Benchmarking the Costs of Ontario Power Distributors

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Table of Contents

Executive Summary

The Ontario Energy Board ("OEB") has in recent years taken a growing interest in benchmarking the performance of power distributors. In November 2006, Board Staff announced a consultation process on cost benchmarking for the next round of Electricity Distribution Rate ("EDR") applications. They released four years of Ontario distributor operating data and requested feedback from stakeholders on a unit cost approach to benchmarking which they developed. The requisite data for these metrics have become available since approval of the Board's Reporting and Record-Keeping Requirements ("RRR") system in 2001.

Staff retained Pacific Economics Group to help it develop an operational benchmarking method for ratemaking. We were asked to

- Review and appraise staff's unit cost benchmarking approach;
- Consider other approaches and recommend a best approach;
- Review precedents for the use of benchmarking in regulation; and
- Recommend reforms in the Board's data collection.

A report on our work was released by the OEB on April 27, 2007 and comments from interested parties were solicited. The report presented benchmarking results based on two econometric cost models, as well as results based on peer groups where unit cost and productivity indexes were used as performance indicators.

In the summer of 2007, Board Staff commissioned PEG to update the study to include 2006 data. A technical conference was held in Toronto in September 2007 to discuss issues raised by the April 27th report. There was general agreement that the new study should consider the impact of service quality and capital use on operation, maintenance, and administration ("OM&A") expenses and explore the potential for benchmarking capital costs. This is the final report on our research.

Introduction to Statistical Benchmarking and Uses in Other Jurisdictions

Our report of April 27, 2007 provides a comprehensive discussion of the principles and concepts of benchmarking and its uses in other jurisdictions. The following points summarize the highlights.

- A central challenge in benchmarking is to fashion benchmarks that accurately reflect the impact that business conditions a company faces have on key performance indicators ("KPIs").
- Benchmarking accuracy is generally harder to achieve for "micro" cost categories. To benchmark OM&A expenses, for instance, a company's reported capital usage should be considered.
- Two statistical methods are used extensively in North American regulation to benchmark costs: indexing and econometrics.
    a) Under the econometric approach, historical operating data are used to estimate the parameters of a model relating cost to various business conditions. A model fitted with values for the business conditions facing a subject utility generates a cost benchmark. There is no need for peer groups. Statistical tests of hypotheses concerning a utility's efficiency can be performed.
    b) Indexing commonly involves the comparison of a company's unit cost or productivity to historical values of such KPIs for a peer group. Accuracy hinges on the degree to which the cost pressures faced by the peer group resemble those faced by the subject utility. Results of econometric cost research are useful in index design and the selection of peer groups.
- The cost of capital ownership (*e.g.*, depreciation expense, return on capital, and tax payments) is the largest single cost of a power distributor. Special challenges are encountered in the benchmarking of capital cost. These include the need to take into account differences in the age of utility systems and in depreciation and cost capitalization practices. Methods designed to accurately incorporate capital cost in benchmarking typically require many

years of data.

- The use of cost benchmarking in ratemaking varies greatly in the advanced industrial world. In the United States and Canada, benchmarking has been largely limited to occasional and voluntary submissions by utilities. These submissions have rarely had a discernible impact on rates. In Western Europe, benchmarking has been used mechanistically in several countries to adjust rate levels and/or the pace of rate escalation in multiyear plans. Regulators in several Australian states were unhappy with early statistical benchmarking experiments and have not continued. However, benchmarking recently played a role in the development of a new ratemaking system for power distributors in New Zealand.
- Where regulators have taken the initiative in statistical benchmarking studies they have generally favored more complex methods over simple unit cost metrics. The OM&A expenses of power distributors have been a common focus. Benchmarking is especially common where regulators have jurisdiction over numerous utilities. There is ample precedent, then, for the use of benchmarking in the regulation of the OM&A expenses of Ontario's numerous power distributors.

Application of Benchmarking in Power Distribution

Econometric research has identified numerous business conditions that drive power distributor cost. These include input prices, operating scale, system undergrounding, customer density, and system age. These business conditions can vary between utilities and a responsible benchmarking study makes an attempt to recognize their impacts.

Ontario Data

The Board has established itself in recent years as a leader in the gathering of data that are useful in power distribution benchmarking. A large and varied set of standardized data is accumulating. These data are, in our view, now sufficient to begin serious benchmarking of OM&A expenses.

Further improvements in the data can lead to better benchmarking and an expanded role for benchmarking in regulation. The following enhancements would be especially worthwhile to pursue:

- better guidelines for, monitoring, and public reporting of pension and benefits expenses and the salary and wage component of net OM&A expenses.
- better guidelines for, and monitoring of, peak load and itemized volume data (including deliveries to embedded distributors) in order to control better for differences in the workloads of distributors;
- better guidelines for, and monitoring of, reliability and other service quality indicators so as to control better for differences in the quality of service offered by distributors; and
- data on plant additions for years prior to 2002.

In addition, if it is considered useful and cost effective to benchmark the cost of *components* of OM&A (*e.g.*, customer care, maintenance, administrative and general activities), greater consistency in the assignment of labour and other expenses to the major categories of distributor activities will be required.

Latest Results of Benchmarking Research

In keeping with good statistical practice we developed in the second round of benchmarking research an econometric model of OM&A expenses using 2002-2006 Board data (see Table 3), the largest available sample. As before, this involved the estimation of the elasticities of cost with respect to several output variables. We used the research results to undertake econometric and unit cost benchmarking exercises (See Tables 4, 6, and 7). To balance the needs for data smoothing and relevance of benchmarking results, we focused on performance from 2004 to 2006. We also analyzed the Board Staff model (Tables 8 and 9). The following are some highlights of the research.

- All of the business condition variables in the featured PEG cost model have statistically significant and sensibly signed parameter estimates. The results suggest that there are at least three important drivers of distributor cost that are scale-related --- the number of customers served, the delivery volume, and circuit kilometers of distribution line (a measure of system extensiveness). As well there are other drivers of cost that are not scale related and these include the input price index, the extent of system undergrounding, and the proximity of the service territory to the Canadian Shield. All have been addressed in our econometric model.

- To further address questions about the impact of capital ownership on OM&A expenses we pursued two forms of analysis.
    1. We estimated the percentage of customers currently served that were added to each system in the last ten years and used these estimates to measure the impact of system age on cost. Econometric work revealed that OM&A expenses were lower the younger the system, as we might expect. We incorporated system age into our benchmarking work. This variable captures one of the most important dimensions of capital usage inasmuch as younger systems have less depreciated capital.
    2. We also developed summary indexes of the amount of capital used by a utility and considered the use of these indexes in OM&A benchmarking. The estimated parameter of the capital quantity variable was found to be sensibly signed (*i.e.* negative) and significant in most models considered. However, our system age metric had much greater explanatory power and was used instead in our featured cost model. This result may be due in part to limitations on the data we employed to measure capital use. These data also do not permit the calculation of highly accurate measures of capital *cost* that might be used to benchmark these costs.

  While it is not then currently possible, when benchmarking OM&A expenses, to take full account of the amount of capital that a utility uses, stakeholders can at least take comfort in the fact that the model we feature already addresses two important dimensions of capital usage ---system undergrounding (the single most important way to substitute capital for OM&A inputs) and system age.

- An attempt was also made to integrate considerations of reliability into the cost benchmarking work. We found one reliability metric, SAIDI, to have a sensible and significant parameter estimate in a number of cost models. However, the integration of reliability data into the benchmarking work involves a number of challenges. Special procedures for estimating model parameters are needed. Reliability metrics do not exclude major events, and the inclusion of reliability in the featured research at this time would therefore exclude many companies from benchmarking, and would substantially reduce the size of the sample needed for accurate cost model estimation.

- Our reliability research required the development of econometric models of the relationship of various reliability measures to business conditions. Initial results are fairly promising. Such models could, with more and better quality data, eventually provide the basis for service quality benchmarking.
- In the first round of work, Hydro One Networks was excluded from the benchmarking due, chiefly, to a lack of data on its deliveries to embedded distributors. Board Staff rectified this problem and we were able to include Hydro One in the sample for cost model estimation and in the econometric benchmarking work. A unit cost appraisal is still impossible due to a lack of comparably-scaled Ontario peers.
- The econometric model generated useful cost benchmarks. We used the econometric estimates of cost elasticities, additionally, to fashion output quantity indexes that simultaneously compare a distributor's customers served, delivery volumes, and kilometers of line to other distributors in the sample. We used these indexes to develop unit cost indexes. To benchmark these indicators, we compared their values to the average values for peer groups. Peer group selection was guided by the econometric results. Specifically, we grouped as peers companies from the same broad region with similar operating scales, system undergrounding, and (where peers were sufficiently numerous) system age.
- Board Staff developed an approach to the benchmarking of power distributor cost that uses a simple unit cost metric – total OM&A cost per customer – as an index. The peer groups used by PEG do a good job of sorting utilities based on differences in the operating scale, input prices, system age, and undergrounding that they face.

- PEG recommends that, instead of simple unit cost metrics, the Board should use unit cost indexes with multidimensional output quantity treatments such as those that we have developed from our econometric work. The Board should also consider replacing or supplementing indexing with direct econometric cost benchmarking.
- In choosing between the benchmarking methods that have been developed for its consideration, the Board must balance the criteria of benchmarking accuracy and simplicity. While the direct econometric approach to benchmarking is more complex than cost indexing, it has a number of advantages that include greater accuracy and the ready availability of sensible statistical tests of hypotheses concerning operating efficiency. Regulators in several countries have concluded that the advantages of greater accuracy that can be attained by more complex methods outweigh the advantages of simplicity when benchmarking is used in ratemaking.

Recommended Role of Benchmarking in Power Distributor Regulation

Our research for the Board has given it the capability to benchmark OM&A expenses using econometric cost models and unit cost indexes that reflect econometric research. In the latest round of work the Board's benchmarking capabilities have improved considerably with the processing of an additional year of data, the inclusion of Hydro One Networks, the development of a useful system age variable, and the refinement of unit cost peer groups. Impediments to accurate benchmarking can still be noted. These include shortcomings in the available data on labour costs, capital usage, reliability, and load factor.

Despite these challenges, we believe that the Board has already achieved a world class capability to benchmark OM&A expenses and that benchmarking is now ready to play a more important role in setting power distributor rates. Benchmarking should be used to identify companies that – thanks to favorable scores – merit expedited processing of rate applications and those that – due to poor scores – should be scheduled for especially thorough rate cases. Furthermore, benchmarking results such as estimated cost savings and surpluses are now sufficiently robust that they can be treated as material evidence in rate cases. Results are also relevant for setting the stretch factor term of rate adjustment mechanisms.

If benchmarking is used in distributor ratemaking it should extend to forward test year expenses as well as historical expenses since these are the costs that have the biggest effect on rates. Statistical tests of efficiency hypotheses can help to ensure the reasonableness of regulatory outcomes. We also encourage the Board to consider whether and how to provide awards for superior performance in addition to penalties for inferior performance. For example, companies that propose costs that reflect a significantly superior performance could be entitled to a premium rate of return or a lower (*e.g.* 0) stretch factor term in their rate adjustment mechanisms.

With additional years of data, better collection of existing data, and updated econometric research to make use of the new information, benchmarking in Ontario should over time reach an even higher level of accuracy that will permit it to play a larger role in the regulation of distributors. Benchmarking can extend to reliability and other service quality dimensions as well as cost. The Board can still undertake more traditional cost of service reviews but can use benchmarking results more mechanistically to set initial rates and the stretch factor terms of rate adjustment mechanisms.

1. Introduction

Statistical benchmarking has in recent years become an accepted tool in the assessment of utility operating performance. Managers look to benchmarking studies for indications of how efficient their companies are. Benchmarking also plays a role in utility regulation in several jurisdictions around the world. Such studies have, for example, been used to inform decisions concerning the initial rates and the rate adjustment mechanisms of multi-year regulatory plans.

Benchmarking of the operating performance of utilities is facilitated by the extensive data that they report to regulators. Accurate performance appraisals are nonetheless challenging. For example, there are important differences between companies in the services provided, the prices of inputs used in service provision, and in other business conditions that influence their costs. The sample of quality, standardized data available for benchmarking is sometimes small and data on key variables needed for benchmarking are sometimes unavailable.

The Ontario Energy Board has in recent years taken a growing interest in the benchmarking of jurisdictional power distributors. Cost benchmarking was used to screen the 2006 electricity distribution rate ("EDR") applications. The Board announced in 2006 that it would continue its work on methods and techniques for distributor cost comparisons. In November 2006, Board staff announced a cost comparison consultation process. It released data on Ontario utility operations for four recent years and requested feedback from stakeholders on a new approach to benchmarking that involved particular cost centers, cost drivers, and peer groups. Data prior to that is generally not available in an organized fashion and the nature of the industry was very different (*e.g.*, incorporation of distributors as business enterprises as opposed to components of Ontario Hydro, consolidation from over 300 distributors to less than 100).

Pacific Economics Group ("PEG") is a leading practitioner of energy utility benchmarking. We have more than forty man-years of experience in the field of utility performance measurement and pioneered the use of scientific benchmarking in US regulation. We have benchmarked power generation, transmission, distribution, customer, and administrative and general services, bundled power service, and gas distribution.

Staff has retained PEG to help it develop an operational benchmarking method for the next round of EDR proceedings. We have been asked, specifically, to

- Review and appraise Staff's benchmarking ideas;
- Recommend a specific approach to benchmarking;
- Review salient precedents for the use of benchmarking in regulation; and
- Identify needed reforms in the Board's data collection process.

This is the final report on our work.

Here is the plan for the paper. An introduction to statistical benchmarking is provided in Section 2, which includes discussions of benchmarking methods. Section 3 provides a brief summary of precedents for benchmarking in energy utility regulation. There follows in Section 4 a discussion of the challenges encountered in benchmarking the costs of electric power distributors. In Section 5 we turn to a review of the data. In Section 6 we report on our empirical research and use the results to make recommendations about the benchmarking program. More technical details of the research are discussed in the Appendix.

2. An Introduction to Benchmarking

In this section, we consider some important benchmarking concepts. The benchmarking methods most widely used in regulation are introduced and explained. The section concludes with a discussion of the special challenges of benchmarking capital costs.

2.1 What is Benchmarking?

The word benchmark comes from the field of surveying. The *Oxford English Dictionary* defines a benchmark as

> A surveyors mark, cut in some durable material, as a rock, wall, gate pillar, face of a building, etc. to indicate the starting, closing, ending or any suitable intermediate point in a line of levels for the determination of altitudes over the face of a country.

The term has subsequently been used more generally to indicate something that embodies a performance standard and can be used as a point of comparison in performance appraisals.

A quantitative benchmarking exercise commonly involves one or more gauges of activity. These are called, variously, comparators and key performance indicators ("KPIs"). The values of the indicators achieved by an entity under scrutiny are compared to benchmark values that reflect performance standards. Given information on the cost of a utility and a certain cost benchmark we might, for instance, measure its cost performance by taking the ratio of the two values:

$$\text{Cost Performance} = \text{Cost}^{\text{Actual}}/\text{Cost}^{\text{Benchmark}}.$$

Benchmarks are often developed using data on the operations of agents that are involved in the activity under study. Statistical methods are useful in both the calculation of benchmarks and the comparison process. An approach to benchmarking that prominently features statistical methods is called statistical benchmarking.

Various performance standards can be used in benchmarking. These standards often reflect statistical concepts. For example, one sensible standard is the average performance of the utilities in the sample. Alternative standards include the apparent frontier (best practice) performance in the sample and the performance that would define the margin of the top quartile of performers.

2.2 External Business Conditions

For costs and many other kinds of performance variables, it is widely recognized that differences in the values of the variables that companies achieve depend partly on differences in operating efficiency and partly on differences in business conditions. In cost research, these conditions are sometimes called cost drivers. In the electric utility industry examples include operating scale and the market prices of labour, capital equipment, and other production inputs. Billing and collection expenses will, for example, vary with the number of customers served.

The cost performance of a company depends on the cost that it achieves given the business conditions that it faces. Benchmarks must therefore reflect business conditions if they are to reflect a chosen performance standard faithfully. This helps to explain why the identification of relevant business conditions and consideration of their impact on performance variables are important tasks in a good benchmarking study.

2.3 Contributions from Cost Theory

Economic theory is useful in identifying cost drivers and controlling for their influence in benchmarking. We begin by positing that the actual cost incurred by a company is the product of the *minimum achievable* cost and an efficiency factor.[1] The goal of cost benchmarking is then to accurately estimate the efficiency factor.

Consider next that, under certain reasonable assumptions, cost functions exist that relate the minimum cost of an enterprise to business conditions in its service territory. Two kinds of cost functions yielded by this theory are useful in benchmarking. One is the *total* cost function in which the minimum total cost of an enterprise is a function of the prices of production inputs, output quantities, and variables representing miscellaneous other business conditions.

The theory allows for the existence of *multiple* output variables. This is important because it is often impossible to accurately measure the workload of a utility using only

[1] Minimum achievable cost is a hypothetical notion and cannot be precisely calculated for specific utilities.

one output variable. The cost of power transmission, for instance, depends on peak demand as well as the distance over which power is delivered. It is also noteworthy that the theory allows for the possibility that numerous business conditions other than input prices and output quantities can affect the minimum cost of service.

Regulators considering the appropriate revenue requirement of a company often have special interest in certain subsets of the total cost of service. Examples include OM&A expenses (sometimes called "opex") and even more "micro" categories such as distribution labour expenses. The interest in these expenses is due in part to the fact that they are subject to greater control by utilities in the short run than are capital costs.

When the focus of benchmarking is a subset of total cost, *restricted* cost functions are useful for identifying the full range of relevant cost drivers. In such functions, the minimum cost of a group of inputs depends on the prices of those inputs, output quantities and, additionally, on the amounts of *other inputs* that the company uses. The existence of the other input variables in restricted cost functions means that a fair appraisal of the efficiency with which a utility uses a certain class of inputs must consider the amounts of *other* inputs it uses.

This result is important for several reasons. One is that there are inconsistencies in the manner in which utilities classify costs. Utilities may, for example, differ in the way that they categorize certain expenditures between administrative and direct operating expenses.

Another reason that excluded inputs matter is that opportunities exist for the substitution of inputs in production. Suppose, for example, that the focus of inquiry is OM&A expenses. It is then germane that the level of expenses depends on the *capital* inputs that the company uses. A firm may, for example, have unusually low opex because its facilities are comparatively modern thanks to brisk output growth. It might also use a capital intensive technology such as undergrounding for service provision.

Suppose, alternatively, that the focus of benchmarking is the efficient use of labour. Economic theory suggests that the amount of labour that a company uses depends on its use of other, non-labour OM&A inputs as well as the amount of capital it uses. A utility may have an unusually small labour force not because it is especially efficient in its use of labour but because it has relatively new facilities and/or outsources a lot of its OM&A activities. By the same token, a company with high labour costs might do very little outsourcing and be fairly efficient.

One complication that benchmarkers encounter in trying to control for the usage of capital inputs is the measurement of that usage. As a practical matter, it isn't always possible to measure capital quantities accurately. However, variables can sometimes be computed that represent important *characteristics* of the capital stock that influence OM&A expenses. For example, one might employ an indicator of the age of a system.

2.4 Benchmarking Methods

In this section we discuss at some length the three most widely used approaches to statistical benchmarking: econometric modeling, indexing, and data envelopment analysis. The econometric approach is discussed first to establish a context for the appraisal of the index approach.

2.4.1 Econometric Modeling

Basic Assumptions

Relationships between the costs of utilities and the business conditions that they face can be estimated using econometric methods. In such an exercise, a specific mathematical form must be chosen for the cost function. The impact of business conditions on cost depends on the form chosen and on the values of model parameters.[2] The various alternative forms include the linear, the double log, and the translog. These forms vary in the flexibility with which they capture relationships between costs and cost drivers. Flexible functional forms are generally preferable. Suppose, for example, that incremental economies of scale from customer growth are exhausted at a certain level of

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[2] Here is a simple example of a cost function for power distribution that conforms to cost theory:

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} \qquad [1]$$

Here for any firm *h* in year *t*, the variable $N_{h,t}$ is the number of customers that the company serves. It quantifies one dimension of the work that it performs. The variable $W_{h,t}$ is a measure of the general run of wages in the service territory. The wage rate and number of customers are the measured business conditions in this cost function. The terms a_0, a_1, and a_2 are model parameters. The function in relationship [1] has a linear form.

output. We would then desire a functional form that permits the elasticity of cost with respect to output to increase with the level of output.

A branch of statistics called econometrics has developed procedures for estimating the parameters of economic models using historical data.[3] For example, cost model parameters can be estimated econometrically using historical data on the costs incurred by a group of utilities and the business conditions they faced.[4] The sample used in model estimation can be a time series consisting of data over several years for a single firm, a cross section consisting of one observation for each of several firms, or a panel data set that pools time series data for several companies.

