unit costs that are ~~just~~ more than 30% below those of their designated peers, on average. In contrast, there are ~~eight~~ four distributors whose unit costs are 30% or more above the average unit costs of their peers. Two~~Four~~ of these distributors have unit costs that are 50% or more above their peer group average~~, and two have unit costs more than 70% above the average unit costs of their peer group~~.

Table 24

Unit Costs By Peer Group

Group A- Large Output, Extensive Area

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
ENERSOURCE HYDRO MISSISSAUGA INC.	44,171,342.06	-3.5%
ENWIN UTILITIES LTD.	52,733,099.86	15.2%
HORIZON UTILITIES CORPORATION	37,404,874.85	-18.3%
HYDRO ONE BRAMPTON NETWORKS INC.	42,873,918.64	-6.3%
HYDRO ONE NETWORKS INC.	58,869,958.84	28.6%
HYDRO OTTAWA LIMITED	42,402,993.49	-7.3%
KITCHENER-WILMOT HYDRO INC.	34,862,300.65	-23.8%
LONDON HYDRO INC.	35,693,442.92	-22.0%
POWERSTREAM INC.	43,521,777.95	-4.9%
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	70,787,098.03	54.7%
VERIDIAN CONNECTIONS INC.	40,069,784.87	-12.4%
Group Average	**45,762,781.10**	

Group B- Small Output, Extensive Area, High Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
BRANT COUNTY POWER INC.	50,356,575.90	13.3%
BURLINGTON HYDRO INC.	39,463,700.77	-11.2%
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	39,158,703.46	-11.9%
CANADIAN NIAGARA POWER INC.	50,197,876.81	12.9%
HALTON HILLS HYDRO INC.	36,020,522.44	-19.0%
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	42,966,128.84	-3.3%
MILTON HYDRO DISTRIBUTION INC.	47,353,397.43	6.5%
NIAGARA-ON-THE-LAKE HYDRO INC.	45,087,493.43	1.4%
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	48,452,933.21	9.0%
WATERLOO NORTH HYDRO INC.	43,463,668.88	-2.2%
WHITBY HYDRO ELECTRIC CORPORATION	46,426,167.71	4.4%
Group Average	**44,449,742.63**	

Group C- Small Output, Extensive Area, Below Average Undergrounding and Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
ALGOMA POWER INC.	86,301,012.53	85.4%
ATIKOKAN HYDRO INC.	52,273,319.23	12.3%
BLUEWATER POWER DISTRIBUTION CORPORATION	41,588,544.77	-10.6%
ERIE THAMES POWERLINES CORPORATION	48,903,704.04	5.1%
GREATER SUDBURY HYDRO INC.	45,892,569.66	-1.4%
HALDIMAND COUNTY HYDRO INC.	35,008,338.00	-24.8%
LAKELAND POWER DISTRIBUTION LTD.	44,442,370.17	-4.5%
NIAGARA PENINSULA ENERGY INC.	44,553,279.32	-4.3%
NORFOLK POWER DISTRIBUTION INC.	44,304,189.59	-4.8%
NORTH BAY HYDRO DISTRIBUTION LIMITED	43,240,820.23	-7.1%
PUC DISTRIBUTION INC.	36,987,434.72	-20.5%
SIOUX LOOKOUT HYDRO INC.	37,960,463.65	-18.4%
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION	43,588,404.83	-6.3%
Group Average	**46,541,880.83**	

Table 24 (cont)

Unit Costs By Peer Group

Group D- Small Output, Small Area, High Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
CENTRE WELLINGTON HYDRO LTD.	38,809,015.11	-7.0%
COLLUS POWER CORPORATION	41,008,125.56	-1.8%
COOPERATIVE HYDRO EMBRUN INC.	51,051,765.03	22.3%
GRIMSBY POWER INCORPORATED	37,102,188.55	-11.1%
GUELPH HYDRO ELECTRIC SYSTEMS INC.	48,983,647.69	17.3%
LAKEFRONT UTILITIES INC.	36,944,557.62	-11.5%
MIDLAND POWER UTILITY CORPORATION	44,602,078.09	6.8%
NEWMARKET-TAY POWER DISTRIBUTION LTD.	41,074,924.28	-1.6%
ST. THOMAS ENERGY INC.	40,913,971.74	-2.0%
WASAGA DISTRIBUTION INC.	36,982,324.00	-11.4%
Group Average	**41,747,259.77**	