Econometric research involves certain critical assumptions. The most important assumption, perhaps, is that the values of some economic variables (called dependent or left-hand side variables) are functions of certain other variables (called explanatory or right hand side variables) and error terms. In an econometric cost model, cost is the dependent variable and the cost drivers are the explanatory variables. The explanatory variables are generally assumed to be independent in the sense that their values are not influenced by the values of dependent variables.[5]

The error term in an econometric cost model is the difference between actual cost and the cost that is predicted by the model. It reflects imperfections in the development of the model. The imperfections may include any or all of the following: the mismeasurement of cost and the external business conditions, the exclusion from the model of relevant business conditions, and the failure of the model to capture the true form of the functional relationship. Error terms are a formal acknowledgement of the fact that the cost model is unlikely to provide a full explanation of the variation in the costs of sampled utilities. It is customary to assume that error terms are random variables with probability distributions that are determined by additional coefficients, such as mean and variance.

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[3] The act of estimating model parameters is sometimes called regression.

[4] A positive estimate for parameter a_1 in equation [1], for instance, would reflect the fact that the costs reported by sampled companies tended to be higher the greater were the number of customers that they served.

[5] In the simple cost model described in equation [1], for instance, we would assume that the number of customers that a utility serves and the price that it faces for labour are not influenced by its cost.

The results of econometric research are useful in selecting business conditions for cost models. Specifically, tests can be constructed for the hypothesis that the parameter for a business condition variable under consideration equals zero. A variable can be deemed a statistically significant cost driver if this hypothesis is rejected at a high level of confidence. In a benchmarking study used in utility regulation it is sensible to exclude from the model candidate business condition variables that do not have statistically significant parameter estimates, as well as those with implausible parameter estimates. Once such variables have been removed, the model is re-estimated.

Estimation Procedures

A variety of estimation procedures are used in econometric research. The appropriateness of each procedure depends on the assumptions that are made about the distribution of the error terms. The estimation procedure that is most widely known, ordinary least squares ("OLS"), is readily available in over the counter econometric software. Another class of procedures, called generalized least squares ("GLS"), is appropriate under assumptions of more complicated error specifications. For example, GLS estimation procedures can permit the variance of the error terms of cost models to be heteroskedastic in the sense that they vary across companies. Variances can, for example, be larger for companies with large operating scale.

Estimation procedures that address *several* of the error term issues that are routinely encountered in utility benchmarking are not readily available in commercial econometric software packages such as Gauss and Stata. They require, instead, the development of customized estimation programs. While the cost of developing sophisticated estimation procedures that are tailored for benchmarking applications is sizable, the incremental cost of applying them to different utilities is typically small once they have been developed.

Cost Predictions and Performance Appraisals

A cost model fitted with econometric parameter estimates may be called an econometric cost model. We can use such a model to predict a company's cost given local values for the business condition variables.[6] These predictions are econometric benchmarks. They can be made for historical years or a hypothetical test year.

Cost performance is measured by comparing a company's cost in year *t* to the cost projected for that year by the econometric model. Suppose, by way of example, that a utility incurred $12,000,000 of OM&A expenses in 2005 and the model projected a cost of $10,000,000 for that year. Taking the ratio of these numbers we find that

$$actual\ cost_t \ /\ projected\ cost_t = 12{,}000{,}000/10{,}000{,}000 = 1.2$$

The percentage difference between the actual and projected cost is

$$\left(actual\ cost_t - projected\ cost_t\right)/\ projected\ cost_t = \frac{12{,}000{,}000 - 10{,}000{,}000}{10{,}000{,}000} = .20$$

Performance Standards

The estimation procedure influences the performance standard that is embodied in the model predictions. Suppose, for example, that we choose a GLS procedure. It can then be shown that since these procedures do not explicitly account for the fact that the error terms are asymmetrically distributed, the predictions generated by the resultant cost model embody a *sample average* efficiency standard.[7] Estimation procedures that fall under the heading of stochastic frontier analysis ("SFA") generate benchmarks that reflect a frontier standard of operating efficiency.

The notion of minimum cost considered in SFA is of a *short run* character. Firms can, in the short run, incur a cost that is considerably below the cost that is sustainable in the long run. Examples from the business of power distribution is the deferral of tree trimming and replacement capital spending. In the long run, utilities that defer

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[6] Suppose, for example, that we wish to benchmark the cost of hypothetical power distributor called Northern Electric. Returning to our example, we might predict the cost of Northern in period *t* using the following model.

$$\hat{C}_{Northern,t} = \hat{a}_0 + \hat{a}_1 \cdot N_{Northern,t} + \hat{a}_2 \cdot W_{Northern,t}.$$

Here $\hat{C}_{Northern,t}$ denotes the predicted cost of the Company, $N_{Northern,t}$ is the number of customers it serves, and $W_{Northern,t}$ measures its wage rate. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are parameter estimates. Performance might then be measured using a formula such as

$$Performance = \left({C_{Northern,t}}\big/{\hat{C}_{Northern,t}} \right).$$

[7] See Appendix section A.1 for further discussion.

maintenance will experience service quality deterioration. A benchmarking model of OM&A expenses that is estimated using a frontier estimation procedure such as SFA might then effectively compare the opex efficiency of a subject utility to that of utilities that have deferred maintenance expenditures.

Capital cost provides another example of the short run/long run issue. Plant investments in the electric utility industry are commonly useful for 30-50 years. The value of an investment in plant is commonly treated as depreciating over the service life. The growth patterns of utilities vary. In comparing two power distributors that serve 100,000 customers we might find, for example, that one of the companies had added 40,000 customers in the last ten years, whereas the other had added only 10,000. It is quite possible for this reason alone that utilities serving the same level of output have different levels of capital cost. A benchmarking model of capital cost that is estimated using SFA might then effectively compare the capital cost efficiency of any subject utility to the capital cost efficiency of utilities with highly depreciated rate bases.

Another problem with the use of a frontier performance standard is that it is unusually sensitive to irregularities in the data. As we discuss further in Section 3 below, such irregularities are frequently encountered in statistical benchmarking work. Efficiency comparisons using frontier cost performance standards are much more sensitive to data irregularities than are efficiency comparisons using a sample average performance standard.

Accuracy of Benchmarking Results

A cost prediction like that generated in the manner just described is our best *single* guess of the Company's cost given the business conditions it faces. This is an example of a "point" prediction. Such predictions are likely to differ from the true benchmark, which accurately embodies the desired standard and controls for the impact of business conditions on cost.

One potential source of inaccuracy is the values of the parameter estimates that measure the impact of business conditions on cost. Another is the ability of the explanatory variables to accurately measure business conditions. A third is the extent to which the model captures the form of the relationship between business conditions and costs. Still another is a failure of the model to include all relevant business conditions.

Statistical theory provides useful guidance regarding the extent of inaccuracy. One important result is that an econometric cost model can yield *biased* predictions of the true benchmark if relevant business condition variables are excluded from the model. A model used to benchmark the opex of a rural power distributor might, for example, yield a value for the benchmark that is below its true value (and is thus excessively challenging) if it failed to include variables that properly represent the extensiveness of a distribution system and the magnitude of rural cost management challenges such as forestation. It is therefore desirable to include in an econometric benchmarking model all business conditions which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.

Even when an econometric benchmarking model is unbiased it can be imprecise, yielding predictions that are sometimes too high and on other occasions too low. Statistical theory provides the foundation for the construction of confidence intervals that represent the full range of possible predictions that are consistent with the data at a given level of confidence. These are readily constructed from the statistical results of an econometric run. A confidence interval is wider the greater is the uncertainty about the true benchmark level. In general, it can be shown that confidence intervals are wider to the extent that:

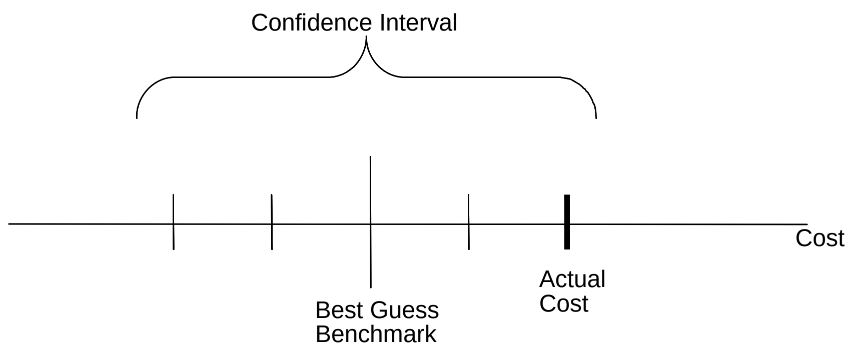
- the model is not successful in explaining the variation in cost in the historical data used in its development;
- the size of the sample is small;
- the number of cost driver variables included in the model is large;
- the business conditions of sample companies are not varied; and
- the business conditions of the subject utility are dissimilar to those of the typical firm in the sample.

These results suggest that econometric benchmarking will in general be more accurate to the extent that it is based on a large sample of good operating data. When the sample is small, it will be difficult to identify all of the relevant cost drivers and the appropriate functional form. It follows that it will generally be preferable to use panel data when these data are available instead of a single cross section of data. Moreover, benchmarking models can improve with each additional year of data that is gathered.

Notice also that the precision of an econometric benchmarking exercise is *enhanced* by using data from companies with diverse operating conditions. For example, we will obtain a better estimate of the impact of line length on cost if we include in the sample companies that, like Toronto Hydro Electric System (THES), have *high* customer density as well as data for companies that, like Sioux Lookout, have low density.

Testing Efficiency Hypotheses

Confidence intervals developed from econometric results do much more than provide indications of the accuracy of a benchmarking exercise. In particular, they permit us to test hypotheses regarding cost efficiency. Suppose, for example, that we use a sample average cost standard and compute the confidence interval that corresponds to the 90% confidence level. It is then possible to test the hypothesis that the company is an average cost performer. If the company's actual cost exceeds the benchmark generated by the model but nonetheless lies within the confidence interval (as in the figure below), this hypothesis cannot be rejected. In other words, the company is not a *significantly* inferior cost performer. Suppose, alternatively, that the company's cost is below the cost predicted by the model by enough to be outside the confidence interval. We may then conclude that it is a *significantly superior* cost performer.



An important advantage of efficiency hypothesis tests based on econometric research is that they take into account the accuracy of the benchmarking exercise. As we have just discussed, there is uncertainty involved in the prediction of benchmarks. These uncertainties are reflected in the confidence interval that surrounds the point estimate (best single guess) of the benchmark value. The confidence interval will be greater the greater is the uncertainty regarding the true benchmark value. If uncertainty is great, our ability to draw conclusions about operating efficiency is hampered. Accurate benchmarking of companies facing business conditions that are atypical of the sample are especially problematic. But with econometric benchmarking regulators at least have a notion of how much they don't know.

2.4.2 Index-Based Approaches to Benchmarking

The index-based approach to benchmarking is commonly employed by utilities in internal reviews of operating performance. Benchmarking indexes are also used in the regulatory arena. We begin our discussion with a review of index basics and then consider unit cost and productivity indexes in turn.

Index Basics

An index is defined in one respected dictionary as "a ratio or other number derived from a series of observations and used as an indicator or measure (as of a condition, property, or phenomenon)".[8] In benchmarking, indexing involves the calculation of ratios of the values of performance variables for a subject utility to corresponding values of the variables among a sample of utilities. The group of companies represented in the sample is called, variously, a cohort or a peer group.[9]

These concepts are usefully illustrated by the process through which decisions are made to elect athletes to Toronto's Hockey Hall of Fame. Statistical benchmarking undoubtedly plays a major (albeit informal) role in player selection. Goalies, for example, are evaluated using multiple performance variables that include the goals-against average. The values achieved by Hall of Fame members like Ken Dryden are useful benchmarks. These values reflect a Hall of Fame performance standard.

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[8] *Webster's Third New International Dictionary of the English Language Unabridged*, Volume 2, p. 1148. (Chicago: G. and C. Merriam and Co. 1966).
[9] The term cohort comes from the Latin word for one of the ten divisions of a Roman legion.

Economic indexes can be designed to summarize the results of multiple comparisons. Such summaries commonly involve the calculation of weighted averages of the comparisons. Consumer price indexes are familiar examples. These summarize the inflation (year to year comparisons) in the prices of hundreds of goods and services. The weight for the inflation in the price of each product is its share of the value of all of the products considered.

To better appreciate the advantages of complex indexes in benchmarking, recall from our discussion in Section 2 that economic theory allows for cost to depend on multiple output quantity variables and that multiple variables are often needed to accurately measure the workload of utilities. We might, then, wish to construct an output quantity index that is a weighted average of comparisons for several output measures. Suppose, by way of example, that we are benchmarking the power supply cost of a utility with a low load factor. It would be desirable in this case to consider its peak demand as well as its sales volume. If we separately calculate the company's cost per megawatt hour and per megawatt we would likely come up with two very different assessments. A final reckoning of performance then requires a sensible weighting of the assessments.

In a cost benchmarking application, it makes sense for the weights of an output quantity index to reflect the relative importance of the output measures as cost drivers. Econometric research is useful in this regard. We can, for example, use as the weight for each measure its share in the sum of the econometric estimates of the output-related cost elasticities.[10]

Summary input price and quantity indexes can also be computed. We might, for example, compare the quantities of OM&A inputs used by a subject utility to those of a cohort using an index that involves weighted averages of the amounts of labour and non-labour OM&A inputs used. In the construction of input quantity indexes it is customary to use the corresponding cost shares to calculate weights. It can be shown that this approach to weighting best reflects the impact of input quantities on cost.

[10] The elasticity of cost with respect to a certain business condition variable is the percentage change in cost that results from a one percent change in the value of the variable.

Unit Cost Indexes

Unit cost indexes are used to make unit cost comparisons. A simple example is the ratio of a company's cost per customer to the average cost per customer of a peer group. This can be stated, alternatively, as the ratio of a cost comparison to a comparison of the number of customers served.[11] In more sophisticated unit cost indexes, the workload comparison is a weighted average of several workload measures.

Unit cost indexes are, effectively, cost comparisons with a built in (but crude) control for differences between companies in one of the most important cost drivers: operating scale. The control is crude to the extent that there are economies of scale in the business that permit larger companies to operate at a lower unit cost than smaller companies. Peer utilities should therefore have operating scales that are, on average, similar to that of the subject utility. The control that is effected by a unit cost metric nonetheless permits us to use as peers utilities that have only broadly similar operating scales in evaluating cost performance.

It should also be noted that unit cost metrics by themselves do not control for all of the other cost drivers that are known to vary between utilities. Our discussion in Section 2 revealed that cost depends on input prices and miscellaneous other business conditions in addition to operating scale. The accuracy of unit cost benchmarking thus depends on the extent to which the cost pressures placed on the peer group by these excluded business conditions are similar on balance to those facing the subject utility. The choice of the peer group is thus an extremely important step in a unit cost benchmarking exercise.

Excluded business conditions are even more problematic when the focus of unit cost indexing is a narrow cost category. In that event, we have seen that a good benchmark should take account of the amounts of other kinds of inputs that a company uses. Suppose, for example, that we compare the labour costs per line mile of two utilities that have a markedly different reliance on outsourced services. In that event, the

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[11] Here is an example of a unit cost index for our hypothetical subject utility.

$$\frac{\left(\dfrac{Cost_{Northern}}{Customer_{Northern}}\right)}{\left(\dfrac{Cost_{Mean}}{Customers_{Mean}}\right)} = \frac{\left(\dfrac{Cost_{Northern}}{Cost_{Mean}}\right)}{\left(\dfrac{Customers_{Northern}}{Customers_{Mean}}\right)}$$

comparison is apt to be unfavourable to the company that doesn't do much outsourcing. It follows that in comparing unit labour costs, attention should be paid to differences in the extent to which candidate peers rely on outsourcing. This discussion suggests that, absent appropriate peer group controls, unit cost benchmarking will tend to be more accurate to the extent that the scope of costs under consideration is comprehensive. It will, for example, be easier to accurately benchmark *OM&A* expenses using unit cost indexes than it will be to accurately benchmark *labour* expenses.

Productivity Indexes

A productivity index is the ratio of an output quantity index to an input quantity index. It is used to make productivity comparisons. Many readers will think of productivity indexes as measures of *trends* in operating efficiency over time. However, they can also be designed to compare the efficiency *levels* of utilities at a point in time.

A simple example of a productivity metric is the number of customers served per employee. When we compare the value for this metric that a company achieves to the mean value for a peer group we, effectively, take the ratio of a customer comparison to an employee comparison.[12] In more sophisticated productivity indexes, the output comparison is a weighted average of several output measures.

A productivity comparison such as this can be shown to be the portion of a unit cost index comparison that is not due to differences in input prices. This result helps to explain why productivity indexes are generally more accurate benchmarking tools than unit cost indexes. Productivity indexes are, effectively, comparisons of cost that provide some control for differences in *two* sets of cost drivers that vary between utilities: the amount of work performed and the prices paid for inputs. These controls make it possible to use data from a more diverse set of companies in choosing a peer group. Peer companies need only have broadly similar operating scales and can, additionally, operate under different input price conditions.

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[12] Returning to our example, this can be expressed formulaically as

$$\frac{\left(\frac{Customers_{Northern}}{Employees_{Northern}}\right)}{\left(\frac{Customers_{Mean}}{Employees_{Mean}}\right)} = \frac{\left(\frac{Customers_{Northern}}{Customer_{Mean}}\right)}{\left(\frac{Employees_{Northern}}{Employees_{Mean}}\right)}$$

Despite these advantages, productivity comparisons do not control for all of the important cost drivers that vary between utilities. For example, a comparison of the productivity of the power generation businesses of two utilities could control for differences in their operating scale and generation fuel prices. However, it would not control for differences in their access to sites that are suitable for low cost hydroelectric generation. Note also that productivity indexes control for differences in operating scale imperfectly, and peers should typically have operating scales that are on average similar to that of the subject utility. It follows that the selection of a peer group is still important to the accuracy of a benchmarking study that is based on productivity indexes.

As we discussed above for unit cost indexes, excluded business conditions are apt to be a bigger complication to the extent that the focus of productivity indexing is a narrow input category. When the focus is narrow, we have seen that a good benchmark should take account of the amounts of other kinds of inputs that a company uses. Suppose, for example, that we compare the labour productivity of two utilities that have a markedly different reliance on outsourced services. In that event, the comparison is apt to be unfair to the company that doesn't do much outsourcing.[13]

This problem can be finessed by considering a broader range of inputs in the productivity index. An index that compares productivity in the use of more than one input is called a multifactor productivity ("MFP") index. An MFP index that covers all inputs used by an enterprise is called a total factor productivity ("TFP") index.

Our discussion suggests that more comprehensive productivity indexes will generally yield more accurate benchmarking results. Consider, for example, the company that uses a lot of in-house labour and outsources very few tasks. Such a company is likely to have low labour productivity but will have high productivity in the use of other OM&A inputs. An MFP index covering *all* OM&A inputs can assess how things balance out.

[13] It follows that in comparing labour productivity, attention should be paid to differences in the extent to which candidate peers rely on outsourcing.

Performance Standards

The cost performance indexes that we have discussed so far in this section embody a sample average standard of performance. Alternative standards can also be implemented. We can, for example, make calculations for each utility in the sample and then assess the apparent productivity shortfall between a subject utility and the utility with the best productivity ranking.

Frontier performance comparisons using indexes are, however, fraught with many of the same limitations as we discussed in the context of econometric modeling. The utilities with the best apparent productivity performance may, for instance, have achieved that status due to deferred maintenance. They may also have risen to the top of the rankings due to data irregularities.

Statistical Tests of Efficiency Hypotheses

Statistical tests are generally not employed in index-based benchmarking but can be developed for regulatory applications. To better appreciate the possibilities, suppose that we are benchmarking the cost performance of a company using a cost per customer metric. The unit costs of the companies in the peer group may vary considerably due to either or both of variations between companies in the many excluded business conditions and to the year-to-year volatility of the data for each company. We can treat the data for the peer group as a sample drawn from a probability distribution that has an unknown mean and variance. The sample mean cost per customer is then an estimate and our best guess of the mean of the population. A confidence interval can be constructed around the sample mean unit cost and a utility may be deemed to have a significantly inferior cost performance if its unit cost exceeds the upper bound of the confidence interval. The confidence interval will generally be wider --- making conclusions about efficiency more difficult to draw --- the smaller is the sample and the less varied are the sampled values of the unit cost metric. As a practical matter, this means that it is desirable for benchmarks to be based on several years of data for several companies. In our experience, it is generally desirable for peer groups to have more than five members.

2.4.3 Index-Econometric Hybrids

Hybrid benchmarking approaches that employ elements of the econometric and indexing approaches are also possible. An example is the "comparators and cohorts" approach to benchmarking that the OEB used to assess the operating efficiency of distributors in the 2006 EDR process. The methodology involved several steps.

1. A number of cost performance variables were chosen.
2. For each such variable, cost models were developed in which the variable (*e.g.* distribution OM&A expenses) was a function of certain business condition variables (*e.g.* the number of customers served). The parameters of the model were estimated econometrically using data on the costs incurred by Ontario distributors and the business conditions that they faced.
3. The parameter estimates obtained from the econometric work were employed in a statistical clustering analysis. This analysis identified, for each cost performance variable, cohorts of distributors with relatively similar values for the measured business conditions.
4. "Comparative diagnostic" variables of more micro character were calculated for the companies in each cohort.