Group E- Small Output, Small Area, Slow Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
CHAPLEAU PUBLIC UTILITIES CORPORATION	42,055,472.80	4.0%
ENTEGRUS POWERLINES	41,094,587.59	1.6%
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	38,852,915.81	-3.9%
FORT FRANCES POWER CORPORATION	48,152,849.74	19.1%
HEARST POWER DISTRIBUTION COMPANY LIMITED	28,679,825.65	-29.1%
HYDRO 2000 INC.	34,730,444.52	-14.1%
HYDRO HAWKESBURY INC.	20,289,273.44	-49.8%
KENORA HYDRO ELECTRIC CORPORATION LTD.	44,189,418.71	9.3%
NORTHERN ONTARIO WIRES INC.	33,646,419.79	-16.8%
ORILLIA POWER DISTRIBUTION CORPORATION	41,706,341.96	3.1%
OTTAWA RIVER POWER CORPORATION	42,939,091.97	6.2%
PARRY SOUND POWER CORPORATION	45,240,103.16	11.9%
RENFREW HYDRO INC.	50,178,128.48	24.1%
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	37,285,466.09	-7.8%
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	36,266,449.98	-10.3%
WELLINGTON NORTH POWER INC.	54,780,232.87	35.4%
WEST COAST HURON ENERGY INC.	44,809,620.80	10.8%
WESTARIO POWER INC.	43,123,590.05	6.6%
Group Average	**40,445,568.52**	

Group F- Small Output, Above Average Undergrounding, Below Average Growth

Company Name	2009-2011 Unit Cost Average	Benchmark Unit Cost Comparison
BRANTFORD POWER INC.	42,708,771.79	-4.1%
E.L.K. ENERGY INC.	37,326,747.36	-16.2%
ESSEX POWERLINES CORPORATION	40,981,405.89	-8.0%
FESTIVAL HYDRO INC.	49,276,104.35	10.6%
KINGSTON HYDRO CORPORATION	40,315,352.43	-9.5%
ORANGEVILLE HYDRO LIMITED	45,189,614.78	1.4%
OSHAWA PUC NETWORKS INC.	39,709,013.51	-10.9%
PETERBOROUGH DISTRIBUTION INCORPORATED	44,808,269.63	0.6%
TILLSONBURG HYDRO INC.	44,484,426.14	-0.2%
WOODSTOCK HYDRO SERVICES INC.	60,745,230.93	36.3%
Group Average	**44,554,493.68**	

Table 25

Unit Cost Evaluations

Company Name	2009-2011 Average / 2009-2011 Group Average	Efficiency Ranking
HYDRO HAWKESBURY INC.	-49.8%	1
HEARST POWER DISTRIBUTION COMPANY LIMITED	-29.1%	2
HALDIMAND COUNTY HYDRO INC.	-24.8%	3
KITCHENER-WILMOT HYDRO INC.	-23.8%	4
LONDON HYDRO INC.	-22.0%	5
PUC DISTRIBUTION INC.	-20.5%	6
HALTON HILLS HYDRO INC.	-19.0%	7
SIOUX LOOKOUT HYDRO INC.	-18.4%	8
HORIZON UTILITIES CORPORATION	-18.3%	9
NORTHERN ONTARIO WIRES INC.	-16.8%	10
E.L.K. ENERGY INC.	-16.2%	11
HYDRO 2000 INC.	-14.1%	12
VERIDIAN CONNECTIONS INC.	-12.4%	13
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.	-11.9%	14
LAKEFRONT UTILITIES INC.	-11.5%	15
WASAGA DISTRIBUTION INC.	-11.4%	16
BURLINGTON HYDRO INC.	-11.2%	17
GRIMSBY POWER INCORPORATED	-11.1%	18
OSHAWA PUC NETWORKS INC.	-10.9%	19
BLUEWATER POWER DISTRIBUTION CORPORATION	-10.6%	20
WELLAND HYDRO-ELECTRIC SYSTEM CORP.	-10.3%	21
KINGSTON HYDRO CORPORATION	-9.5%	22
ESSEX POWERLINES CORPORATION	-8.0%	23
RIDEAU ST. LAWRENCE DISTRIBUTION INC.	-7.8%	24
HYDRO OTTAWA LIMITED	-7.3%	25
NORTH BAY HYDRO DISTRIBUTION LIMITED	-7.1%	26
CENTRE WELLINGTON HYDRO LTD.	-7.0%	27
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION IN	-6.3%	28
HYDRO ONE BRAMPTON NETWORKS INC.	-6.3%	29
POWERSTREAM INC.	-4.9%	30
NORFOLK POWER DISTRIBUTION INC.	-4.8%	31
LAKELAND POWER DISTRIBUTION LTD.	-4.5%	32
NIAGARA PENINSULA ENERGY INC.	-4.3%	33
BRANTFORD POWER INC.	-4.1%	34
ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPO	-3.9%	35
ENERSOURCE HYDRO MISSISSAUGA INC.	-3.5%	36
INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	-3.3%	37
WATERLOO NORTH HYDRO INC.	-2.2%	38
ST. THOMAS ENERGY INC.	-2.0%	39
COLLUS POWER CORPORATION	-1.8%	40
NEWMARKET-TAY POWER DISTRIBUTION LTD.	-1.6%	41
GREATER SUDBURY HYDRO INC.	-1.4%	42
TILLSONBURG HYDRO INC.	-0.2%	43

Table 25 (cont)

Unit Cost Evaluations

Company Name	2009-2011 Average / 2009-2011 Group Average	Efficiency Ranking
PETERBOROUGH DISTRIBUTION INCORPORATED	0.6%	44
ORANGEVILLE HYDRO LIMITED	1.4%	45
NIAGARA-ON-THE-LAKE HYDRO INC.	1.4%	46
ENTEGRUS POWERLINES	1.6%	47
ORILLIA POWER DISTRIBUTION CORPORATION	3.1%	48
CHAPLEAU PUBLIC UTILITIES CORPORATION	4.0%	49
WHITBY HYDRO ELECTRIC CORPORATION	4.4%	50
ERIE THAMES POWERLINES CORPORATION	5.1%	51
OTTAWA RIVER POWER CORPORATION	6.2%	52
MILTON HYDRO DISTRIBUTION INC.	6.5%	53
WESTARIO POWER INC.	6.6%	54
MIDLAND POWER UTILITY CORPORATION	6.8%	55
OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.	9.0%	56
KENORA HYDRO ELECTRIC CORPORATION LTD.	9.3%	57
FESTIVAL HYDRO INC.	10.6%	58
WEST COAST HURON ENERGY INC.	10.8%	59
PARRY SOUND POWER CORPORATION	11.9%	60
ATIKOKAN HYDRO INC.	12.3%	61
CANADIAN NIAGARA POWER INC.	12.9%	62
BRANT COUNTY POWER INC.	13.3%	63
ENWIN UTILITIES LTD.	15.2%	64
GUELPH HYDRO ELECTRIC SYSTEMS INC.	17.3%	65
FORT FRANCES POWER CORPORATION	19.1%	66
COOPERATIVE HYDRO EMBRUN INC.	22.3%	67
RENFREW HYDRO INC.	24.1%	68
HYDRO ONE NETWORKS INC.	28.6%	69
WELLINGTON NORTH POWER INC.	35.4%	70
WOODSTOCK HYDRO SERVICES INC.	36.3%	71
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	54.7%	72
ALGOMA POWER INC.	85.4%	73

7.4 Recommended Efficiency Cohorts and Stretch Factors

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

PEG recommends that both benchmarking models again be used to assign stretch factors in 4th Gen IR. While significant progress has been made in developing a total cost econometric benchmarking model for the Ontario electricity distribution sector, we do not recommend that the Board rely exclusively on econometric benchmarking to inform stretch factor assignments. Unit cost benchmarking analysis is not as technically sophisticated as econometric benchmarking, but it is more transparent and accessible. The unit cost benchmarking results are also broadly consistent with the econometric results, which implies that the unit cost benchmarking provides generally reliable information on relative cost performance. For these reasons, PEG believes that the unit cost benchmarking exercise has value and should be used by the Board to inform its assignment of company-specific stretch factors to distributors.