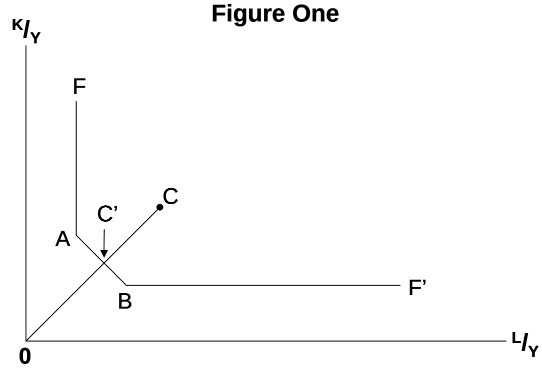
2.4.4 Data Envelopment Analysis

Data Envelopment Analysis ("DEA") uses linear programming techniques to "envelope" data on sample firms that relate outputs to inputs. It is therefore essentially a technique for identifying what are known in economics as isoquant or isocost curves. Efficiency is measured as the distance from the best attainable curve.

In a basic input-oriented DEA model, the relative efficiency of a firm is determined by assigning weights to firm inputs and outputs such that the ratio of aggregated outputs to aggregated inputs is maximized. This linear programming problem is subject to the constraint that the efficiency score cannot exceed a value of one for a firm using the same set of weights. The result of this process will be an efficiency measure for each firm that takes a value between zero and 100%. A perfect efficiency score would be 100%. A more typical score might be 80%.

These scores are relative to "peers" identified through the analysis and which set the efficiency "frontier." The DEA efficiency score has the intuitive interpretation that, relative to the peers, it measures the amount by which a firm can radially contract all of its inputs while still producing the same level of output. This can perhaps be clarified through a visual example. In Figure 1, there are two inputs, capital (K) and labour (L). The X axis in this figure is labour per unit of output (L/Y) while the Y axis is capital per unit of output (K/Y).

Figure One



In this example, the points A, B and C refer to specific firms that are identified as peers. It can be seen that firms A and B are using fewer capital and labour inputs per unit of output than firm C. The DEA technique would construct a piece-wise linear frontier through points A and B, which is identified by the line FABF'. This line is the production frontier. The efficiency of firm C is measured relative to this frontier, and the efficiency measure is equal to OC'/OC. Suppose this value turns out to be 0.6. This implies that firm C is 40% below the production frontier, and it can reach the frontier by reducing both its capital and labour inputs by 40%. Under input-oriented DEA, the firm's measured inefficiency is therefore equal to the entire difference between its position and the constructed efficiency frontier.

The basic input-oriented DEA model can be expanded in various ways. Technically, this occurs by modifying the linear programming problem to relax various assumptions. These more sophisticated DEA models can break down the sources of efficiency into various components. As one example, the model above assumes *constant* returns to scale in the relationship between inputs and outputs. This assumption can be relaxed to allow for *variable* returns to scale. Under variable returns to scale, returns to scale can differ at different levels of output. A firm of average size would typically realize greater scale economies than one of small size. A DEA model with variable returns to scale permits the efficiency measure described above to be decomposed into scale efficiency and "pure" technical efficiency.

Another enhancement possible in a DEA analysis is to incorporate data on input prices into the analysis. It is then possible to consider a company's *allocative* efficiency (its success in choosing the right input mix given current input prices) as well as its technical efficiency. The sum of allocative efficiency and operating efficiency is a more complete measure of operating efficiency than technical efficiency alone.

To compute allocative efficiency, we proceed in two steps. First we calculate technical efficiency as described above. Then we use the output maximizing input variables, "the optimal inputs," that result from the first step for each cross section and multiply these with the input price data to be used in a second round of linear programs. In particular, in the second stage we envelop the data once again using price weighted optimal inputs and the original outputs. The resulting set of price weighted optimal inputs, which are really the minimum cost for each cross section, are then compared to actual cost to determine allocative efficiency. In particular, the ratio of the minimum to the actual form allocative efficiency. Total cost efficiency is then the product of technical efficiency and allocative efficiency.

DEA can also be modified to include second-stage regressions that regress DEA efficiency scores on other business condition variables. The results of these regressions can then be used to adjust the efficiency scores resulting from the DEA analysis. The primary reason for undertaking such regressions rather than including all relevant business condition variables in the linear programming problem is that increasing the number of inputs in DEA analysis tends to reduce the number of peers that are identified for any firm. Having fewer peer firms can artificially inflate the efficiency measure. Indeed, in the limit, if enough inputs are introduced in the analysis, no firm may be identified as a peer for any other firm. The DEA measure therefore becomes one for all firms by default, which is usually an unrealistic result

2.5 Capital Cost

Capital inputs play important roles in utility operations. They are especially important in network businesses like power transmission and distribution. In these businesses, capital typically accounts for half or more of total cost. It follows that, in the long run, the success utilities have at holding down their costs depends greatly on their management of capital costs.

The cost of capital ownership has several components. One is the opportunity cost of having funds tied up in ownership. To the extent that the company borrows money, this is the interest that it must pay. To the extent that it secures financing in equity markets, this is the return on equity. Another important component of capital cost is depreciation. A third component of capital cost is taxes. The relevant taxes include income and property taxes and certain implicit taxes such as franchise fees.

The computation of depreciation and opportunity cost requires a valuation of utility plant. Two basic approaches to valuation can be used. One is book (historical cost) valuation. The other is current (replacement cost) valuation. Regulators must choose a method for calculating capital cost to establish revenue requirements. North American regulators commonly use book valuations of plant.[14]

Accurate benchmarking of the cost of any input generally requires a measure of the local input price. Accurate benchmarking of the cost of plant ownership requires, specifically, an estimate of the price of holding a unit of capital. These prices are sometimes called capital *service* (or rental) prices since prices for the rental of a unit of capital in competitive rental markets (*e.g.* those for real estate or automobiles) tend in theory to reflect the cost of owning a unit of capital. It can be shown that capital service prices reflect the cost of funds, depreciation and tax rates, and the cost of buying or building a unit of plant.

The benchmarking of capital cost involves special challenges. One is inconsistencies in the manner in which capital cost is reported. Companies differ most notably, perhaps, in the way that they calculate depreciation. Another problem is that the book valuation of plant used in regulatory accounts makes the reported net value of plant

[14] Replacement valuations are used by regulators in some other countries, including Australia.

especially sensitive to the historical pattern of capital investment. Two utilities could thus own the same amount of plant, but one could have a lower net plant value because its plant is of older vintage.

A means of computing capital cost has been developed by scholars to help finesse these problems. This method is commonly employed in rigorous research on capital cost. The basic idea is to recompute the cost of capital using a standardized treatment of depreciation and historical data on plant additions and on net plant value in a certain benchmark year which have been deflated using a construction cost index. The methodology involves the calculation of a capital quantity index using a perpetual inventory equation. The intent is to base capital cost calculation as much as possible on the plant additions data, which are less idiosyncratic.

The accuracy of this general approach to capital cost measurement is increased to the extent that the benchmark year that is used to start the index series is far in the past. In the electric power research of PEG that uses US data, for instance, we use *1964* as the benchmark year. Computing past values of capital quantity indexes is complicated by past mergers and acquisitions involving sampled firms.

When this methodology is employed, data on capital cost and the amount of capital that utilities use is still sensitive to their patterns of plant additions over the years. For example, two utilities with the same operating scale and level of capital cost efficiency can still have different capital costs (and quantities) if one system has an average asset age of 20 years while the other has an average asset age of 30 years. This problem is just beginning to receive the attention that it deserves from benchmarking experts.

3. Precedents for Benchmarking In Regulation

The Board's decision on a strategy for benchmarking should be informed by knowledge of precedents for its use in regulation around the world. In this section we summarize salient precedents for benchmarking in the advanced industrial world. North America, Europe, and Australia and New Zealand are considered in turn.

3.1 North America

Statistical benchmarking has not to date been extensively used in North American regulation. Most benchmarking evidence that is filed comes voluntarily from utilities. An industry average or top quartile performance standard is usually employed. Benchmarking results have rarely had a material impact on rates.

The lack of interest by North American regulators in benchmarking is, in our view, due chiefly to two considerations. Most regulation on this continent occurs at the state and provincial level, and most of these jurisdictions involve only a few utilities. Benchmarking is also discouraged by the extensive investment that has been made over the years in the cost of service approach to regulation.

Most studies that have been offered in North American proceedings use either indexing or econometric methods. In the United States, the development of sophisticated econometric cost models has been favored by the large amount of standardized data of good quality that has been gathered over the years on FERC Form 1 and other federal government forms. Statistical tests of efficiency hypotheses have been performed in several of the studies prepared by PEG.

The index and econometric approaches to benchmarking have both been used in Ontario proceedings. For example, the indexing approach was used in 2006 testimony by Hydro One Networks on its power transmission cost. PEG used both indexing and econometric methods in 2004 and 2005 testimony on the OM&A expenses of Enbridge Gas Distribution. Statistical tests of efficiency hypotheses were featured in this evidence.

3.2 Western Europe

Benchmarking has played a much more important role in regulation overseas than in North America. Most notable has been its use in Britain, Germany, the Netherlands, Norway, and other European countries. Power distribution cost has been the most common benchmarking focus.

The greater use of benchmarking in Europe reflects in part the fact that there is not a well-established heritage of cost of service regulation. It is also due to the fact that regulators in many countries have jurisdiction over numerous distributors. The number of distributors in Norway, for instance, is comparable to that in Ontario, and the number of distributors in Germany is much greater. Benchmarking thus makes possible significant economies in the regulatory process, and can potentially make use of fairly sizable samples of standardized data.

European regulators tend to favour a frontier benchmarking standard. Britain's energy regulator recently moved from a frontier to a top quartile standard. Companies in the top quartile were given revenue requirements in excess of their costs. Benchmarking has been used to adjust the initial rates and the pace of rate escalation in multi-year rate plans. In some countries, rate escalation mechanisms have been calibrated to move rates toward the estimated performance frontier over time.

As for benchmarking methods, the DEA approach to benchmarking has been favored in continental Europe. This is due in part to a comparative paucity of good operating data that might be used to develop good econometric cost models. It also reflects a preference for DEA by European economists.

Regulators in Britain have favored econometric benchmarking models. These models are quite crude, however, because they are based on samples that are miniscule by North American standards. British regulators have not seen fit to accumulate and use years of standardized panel data.

No regulator in Europe has, to our knowledge, employed statistical tests of efficiency hypotheses in ratemaking. This is due in part to the fact that regulators have not generally favored direct econometric benchmarking. Statistical tests can be constructed using DEA but their use appears to be quite rare.

Benchmarking is sometimes used mechanistically in European ratemaking. In the Netherlands, for example, the cost performances of gas and electric power distributors were appraised using DEA and a frontier performance standard. Rate escalation mechanisms were calibrated to move the rates for all utilities to a level commensurate with frontier cost performance over a multiyear period. Distributor rates will, prospectively, be escalated by a common formula that reflects the TFP trend of the industry.

3.3 Australia and New Zealand

The situation is more mixed in the ANZ countries. Regulators in New South Wales, Queensland, and Victoria have all initiated statistical cost benchmarking studies. Indexing, econometrics (based on models developed from US data), and DEA have all been used, as have both frontier and industry average performance standards. Methodological controversies erupted in proceedings in New South Wales and Victoria, and the studies in these proceedings seem to have carried little weight in final ratemaking decisions. Regulators have generally been dissatisfied with the outcome of benchmarking experiments and have not featured statistical benchmarking in subsequent proceedings.

In New Zealand, benchmarking evidence was recently used to design a mechanism for escalating certain price "thresholds" for power distributors. The escalation mechanism featured an inflation measure and an X factor. Distributors deemed to have inferior cost performance were assigned higher X factors. An industry average performance standard was employed in the benchmarking work. TFP indexes were the featured KPIs. The productivity indexes featured multidimensional output quantity indexes that summarized comparisons concerning customer numbers, the delivery volume, and a system line capacity measure, expressed in MVA-km.

A usage in the ANZ jurisdictions of benchmarking in regulation that is intermediate between that of North America and Europe can be explained by underlying conditions. Since ANZ countries do not have a long history of cost of service regulation of electric utilities, regulators were understandably intrigued with the benchmarking option. However, only New Zealand has to date confronted a situation in which a single regulator has jurisdiction over more than a dozen distributors.

3.4 Conclusions

Our review of benchmarking in the energy utility regulation of advanced industrial countries suggests that its use is more likely where regulators have limited experience with the prudence reviews that typify traditional cost of service regulation (COSR) and have responsibility over numerous utilities. For example, regulators in Britain, Germany, New Zealand, Norway and the Netherlands have limited experience with COSR and jurisdiction over more than ten utilities. In contrast, regulators in Australia, Canada, and the United States typically have jurisdiction over five or fewer utilities in each energy industry. Most North American regulators, additionally, have extensive COSR experience. In applying these lessons to Ontario, it is plain that the regulatory community has extensive COSR experience but that the Board must regulate more than eighty power distributors. This situation gives the Board an understandable interest in taking a different path than most of its North American brethren.

4. Application: Power Distribution

The challenge of accurate benchmarking is better appreciated by considering its application to a specific sector of the electric power industry. In this section we take an in-depth look at power distribution. We consider in turn the challenges encountered in benchmarking the costs of local delivery and customer care services.

4.1 Benchmarking Local Delivery

4.1.1 The Local Delivery Business

The distributor receives power in bulk from points on a high-voltage transmission grid and delivers it to consumers. Receipt commonly occurs at substations, where voltage is reduced from transmission to distribution levels. Power is in most cases delivered to end users at the even lower voltage at which it is typically consumed.[15]

Continuous use of electric power is essential to the functioning of modern homes and businesses. Power storage and self-delivery are, additionally, generally not cost competitive with power produced in bulk and delivered by utilities. It follows from these circumstances that customers want local delivery capability to be continuous. The technology for providing continuous service requires a network in the sense of a system that is physically connected to end user premises.

Power flows to the customer through wire conductors. Other capital inputs used in local delivery include poles, conduits, station equipment, meters, vehicles, storage yards, office buildings, and information technology ("IT") inputs such as computer hardware and software. Distributors commonly operate and maintain such facilities and are also frequently involved in the construction of distribution plant. These activities require labour, materials, and services. Local delivery also typically requires a certain amount of power in the form of line losses. Opportunities are available to outsource many OM&A and construction activities. Distributors vary greatly in the extent of their outsourcing.

[15] However, some large volume customers perform their own voltage stepdowns. At the extreme, they may take delivery of power from the grid and bypass the distribution system entirely.

Local Delivery Cost

The total cost of local delivery service comprises OM&A expenses and the costs of plant ownership. At current input prices, capital inputs typically account for between 45 and 60 percent of the total cost of local power delivery and constitute the single most important input group. The exact cost share of capital depends on the age of a system. The relative shares of labour and other OM&A inputs vary greatly. Prices for labour, capital, and other inputs are important drivers of power distribution cost.

Certain expenditures by distributors have a periodic character. As one example, overhead line maintenance activities such as tree trimming do not have to be undertaken at the same level each year. As another, distributor makes capital investments in response to expected output growth. These investments, once made, may not require replacement for 30-50 years. The amount and cost of capital in a particular year therefore depend greatly on the historic pattern of output growth. For example, a distributor serving a region that grew much more rapidly in the 1960s than in recent years may today have a highly depreciated system and an unusually large need to make replacement investments. However, distributors usually have quite a bit of discretion over when replacement investments are made.

Distribution Outputs

Cost theory suggests that the operating scale of a utility is an important cost driver. The outputs of a power distributor may be narrowly defined as measures of its operating scale that also serve as billing determinants. Three such measures are salient: the delivery volume, the peak load, and the number of customers served.

The reliability of distribution services is another important output dimension. The reliability achieved by power distributors varies considerably. Better reliability generally comes at a higher cost. The cost impact of quality is thus a valid issue in distribution benchmarking. There are special challenges in the estimation of the cost impact of quality. Despite its importance, empirical research on this topic is not well advanced.

Services Provided

Distributors vary in the package of local delivery services they provide. These differences can have a sizable impact on the cost of service. Here are some prominent examples.

- One of the most important differences between distributor service packages concerns the involvement in transformation of voltage from the transmission to the distribution level. Where transmission and distribution services are provided by separate companies, policymakers often decide which kind of company provides this service. Where transmission and distribution services are provided by the same company, as is commonly the case in North America, the issue is how these services are *categorized*.
- Many power systems have lines with voltages that are intermediate between the extra high voltage lines used for long distance transmission and the low voltage lines used to deliver power locally. These "subtransmission" lines are sometimes counted as transmission and sometimes as distribution facilities.

Other Network Characteristics

Power distribution networks vary in a number of other respects that affect their cost.

- Systems vary widely in customer density. Density is highest in urban areas and is lowest in sparsely populated rural areas. All else equal, distribution cost is typically higher the lower is customer density. In cost research, system extensiveness is commonly measured by the number of line kilometers. This cost driver is sometimes treated as an output variable in benchmarking work due to its importance and its relevance to operating scale.
- There is marked diversity in the extent of distribution system undergrounding. Undergrounding generally raises the *total* cost of local delivery service but can lower local delivery OM&A expenses due to the reduced need for line maintenance. Undergrounding is most common in

the central cities of major urban areas such as Toronto. Its prevalence in smaller towns depends greatly on public policy and local growth patterns.

- The shape of distribution systems must conform to special features of the landscape. For example, distribution lines will typically go around lakes and other large water bodies. Distribution cost can be raised by such complications.

Other Cost Drivers

Cost research by PEG and others using US data has identified a range of additional business conditions that are drivers of local delivery costs.

- Distribution OM&A expenses are generally *lower* the younger is the system. *Capital* cost is typically *higher* in a young system. The net effect of system age then depends on the relative magnitudes of OM&A and capital cost effects. Our research to date has suggested that the *total* cost of power distribution is on balance *lower* in a younger power distribution system.
- Distribution cost is typically higher the greater is the degree of forestation in a service territory. An obvious reason is the greater need for tree-trimming and other maintenance expenses. Another is the greater difficulty in creating and accessing power line corridors.
- The rockiness of soil affects the cost of distribution pole installation.

4.1.2 Data Problems

Reporting Inconsistencies

Research has identified numerous inconsistencies in the manner in which distributors report operating data. These problems tend to be especially marked where utilities have some discretion in cost reporting due to lax reporting guidelines and/or the inherent arbitrariness of cost allocations. One area of reporting inconsistency is the capitalization of OM&A expenses. An example of OM&A expenses that are capitalized by most utilities is those for plant construction labour. Areas where practices are more varied include work on software.

Another area where reporting inconsistencies tend to develop is the categorization of OM&A expenses between distributor activities. One issue is the breakdown between direct expenses and administrative and general ("A&G") expenses. The latter category of expenses, sometimes called corporate service expenses, is those that cannot be directly attributed to specific lines of business. Inconsistencies are also encountered in the allocation of direct expenses. An example from the United States is the grey area between billings and collections and customer service and information expenses.

Missing Data

Benchmarking is also complicated by the unavailability of important data. One major problem is the unavailability of good capital data. Adequate data for the calculation of standardized capital costs and quantities are not available for Canada or most other countries of the world. The United States is a prominent exception to this rule since detailed capital cost data have been reported there by major investor-owned utilities for decades.

4.2 Benchmarking Customer Services

4.2.1 The Customer Care Business

The customer care unit of a distributor is responsible for revenue cycle and other customer contact responsibilities. Revenue cycle services include meter reading, billing, collection, and payment processing. Other customer contact responsibilities of distributors include the handling of calls and other contacts, arrangements to start and end services, and demand-side management.

The provision of customer care services requires capital, labour, and other operating inputs. Technological change has been rapid in the business in recent years. For example, software systems are now extensively used to manage customer information and prepare bills. With the advent of the internet, the technology exists for customers to access account information, pay bills, and change service requests electronically. Automated meter reading makes possible more sophisticated rate structures such as hourly pricing. Because of these changes, customer care technology has become more capital intensive and software has become an important class of capital inputs. This also means that the cost of customer services is more prone than in the past to occasional “bumps” when major new automated systems are introduced.

The cost effectiveness of software is generally greater the larger is the scale of a distributor’s operations. That is because the chief cost in the use of an information system is its initial purchase and/or development. The cost incurred to serve an additional customer once a system is up and running is relatively modest. Major changes in the package of customer care services, such as those occasioned by the introduction of retail competition, can involve sizable short run cost growth due to investments in new systems.

There are many opportunities today to outsource calling centers and other customer care tasks. Customer service specialists can achieve scale economies by serving multiple utilities. Some utilities in the US and Canada have outsourced the major portion of their customer service activities.

Customer Service Cost Drivers

The outputs of a customer service business can be narrowly defined as measures of its operating scale that also serve as billing determinants. One such measure is salient: the number of customers served. Our research on customer service expenses over the years has revealed some additional drivers of customer service cost. These include the following.

- The cost of local delivery services was noted above to be influenced by customer density. Customer density is likely to have an impact on the cost of customer service as well. One reason is that meter reading is a customer service. System extensiveness can once again be measured by the length of distribution lines.
- Customer service cost is quite sensitive to the scale of demand-side management activities. These activities, which can include the development of initiatives, equipment merchandizing, and extensive communications, can be quite expensive,
- Customer service cost will generally be raised by the transition to retail competition. The experience of Ontario is illustrative in this respect.

Retail competition led to more complex customer bills and more frequent rate changes. Relationships had to be established with independent power suppliers that included an extensive exchange of information. Distributors were required to have the capability to perform transactions with these suppliers electronically. The many changes in customer service responsibilities prompted larger distributors to make substantial and costly upgrades to their information systems.

- Cost is generally higher the greater is the number of languages spoken in the service territory. The service territories of several Canadian utilities have a mix of English and French-speaking customers that necessitates bilingual services.
- Cost is generally higher in areas that involve high customer migration or turnover. An example of the former might be rapidly growing areas such as Calgary or Alberta's tar sands region. An example of the latter might be a college town such as Guelph, Ontario.
- The quality of customer service matters to customers and some quality measures are used in service quality incentive plans. Important measures of customer service quality include billing accuracy, call response time, and the time required to resolve customer queries. The handling of sophisticated rate offerings such as real time pricing should be viewed as a premium quality service. Higher quality services are, in general, more costly.[16] Service quality expectations are generally highest in urban areas.

4.2.2 Data Problems and International Benchmarking Challenges

The data categorization problems discussed above for local power delivery apply with equal or greater force to customer services.

- Companies are inconsistent in their capitalization of OM&A expenses. A good example is the treatment of software maintenance expenses.

[16] This implies that requests for better service by regulators can involve material cost increases.

Companies that outsource customer care tasks will report more of their IT costs as OM&A expenses.[17]

- Companies are inconsistent in their allocation of certain expenses between the customer care and A&G functions. For example, some companies assign most IT costs to A&G, whereas others allocate a sizeable share of the cost to customer care.

Missing data problems are, if anything, more severe for customer service benchmarking than for local delivery benchmarking. Data are not readily available in the public domain for important drivers of customer care cost such as service quality, language diversity, and customer turnover. Another salient problem is the poor quality of data on software costs. Data on the costs of intangible "plant" are not always reported with the same care as data on the costs of tangible plant. In the United States, the FERC Form 1 contains no itemized data on the cost of software plant whatsoever, much less a breakdown into software used for distribution and customer service. This is also a problem in local delivery cost research, as noted above, but is more of a problem for customer services because of the greater prominence of IT in customer service costs.

For all of these reasons, customer service costs have in our experience been more difficult to benchmark accurately than power delivery costs. Econometric research on customer service cost is much less advanced than in the power delivery sector. Benchmarking of detailed customer care cost items can be especially problematic due to the cost allocation inconsistencies we have discussed.

[17] Outsourcing companies will, furthermore, be less able to detail customer care expenses.

5. Ontario Data

We turn now to our empirical research on the benchmarking of Ontario power distributors. This section begins with an inventory of the data available. There follows an appraisal of the data and a suggested list of priority upgrades.

5.1 An Inventory of Available Data

Extensive data are available today on the operations of Ontario power distributors which are potentially useful in benchmarking their performance. The OEB is the primary source of such information. Statistics Canada and various geographical surveys can provide useful supplements. At the time of our updated study, OEB operating data from 2002 to 2006 were available. Data for 2007 should become available in the first half of 2008.

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 reported costs are expected to conform with Ontario's Uniform System of Accounts ("USoA"). They support the audited financial statements of the corporate entity that the Board regulates.

The available cost data include detailed itemizations of OM&A expenses. The itemizations include the cost of "labour with payroll burden" (presumably salaries and wages) for the following six distribution activities:

- transformer station equipment operation;
- distribution station equipment operation;
- overhead distribution lines and feeders operation;
- underground distribution lines and feeders operation;
- customer premises operation; and
- sentinel lights maintenance.

No comparable labour cost itemization exists for other distribution functions, or for any customer care or A&G functions.

There is, for each major activity group (*e.g.* billing and collection), a "supervision" category. There are, additionally, A&G expense categories for Executive

Salaries and Expenses, Management Salaries and Expenses, and General Administrative Salaries and Expenses. Notice that in all of these cases the USoA instructions speak of "expenses" in addition to payroll costs. Companies may vary considerably in their propensity to assign expenses other than salaries and wages to these categories.

The trial balances also include highly itemized data on gross plant value. The accumulated "amortization" (actually depreciation) on electric utility property plant and equipment is reported, as well as the accumulated amortization on intangible plant. These accumulations are not itemized with respect to plant function, nor to our knowledge are data reported (itemized or otherwise) on the corresponding plant additions.

Plant value data are also provided under the terms of RRR section 2.1.5. These do include data on plant additions. Capital spending data are also provided on the audited financial statements.

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. One item of interest in the reports is the breakout of the labour component for three categories of OM&A expenses:

- operation and maintenance (*i.e.* distribution OM&A);
- billing and collection; and
- administration.[18]

Unfortunately, these costs are deemed confidential per section 1.7 of the RRR.

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 available for the following five customer classes:

- residential;
- general service;
- large use (>5,000 kW);
- street lighting; and
- sentinel lighting.

[18] We do not know whether administration as here described includes the cost of administration of transmission operations a distributor may have.

PBR data include, as well, the total wholesale and retail kWh. The wholesale kWh evidently excludes deliveries that a utility may make to other (*e.g.* embedded) power distributors. Board staff have provided us with data on the deliveries of Hydro One to embedded distributors but have not provided the analogous data for any other company that makes such deliveries. PBR data are also available on the following characteristics of a distributor's network and service territory:

- urban, rural, and total areas of service territory;
- service area population;
- municipal population;
- number of seasonal occupancy customers;
- winter and summer maximum monthly and average peak loads;
- average load factor;
- overhead, underground, and total circuit kilometers of line;[19] and
- number of transmission, subtransmission, and distribution transformers.

5.2 Data Appraisal

Our appraisal of these data as a basis for distribution cost benchmarking identified a number of noteworthy strengths and weakness. In this section we discuss each in turn.

5.2.1 Data Strengths

The OEB has gone further than most regulatory commissions around the world to facilitate the development of data that are useful in benchmarking power distributor operations. The trial balance cost data are, like those gathered on FERC Form 1 in the United States, highly detailed and a USoA facilitates standardized reporting. The PBR data include potentially useful detailed data on revenues and output, including data on peak loads that are unavailable for US power distributors. The copious information on network and service territory characteristics also has no counterpart in US government data collection. Last but not least, the large number of reporting distributors and the diverse character of their operating scale and other business conditions mean that a data

[19] The circuit kilometer data are also available broken down between 3 phase, 2 phase, and single phase.

set of considerable size and diversity has already accumulated and will continue to grow with each passing year. A large and diverse set of data is noted in Section 2 to be a highly desirable for statistical benchmarking. As we will discuss further below, the data set is already sufficient to develop fairly sophisticated econometric cost models.

5.2.2 Data Weaknesses

The formidable advantages of OEB data are offset by some noteworthy disadvantages that materially limit their usefulness. Good benchmarking work is possible only if these limitations are recognized and the data are used cautiously. The constructive contributions of benchmarking to Ontario regulation can grow if the data are improved.

One of the most important problems is the limited potential of available capital cost data. As we discussed in section 2.5, the accurate calculation of standardized capital costs and quantities requires years of good plant additions data. While the PBR data on plant additions permit us to *begin* calculation of standardized capital costs and quantities, the accuracy of the calculations is hampered by the scant number of years for which these data are as yet available. Benchmarking results will be quite sensitive to our estimate of the cost and quantity of capital on hand in 2002. This "benchmark year" calculation requires a suitably weighted index of construction costs over the past forty years that is difficult to compute accurately.

Labour cost data are also problematic. Staff observed in its November 2006 notice that distributors seem to report most customer care labour expenses as administration expenses. We have found that many companies seem to misallocate distribution labour expenses as well. Another concern is the lack of good data on the salary and wage component of net OM&A expenses. On the United States FERC Form 1 all salaries and wages assigned directly to net OM&A expenses are, in contrast, reported on an itemized basis for all major power distributor activity groups (distribution, customer accounts, customer service and information, and administration and general).

There are also problems with the reporting of pension and benefit expenses. Many and perhaps most distributors appear not to have reported all such expenses in the pension and benefit category.[20] It is for this reason impossible to exclude pensions and benefits from an OM&A benchmarking study.

These limitations of the Ontario labour cost data make it impossible at present to benchmark labour costs with much accuracy. Furthermore, uncertainty concerning the share of labour in net OM&A expenses reduces the accuracy of OM&A multifactor productivity indexes and econometric models of OM&A expenses that might be developed since both of these benchmarking tools require a breakdown of these expenses between labour and other inputs.

As for the output data, one major problem is the general non-availability of data on power deliveries made by some distributors to other distributors. Another problem is inconsistencies in the reporting of the detailed "billed" retail delivery volumes and peak demand. Some companies appear to have reported volumes only for service classes with volumetric rates and peak demand only for service classes with demand charges. Other companies appear to have reported volumes and peaks for *all* services. Absent standardization of these detailed output data it is difficult to control for differences between utilities in load factors and the mix of customers served. It is desirable for benchmarking purposes to have a breakdown of total deliveries by service class, as well as a measure of peak demand. With such data in hand, we can control better for the cost impact of differences in the service mixes of utilities.

It also merits note that inconsistencies in reporting limit the usefulness of some of the data on service territory characteristics. In our view, inconsistencies are especially pervasive with respect to the following characteristics:

- rural vs. urban service area; and
- number of seasonal occupancy customers.

Hydro One, for example, reports that all of its service territory is rural when in fact many of its customers live in towns.

[20] In 2006, for instance, 37 distributors reported 0 pension and benefit expenses, but these costs were included in other accounts.

5.2.3 Conclusions

We believe that the OEB data are solid enough to provide the foundation for the continued use of benchmarking in power distributor regulation, but must be used cautiously. The data are inadequate for accurate benchmarking of the following costs: labour expenses (with or without pensions and benefits); detailed OM&A (*e.g.* customer care) expenses; OM&A expenses net of pensions and benefits; capital cost; and total cost. However, data are adequate to begin serious benchmarking of total OM&A expenses. This exercise is also worthwhile inasmuch as these expenses normally account for half or more of a distributor's controllable cost.

Improvements in the data can make it possible to expand the role of benchmarking in Ontario regulation. Here is a suggested list of high-priority upgrades:

- Tighten data reporting rules and enforcement so as to encourage more consistent allocations of labour costs between distributor functions and between salaries and wages and pensions and benefits.
- Make public the share of net OM&A expenses attributable to labour, ideally with itemization with respect to the major distributor functions.
- Gather plant addition data for years prior to 2002, and for net plant value in an earlier benchmark year.
- Gather detailed plant addition data. At a minimum, the value of gross plant additions should be reported each year for the following asset categories:
    - Distribution Plant
    - General Plant - Software
    - General Plant – Other.

  The following more detailed data, which are similar to those gathered on the FERC Form 1, would also be useful:
    - Distribution Plant - Land
    - Distribution Plant - Structures
    - Distribution Plant - Station Equipment
    - Distribution Plant - Poles, Towers, & Fixtures
    - Distribution Plant - Overhead Conductors and Devices

- Distribution Plant - Underground Conduit
- Distribution Plant - Underground Conductors and Devices
- Distribution Plant - Line Transformers
- Distribution Plant - Services
- Distribution Plant - Meters
- Distribution Plant - Customer Premises Equipment
- Distribution Plant - Street Lighting & Signal Systems
- General Plant - Structures
- General Plant - Software
- General Plant – Other.

- Tighten the rules and enforcement to ensure that accurate data are available on delivery volumes by service class, as well as data on the overall peak demand.
- Gather data from all companies on the volume of deliveries to other distributors.[21]
- Tighten rules and enforcement concerning the reporting of network and service territory characteristics.

[21] This upgrade should be made immediately and retrospectively.

6. Empirical Research

We turn now to a discussion of our benchmarking work. We first address three subjects --- the sample, the definition of cost, and cost drivers --- that are relevant to both our econometric and our indexing research. We then discuss details of our research using these two methods. There follows an appraisal of the benchmarking work that has been done by Board staff.

6.1 The Sample

The econometric model that we developed was based on the largest sample of data available. This, as we have seen, is in keeping with good econometric practice since a larger sample reduces the variance of parameter estimates and thereby helps us develop models with more variables and more flexible forms. The full sample period available was 2002-2006. We included in the sample data for all companies for which requisite data of good quality were available for at least two of the four years. The companies represented in the sample are identified in Table 1, together with information on their headquarters location and the number of customers served in a recent year.

A review of the table reveals that the number of companies in the sample is sizable. Since, additionally, there are several observations for each company and the business conditions faced by the companies are varied, the prospects are good that econometric research can shed light on the drivers of distributor cost. Estimates of the cost impact of these business conditions are useful in peer group design and econometric cost models can also be used directly in benchmarking.

In the first round of work, Hydro One Networks ("HON") was excluded from the benchmarking due, in part, to a lack of data on its sizable deliveries to embedded distributors. Board Staff rectified this problem and we were able to include HON in the new econometric modeling exercise. The statistical test of the efficiency hypothesis that we have developed for econometric models has the advantage of being sensitive to the unusual character of its business conditions.

Table 1

SAMPLED POWER DISTRIBUTORS FOR BENCHMARKING RESEARCH

Company	Customers Served [1]	Headquarters Location
Atikokan Hydro	1,720	NW, near Quetico Provincial Park
Barrie Hydro Distribution	67,523	SC, on Lake Simcoe
Bluewater Power Distribution	35,510	SW, on Detroit River
Brant County Power	9,284	SW, 40 km W Hamilton
Brantford Power	36,569	SW, 30 km SW Hamilton
Burlington Hydro	60,749	SW, near Hamilton
Cambridge and North Dumfries Hydro	48,619	SW, 30 km NW Hamilton
Centre Wellington Hydro	6,158	SW, 20 km NW Guelph
Chapleau Public Utilities	1,316	NC, 60 km E Lake Superior Provincial Park
Chatham-Kent Hydro	31,966	SW, 20 km E Lake St. Clair
Clinton Power	1,616	SW, 15 km E Lake Huron
COLLUS Power	14,300	SW, on Georgian Bay
Cooperative Hydro Embrun	1,836	SE, 40 km ESE of Ottawa
Dutton Hydro	600	SW, 10 km N Lake Erie
Eastern Ontario Power (CNP)	3,552	SE, on St. Lawrence
E.L.K. Energy	10,626	SW, 30 km SE Windsor
Enersource Hydro Mississauga	182,596	SC, Suburban Toronto
ENWIN Powerlines	84,701	SW, on Detroit River
Erie Thames Powerlines	13,807	SW, 15 km N Lake Erie
Espanola Regional Hydro Distribution	3,331	NC, 40 km N Little Current
Essex Powerlines	27,636	SW, 30 KM ESE Windsor
Festival Hydro	19,025	SW, 40 km ESE Kitchener
Fort Erie (CNP)	15,329	SC, Niagara Peninsula, near Buffalo
Fort Frances Power	3,981	W, adjacent to International Falls. MN
Grand Valley Energy	678	SW, Between Barrie and Toronto
Great Lakes Power	11,491	NC, on Sault St. Marie
Greater Sudbury Hydro	42,912	NC, Sudbury
Grimsby Power	9,508	SC, on Niagara Peninsula 20 km W Hamilton
Guelph Hydro Electric Systems	46,276	SW, 50 km NW Hamilton
Haldimand County Hydro	20,577	SW, 20 km SW Hamilton
Halton Hills Hydro	19,007	SW, 60 km W Toronto
Hearst Power Distribution	2,757	NC, 300 km NNW Wawa
Horizon Utilities	231,499	SW, 60 km SW Toronto
Hydro 2000	1,138	SE, 20 km west of Hawkesbury (WL), 70 km east of Ottawa (WK)
Hydro Hawkesbury	5,286	SE, on Ottawa River 60 km ENE Ottawa
Hydro One Networks	1,163,961	SC, Toronto
Hydro One Brampton Networks	120,364	SC, Suburban Toronto
Hydro Ottawa	282,393	SE, Ottawa
Innisfil Hydro Distribution Systems	13,832	SC, 12 km south of Barrie
Kenora Hydro Electric	5,828	NW, Kenora on Lake of the Woods
Kingston Electricity Distribution	26,525	SE, on St. Lawrence River
Kitchener-Wilmot Hydro	80,940	SW, 15 km SW Guelph
Lakefront Utilities	9,048	SC, on Lake Ontario 100 km E Toronto
Lakeland Power Distribution	9,050	NE, between Georgian Bay & Algonquin PP
London Hydro	140,007	SW, London
Middlesex Power Distribution	6,909	SW, 80 km E Windsor
Midland Power Utility	6,634	NC, on Georgian Bay 50 km N Barrie
Milton Hydro Distribution	20,975	SW, 35 km N Hamilton
Newbury Power	192	SW, 49 km SW London
Newmarket Hydro	26,647	SC, between Toronto & Lake Simcoe
Niagara Falls Hydro	33,234	SC, Niagara Peninsula
Niagara-on-the-Lake Hydro	7,703	SC, Niagara Peninsula 15 km N Niagara Falls
Norfolk Power Distribution	18,384	SW, near Lake Erie
North Bay Hydro Distribution	23,493	NE, on Lake Nipissing 160 km E Sudbury
Northern Ontario Wires	6,135	NC, 105 km NNE Timmins
Oakville Hydro Electricity Distribution	58,220	SC, Suburban Toronto on Lake Ontario
Orangeville Hydro	9,997	SW, 80 km NW Toronto
Orillia Power Distribution	12,551	SC, on Lake Simcoe 35 km NE Barrie
Oshawa PUC Networks	50,528	SC, Toronto metro area
Ottawa River Power	10,230	C, on Ottawa River near Algonquin PP
Parry Sound Power	3,271	C, on Georgian Bay 130 km N Barrie
Peninsula West Utilities	14,276	SW, Niagara Peninsula 38 km E Hamilton
Peterborough Distribution	33,866	SE, 70 km ENE Toronto
Port Colborne	9,143	SC, Niagara Peninsula on Lake Erie 60 km W Buffalo
Powerstream	228,471	SC, suburban Toronto
PUC Distribution	32,438	NC, Sault St. Marie
Renfrew Hydro	4,133	SE, 90 km W Ottawa
Rideau St. Lawrence Distribution	5,839	SE, on St. Lawrence River 100 km SSE Ottawa
Sioux Lookout Hydro	2,734	NW, 230 km ENE Kenora
St. Thomas Energy	15,597	SW, 10 km N Lake Erie
Tay Hydro Electric Distribution	4,037	SC, near Georgian Bay 50 km north of Barrie
Terrace Bay Superior Wires	926	NC, on Lake Superior 215 km E Thunder Bay
Thunder Bay Hydro Electricity Distribution	49,556	NW, on Thunder Bay
Tillsonburg Hydro	6,457	SW, 62 km ESE London
Toronto Hydro-Electric System	678,106	SC, at center of Golden Horseshoe on Lake Ontario
Veridian Connections	107,231	SC, on Lake Ontario between Toronto & Oshawa
Wasaga Distribution	10,902	SC, on Georgian Bay 38 km NW Barrie
Waterloo North Hydro	48,777	SW, adjacent to Kitchener 100 km WSW Toronto
Welland Hydro-Electric System	21,295	SC, Niagara Peninsula 70 km W Buffalo
Wellington North Power	3,454	SW, between Kitchener & Owen Sound
West Coast Huron Energy	3,811	SW, on Lake Huron 129 km ENE Sarnia
West Nipissing Energy Services	3,108	NC, on Lake Nipissing 38 km W North Bay
West Perth Power	1,976	SW, 80 km N London
Westario Power	20,983	SW, on Lake Huron 89 km SW Owen Sound
Whitby Hydro Electric	37,473	SC, on Lake Ontario between Ajax and Oshawa
Woodstock Hydro Services	14,316	SW, on Thames River 50 km ENE London

[1] Latest year of available data.

We based model estimates on as many as five years of data, but benchmarked the distributors' cost over the last three years. The most recent three years have the greatest relevance in ratesetting.

6.2 Definition of Cost

In Section 5.2.3 we reported our conclusion that only total OM&A expenses can be benchmarked with reasonable accuracy with available data. These expenses have been the focus of our empirical research for the Board. The OM&A cost that we benchmark is from the 2006 EDR groupings for operation, maintenance, billing and collection, community relations, administrative and general, insurance, bad debt, advertising, and other distribution.

It is our understanding that the A&G expenses that Board staff have provided to us exclude expenses that have been allocated to power transmission services by Great Lakes Power, Canadian Niagara Power, and Hydro One. While this in principle affords these companies a small cost advantage, it is difficult to control for this business condition in the benchmarking work since no other company in the sample has this advantage.

6.3 Cost Drivers

In this section, we discuss important drivers of the cost of power distribution. These drivers should be considered in the design of peer groups when benchmarking is undertaken using unit cost or productivity indexes. The importance of possible cost drivers can be assessed by including variables that quantify them in econometric cost models. The models can be used, additionally, to benchmark costs directly. The estimates of the corresponding parameters should be plausible with regard to sign (positive or negative) and magnitude (large or small).