However, PEG also recommends that the number of efficiency cohorts be expanded from three to five. This recommendation is based on PBR Working Group discussions in which company representatives claimed that 3rd Gen IR cohorts are too large and make it difficult for distributors to migrate out of their existing cohort and into higher cohorts through cost-cutting efforts. All else equal, increasing the number of cohorts should facilitate the movement of distributors into higher cohorts and thereby reward companies that have improved their relative cost efficiency with reductions in their stretch factors. Because increasing the number of cohorts from three to five appears to be consistent with Board's objectives for encouraging efficiency improvements, PEG recommends that the number of cohorts be expanded from three to five.

PEG recommends that these five cohorts be established in the following manner. Distributors will be assigned to efficiency cohort I if they are significantly superior cost performers at a 90% confidence level and if they are in the top quintile of distributors on the peer group/unit cost benchmarking analysis. ~~Six~~Eight distributors satisfy these criteria, and we recommend that the six distributors in cohort I be assigned a stretch factor of 0. Distributors will be assigned to efficiency cohort II if they are significantly superior cost performers at a 90% confidence level and if they are in the second quintile of distributors on the peer group/unit cost benchmarking analysis. ~~One~~Four distributors satisfy~~ies~~ these criteria, and we recommend that the four~~is~~ distributors in cohort II be assigned a stretch factor of 0.15%.

Conversely, PEG recommends that distributors be assigned to efficiency cohort V if they are significantly inferior cost performers at a 90% confidence level and if they are in the bottom quintile of distributors on the peer group/unit cost benchmarking analysis. Thirteen~~Eleven~~ distributors satisfy these criteria, and we recommend that the 13~~1~~ distributors in cohort V be assigned a stretch factor of 0.6%. Distributors will be assigned to efficiency cohort IV if they are significantly inferior cost performers at a 90% confidence level and if they are in the fourth quintile of distributors on the peer group/unit cost benchmarking analysis. F~~ive~~our distributors satisfy these criteria, and we recommend that the ~~5~~four distributors in cohort IV be assigned a stretch factor of 0.45%. The remaining ~~50~~44 distributors are in cohort III and will be assigned a stretch factor of 0.3%. These cohort and stretch factor assignments are presented in Table 26.

By increasing the number of cohorts from three to five, this approach for assigning stretch factors would make it easier for distributors to migrate into higher cohorts by controlling costs. The recommended maximum stretch factor remains 0.6%, but PEG recommends that the minimum stretch factor be reduced to zero to encourage and reward efforts to reduce unit cost. PEG also recommends that the stretch factor for the largest group of distributors be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time. ~~Given that our~~

~~recommended productivity factor is zero, the values of these stretch factors would set the value of the X factors that apply to each respective cohort of distributors in 4th Gen IR.~~

Table 26

Efficiency Cohorts for Ontario Electricity Distributors

Cohort I	Cohort II	Cohort III	Cohort IV	Cohort V
Distributor 73	Distributor 5	All Other	Distributor 47	Distributor 61
Distributor 24	Distributor 35		Distributor 45	Distributor 53
Distributor 69	Distributor 38		Distributor 55	Distributor 37
Distributor 14	Distributor 54		Distributor 66	Distributor 42
Distributor 44				Distributor 36
Distributor 15				Distributor 34
Distributor 11				Distributor 72
Distributor 21				Distributor 40
				Distributor 48
				Distributor 26
				Distributor 9
				Distributor 68
				Distributor 49

7.5 Recommended Cost/Efficiency Measure for Scorecard

Finally, PEG was asked to advise Board Staff on which cost/efficiency measures should appear on the Scorecard. PEG believes the Scorecard should report each distributor's overall efficiency assessment as reflected in its assigned cohort. This is the most consequential evaluation of efficiency from a ratemaking perspective, since the cohort assignment is directly tied to the value of the stretch factor and therefore rate adjustments for distributors that elect 4th Gen IR. The cohort assignment is also the most comprehensive assessment of a distributor's efficiency since it is based on a consideration of both the econometric and unit cost/peer group benchmarking models.