6.3.1 Output Quantities

As noted above, economic theory suggests that quantities of work performed by utilities are cost drivers and should be included in our cost models as business condition variables. We considered three output variables in our econometric research: the number of retail customers, the total retail delivery volume, and the total circuit km of distribution line.[23] Recall from Section 2 that circuit km is the best available proxy for the distances over which power is carried. Cost should be higher the higher are the values of all of these variables. We, accordingly, expect the parameter for each output variable to have a positive sign.

6.3.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. We developed an input price index that summarizes differences, over time and between companies in each year of the sample period, in the prices they pay for OM&A inputs. Cost should be higher the higher is the value of the index. We, accordingly, expect the parameter of this variable to have a positive sign.

Our input price index is a weighted average of subindexes for labour and a miscellaneous category of inputs that includes materials and services. In the first phase of our research the weights assigned to these input classes in index construction (.35 and .65 respectively) reflected our knowledge of the corresponding cost shares for power distributor OM&A expenses in the United States. The low weight for labour reflected the extensive outsourcing of labour services to utility affiliates in the US. Upon further reflection, we feel that there is no empirical basis for using these shares in an Ontario application since outsourcing to affiliates is generally less prevalent.

The second-phase research has been based instead on the assumption that the cost share weights will be 50/50 for the two input categories on average for the sample. These weights are adjusted formulaically so that the labour cost share is higher (lower) where wage rates are expected to be high (low). One year of good data on the share of

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[23] For Hydro One Networks, we added to the total retail delivery volume the volume of their reported deliveries to embedded distributors.

labour in net OM&A expenses will permit a material upgrade to the input price index in the future.

The labour price subindex was constructed by PEG using Stats Canada data. Data from the 2001 census were used to compute average employment income by level of educational attainment in various Ontario cities. The index reflects an (employment-cost weighted) average of ratios of the local cost per employee to provincial averages for each level of educational attainment. The averaging technique mitigates the aggregation bias that would result from using cost per employee as a labour price index. Cost per employee in Toronto, for instance, exaggerates the pay premiums paid there because a larger share of the labour force is engaged in high-paying managerial and professional occupations. Values of the labour cost indexes for other years of the sample period were calculated by adjusting the 2001 levels for changes in an index of labour cost trends in Ontario.

Results of our labour price index calculations appear in Table 2. It can be seen that the variation in input prices was considerable. The highest labor prices were almost 40% higher than the lowest. Our use of external labour price comparisons rather than company data means that our benchmarking encompasses the compensation per employee that a company pays as well as the number of employees.

The prices for materials and services were assumed to be the same in a given year on average for all sampled companies. As a measure of inflation in these prices we used the Ontario gross domestic product implicit price index ("GDP-IPI") for final domestic demand. In our US research, we have found that indexes like the GDP-IPI track the trend in the prices of materials and services used by utilities fairly well.

6.3.3 Other Business Conditions

Three other business condition variables were found to be statistically significant cost drivers in the second round of econometric research. One is the percentage of the total circuit kilometers of lines that are undergrounded. We use this variable to measure

Table 2

Labour Price Levelizations for Ontario LDCs[1]

LDC	City Mapping	Labour Price Level Index for 2000
E.L.K. Energy Inc.	Windsor	1.081
ENWIN Powerlines	Windsor	1.081
Essex Powerlines	Windsor	1.081
Veridian Connections	Oshawa	1.062
Whitby Hydro Electric	Oshawa	1.062
Enersource Hydro Mississauga	Toronto	1.057
Hydro One Brampton Networks	Toronto	1.057
Oshawa PUC Networks	Toronto	1.057
Powerstream	Toronto	1.057
Toronto Hydro-Electric System	Toronto	1.057
Cooperative Hydro Embrun	Ottawa	1.048
Hydro Ottawa	Ottawa	1.048
Halton Hills Hydro	Toronto/Hamilton	1.036
Oakville Hydro Electricity Distribution	Toronto/Hamilton	1.036
Grand Valley Energy	Toronto/Barrie	1.024
Newmarket Hydro	Toronto/Barrie	1.024
Orangeville Hydro	Toronto/Barrie	1.024
Burlington Hydro	Hamilton	1.015
Grimsby Power	Hamilton	1.015
Horizon Utilities	Hamilton	1.015
Milton Hydro Distribution	Hamilton	1.015
Peninsula West Utilities	Hamilton	1.015
Hydro One Networks	N/A	1.000
Barrie Hydro Distribution	Barrie	0.991
Innisfil Hydro Distribution Systems	Barrie	0.991
Orillia Power Distribution	Barrie	0.991
Tay Hydro Electric Distribution Company	Barrie	0.991
Wasaga Distribution	Barrie	0.991
Cambridge and North Dumfries Hydro	Kitchener	0.986
Kitchener-Wilmot Hydro	Kitchener	0.986
Waterloo North Hydro	Kitchener	0.986
West Coast Huron Energy	Kitchener	0.986
Bluewater Power Distribution	Sarnia	0.963
Tillsonburg Hydro	Woodstock	0.954
Woodstock Hydro Services	Woodstock	0.954
Centre Wellington Hydro	Guelph	0.949
Guelph Hydro Electric Systems	Guelph	0.949
Parry Sound Power	Barrie/Sudbury	0.946
Kenora Hydro Electric Corporation	Kenora	0.946
Northern Ontario Wires	Timmins	0.935
Clinton Power	London	0.926
Dutton Hydro	London	0.926
Erie Thames Powerlines	London	0.926
London Hydro	London	0.926
Newbury Power	London	0.926
St. Thomas Energy	London	0.926
Chatham-Kent Hydro	Chatham-Kent	0.920
Middlesex Power Distribution	Chatham-Kent	0.920
Lakeland Power Distribution	Barrie/North Bay	0.916
Lakefront Utilities	Cobourg	0.908
Festival Hydro	Stratford	0.904
West Perth Power	Stratford	0.904
Brant County Power	Brantford	0.903
Brantford Power	Brantford	0.903
Haldimand County Hydro	Brantford	0.903
Norfolk Power Distribution	Brantford	0.903

[1]Calculated using 2001 Census data on Average Employment Income by Historical Highest Level of Schooling.
A Tornquist index was used in determining the labour levelization index value.

Table 2, continued

Labour Price Levelizations for Ontario LDCs[1]

LDC	City Mapping	Labour Price Level Index for 2000
Chapleau Public Utilities	Sudbury	0.901
Espanola Regional Hydro Distribution	Sudbury	0.901
Greater Sudbury Hydro	Sudbury	0.901
Hearst Power Distribution Company	Sudbury	0.901
Wellington North Power	Kitchener/Owen Sound	0.900
Rideau St. Lawrence Distribution	Brockville	0.894
Fort Erie (CNP)	St. Catharines-Niagara	0.891
Niagara Falls Hydro	St. Catharines-Niagara	0.891
Niagara-on-the-Lake Hydro	St. Catharines-Niagara	0.891
Port Colborne	St. Catharines-Niagara	0.891
Welland Hydro-Electric System	St. Catharines-Niagara	0.891
Atikokan Hydro Inc.	Thunder Bay	0.890
Fort Frances Power	Thunder Bay	0.890
Sioux Lookout Hydro	Thunder Bay	0.890
Terrace Bay Superior Wires	Thunder Bay	0.890
Thunder Bay Hydro Electricity Distribution	Thunder Bay	0.890
COLLUS Power	Collingwood	0.860
Eastern Ontario Power (CNP)	Kingston	0.859
Kingston Electricity Distribution	Kingston	0.859
Peterborough Distribution	Petersborough	0.853
Midland Power Utility	Midland	0.844
North Bay Hydro Distribution	North Bay	0.840
West Nipissing Energy Services	North Bay	0.840
Great Lakes Power	Sault Ste. Marie	0.838
PUC Distribution	Sault Ste. Marie	0.838
Hydro 2000	Hawkesbury	0.822
Hydro Hawkesbury	Hawkesbury	0.822
Westario Power	Owen Sound	0.814
Ottawa River Power	Pembroke	0.773
Renfrew Hydro	Pembroke	0.773

[1]Calculated using 2001 Census data on Average Employment Income by Historical Highest Level of Schooling.
A Tornquist index was used in determining the labour levelization index value.

the extent of system undergrounding. Undergrounded lines typically involve higher capital costs and lower OM&A expenses. The extent of undergrounding varies greatly across Ontario's distribution systems. Generally speaking, undergrounding is greater in cities and towns and where local governments encourage it. Outside of Ontario's major cities, we have found that the extent of system undergrounding varies considerably and should not be ignored in a benchmarking study. We expect OM&A expenses to be lower the greater is the value of our undergrounding variable. The parameter for this variable should therefore have a negative sign.

A second cost driver that we have identified is a binary variable[24] that indicates if most or all of the company's service territory is located on the Canadian Shield. We developed this variable using a map from an authoritative text on Ontario's geography.[25] The Shield is a physiographic region characterized by shallow, rocky soils and numerous lakes. Since the land receives considerable precipitation but is unsuited for agriculture, rural areas of the Shield are typically forested. We expect OM&A expenses to be higher on the Shield. Accordingly, we expect this variable's parameter estimate to have a positive sign.

In the second phase of the study, we considered several new variables that address capital usage and service quality (SQ) issues. The most successful of these is a measure of system age. Board staff provided us with data on the number of customers served by each utility and any predecessor companies in 1992 and 1997. We estimated the number of customers in the other recent years for which data are lacking by interpolation. The measure of system age is

$$\frac{N_t - N_{10}}{YNDX}$$

where in each year t, N_t is the number of customers served and YNDX is an even-weighted index of the three output quantities.[26] Values for the variable tend to be highest in suburban Toronto and lowest in slow-growing rural areas.[27] A high value for this

[24] A binary variable assumes a value that is either one or zero. In this case, the variable will have a value of one if a company's service territory is on the Canadian Shield.
[25] See L.J. Chapman and D.F. Putnam, *The Physiography of Southern Ontario* (Toronto: University of Toronto Press, 1996).
[26] The output index was used in lieu of the number of customers to reduce multicollinearity.
[27] The value for Toronto Hydro is also low.

variable is indicative of a young system, which affords opportunities for OM&A cost savings. We, accordingly, expect the parameter for this variable to be negatively signed.

A rural forestation variable was also considered for inclusion in the econometric model but failed to pass the significance test. Recall that this variable was included in the double log model in our April study. Average values of the business condition variables for all sampled companies are reported in Table A in the Appendix.

6.4 Functional Forms and Estimation Procedures

We estimated cost models using a variety of functional forms that included the double log and the translog. We found that the data did not support the development of a full translog model. Most troublesome was the tendency of translog models to produce a large number of negative output elasticities.[28] The double-log model, on the other hand, did not help us to recognize additional cost drivers, as it did in the Phase 1 work. This may be due to the fact that the additional year of data available for parameter estimation reduced the need for a simpler functional form. The double-log form also has the disadvantage that it cannot recognize the special cost impacts of unusually large and small operating scales. Faced with these challenges, we found that we could add a full set of quadratic (*i.e.* squared) input price and output terms to the double log model to address the latter problem while maintaining reasonable estimates of the company-specific output elasticities. Three of the four parameter estimates for the quadratic terms were statistically significant. This "quadratic" functional form was, for these reasons, used in the featured model.

With regard to the procedure for estimating model parameters, statistical tests revealed the presence of groupwise heteroskedasticity in the sample. This is a phenomenon, often encountered in cost research, in which the variance of error terms varies by company. We corrected for this problem with a custom, in house procedure using the Gauss estimation software package.

[28] This problem was also encountered in PEG's recent work for the OEB to develop an incentive regulation mechanism for Ontario gas utilities.

6.5 Model Estimation Results

6.5.1 Featured Model

Estimation results for the featured econometric model are presented in Table 3. Working papers for these runs are available on request. Sample mean values of the data for each company can be found in the Appendix.

The parameters for the "first order" terms are the elasticities of the cost of the sample mean firm with respect to the basic variable. These are the terms that do not involve squared values of business condition variables. Estimates of these elasticities are shaded in the table for reader convenience. The tables also report the values of the asymptotic *t* ratios that correspond to each parameter estimate. These were also generated by the estimation program. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed a critical value of 1.645, which is appropriate for a 90% confidence level given a large sample.

All included business conditions were required to have elasticity estimates that were plausible (*e.g.* sensibly signed) and significantly different from zero. All variables found to be statistically significant were included in the final model. Since, additionally, we consider for inclusion only variables that are predicted by theory or that seem relevant on the basis of our industry experience, the model is not a "black box" that confounds attempts at earnest appraisal.

Examining the results, it can be seen that all of the key cost function parameter estimates are plausible in sign and magnitude. Cost was found to be higher the higher were output quantities. At the sample mean, a 1% increase in the number of customers served was estimated to raise OM&A expenses by 0.49%. 1% hikes in the delivery volume and circuit km of distribution line were estimated to raise expenses by 0.37% and 0.09% respectively.

Table 3

Econometric Model of OM&A Expenses

VARIABLE KEY

N= Number Retail Customers
V= Total Volumes
M= Total Kilometers of Line
W= Input Price Index
UN= Percent of Distribution Lines Underground
CG= 10 Year Customer Growth / Output Index
CS= Canadian Shield (binary)

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC[1]	EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC[1]
N	0.491	15.28	**W**	1.399	7.24
NN	-0.115	-6.21	**WW**	-0.372	-0.12
V	0.366	11.37	**UN**	-0.096	-8.08
VV	0.093	5.55			
			CG	-0.106	-13.54
M	0.094	4.83			
MM	0.008	0.92	**CS**	0.011	2.27
MCS	0.005	2.18			
Constant	16.341	862.73			
Trend	-0.002	-0.35			

Other Results

Rbar-Squared	0.983
Sample Period	2002-2006
Number of Observations	410

[1] The critical value for the t statistic is around 1.648 for a 90% confidence level and two-tailed hypothesis tests.

At each level of operating scale, cost theory suggests that economies of scale are available from further output growth if the sum of the cost elasticities of the scale variables is less than one. Our research suggests that incremental (albeit modest) scale economies can still be realized from output growth by most distributors in Ontario. For example, at sample mean values of our three output variables, the sum of the estimated output elasticities is 0.95. Thus, a 1% increase in output is estimated to raise OM&A expenses by 0.95%.

Our research suggests that scale economies generally confer on the larger Ontario utilities a material unit cost advantage over smaller utilities. The potential of each company to realize scale economies should therefore be recognized in responsible benchmarking work.[29]

The parameter estimates for the other business condition variables were also sensible. OM&A expenses were found to be higher the higher were the prices of OM&A inputs, the older was the system (as measured by how few customers were added in the last ten years), if the service territory was located on the Canadian Shield, and the lesser was the extent of line undergrounding.

The model also contains a trend variable. The -0.002 value of its parameter estimate and its low (-0.35) t-statistic suggest that there was essentially no trend in the OM&A expenses of the sampled utilities. The lack of a significant negative estimate for this parameter in a study of OM&A expenses is, in our experience, unusual. We believe that it may reflect the weakening of the incentives for cost containment that occurred when the rate plan/rate freeze under which the distributors recently operated came to an end.

Table 3 also reports the adjusted R^2 statistic for the featured model. This measures the ability of the model to explain variation in the sampled costs of the distributors. Its value was 0.98, suggesting that the explanatory power of the model was high. Please note, however, that a high R^2 statistic is fairly common when cost models are estimated using data from companies with diverse operating scales.

[29] Econometric cost research can also assess the potential OM&A cost savings from mergers. Better estimates of scale economies will be possible as additional years of data become available for use in the econometric sample.

At the technical conference, we were asked by an intervenor to reestimate the econometric cost model using only data for the 2003-2006 period in order to gauge the stability of model results. We performed this task and found that model results and the resultant performance rankings using direct econometric benchmarking are similar to those from the model based on the full sample. We did find a somewhat greater prevalence of negative company-specific elasticities but this is not surprising inasmuch as the multicollinearity in the data that gives rise to this problem needs to be contained by using the largest sample available in parameter estimation.

6.6 Econometric Cost Benchmarking Results

Table 4 presents the results of our appraisals of the OM&A expenses of the sampled distributors using the featured econometric cost model. For each company we report the ratio of the average cost incurred by the company in the last three years for which good data are available to the average of the model's cost projections over the same years. Results pertain to the average of the reported cost over the 2004-2006 period unless data for one or two of these years were unavailable or implausible.

Statistical tests were conducted for each distributor of the hypothesis that it was an average cost performer over the sample period. A 90% confidence level was utilized for these tests. The p-values reported in Table 4 indicate the results of the tests. For any distributor with a favorable appraisal and a p-value between 0 and 0.10, the hypothesis of average performance can be rejected and we may conclude that the company was a *significantly superior* performer. Any distributor with an unfavorable appraisal and a p-value between 0 and 0.10 was, by analogous reasoning, a *significantly inferior* performer.

Eighteen distributors were found to be significantly superior, including three of the larger companies: Hydro One Networks, Hydro One Brampton, and Hydro Ottawa. Fifteen distributors were significantly inferior. The number of significantly superior and inferior utilities would be higher using a lower (*e.g.* 75%) confidence level. The p-values reflect, as they should, how out-of-the-ordinary are the business conditions faced by subject utilities.

The rankings generated by the new cost model are broadly similar to those generated using the model in our previous report. Differences in rankings are apt to

Table 4

Performance Rankings Based on Econometric Benchmarks

	Years Benchmarked	Actual/Predicted[1]	Percentage [A-1][1]	P-Value	Cost surplus (savings) in $[1]	Rank[1]
Hydro Hawkesbury	2004-2006	**0.598**	-0.402	0.000	-470,827	1
Tay Hydro Electric Distribution	2004-2006	**0.632**	-0.368	0.000	-464,009	2
Chatham-Kent Hydro	2004-2006	**0.725**	-0.275	0.003	-1,945,711	3
Cambridge and North Dumfries Hydro	2004-2006	**0.742**	-0.258	0.005	-2,589,805	4
Renfrew Hydro	2004-2006	**0.749**	-0.251	0.006	-260,072	5
Hydro 2000	2004-2006	**0.765**	-0.235	0.010	-65,148	6
Northern Ontario Wires	2004-2006	**0.770**	-0.230	0.012	-512,873	7
Kitchener-Wilmot Hydro	2004-2006	**0.776**	-0.224	0.014	-3,218,542	8
Grimsby Power	2004-2006	**0.778**	-0.222	0.014	-420,832	9
Lakefront Utilities	2004-2006	**0.785**	-0.215	0.018	-443,597	10
Hydro One Brampton Networks	2004-2006	**0.794**	-0.206	0.022	-3,895,857	11
Oshawa PUC Networks	2004-2006	**0.810**	-0.190	0.033	-2,032,863	12
Hydro One Networks	2004-2006	**0.822**	-0.178	0.045	-78,297,965	13
Lakeland Power Distribution	2004-2006	**0.826**	-0.174	0.048	-430,332	14
Hydro Ottawa	2004-2006	**0.833**	-0.167	0.056	-8,162,619	15
Festival Hydro	2004-2006	**0.838**	-0.162	0.062	-654,324	16
Barrie Hydro Distribution	2004-2006	**0.845**	-0.155	0.071	-1,506,001	17
Hearst Power Distribution	2004-2006	**0.847**	-0.153	0.073	-110,682	18
Welland Hydro-Electric System	2004-2006	**0.875**	-0.125	0.122	-552,629	19
Kenora Hydro Electric	2004-2006	**0.885**	-0.115	0.144	-161,218	20
Rideau St. Lawrence Distribution	2004-2006	**0.910**	-0.090	0.206	-128,882	21
Niagara-on-the-Lake Hydro	2004-2006	**0.913**	-0.087	0.214	-142,051	22
Horizon Utilities	2004-2006	**0.915**	-0.085	0.220	-3,255,643	23
Waterloo North Hydro	2004-2006	**0.923**	-0.077	0.242	-729,295	24
Peterborough Distribution	2004-2006	**0.923**	-0.077	0.243	-483,456	25
Orangeville Hydro	2004-2006	**0.923**	-0.077	0.243	-143,643	26
West Nipissing Energy Services	2003,2004,2006	**0.924**	-0.076	0.244	-56,159	27
Halton Hills Hydro	2004-2006	**0.926**	-0.074	0.251	-334,420	28
Atikokan Hydro	2004-2006	**0.929**	-0.071	0.263	-49,682	29
E.L.K. Energy	2002-2004	**0.931**	-0.069	0.267	-131,454	30
Espanola Regional Hydro Distribution	2004-2006	**0.938**	-0.062	0.289	-54,946	31
Newbury Power	2004-2005	**0.940**	-0.060	0.326	-2,868	32
Peninsula West Utilities	2004-2006	**0.956**	-0.044	0.346	-196,411	33
North Bay Hydro Distribution	2004-2006	**0.966**	-0.034	0.380	-183,799	34
Burlington Hydro	2004-2006	**0.984**	-0.016	0.443	-185,699	35
Middlesex Power Distribution	2004-2006	**0.984**	-0.016	0.444	-22,963	36
Innisfil Hydro Distribution Systems	2004-2006	**0.991**	-0.009	0.469	-26,101	37
Tillsonburg Hydro	2002,2006	**0.996**	-0.004	0.488	-5,798	38
Ottawa River Power	2004-2006	**0.997**	-0.003	0.488	-6,667	39
Enersource Hydro Mississauga	2004-2006	**0.998**	-0.002	0.491	-100,205	40
London Hydro	2004-2006	**1.003**	0.003	0.489	70,876	41
PUC Distribution	2004-2006	**1.008**	0.008	0.474	52,651	42
Cooperative Hydro Embrun	2004-2006	**1.009**	0.009	0.468	3,053	43
Milton Hydro Distribution	2004-2006	**1.017**	0.017	0.442	65,737	44
Wellington North Power	2004-2006	**1.017**	0.017	0.441	16,190	45
Terrace Bay Superior Wires	2003-2005	**1.019**	0.019	0.434	5,376	46
Clinton Power	2003,2005,2006	**1.027**	0.027	0.408	10,710	47
Veridian Connections	2004-2006	**1.029**	0.029	0.402	545,928	48
Parry Sound Power	2004-2006	**1.030**	0.030	0.399	28,190	49
Woodstock Hydro Services	2004-2006	**1.032**	0.032	0.391	96,927	50
Haldimand County Hydro	2004-2006	**1.033**	0.033	0.388	172,794	51
Greater Sudbury Hydro	2004-2006	**1.036**	0.036	0.380	319,816	52
Newmarket Hydro	2004-2006	**1.037**	0.037	0.376	180,320	53
Norfolk Power Distribution	2004-2006	**1.048**	0.048	0.341	179,839	54
COLLUS Power	2004-2006	**1.052**	0.052	0.328	138,852	55
Wasaga Distribution	2004-2006	**1.054**	0.054	0.323	80,474	56
Orillia Power Distribution	2004-2006	**1.057**	0.057	0.315	171,210	57
Toronto Hydro-Electric System	2004-2006	**1.057**	0.057	0.314	8,600,504	58
St. Thomas Energy	2004-2006	**1.058**	0.058	0.311	173,770	59
Brantford Power	2004-2006	**1.060**	0.060	0.304	392,575	60
Guelph Hydro Electric Systems	2004-2006	**1.071**	0.071	0.275	578,563	61
Kingston Electricity Distribution	2003-2005	**1.072**	0.072	0.272	379,684	62
Sioux Lookout Hydro	2004-2006	**1.076**	0.076	0.262	70,887	63
West Perth Power	2003-2005	**1.091**	0.091	0.223	40,369	64
Fort Erie (CNP)	2004-2006	**1.092**	0.092	0.222	352,619	65
Powerstream	2004-2006	**1.095**	0.095	0.215	3,441,512	66
Bluewater Power Distribution	2004-2006	**1.097**	0.097	0.210	808,780	67
Grand Valley Energy	2004-2006	**1.110**	0.110	0.182	20,032	68
Oakville Hydro Electricity Distribution	2004-2006	**1.111**	0.111	0.180	1,129,620	69
Fort Frances Power	2004-2006	**1.111**	0.111	0.180	103,831	70
Thunder Bay Hydro Electricity Distribution	2004-2006	**1.121**	0.121	0.159	1,178,525	71
Chapleau Public Utilities	2004-2006	**1.177**	0.177	0.078	75,185	72
Dutton Hydro	2004-2006	**1.181**	0.181	0.074	25,769	73
Eastern Ontario Power (CNP)	2004-2006	**1.182**	0.182	0.073	192,248	74
Westario Power	2003,2004,2006	**1.183**	0.183	0.072	712,095	75
Port Colborne (CNP)	2004-2006	**1.195**	0.195	0.060	502,135	76
ENWIN Powerlines	2004-2005	**1.197**	0.197	0.098	3,623,405	77
Whitby Hydro Electric	2004-2006	**1.202**	0.202	0.055	1,209,064	78
Niagara Falls Hydro	2004-2006	**1.202**	0.202	0.054	1,337,195	79
Midland Power Utility	2004-2006	**1.209**	0.209	0.049	295,650	80
Essex Powerlines	2004-2006	**1.251**	0.251	0.026	1,213,957	81
Centre Wellington Hydro	2004-2006	**1.252**	0.252	0.025	291,458	82
West Coast Huron Energy	2004-2006	**1.309**	0.309	0.010	307,530	83
Erie Thames Powerlines	2004-2006	**1.335**	0.335	0.006	1,067,189	84
Brant County Power	2004-2006	**1.432**	0.432	0.001	964,216	85
Great Lakes Power	2004-2006	**1.544**	0.544	0.000	2,674,315	86

[1] Lower values imply better performance.

reflect the methodological refinements, and may also reflect the update in the benchmark period. Consider, by way of illustration, the change in the results for Powerstream. Its ranking slipped from 37th in the April report (using the double log econometric model) to 66th in the latest report. However, the econometric appraisal changed only modestly from a cost that was 2.6% below the model's projection to a cost 9.5% above the projection. Using both models, the hypothesis that the company was an average cost performer during the benchmark years cannot be rejected. The modest deterioration in the measured performance of Powerstream reflects the following: the introduction of a system age variable (Powerstream has a comparatively young system); the introduction of a negatively signed squared customer term that suggests that there are considerable economies of customer density (Powerstream is a large urban utility); and a somewhat higher elasticity estimate for undergrounding (Powerstream has a lot).

Please note, finally, that HON was not an extreme performance outlier in this benchmarking work. This finding suggests that it may be possible to benchmark HON with reasonable accuracy using Ontario data and econometric methods. This would reduce the need for HON to file additional benchmarking studies, based on other data sources, that are costly to prepare and review.

6.7 Indexing Results

Recall now from Section 2 that summary output quantity indexes can be constructed in which estimates of the elasticity of cost with respect to the measures of the individual workload dimensions serve as weights. We used the new econometric estimates of the cost elasticities under sample mean conditions to calculate output indexes that summarize comparisons of circuit km, retail deliveries, and the number of customers served. Recall that the estimated elasticities were 0.09, 0.37, and 0.49. The corresponding elasticity weights were 9.9%, 38.5%, and 51.6%, respectively. The unit cost metrics that result from this approach, obtained by dividing OM&A cost by the output index, are properly called unit cost indexes.

Unit cost indexes were shown in Section 2 to be benchmarked with peer groups. In Phase 1 of this study we used peer groups chosen by Board Staff. In this second phase of the study we have developed new peer groups that more closely reflect our econometric results. Companies are still grouped on the basis of region, service to a large city, and operating scale. The difference in the new set of peer groups is that there are further groupings to reflect differences between utilities in the degree of undergrounding and, where peers were sufficiently numerous, system age. This practice conforms with our view that peer groups should reflect material differences in business conditions subject to the constraint that they maintain a certain minimum size. The peer groups that result from this application of the econometric results are detailed in Table 5.

Unit cost indexes for the peers are presented in Table 6. For each company, we report the unit cost index for each year of the sample period. These annual values are relative to the mean for the *full* sample. We then report the average of these annual values for the last three years for which data are available. The average of *these* values for each peer group is the benchmark for the group. Please note that since comparisons are made to peer group norms and peer groups involve similar operating scales, we do not consider the further operating efficiency gains that might be achieved by consolidation.

A useful gauge of the correspondence of the peer group results to our econometric work on the drivers of OM&A cost is to compare the average values of the unit cost indexes for the various peer groups. It can be seen that the comparisons are generally quite sensible. Peer groups typically have lower average unit costs to the extent that they involve companies with large operating scale and young systems with extensive undergrounding. For example, the highest average unit cost (1.493) is that for small northern distributors with low undergrounding. The average unit cost is lowest for large urban distributors with high undergrounding.

The recent operating performance of each utility is best assessed using these indexes by taking the ratio of its average index value for the last three years to the average for the corresponding peer group. That is because the peer groups provide important controls for business conditions that are not provided automatically by the indexes themselves. To illustrate this point, consider that the average value of the unit

Table 5

PEG Proposed Peer Groups for Ontario LDCs

Peer Group Designation	Distributor	Customers[1,2,3,4]	% Undergrounding[1,5,6,7,8]	Canadian Shield	Customer Growth/Output Index[1,9]
Small Northern Low Undergrounding	Atikokan Hydro	1,720	0.5%	Yes	-1,346
Small Northern Low Undergrounding	Chapleau Public Utilities	1,316	3.7%	Yes	-2,386
Small Northern Low Undergrounding	Espanola Regional Hydro Distribution	3,331	8.1%	Yes	772
Small Northern Low Undergrounding	Fort Frances Power	3,981	9.5%	Yes	1,151
Small Northern Low Undergrounding	Great Lakes Power	11,491	0.1%	Yes	231
Small Northern Low Undergrounding	Northern Ontario Wires	6,135	1.4%	Yes	-540
Small Northern Low Undergrounding	Parry Sound Power	3,271	8.6%	Yes	357
Small Northern Low Undergrounding	Renfrew Hydro	4,133	3.6%	Yes	477
Small Northern Low Undergrounding	Sioux Lookout Hydro	2,734	2.8%	Yes	41
Small Northern Low Undergrounding	Terrace Bay Superior Wires	926	2.0%	Yes	-101
Small Northern Low Undergrounding	West Nipissing Energy Services	3,108	5.3%	Yes	544
Small Northern Medium Undergrounding	Hearst Power Distribution	2,757	16.2%	Yes	492
Small Northern Medium Undergrounding	Kenora Hydro Electric	5,828	10.2%	Yes	953
Small Northern Medium Undergrounding	Lakeland Power Distribution	9,050	17.2%	Yes	744
Small Northern Medium Undergrounding	Ottawa River Power	10,230	13.0%	Yes	971
Mid-Size Northern	Greater Sudbury Hydro	42,912	20.8%	Yes	-60
Mid-Size Northern	North Bay Hydro Distribution	23,493	15.2%	Yes	355
Mid-Size Northern	PUC Distribution	32,438	15.5%	Yes	237
Mid-Size Northern	Thunder Bay Hydro Electricity Distribution	49,556	33.9%	Yes	550
Large Northern	Hydro One Networks	1,163,961	3.5%	Yes	864
Small Southern Low & Medium Undergrounding	Brant County Power	9,284	11.8%	No	2,334
Small Southern Low & Medium Undergrounding	Clinton Power	1,616	19.0%	No	175
Small Southern Low & Medium Undergrounding	Dutton Hydro	600	14.3%	No	2,678
Small Southern Low & Medium Undergrounding	Eastern Ontario Power	3,552	2.3%	No	338
Small Southern Low & Medium Undergrounding	Grand Valley Energy	678	11.1%	No	1,400
Small Southern Low & Medium Undergrounding	Hydro 2000	1,138	10.0%	No	943
Small Southern Low & Medium Undergrounding	Hydro Hawkesbury	5,286	13.8%	No	1,787
Small Southern Low & Medium Undergrounding	Lakefront Utilities	9,048	16.7%	No	2,170
Small Southern Low & Medium Undergrounding	Port Colborne	9,143	2.6%	No	406
Small Southern Low & Medium Undergrounding	Rideau St. Lawrence Distribution	5,839	10.3%	No	327
Small Southern Low & Medium Undergrounding	Tay Hydro Electric Distribution	4,037	3.9%	No	994
Small Southern Low & Medium Undergrounding	Wellington North Power	3,454	8.6%	No	825
Small Southern Medium-High Undergrounding	Middlesex Power Distribution	6,909	24.0%	No	1,917
Small Southern Medium-High Undergrounding	Midland Power Utility	6,634	31.3%	No	1,520
Small Southern Medium-High Undergrounding	Newbury Power	192	25.0%	No	564
Small Southern Medium-High Undergrounding	Tillsonburg Hydro	6,457	32.5%	No	1,672
Small Southern Medium-High Undergrounding	West Coast Huron Energy	3,811	20.0%	No	944
Small Southern Medium-High Undergrounding	West Perth Power	1,976	20.6%	No	1,525
Small Southern Medium-High Undergrounding with Rapid Growth[10]	Centre Wellington Hydro	6,158	45.0%	No	3,556
Small Southern Medium-High Undergrounding with Rapid Growth	Cooperative Hydro Embrun	1,836	42.9%	No	5,985
Small Southern Medium-High Undergrounding with Rapid Growth	Grimsby Power	9,508	24.3%	No	3,395
Small Southern Medium-High Undergrounding with Rapid Growth	Niagara-on-the-Lake Hydro	7,703	24.6%	No	2,720
Small Southern Medium-High Undergrounding with Rapid Growth	Orangeville Hydro	9,997	41.7%	No	3,678
Mid-size Southern Low & Medium Undergrounding	Fort Erie	15,329	7.1%	No	384
Mid-size Southern Low & Medium Undergrounding	Haldimand County Hydro	20,577	4.6%	No	823
Mid-size Southern Low & Medium Undergrounding	Innisfil Hydro Distribution Systems	13,832	17.6%	No	2,184
Mid-size Southern Low & Medium Undergrounding	Norfolk Power Distribution	18,384	12.3%	No	3,013
Mid-size Southern Low & Medium Undergrounding	Orillia Power Distribution	12,551	18.9%	No	1,181
Mid-size Southern Low & Medium Undergrounding	Peninsula West Utilities	14,276	4.1%	No	142
Mid-size Southern Medium-High Undergrounding	Bluewater Power Distribution	35,510	21.9%	No	778
Mid-size Southern Medium-High Undergrounding	Chatham-Kent Hydro	31,966	27.5%	No	485
Mid-size Southern Medium-High Undergrounding	COLLUS Power	14,300	32.9%	No	2,678
Mid-size Southern Medium-High Undergrounding	E.L.K. Energy	10,626	35.5%	No	3,138
Mid-size Southern Medium-High Undergrounding	Erie Thames Powerlines	13,807	21.3%	No	1,146
Mid-size Southern Medium-High Undergrounding	Essex Powerlines	27,636	49.6%	No	3,194
Mid-size Southern Medium-High Undergrounding	Festival Hydro	19,025	32.8%	No	1,499
Mid-size Southern Medium-High Undergrounding	Kingston Electricity Distribution	26,525	30.5%	No	-22
Mid-size Southern Medium-High Undergrounding	Niagara Falls Hydro	33,234	42.3%	No	690
Mid-size Southern Medium-High Undergrounding	Peterborough Distribution	33,866	29.5%	No	1,319
Mid-size Southern Medium-High Undergrounding	St. Thomas Energy	15,597	30.5%	No	2,430
Mid-size Southern Medium-High Undergrounding	Wasaga Distribution	10,902	45.3%	No	6,249
Mid-size Southern Medium-High Undergrounding	Welland Hydro-Electric System	21,295	24.1%	No	820
Mid-size Southern Medium-High Undergrounding	Westario Power	20,983	28.9%	No	999
Mid-size Southern Medium-High Undergrounding	Woodstock Hydro Services	14,316	40.4%	No	1,640
Large City Southern Medium-High Undergrounding	ENWIN Powerlines	84,701	38.5%	No	1,659
Large City Southern Medium-High Undergrounding	Hydro Ottawa	282,393	36.7%	No	2,558
Large City Southern Medium-High Undergrounding	Toronto Hydro-Electric System	678,106	45.5%	No	454
Large City Southern Medium-High Undergrounding	Veridian Connections	107,231	31.9%	No	2,755
Large City Southern High Undergrounding	Enersource Hydro Mississauga	182,596	65.5%	No	2,631
Large City Southern High Undergrounding	Horizon Utilities	231,499	53.3%	No	1,384
Large City Southern High Undergrounding	Hydro One Brampton Networks	120,364	69.8%	No	5,500
Large City Southern High Undergrounding	London Hydro	140,007	51.0%	No	2,160
Large City Southern High Undergrounding	PowerStream	228,471	69.0%	No	4,436
Mid-size GTA Medium-High & High Undergrounding	Barrie Hydro Distribution	67,523	54.6%	No	5,169
Mid-size GTA Medium-High & High Undergrounding	Brantford Power	36,569	43.6%	No	2,058
Mid-size GTA Medium-High & High Undergrounding	Burlington Hydro	60,749	40.8%	No	3,102
Mid-size GTA Medium-High & High Undergrounding	Cambridge and North Dumfries Hydro	48,619	33.6%	No	2,764
Mid-size GTA Medium-High & High Undergrounding	Guelph Hydro Electric Systems	46,276	57.6%	No	3,087
Mid-size GTA Medium-High & High Undergrounding	Halton Hills Hydro	19,007	34.2%	No	2,226
Mid-size GTA Medium-High & High Undergrounding	Kitchener-Wilmot Hydro	80,940	42.0%	No	2,539
Mid-size GTA Medium-High & High Undergrounding	Milton Hydro Distribution	20,975	33.0%	No	5,487
Mid-size GTA Medium-High & High Undergrounding	Newmarket Hydro	26,647	63.5%	No	3,188
Mid-size GTA Medium-High & High Undergrounding	Oakville Hydro Electricity Distribution	58,220	60.6%	No	3,949
Mid-size GTA Medium-High & High Undergrounding	Oshawa PUC Networks	50,528	46.1%	No	1,580
Mid-size GTA Medium-High & High Undergrounding	Waterloo North Hydro	48,777	30.0%	No	3,000
Mid-size GTA Medium-High & High Undergrounding	Whitby Hydro Electric	37,473	52.2%	No	5,383

[1]Latest year of available data.
[2]Small is defined as less than 10,000 customers with the exception of Great Lakes Power and Ottawa River Power, who have more than 10,000 customers but are defined as "small."
[3]Mid-size is defined as between 10,000 and 82,000 customers.
[4]Large is defined as more than 82,000 customers.
[5]Low undergrounding is defined as 0% to 10%.
[6]Medium undergrounding is between 10% and 20%.
[7]Medium-high undergrounding is between 20% and 50%.
[8]High undergrounding is over 50%.
[9]Rapid growth is defined as a value for (Customer Growth/Output Index) that exceeds 2,000.
[10] Centre Wellington is in the GTA but no GTA peer group is appropriate.