In addition, it would be instructive to report the outcomes of the two benchmarking assessments. Doing so can provide context and further detail on why a distributor has been assigned to its particular cohort. On the econometric test, these outcomes would be either: 1) significantly superior cost performer, 2) average cost performer, or 3) significantly inferior cost performer. On the unit cost/peer group test, the outcomes would be 1) top quintile of industry, 2) second quintile of industry, 3) third quintile of industry, 4) fourth quintile of industry, or 5) bottom quintile of industry.

In summary, PEG recommends that the cost/efficiency measure on the scorecard report the following:

Efficiency Assessment:	Cohort Ranking I through V
Econometric benchmarking:	One of three outcomes listed above
Unit cost/peer group benchmarking:	One of five outcomes listed above

8. Concluding Remarks

PEG was asked to develop specific, quantitative recommendations for three elements of the 4th Gen IR rate adjustment formula: 1) the inflation factor; 2) the productivity factor that applies to the entire industry; and 3) stretch factors that apply to different cohorts of distributors in the industry. PEG was also asked to develop a total cost benchmarking approach. PEG endeavored to base our recommendations on all three factors using rigorous and objective empirical research that could be replicated, refined and extended in future IR applications. Our recommendations were also informed by, and consistent with, the principles for effective incentive regulation and salient regulatory precedents from around the world.

On the inflation factor, PEG recommends that it be constructed as a weighted average of inflation in three separate indices: 1) a capital service price that PEG has constructed using publicly available information; 2) average weekly earnings for workers in Ontario; and 3) the GDP-IPI. The weights that apply to each index are equal to the estimated shares of capital, labor, and non-labor OM&A expenses, respectively, in total distribution cost for the Ontario electricity distribution industry. This inflation factor can be updated and computed each year using publicly-available information on inflation in the selected indices and, when relevant, changes in the Board's approved rates of return.

We also recommend that, in each year, the inflation factor be measured as the average value of inflation in our recommended input price index (IPI) over the three most recent years. Measuring inflation as the three-year moving average in our recommended IPI substantially reduces the volatility of the inflation factor. Evidence over the 2002-2011 period suggests that the volatility of PEG's recommended IPI will be similar to the volatility of the inflation factor that is currently used in 3rd Gen IR.

PEG obtained two estimates of TFP growth for Ontario electricity distributors over the 2002-2011 period. Both estimates excluded Toronto Hydro and Hydro One because of evidence showing that these firms directly impacted the industry's estimated TFP growth, and the measured TFP growth trend in an IR plan should be "external" to utilities 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 annual rate of ~~-~~0.10~~05~~% per annum. PEG also used an econometric cost model estimated for the industry to backcast TFP growth between 2002 and 2011. The backcast analysis predicted average TFP growth of ~~-~~0.07~~3~~% over the sample period.

Given that the index-based and econometric-based TFP estimates are both close to ~~zero~~0.1%, PEG recommends that the productivity factor for 4th Gen IR be set equal to 0.1%~~zero~~. In addition to being consistent with the two empirical estimates, PEG believes a productivity factor of ~~zero~~ 0.1% is reasonable for several reasons. First, PEG's analysis shows that the industry's slower TFP growth stems primarily from a slowdown in output growth rather than an acceleration in distributors' spending. The slower output growth has been particularly pronounced since the introduction of CDM programs in 2006. PEG believes the continued emphasis on CDM policies in Ontario will continue to limit the potential for output quantity and TFP gains for the industry.

Second, we find the available evidence does not support a negative productivity factor. While TFP growth for the Ontario electricity distribution industry has been negative since 2007, much of this decline is attributable to the severe recession in 2008-09. This was a one-time event and is not anticipated to recur during the term of 4th Gen IR. PEG also concludes that the experience since 2007 is not long enough to be the basis for a productivity factor; TFP trends should be calculated over at least a nine-year period. We also do not favor treating sub-periods within a sample period differently (*e.g.* by placing more weight on one sub-period rather than another), since such an approach can give rise to "cherry picking" and artificial manipulation of the available data. The nine-year industry TFP trend is more consistent with a productivity factor of ~~zero~~0.1% than a substantially negative productivity factor.

Third, an IPI inflation factor combined with a productivity factor of ~~zero~~0.1% would mean electricity distributor prices grow at nearly the same rate as the industry's input price inflation, if all else is held equal. PEG's research shows that input price inflation for the electricity distribution industry has been slightly below GDP-IPI inflation. It is not unusual for price inflation in a particular sector (such as electricity distribution) to be similar to average price inflation in the economy. If the productivity factor was the only component of the X factor, a productivity factor equal to ~~zero~~ 0.1% would likely mean that electricity distribution prices grow at rates similar to the prices of other goods and services in the economy. Price inflation in a particular sector that is similar to aggregate, economy-wide inflation is not necessarily a sign of sub-par productivity performance in that sector.

However, the productivity factor is *not* the only component of the X factor, nor is it the component of the X factor that is designed to ensure that consumers benefit from incentive rate setting. Stretch factors are intended to reflect distributors' incremental efficiency gains under incentive ratemaking. Adding a stretch factor to the productivity factor allows customers to share in these anticipated efficiency gains.

PEG used econometric and unit cost/peer group models that we developed to benchmark distributors' total cost performance and inform stretch factor assignments. As in 3rd Gen IR, both benchmarking methods were used to identify efficiency cohorts in the industry, but we recommend expanding the number of these cohorts from three (in 3rd Gen IR) to five. This recommendation is designed to facilitate the movement of distributors into higher cohorts. Since distributors in higher cohorts are subject to lower recommended stretch factors, a larger number of cohorts strengthens distributors' incentives to pursue efficiency.

PEG recommends that distributors be assigned to efficiency cohort I if they are significantly superior cost performers at a 90% confidence level and if they are in the top quintile of distributors on the peer group/unit cost benchmarking analysis. ~~Six~~ Eight distributors satisfy these criteria, and we recommend that the eight ~~six~~ distributors in cohort I be assigned a stretch factor of 0. Distributors will be assigned to efficiency cohort II if they are significantly superior cost performers at a 90% confidence level and if they are in the second quintile of distributors on the peer group/unit cost benchmarking analysis. Four~~One~~ distributors satisfy~~ies~~ these criteria, and we recommend that the four~~is~~ distributors in cohort II be assigned a stretch factor of 0.15%.

Conversely, PEG recommends that distributors be assigned to efficiency cohort V if they are significantly inferior cost performers at a 90% confidence level and if they are in the bottom quintile of distributors on the peer group/unit cost benchmarking analysis. Thirteen~~Eleven~~ distributors satisfy these criteria, and we recommend that the 13~~1~~ distributors in cohort V be assigned a stretch factor of 0.6%. Distributors will be assigned to efficiency cohort IV if they are significantly inferior cost performers at a 90% confidence level and if they are in the fourth quintile of distributors on the peer group/unit cost benchmarking analysis. Four~~ive~~ distributors satisfy these criteria, and we recommend that the ~~5~~four distributors in cohort IV be assigned a stretch factor of 0.45%. The remaining 44~~50~~ distributors are in cohort III and will be assigned a stretch factor of 0.3%.

By increasing the number of cohorts from three to five, this approach for assigning stretch factors would make it easier for distributors to migrate into higher cohorts by controlling costs. The recommended maximum stretch factor remains 0.6%, but PEG recommends that the minimum stretch factor be reduced to zero to encourage and reward efforts to reduce unit cost. PEG also recommends that the stretch factor for the largest group of distributors be reduced from 0.4% to 0.3% to reflect the expectation that, on average, incremental efficiency gains become more difficult to achieve over time.

~~Given that our recommended productivity factor is zero, the values of these stretch factors would set the value of the X factors that apply to each respective cohort of distributors in 4th Gen IR.~~ Particularly b~~B~~ecause PEG has recommended positive stretch factors for most distributors, electricity distributor prices ~~are still expected to~~ will fall in "real," inflation-adjusted terms under the index-based rate adjustments in 4th Gen IR. A productivity factor of ~~zero~~ 0.1% is therefore not incompatible with the Board's incentive rate-setting objectives of encouraging cost efficiency and ensuring that customers share in these efficiency gains.

PEG's recommendations are based on empirical techniques that we believe strike an appropriate balance between rigor, objectivity and feasibility given the data currently available in Ontario. Our recommendations have also been informed by economic reason, approved precedents in North America and valuable regulatory approaches around the world. Our methods have also built on information sources and techniques that PEG has developed in our previous comparative cost and IR work for Board Staff.