Table 6

Unit OM&A Cost Indexes

	Average OM&A cost[1]	2002	2003	2004	2005	2006	Average of Last 3 Available Years[2]	Average / Group Average[2] [A]	Percentage Differences[2] [A - 1]	Implied Cost Surplus (Savings) per year[2]
Small Northern Low Undergrounding										
Renfrew Hydro	$780,551	0.940	1.006	0.932	0.822	1.038	0.931	**0.623**	-37.7%	-$293,912
West Nipissing Energy Services	$683,961	1.253	1.181	1.357	NA	1.011	1.184	**0.793**	-20.7%	-$141,280
Espanola Regional Hydro Distribution	$841,891	1.369	1.138	1.061	1.123	1.450	1.211	**0.811**	-18.9%	-$158,762
Northern Ontario Wires	$1,718,619	1.336	1.192	1.317	1.155	1.233	1.235	**0.827**	-17.3%	-$296,790
Parry Sound Power	$972,011	0.999	1.201	1.210	1.275	1.329	1.272	**0.852**	-14.8%	-$143,948
Fort Frances Power	$1,040,855	1.196	1.210	1.230	1.302	1.341	1.291	**0.865**	-13.5%	-$140,649
Sioux Lookout Hydro	$1,005,189	1.084	0.876	1.255	1.356	1.386	1.333	**0.893**	-10.7%	-$107,847
Terrace Bay Superior Wires	$285,360	1.649	1.487	1.396	1.651	NA	1.511	**1.013**	1.3%	$3,595
Atikokan Hydro	$654,815	1.430	2.672	1.703	1.591	1.594	1.629	**1.092**	9.2%	$59,987
Chapleau Public Utilities	$500,439	1.635	1.696	1.730	1.912	1.834	1.825	**1.223**	22.3%	$111,484
Great Lakes Power	$7,595,440	2.644	2.693	2.843	3.029	3.120	2.997	**2.008**	100.8%	$7,655,513
GROUP AVERAGE							**1.493**			
Small Northern Medium Undergrounding										
Hearst Power Distribution	$610,806	0.666	0.642	0.804	0.788	0.870	0.821	**0.837**	-16.3%	-$99,539
Lakeland Power Distribution	$2,045,570	1.047	1.261	0.880	0.884	1.052	0.939	**0.958**	-4.2%	-$86,503
Ottawa River Power	$1,983,425	0.940	1.050	1.026	0.993	1.071	1.030	**1.050**	5.0%	$99,852
Kenora Hydro Electric	$1,242,833	1.092	1.114	1.147	1.108	1.142	1.132	**1.155**	15.5%	$192,524
GROUP AVERAGE							**0.980**			
Mid-Size Northern										
North Bay Hydro Distribution	$5,190,890	1.137	1.014	1.000	0.887	1.150	1.013	**0.965**	-3.5%	-$183,646
PUC Distribution	$7,019,446	0.867	0.939	1.072	1.047	1.026	1.048	**0.998**	-0.2%	-$10,789
Thunder Bay Hydro Electricity Distribution	$10,901,716	1.077	1.168	1.120	1.007	1.059	1.062	**1.012**	1.2%	$126,947
Greater Sudbury Hydro	$9,265,623	1.014	0.983	1.108	1.048	1.072	1.076	**1.025**	2.5%	$234,150
GROUP AVERAGE							**1.050**			
Large Northern										
Hydro One Networks	$363,882,976	NA	1.045	1.003	1.076	1.238	1.106	**NA**	NA	NA
GROUP AVERAGE							**1.106**			
Small Southern Low & Medium Undergrounding										
Hydro Hawkesbury	$702,151	0.528	0.553	0.506	0.604	0.571	0.560	**0.431**	-56.9%	-$399,332
Lakefront Utilities	$1,633,636	0.705	0.626	0.717	0.853	0.919	0.830	**0.639**	-36.1%	-$590,257
Hydro 2000	$217,056	0.576	0.655	0.655	1.178	0.939	0.924	**0.711**	-28.9%	-$62,655
Tay Hydro Electric Distribution	$799,516	0.878	1.003	1.112	1.255	0.975	1.114	**0.857**	-14.3%	-$114,026
Rideau St. Lawrence Distribution	$1,303,605	1.040	1.074	1.070	1.171	1.203	1.148	**0.884**	-11.6%	-$151,637
Wellington North Power	$946,920	1.177	1.073	1.122	1.171	1.237	1.177	**0.906**	-9.4%	-$89,080
Clinton Power	$411,816	1.250	1.308	NA	1.230	1.604	1.381	**1.063**	6.3%	$25,864
Brant County Power	$3,201,409	1.256	1.421	1.483	1.484	1.625	1.531	**1.178**	17.8%	$570,779
Eastern Ontario Power	$1,262,279	NA	1.673	1.280	1.541	1.885	1.569	**1.207**	20.7%	$261,744
Port Colborne	$3,306,745	0.753	0.843	0.920	2.106	2.118	1.715	**1.320**	32.0%	$1,057,653
Dutton Hydro	$171,512	1.280	1.397	2.281	1.574	1.494	1.783	**1.372**	37.2%	$63,871
Grand Valley Energy	$204,786	1.578	1.433	1.565	1.785	2.227	1.859	**1.431**	43.1%	$88,266
GROUP AVERAGE							**1.299**			
Small Southern Medium-High Undergrounding										
Tillsonburg Hydro	$1,420,170	0.827	NA	NA	NA	1.002	0.914	**0.832**	-16.8%	-$238,247
Middlesex Power Distribution	$1,417,372	0.976	1.117	0.914	1.091	0.933	0.979	**0.891**	-10.9%	-$153,873
West Perth Power	$485,790	NA	1.183	1.087	0.921	NA	1.064	**0.969**	-3.1%	-$15,276
Midland Power Utility	$1,713,289	1.158	1.124	1.101	1.023	1.139	1.088	**0.990**	-1.0%	-$16,739
Newbury Power	$44,795	NA	NA	1.311	1.034	NA	1.172	**1.067**	6.7%	$3,011
West Coast Huron Energy	$1,312,138	1.181	1.188	1.163	1.461	1.497	1.373	**1.250**	25.0%	$328,442
GROUP AVERAGE							**1.098**			
Small Southern Medium-High Undergrounding with Rapid Growth										
Grimsby Power	$1,472,950	0.717	0.727	0.798	0.837	0.818	0.818	**0.872**	-12.8%	-$189,010
Orangeville Hydro	$1,730,304	0.853	0.912	0.845	0.858	0.843	0.849	**0.905**	-9.5%	-$164,541
Niagara-on-the-Lake Hydro	$1,489,190	0.874	0.817	0.899	0.826	0.913	0.879	**0.937**	-6.3%	-$93,189
Cooperative Hydro Embrun	$336,010	0.964	1.040	0.933	1.100	1.112	1.048	**1.118**	11.8%	$39,520
Centre Wellington Hydro	$1,448,570	1.214	1.156	1.093	1.090	1.104	1.096	**1.168**	16.8%	$243,902
GROUP AVERAGE							**0.938**			
Mid-Size Southern Low & Medium Undergrounding										
Norfolk Power Distribution	$3,932,280	1.130	1.094	1.030	1.016	1.008	1.018	**0.868**	-13.2%	-$518,353
Innisfil Hydro Distribution Systems	$2,944,339	0.985	1.153	1.201	1.009	1.078	1.096	**0.935**	-6.5%	-$191,541
Orillia Power Distribution	$3,195,143	0.947	1.053	1.086	1.216	1.186	1.163	**0.992**	-0.8%	-$25,835
Peninsula West Utilities	$4,236,906	1.050	1.090	1.140	1.247	1.174	1.187	**1.013**	1.3%	$52,984
Haldimand County Hydro	$5,398,162	1.167	1.105	1.192	1.189	1.269	1.217	**1.038**	3.8%	$205,059
Fort Erie	$4,203,959	1.403	1.252	1.266	1.324	1.471	1.353	**1.154**	15.4%	$649,376
GROUP AVERAGE							**1.172**			

1 Last three years of available data.
2 Lower values imply better performance.

Table 6, continued

Unit OM&A Cost Indexes

	Average OM&A cost[1]	2002	2003	2004	2005	2006	Average of Last 3 Available Years[2]	Average / Group Average[2] [A]	Percentage Differences[2] [A - 1]	Implied Cost Surplus (Savings) per year[2]
Mid-Size Southern Medium-High Undergrounding										
Chatham-Kent Hydro	$5,142,308	0.682	0.676	0.712	0.703	0.712	0.709	**0.720**	-28.0%	-$1,441,214
Festival Hydro	$3,382,003	0.793	0.745	0.761	0.734	0.820	0.772	**0.784**	-21.6%	-$732,185
Peterborough Distribution	$5,818,420	0.810	0.754	0.815	0.793	0.900	0.836	**0.849**	-15.1%	-$878,680
Welland Hydro-Electric System	$3,879,904	0.825	0.912	0.988	0.849	0.791	0.876	**0.890**	-11.0%	-$428,111
COLLUS Power	$2,801,949	0.849	0.812	0.858	0.854	1.027	0.913	**0.927**	-7.3%	-$203,343
E.L.K. Energy	$1,788,169	0.960	1.013	0.859	NA	NA	0.944	**0.959**	-4.1%	-$74,146
Woodstock Hydro Services	$3,087,875	0.857	0.928	0.951	0.962	0.997	0.970	**0.985**	-1.5%	-$46,250
Wasaga Distribution	$1,572,540	0.790	0.836	0.908	1.002	1.071	0.994	**1.009**	0.9%	$14,377
St. Thomas Energy	$3,169,519	0.800	0.835	0.901	0.983	1.117	1.000	**1.016**	1.6%	$50,296
Kingston Electricity Distribution	$5,666,409	0.945	1.039	1.028	0.951	NA	1.006	**1.022**	2.2%	$123,388
Niagara Falls Hydro	$7,945,520	0.992	1.021	1.021	1.078	1.107	1.069	**1.085**	8.5%	$676,755
Westario Power	$4,615,081	0.991	1.142	1.160	NA	1.004	1.102	**1.119**	11.9%	$549,880
Bluewater Power Distribution	$9,176,340	1.004	1.082	1.049	1.068	1.201	1.106	**1.123**	12.3%	$1,129,658
Essex Powerlines	$6,057,329	1.061	0.959	1.067	1.185	1.163	1.138	**1.156**	15.6%	$943,610
Erie Thames Powerlines	$4,255,980	1.080	1.275	1.318	1.374	1.318	1.336	**1.357**	35.7%	$1,519,969
GROUP AVERAGE							**0.985**			
Large City Southern Medium-High Undergrounding										
Hydro Ottawa	$40,973,904	0.862	0.781	0.657	0.609	0.738	0.668	**0.733**	-26.7%	-$10,943,087
Veridian Connections	$19,517,364	0.971	1.141	0.943	0.841	0.886	0.890	**0.976**	-2.4%	-$458,970
Toronto Hydro-Electric System	$158,946,624	0.886	0.919	0.949	0.893	0.887	0.910	**0.998**	-0.2%	-$267,171
ENWIN Powerlines	$22,496,714	1.344	1.226	1.230	1.127	1.176	1.178	**1.292**	29.2%	$6,575,146
GROUP AVERAGE							**0.911**			
Large City Southern High Undergrounding										
Hydro One Brampton Networks	$15,003,912	0.597	0.582	0.534	0.532	0.578	0.548	**0.754**	-24.6%	-$3,697,545
Horizon Utilities	$35,303,064	0.659	0.776	0.699	0.826	0.729	0.751	**1.034**	3.4%	$1,182,831
London Hydro	$22,064,690	0.750	0.736	0.729	0.733	0.802	0.755	**1.038**	3.8%	$843,159
PowerStream	$39,783,600	0.650	0.741	0.768	0.791	0.718	0.759	**1.044**	4.4%	$1,736,186
Enersource Hydro Mississauga	$40,596,044	0.755	0.756	0.786	0.819	0.862	0.822	**1.131**	13.1%	$5,321,326
GROUP AVERAGE							**0.727**			
Mid-Size GTA Medium-High Undergrounding										
Barrie Hydro Distribution	$8,198,603	0.609	0.741	0.649	0.548	0.605	0.601	**0.750**	-25.0%	-$2,047,843
Cambridge and North Dumfries Hydro	$7,461,787	0.648	0.638	0.692	0.627	0.617	0.645	**0.806**	-19.4%	-$1,447,940
Kitchener-Wilmot Hydro	$11,147,972	0.609	0.624	0.620	0.635	0.695	0.650	**0.812**	-18.8%	-$2,099,182
Guelph Hydro Electric Systems	$8,746,005	0.768	0.857	0.804	0.765	0.771	0.780	**0.974**	-2.6%	-$227,516
Waterloo North Hydro	$8,712,183	0.847	0.819	0.821	0.775	0.794	0.796	**0.995**	-0.5%	-$45,924
Oshawa PUC Networks	$8,730,236	0.911	0.985	0.969	0.714	0.727	0.803	**1.004**	0.4%	$31,002
Milton Hydro Distribution	$3,976,535	0.882	0.833	0.811	0.820	0.801	0.811	**1.013**	1.3%	$50,147
Burlington Hydro	$11,296,827	0.754	0.787	0.812	0.800	0.872	0.828	**1.034**	3.4%	$387,839
Newmarket Hydro	$5,067,834	0.856	0.962	0.917	0.832	0.862	0.870	**1.087**	8.7%	$440,689
Oakville Hydro Electricity Distribution	$11,341,493	0.813	0.902	0.901	0.850	0.915	0.889	**1.110**	11.0%	$1,246,416
Halton Hills Hydro	$4,183,650	0.967	0.873	0.894	0.829	0.991	0.904	**1.130**	13.0%	$542,725
Brantford Power	$6,903,747	0.782	0.893	0.955	0.932	0.828	0.905	**1.130**	13.0%	$900,304
Whitby Hydro Electric	$7,208,252	0.928	0.999	0.895	0.918	0.964	0.925	**1.156**	15.6%	$1,123,983
GROUP AVERAGE							**0.801**			
AVERAGE: ALL COMPANIES	**NA**	**0.989**	**1.039**	**1.040**	**1.061**	**1.104**	**1.070**	**1.000**	**0.000**	**NA**

[1] Last three years of available data.
[2] Lower values imply better performance.

cost index of Northern Ontario Wires was about 23.5% above the full sample norm. This result does not control, however, for the special cost challenges that the company faces. To assess its performance, we must take the ratio of its average unit cost index value to that of the small northern LDC peer group, which is 49.3% above the full sample norm. We obtain the number 1.235/1.493= 0.83. The unit cost of Northern Ontario Wires was thus well below the peer group benchmark. Given typical OM&A expenses of around $1.7 million annually, this implies cost savings for the company on the order of $297,000.

6.8 Comparing Performance Rankings

In Table 7 we provide overall rankings for the companies that are based on the peer group unit cost benchmarks.[30] These rankings are comparable to those that result from the econometric models. Inspecting the results, it can be seen that the rankings from the indexing and econometric work are broadly similar. For example, Hydro Ottawa has a good performance ranking using both methods.

The degree of similarity between rankings like these can be estimated statistically using Spearman rank correlation coefficients. A Spearman rank correlation coefficient provides the direction and extent of the relationship between two rank ordering variables. In the present application, it allows us to compute the degree of similarity with which two benchmarking methods rank the efficiency of a set of firms. The coefficient for the two rankings is 0.74. This supports the notion that the rankings are similar but involve important differences. The results differ considerably for some companies. In these cases, we believe that the results from direct econometric benchmarking are generally more accurate.

6.9 Capital Quantity Index and Service Quality

6.9.1 Capital Quantity Index

We turn, next, to attempts to refine our benchmarking methods that did not pan out as well statistically. We developed a capital quantity index (*XK*) for each distributor

[30] Hydro One Networks is excluded from this ranking because it has no peer group.

Table 7

Performance Rankings Based on Unit Cost Indexes

	Average / Group Average[1] [A]	**Percentage Differences[1]** [A - 1]	**Implied Cost Surplus (Savings) per year[1]**	**Efficiency Ranking[1]**
Hydro Hawkesbury	**0.431**	-56.9%	-$399,332	1
Renfrew Hydro	**0.623**	-37.7%	-$293,912	2
Lakefront Utilities	**0.639**	-36.1%	-$590,257	3
Hydro 2000	**0.711**	-28.9%	-$62,655	4
Chatham-Kent Hydro	**0.720**	-28.0%	-$1,441,214	5
Hydro Ottawa	**0.733**	-26.7%	-$10,943,087	6
Barrie Hydro Distribution	**0.750**	-25.0%	-$2,047,843	7
Hydro One Brampton Networks	**0.754**	-24.6%	-$3,697,545	8
Festival Hydro	**0.784**	-21.6%	-$732,185	9
West Nipissing Energy Services	**0.793**	-20.7%	-$141,280	10
Cambridge and North Dumfries Hydro	**0.806**	-19.4%	-$1,447,940	11
Espanola Regional Hydro Distribution	**0.811**	-18.9%	-$158,762	12
Kitchener-Wilmot Hydro	**0.812**	-18.8%	-$2,099,182	13
Northern Ontario Wires	**0.827**	-17.3%	-$296,790	14
Tillsonburg Hydro	**0.832**	-16.8%	-$238,247	15
Hearst Power Distribution	**0.837**	-16.3%	-$99,539	16
Peterborough Distribution	**0.849**	-15.1%	-$878,680	17
Parry Sound Power	**0.852**	-14.8%	-$143,948	18
Tay Hydro Electric Distribution	**0.857**	-14.3%	-$114,026	19
Fort Frances Power	**0.865**	-13.5%	-$140,649	20
Norfolk Power Distribution	**0.868**	-13.2%	-$518,353	21
Grimsby Power	**0.872**	-12.8%	-$189,010	22
Rideau St. Lawrence Distribution	**0.884**	-11.6%	-$151,637	23
Welland Hydro-Electric System	**0.890**	-11.0%	-$428,111	24
Middlesex Power Distribution	**0.891**	-10.9%	-$153,873	25
Sioux Lookout Hydro	**0.893**	-10.7%	-$107,847	26
Orangeville Hydro	**0.905**	-9.5%	-$164,541	27
Wellington North Power	**0.906**	-9.4%	-$89,080	28
COLLUS Power	**0.927**	-7.3%	-$203,343	29
Innisfil Hydro Distribution Systems	**0.935**	-6.5%	-$191,541	30
Niagara-on-the-Lake Hydro	**0.937**	-6.3%	-$93,189	31
Lakeland Power Distribution	**0.958**	-4.2%	-$86,503	32
E.L.K. Energy	**0.959**	-4.1%	-$74,146	33
North Bay Hydro Distribution	**0.965**	-3.5%	-$183,646	34
West Perth Power	**0.969**	-3.1%	-$15,276	35
Guelph Hydro Electric Systems	**0.974**	-2.6%	-$227,516	36
Veridian Connections	**0.976**	-2.4%	-$458,970	37
Woodstock Hydro Services	**0.985**	-1.5%	-$46,250	38
Midland Power Utility	**0.990**	-1.0%	-$16,739	39
Orillia Power Distribution	**0.992**	-0.8%	-$25,835	40
Waterloo North Hydro	**0.995**	-0.5%	-$45,924	41
Toronto Hydro-Electric System	**0.998**	-0.2%	-$267,171	42
PUC Distribution	**0.998**	-0.2%	-$10,789	43
Oshawa PUC Networks	**1.004**	0.4%	$31,002	44
Wasaga Distribution	**1.009**	0.9%	$14,377	45
Thunder Bay Hydro Electricity Distribution	**1.012**	1.2%	$126,947	46
Peninsula West Utilities	**1.013**	1.3%	$52,984	47
Terrace Bay Superior Wires	**1.013**	1.3%	$3,595	48
Milton Hydro Distribution	**1.013**	1.3%	$50,147	49
St. Thomas Energy	**1.016**	1.6%	$50,296	50
Kingston Electricity Distribution	**1.022**	2.2%	$123,388	51
Greater Sudbury Hydro	**1.025**	2.5%	$234,150	52
Horizon Utilities	**1.034**	3.4%	$1,182,831	53
Burlington Hydro	**1.034**	3.4%	$387,839	54

[1] Lower values imply better performance.

[2] Hydro One Networks has no peer group and is not included in this analysis.

Table 7, continued

Performance Rankings Based on Unit Cost Indexes

	Average / Group Average[1] [A]	Percentage Differences[1] [A - 1]	Implied Cost Surplus (Savings) per year[1]	Efficiency Ranking[1]
Haldimand County Hydro	**1.038**	3.8%	$205,059	55
London Hydro	**1.038**	3.8%	$843,159	56
PowerStream	**1.044**	4.4%	$1,736,186	57
Ottawa River Power	**1.050**	5.0%	$99,852	58
Clinton Power	**1.063**	6.3%	$25,864	59
Newbury Power	**1.067**	6.7%	$3,011	60
Niagara Falls Hydro	**1.085**	8.5%	$676,755	61
Newmarket Hydro	**1.087**	8.7%	$440,689	62
Atikokan Hydro	**1.092**	9.2%	$59,987	63
Oakville Hydro Electricity Distribution	**1.110**	11.0%	$1,246,416	64
Cooperative Hydro Embrun	**1.118**	11.8%	$39,520	65
Westario Power	**1.119**	11.9%	$549,880	66
Bluewater Power Distribution	**1.123**	12.3%	$1,129,658	67
Halton Hills Hydro	**1.130**	13.0%	$542,725	68
Brantford Power	**1.130**	13.0%	$900,304	69
Enersource Hydro Mississauga	**1.131**	13.1%	$5,321,326	70
Fort Erie	**1.154**	15.4%	$649,376	71
Kenora Hydro Electric	**1.155**	15.5%	$192,524	72
Essex Powerlines	**1.156**	15.6%	$943,610	73
Whitby Hydro Electric	**1.156**	15.6%	$1,123,983	74
Centre Wellington Hydro	**1.168**	16.8%	$243,902	75
Brant County Power	**1.178**	17.8%	$570,779	76
Eastern Ontario Power	**1.207**	20.7%	$261,744	77
Chapleau Public Utilities	**1.223**	22.3%	$111,484	78
West Coast Huron Energy	**1.250**	25.0%	$328,442	79
ENWIN Powerlines	**1.292**	29.2%	$6,575,146	80
Port Colborne	**1.320**	32.0%	$1,057,653	81
Erie Thames Powerlines	**1.357**	35.7%	$1,519,969	82
Dutton Hydro	**1.372**	37.2%	$63,871	83
Grand Valley Energy	**1.431**	43.1%	$88,266	84
Great Lakes Power	**2.008**	100.8%	$7,655,513	85

[1] Lower values imply better performance.

[2] Hydro One Networks has no peer group and is not included in this analysis.

using an estimate of its capital quantity at year end 2002 and its reported plant additions for 2003-2006. Our estimate of the 2002 capital quantity was the ratio of net plant value (reported gross plant value less reported accumulated depreciation) to a construction cost index. This index was a weighted average of values of a Statistics Canada construction cost index for the prior 40 years. The weighting reflected estimates of plant additions in these years and two assumptions: depreciation is of straight line character and the average service life of assets is 40 years. The estimates of plant additions made use of our estimates of the number of customers served by each utility in prior years.[31] We developed a simple econometric model of the relationship between plant additions and the number of customers served and customers added. We adjusted the average plant additions for the 2003-2006 period to apply to each earlier year by taking the ratio of the model's prediction for each such year to the model's predictions for 2003-2006.

Econometric results using the capital quantity index were only modestly encouraging. The estimate of the cost model parameter for the index was not consistently negative and statistically significant in the models considered.[32] When the capital quantity index and the system age variable both appeared in a cost model only the system age variable had a significant and plausibly signed parameter estimate. These results suggest that it is preferable to use the system age variable in the model at the present time. Better results for the capital quantity index may be obtained in the future by estimating models with additional years of data and by improving the capital quantity index (and simplifying its calculation) by gathering more data on pre-2002 customers served or (preferably) on net plant value and plant additions to use in the index formula. These additional data would also improve the prospects for accurate capital cost benchmarking.

6.9.2 Reliability

Several challenges are encountered in integrating consideration of reliability in the benchmarking work. One is that the available reliability measures are sensitive to

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[31] Recall that these customer estimates are also used to construct the system age variable.
[32] Results were generally better when we used the ratio of the capital quantity index to the output quantity index as the capital usage variable.

major external events such as upstream outages. Board Staff will not begin to gather data that permit the removal of outages related to such events until April of this year.