PEG believes that the methods used to develop the inflation factor and X factor recommendations in 4th Gen IR can provide a solid foundation for future incentive regulation proceedings in Ontario. Our approach brings together a wealth of techniques and alternative data sources that can be useful in future IR applications. These techniques include index-based measures of industry TFP trends in Ontario and econometric and unit cost/peer group benchmarking of Ontario distributors' total cost performance. At the same time, our methodology is flexible enough to allow the techniques used to estimate inflation factors and

X 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.[34]

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

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

[34] 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.[35]

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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[35] 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.[36] This very flexible function is the most frequently used in econometric cost research, and by some account the most reliable of several available alternatives.[37] The general form of the translog cost function is:

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

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:

[36] 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.

[37] 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).[38] 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.[39] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[40]

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.[41] 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.

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

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

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

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

Appendix Three: Tests on Output and Trend Parameters

This appendix tests whether Hydro One and Toronto Hydro have had a statistically significant impact on four parameters in PEG's econometric cost model. These are the parameters on the customer, system capacity peak, and kWh delivery outputs, and on the time trend. To test this hypothesis, we began with the econometric cost model presented in Tables 10 and 12 but added a number of interaction terms which interacted a dummy variable (which takes a value of 1 for Toronto Hydro and Hydro One but 0 for all other distributors) with these four variables and other variables in the model.

We call the model that includes the interaction terms the "unrestricted model," while the model where the four parameters of interest are restricted to be equal to zero is called the "restricted model." Each product of the dummy variable and one of the four variables of interest is an "impact effect," and the set of all four of these products is known as the "impact effects." The econometric results for the unrestricted and restricted models are presented in Tables A3-1 and A3-2, respectively.

We test whether the four interaction parameter estimates are jointly significant using three widely recognized test statistics: 1) a Chi-Squared Test; 2) a Joint F-Test; and 3) a Wald Statistic. Formulas and a description of these tests in the SUR context are given in J. Wooldridge 2010, Econometric Analysis of Cross Section and Panel Data , 2nd edition MIT Press, pp. 172-3, 180 and 184.

Test #1: Chi-Squared test The difference between the sum of squared residuals in the restricted model (with the four impact effects constrained to be zero) and the sum of squared residuals in the unrestricted model, is distributed chi-squared with four degrees of freedom under the null hypothesis that the four interaction terms in question have true values of zero. To do this test the residuals are transformed by the method of Feasible GLS that is used to estimate the model. The calculated test statistic is ~~24~~51.83, with an associated probability value of .0000~~1~~. This test therefore rejects the hypothesis that the four impact effects are jointly equal to zero.

Table A3-1

Econometric Models Assessing Impact of Hydro One and Toronto Hydro on Industry TFP

Variable Key

N = Number of Customers
C = System Capacity Peak Demand
D= Retail Deliveries
A = Service Territory Area
U = Percentage of Lines Underground
L = Average Line Length (km)
NG = % of 2011 customers added in the last 10 years
TH = Toronto Hydro Electric and Hydro One Networks dummy variable
W_K = Capital Input Price
Trend = Time Trend

Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value	Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value
N*	0.311	4.722	0.000	**TH Trend***	0.001	6.416	0.000
C*	0.285	4.575	0.000	**TH·N***	-4.823	-7.544	0.000
D*	0.069	2.084	0.038	**TH·C***	-18.746	-8.835	0.000
W_K*	0.630	78.173	0.000	**TH·D**	-1.079	-1.761	0.079
N·N	-0.512	-1.623	0.105	**TH·W_K**	-0.026	-1.251	0.211
C·C	0.330	1.130	0.259	**TH·N·N***	0.259	4.825	0.000
D·D*	0.119	1.488	0.137	**TH·C·C***	4.274	8.218	0.000
W_K·W_K*	0.058	1.304	0.193	**TH·D·D***	-0.949	-7.073	0.000
N·C	0.118	0.412	0.680	**TH·W_K·W_K**	0.011	2.084	0.038
N·D	0.164	1.384	0.167	**TH·W_K·N***	-0.004	-1.838	0.067
C·D	-0.267	-2.641	0.008	**TH·W_K·C***	0.013	1.793	0.074
N·W_K*	0.032	1.675	0.094	**TH·W_K·D**	0.001	0.216	0.829
C·W_K	0.029	1.612	0.107	**TH·N·C***	1.541	9.330	0.000
D·W_K	0.000	-0.045	0.964	**TH·N·D**	0.056	1.287	0.199
A*	0.019	1.473	0.141	**TH·D·C***	1.332	8.534	0.000
U*	0.049	6.995	0.000				
L*	0.248	8.065	0.000				
NG*	0.018	2.295	0.022				
TH*	32.187	7.851	0.000				
Trend*	0.011	7.169	0.000				
Constant*	12.749	333.764	0.000				

System Rbar-Squared	0.984
Sample Period	2002-2011
Number of Observations	729

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

Table A3-2

Econometric Models Assessing Impact of Hydro One and Toronto Hydro on Industry TFP

Variable Key

N = Number of Customers
C = System Capacity Peak Demand
D= Retail Deliveries
A = Service Territory Area
U = Percentage of Lines Underground
L = Average Line Length (km)
NG = % of 2011 customers added in the last 10 years
TH = Toronto Hydro Electric and Hydro One Networks dummy variable
W_K = Capital Input Price
Trend = Time Trend

Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value	Explanatory Variable	Estimated Coefficient	T-Statistic	P-Value
N*	0.294	4.260	0.000	**$TH\cdot W_K$**	-0.002	-0.118	0.906
C*	0.291	4.455	0.000	**TH·N·N***	-0.190	-10.492	0.000
D*	0.101	2.918	0.004	**TH·C·C***	-0.425	-5.045	0.000
W_K*	0.631	78.067	0.000	**TH·D·D**	-0.183	-2.552	0.011
N·N	-0.386	-1.160	0.246	**$TH\cdot W_K\cdot W_K$**	0.002	0.420	0.675
C·C	0.494	1.608	0.108	**$TH\cdot W_K\cdot N$***	-0.006	-2.560	0.011
D·D*	0.194	2.310	0.021	**$TH\cdot W_K\cdot C$**	0.004	0.583	0.560
$W_K\cdot W_K$*	0.084	1.893	0.059	**$TH\cdot W_K\cdot D$**	0.002	0.535	0.593
N·C	0.010	0.035	0.972	**TH·N·C***	0.217	11.056	0.000
N·D	0.134	1.066	0.287	**TH·N·D**	-0.013	-1.718	0.086
C·D	-0.313	-2.938	0.003	**TH·D·C**	0.200	2.648	0.008
$N\cdot W_K$*	0.032	1.676	0.094				
$C\cdot W_K$	0.031	1.678	0.094				
$D\cdot W_K$	-0.001	-0.124	0.901				
A*	-0.007	-0.514	0.607				
U*	0.020	2.590	0.010				
L*	0.252	7.778	0.000				
NG*	0.021	2.496	0.013				
TH	-0.010	-1.155	0.249				
Trend*	0.018	12.482	0.000				
Constant*	12.704	319.957	0.000				

System Rbar-Squared	0.983
Sample Period	2002-2011
Number of Observations	729

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

Test #2: Joint F test When the difference in the sum of squared errors used in the chi-squared test is divided by the sum of squared residuals from the unrestricted model, and then multiplied by (n*g – k)/q, where n is the number of observations (729), g the number of equations (2), k the number of explanatory variables in the unrestricted model (46), and q is the number of restrictions (4), this test statistic is distributed F(4, 1412). This test statistic has a value of 12,5~~6.2~~8, with a probability value of .0000~~1~~. This test therefore rejects the hypothesis that the four impact effects are jointly equal to zero

Test #3: Wald Test The Wald Statistic provides a robust significance test calculated using a q x k matrix of restrictions R placed on the k x 1 vector b of estimated coefficients with an estimated k x k variance covariance matrix V(b) and qx1 vector of restrictions r:

$(R \cdot b - r)' \cdot (R \cdot V(b) \cdot R')^{-1} \cdot (R \cdot b - r)$ is distributed chi-squared with q=4 degrees of freedom.

Here, r is a column of 4 zeros and R is constructed of zeros and ones to satisfy $R \cdot b = r$. The calculated test statistic is ~~62.~~90.12~~7~~ which has a probability level of .0000. This test therefore rejects the hypothesis that the four impact effects are jointly equal to zero.

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