A second challenge is that the reliability measures are not entirely *external* business conditions since their values are to some degree subject to management control. Econometric theory suggests that special multistage parameter estimation procedures should be used in this situation. In the first stage, we regressed each reliability measure considered on an array of business condition variables (*e.g.* undergrounding). In the second stage, we used the reliability values predicted by the first stage models as reliability variables in cost model regressions.

A third challenge encountered in such an exercise is that good reliability data are not available for about a quarter of the distributors in the sample. The incorporation of reliability in the benchmarking exercise would thus exclude many companies at the present time. It would also reduce substantially the data available for parameter estimation, thereby reducing the accuracy of cost model parameter estimates.

Research using the available data and our two stage estimation procedure revealed that cost model parameter estimates variables were consistently sensible (*e.g.* negatively signed) and significant only for the SAIDI variable.[33] Estimates of first stage (reliability) model parameters were not always sensible, and different first stage models materially influenced the cost performance rankings from the second stage models. The range of measured cost performance was, disconcertingly, often much greater than the range produced by our featured cost model. The explanatory power of the first stage models was much lower than that for our cost models. Cost performance rankings for some companies were sensitive to the quality metric used.

We conclude from this exercise that while initial results have some promise it is not currently advisable to incorporate service quality into the distribution cost benchmarking work. Incorporation may be possible in the future if reforms are made in the instructions for and monitoring of service quality data so that more companies can be included in the analysis. Additional years of data for the estimation of the cost and quality models would also be helpful.

[33] Results were marginally significant for the CAIDI variable and many improve with better data.

We should also note that the some of the results from the first stage econometric models for the reliability variables were sensible. In the research using SAIDI as the dependent variable, for instance, we found that SAIDI was generally higher (suggesting low reliability) for companies that had more rural and less undergrounded systems and used less capital. Models of this kind could eventually be used to benchmark distributor reliability via either peer group selection or direct econometric benchmarking.

6.10 The Board Staff Methodology

Our review of benchmarking methods in Section 2, combined with the empirical results just presented, provide us with a solid foundation for appraising the benchmarking method developed by Board staff. In this section we first explain the suggested method. Our appraisal immediately follows.

6.10.1 Staff's Methodology

Board Staff detailed an illustrative methodology in its November 2006 notice. It featured the calculation of an array of simple unit cost metrics based on publicly available data. Each metric was the ratio of a certain cost to a certain cost driver. The cost "centers" considered were:

Total OM&A Expenses

Distribution Expenses

Customer Care, Administrative and General Expenses

Depreciation and Amortization Expenses

All of the cost data were drawn from Trial Balance filings. Customer care and A&G expenses were grouped together because some distributors reportedly include administrative customer service costs in A&G expenses. The expense data used in the benchmarking excluded bad debt expenses to reduce anomalies.

Four cost drivers were considered:

- Total number of customers served
- Total Retail Delivery Volume (MWh)
- Total circuit km of line
- Total Service Area (km^2)

The data for all of these quantities were drawn from PBR filings.

For the April 2007 report, Staff settled upon a single unit cost center (a broad aggregate of OM&A expenses) and a single cost driver (number of customers). The result was a single unit cost metric: OM&A expenses per customer.

For comparison purposes, Staff divided the sampled companies into the following 7 groupings based on company size and region served:

- Small Northern (*e.g.* Atikokan Hydro)
- Large Northern (*e.g.* Greater Sudbury Hydro)
- Southwestern – Smaller Towns (*e.g.* Brant County Power)
- Southwestern – Midsized Towns (*e.g.* Chatham-Kent Hydro)
- Eastern (*e.g.* Peterborough Distribution)
- GTA Towns (*e.g.* Kitchener-Wilmot Hydro)
- Large City Southern (*e.g.* Toronto Hydro-Electric System)

Staff now proposes to use the latest peer groups devised by PEG.

Tables 8 and 9 present the results that would be obtained under this approach. As in Table 6, the average unit costs for each peer group are the benchmarks for the group. The performances measured by taking the ratio of each company's unit cost to the peer group average are ranked in Table 9.

The Spearman rank correlation coefficient between the rankings from Staff's unit cost metric and the rankings from PEG's unit cost index is 0.83. The rank correlation coefficient between the rankings from Staff's unit cost values and the rankings from PEG's econometric benchmarking exercise is 0.70. These results suggest that some accuracy is lost in using Staff's simpler benchmarking method.

6.10.2 Appraisal

We feel that Staff's illustrative approach to benchmarking has considerable merit if a methodological upgrade is made that takes account of the results of our research for the Board. The new peer groups go a considerable way towards controlling for differences between utilities in input prices, operating scale, and undergrounding. The

Table 8

Staff Proposed Metrics Sorted by PEG Peer Groups

Peer Group Designation	Distributor	Total OM&A Per Customer ($)[1]	Group Average ($)	Average/Group Average	Percentage Differences
Small Northern Low Undergrounding	West Nipissing Energy Services	168		**0.525**	-47.5%
Small Northern Low Undergrounding	Renfrew Hydro	190		**0.593**	-40.7%
Small Northern Low Undergrounding	Espanola Regional Hydro Distribution	254		**0.791**	-20.9%
Small Northern Low Undergrounding	Fort Frances Power	259		**0.806**	-19.4%
Small Northern Low Undergrounding	Northern Ontario Wires	278		**0.865**	-13.5%
Small Northern Low Undergrounding	Parry Sound Power	299		**0.930**	-7.0%
Small Northern Low Undergrounding	Terrace Bay Superior Wires	307		**0.955**	-4.5%
Small Northern Low Undergrounding	Sioux Lookout Hydro	366		**1.140**	14.0%
Small Northern Low Undergrounding	Chapleau Public Utilities	374		**1.164**	16.4%
Small Northern Low Undergrounding	Atikokan Hydro	376		**1.170**	17.0%
Small Northern Low Undergrounding	Great Lakes Power	662	**321**	**2.063**	106.3%
Small Northern Medium Undergrounding	Ottawa River Power	195		**0.912**	-8.8%
Small Northern Medium Undergrounding	Kenora Hydro Electric	213		**0.996**	-0.4%
Small Northern Medium Undergrounding	Hearst Power Distribution	220		**1.029**	2.9%
Small Northern Medium Undergrounding	Lakeland Power Distribution	227	**214**	**1.064**	6.4%
Mid-Size Northern	Greater Sudbury Hydro	215		**0.987**	-1.3%
Mid-Size Northern	PUC Distribution	216		**0.991**	-0.9%
Mid-Size Northern	Thunder Bay Hydro Electricity Distribution	220		**1.009**	0.9%
Mid-Size Northern	North Bay Hydro Distribution	221	**218**	**1.013**	1.3%
Large Northern	Hydro One Networks	316	**316**	**NA**	NA
Small Southern Low & Medium Undergrounding	Hydro Hawkesbury	134		**0.515**	-48.5%
Small Southern Low & Medium Undergrounding	Lakefront Utilities	187		**0.718**	-28.2%
Small Southern Low & Medium Undergrounding	Hydro 2000	192		**0.738**	-26.2%
Small Southern Low & Medium Undergrounding	Tay Hydro Electric Distribution	201		**0.773**	-22.7%
Small Southern Low & Medium Undergrounding	Rideau St. Lawrence Distribution	225		**0.865**	-13.5%
Small Southern Low & Medium Undergrounding	Clinton Power	243		**0.934**	-6.6%
Small Southern Low & Medium Undergrounding	Wellington North Power	278		**1.070**	7.0%
Small Southern Low & Medium Undergrounding	Dutton Hydro	294		**1.132**	13.2%
Small Southern Low & Medium Undergrounding	Grand Valley Energy	301		**1.160**	16.0%
Small Southern Low & Medium Undergrounding	Eastern Ontario Power	351		**1.353**	35.3%
Small Southern Low & Medium Undergrounding	Brant County Power	352		**1.354**	35.4%
Small Southern Low & Medium Undergrounding	Port Colborne	361	**260**	**1.389**	38.9%
Small Southern Medium-High Undergrounding	Middlesex Power Distribution	207		**0.820**	-18.0%
Small Southern Medium-High Undergrounding	Tillsonburg Hydro	226		**0.894**	-10.6%
Small Southern Medium-High Undergrounding	West Perth Power	232		**0.919**	-8.1%
Small Southern Medium-High Undergrounding	Newbury Power	242		**0.956**	-4.4%
Small Southern Medium-High Undergrounding	Midland Power Utility	263		**1.039**	3.9%
Small Southern Medium-High Undergrounding	West Coast Huron Energy	347	**253**	**1.372**	37.2%
Small Southern Medium-High Undergrounding with Rapid Growth	Grimsby Power	156		**0.814**	-18.6%
Small Southern Medium-High Undergrounding with Rapid Growth	Orangeville Hydro	174		**0.912**	-8.8%
Small Southern Medium-High Undergrounding with Rapid Growth	Cooperative Hydro Embrun	189		**0.987**	-1.3%
Small Southern Medium-High Undergrounding with Rapid Growth	Niagara-on-the-Lake Hydro	199		**1.042**	4.2%
Small Southern Medium-High Undergrounding with Rapid Growth	Centre Wellington Hydro	238	**191**	**1.246**	24.6%
Mid-size Southern Low & Medium Undergrounding	Innisfil Hydro Distribution Systems	214		**0.848**	-15.2%
Mid-size Southern Low & Medium Undergrounding	Norfolk Power Distribution	216		**0.856**	-14.4%
Mid-size Southern Low & Medium Undergrounding	Orillia Power Distribution	258		**1.020**	2.0%
Mid-size Southern Low & Medium Undergrounding	Haldimand County Hydro	264		**1.044**	4.4%
Mid-size Southern Low & Medium Undergrounding	Fort Erie	273		**1.079**	7.9%
Mid-size Southern Low & Medium Undergrounding	Peninsula West Utilities	291	**253**	**1.153**	15.3%
Mid-size Southern Medium-High Undergrounding	E.L.K. Energy	147		**0.723**	-27.7%
Mid-size Southern Medium-High Undergrounding	Wasaga Distribution	149		**0.731**	-26.9%
Mid-size Southern Medium-High Undergrounding	Chatham-Kent Hydro	161		**0.789**	-21.1%
Mid-size Southern Medium-High Undergrounding	Peterborough Distribution	173		**0.848**	-15.2%
Mid-size Southern Medium-High Undergrounding	Festival Hydro	179		**0.879**	-12.1%
Mid-size Southern Medium-High Undergrounding	Welland Hydro-Electric System	182		**0.892**	-10.8%
Mid-size Southern Medium-High Undergrounding	COLLUS Power	201		**0.983**	-1.7%
Mid-size Southern Medium-High Undergrounding	Kingston Electricity Distribution	201		**0.987**	-1.3%
Mid-size Southern Medium-High Undergrounding	St. Thomas Energy	207		**1.017**	1.7%
Mid-size Southern Medium-High Undergrounding	Westario Power	215		**1.054**	5.4%
Mid-size Southern Medium-High Undergrounding	Woodstock Hydro Services	218		**1.068**	6.8%
Mid-size Southern Medium-High Undergrounding	Essex Powerlines	221		**1.084**	8.4%
Mid-size Southern Medium-High Undergrounding	Niagara Falls Hydro	233		**1.144**	14.4%
Mid-size Southern Medium-High Undergrounding	Bluewater Power Distribution	260		**1.276**	27.6%
Mid-size Southern Medium-High Undergrounding	Erie Thames Powerlines	311	**204**	**1.525**	52.5%
Large City Southern Medium-High Undergrounding	Hydro Ottawa	147		**0.705**	-29.5%
Large City Southern Medium-High Undergrounding	Veridian Connections	186		**0.889**	-11.1%
Large City Southern Medium-High Undergrounding	Toronto Hydro-Electric System	235		**1.126**	12.6%
Large City Southern Medium-High Undergrounding	ENWIN Powerlines	267	**209**	**1.281**	28.1%
Large City Southern High Undergrounding	Hydro One Brampton Networks	130		**0.763**	-23.7%
Large City Southern High Undergrounding	Horizon Utilities	153		**0.902**	-9.8%
Large City Southern High Undergrounding	London Hydro	160		**0.939**	-6.1%
Large City Southern High Undergrounding	PowerStream	181		**1.063**	6.3%
Large City Southern High Undergrounding	Enersource Hydro Mississauga	226	**170**	**1.333**	33.3%
Mid-size GTA Medium-High & High Undergrounding	Barrie Hydro Distribution	125		**0.690**	-31.0%
Mid-size GTA Medium-High & High Undergrounding	Kitchener-Wilmot Hydro	141		**0.777**	-22.3%
Mid-size GTA Medium-High & High Undergrounding	Cambridge and North Dumfries Hydro	157		**0.870**	-13.0%
Mid-size GTA Medium-High & High Undergrounding	Guelph Hydro Electric Systems	167		**0.923**	-7.7%
Mid-size GTA Medium-High & High Undergrounding	Oshawa PUC Networks	176		**0.976**	-2.4%
Mid-size GTA Medium-High & High Undergrounding	Waterloo North Hydro	182		**1.006**	0.6%
Mid-size GTA Medium-High & High Undergrounding	Burlington Hydro	190		**1.049**	4.9%
Mid-size GTA Medium-High & High Undergrounding	Brantford Power	192		**1.061**	6.1%
Mid-size GTA Medium-High & High Undergrounding	Newmarket Hydro	194		**1.071**	7.1%
Mid-size GTA Medium-High & High Undergrounding	Whitby Hydro Electric	199		**1.100**	10.0%
Mid-size GTA Medium-High & High Undergrounding	Oakville Hydro Electricity Distribution	205		**1.133**	13.3%
Mid-size GTA Medium-High & High Undergrounding	Milton Hydro Distribution	206		**1.139**	13.9%
Mid-size GTA Medium-High & High Undergrounding	Halton Hills Hydro	218	**181**	**1.206**	20.6%

[1]Average of Latest 3 years of available data

Table 9

Efficiency Rankings Using Staff Metrics and PEG Peer Groups

Distributor	Average/Group Average [A]	Percentage Differences [A-1]	Efficiency Ranking
Hydro Hawkesbury	**0.515**	-48.5%	1
West Nipissing Energy Services	**0.525**	-47.5%	2
Renfrew Hydro	**0.593**	-40.7%	3
Barrie Hydro Distribution	**0.690**	-31.0%	4
Hydro Ottawa	**0.705**	-29.5%	5
Lakefront Utilities	**0.718**	-28.2%	6
E.L.K. Energy	**0.723**	-27.7%	7
Wasaga Distribution	**0.731**	-26.9%	8
Hydro 2000	**0.738**	-26.2%	9
Hydro One Brampton Networks	**0.763**	-23.7%	10
Tay Hydro Electric Distribution	**0.773**	-22.7%	11
Kitchener-Wilmot Hydro	**0.777**	-22.3%	12
Chatham-Kent Hydro	**0.789**	-21.1%	13
Espanola Regional Hydro Distribution	**0.791**	-20.9%	14
Fort Frances Power	**0.806**	-19.4%	15
Grimsby Power	**0.814**	-18.6%	16
Middlesex Power Distribution	**0.820**	-18.0%	17
Innisfil Hydro Distribution Systems	**0.848**	-15.2%	18
Peterborough Distribution	**0.848**	-15.2%	19
Norfolk Power Distribution	**0.856**	-14.4%	20
Northern Ontario Wires	**0.865**	-13.5%	21
Rideau St. Lawrence Distribution	**0.865**	-13.5%	22
Cambridge and North Dumfries Hydro	**0.870**	-13.0%	23
Festival Hydro	**0.879**	-12.1%	24
Veridian Connections	**0.889**	-11.1%	25
Welland Hydro-Electric System	**0.892**	-10.8%	26
Tillsonburg Hydro	**0.894**	-10.6%	27
Horizon Utilities	**0.902**	-9.8%	28
Ottawa River Power	**0.912**	-8.8%	29
Orangeville Hydro	**0.912**	-8.8%	30
West Perth Power	**0.919**	-8.1%	31
Guelph Hydro Electric Systems	**0.923**	-7.7%	32
Parry Sound Power	**0.930**	-7.0%	33
Clinton Power	**0.934**	-6.6%	34
London Hydro	**0.939**	-6.1%	35
Terrace Bay Superior Wires	**0.955**	-4.5%	36
Newbury Power	**0.956**	-4.4%	37
Oshawa PUC Networks	**0.976**	-2.4%	38
COLLUS Power	**0.983**	-1.7%	39
Cooperative Hydro Embrun	**0.987**	-1.3%	40
Kingston Electricity Distribution	**0.987**	-1.3%	41
Greater Sudbury Hydro	**0.987**	-1.3%	42
PUC Distribution	**0.991**	-0.9%	43
Kenora Hydro Electric	**0.996**	-0.4%	44
Waterloo North Hydro	**1.006**	0.6%	45
Thunder Bay Hydro Electricity Distribution	**1.009**	0.9%	46
North Bay Hydro Distribution	**1.013**	1.3%	47
St. Thomas Energy	**1.017**	1.7%	48
Orillia Power Distribution	**1.020**	2.0%	49
Hearst Power Distribution	**1.029**	2.9%	50
Midland Power Utility	**1.039**	3.9%	51
Niagara-on-the-Lake Hydro	**1.042**	4.2%	52
Haldimand County Hydro	**1.044**	4.4%	53
Burlington Hydro	**1.049**	4.9%	54
Westario Power	**1.054**	5.4%	55
Brantford Power	**1.061**	6.1%	56
PowerStream	**1.063**	6.3%	57
Lakeland Power Distribution	**1.064**	6.4%	58
Woodstock Hydro Services	**1.068**	6.8%	59
Wellington North Power	**1.070**	7.0%	60
Newmarket Hydro	**1.071**	7.1%	61
Fort Erie	**1.079**	7.9%	62
Essex Powerlines	**1.084**	8.4%	63
Whitby Hydro Electric	**1.100**	10.0%	64
Toronto Hydro-Electric System	**1.126**	12.6%	65
Dutton Hydro	**1.132**	13.2%	66
Oakville Hydro Electricity Distribution	**1.133**	13.3%	67
Milton Hydro Distribution	**1.139**	13.9%	68
Sioux Lookout Hydro	**1.140**	14.0%	69
Niagara Falls Hydro	**1.144**	14.4%	70
Peninsula West Utilities	**1.153**	15.3%	71
Grand Valley Energy	**1.160**	16.0%	72
Chapleau Public Utilities	**1.164**	16.4%	73
Atikokan Hydro	**1.170**	17.0%	74
Halton Hills Hydro	**1.206**	20.6%	75
Centre Wellington Hydro	**1.246**	24.6%	76
Bluewater Power Distribution	**1.276**	27.6%	77
ENWIN Powerlines	**1.281**	28.1%	78
Enersource Hydro Mississauga	**1.333**	33.3%	79
Eastern Ontario Power	**1.353**	35.3%	80
Brant County Power	**1.354**	35.4%	81
West Coast Huron Energy	**1.372**	37.2%	82
Port Colborne	**1.389**	38.9%	83
Erie Thames Powerlines	**1.525**	52.5%	84
Great Lakes Power	**2.063**	106.3%	85

use of unit cost metrics provides some control for variations in the size of companies in the peer groups. Overall rankings of OM&A cost management can be obtained by taking the ratio of the unit cost of each company to the average unit cost for its peer group.

Our research points the way to some possible upgrades in Staff's methods. Most notably, our econometric research lays the foundation for an important upgrade: the use of unit cost indexes with multi-dimensional output quantity indexes. These would help control for differences within peer groups in the customer density of service territories. This would be especially useful in the non-urban peer groups, where there can be considerable variation in the degree of customer density.

6.11 Recommendations

Provided that Staff moves, at a minimum, to upgrade its unit cost approach in the ways that we have recommended, we believe that it rises to the standard of accuracy that is needed for use in regulation. The Board should also consider the use of direct econometric benchmarking. This is the approach that PEG favors in its work for most clients and is used in power distributor benchmarking by British regulators. Advantages of econometric benchmarking in the present context include the following.

- Econometric models generally provide better control for the special business conditions that distributors face.
- Benchmarks reflect exactly the local business conditions of the subject utility. There is no need to select peer groups and rankings are not sensitive to peer group assignments. This can be a particular advantage when we wish to benchmark companies with few peers. There is, for example, no company in the sample with an operating scale similar to Toronto Hydro or HON. This feature is especially advantageous in the case of HON since this large rural utility has few close peers *anywhere* in North America. With econometrics we can estimate from data for all of the other companies in the sample, with their varied operating scales, the cost that unusually large companies would incur.
- Sensible statistical tests of efficiency hypothesis have been developed by PEG and made operational. These tests can help the Board determine

when benchmarking results are convincing enough to provide the basis for ratemaking decisions. For example, they provide a rigorous means of determining when results should be discounted because of the atypical character of a company's business conditions.

- Econometric models lend themselves to out of sample projections to bridge years and test years as well as to historical years. We need only insert reasonable values for the bridge/test year input prices, output quantities, and other business conditions.
- An econometric model of OM&A expenses can produce benchmarks that are directly comparable to actual costs. The cost surplus or saving revealed by benchmarking is simply the difference between actual costs and the cost projection. There is no need to compute the saving or surplus that is implied by a ratio of unit cost metrics.
- Models are likely to improve with each year of additional data that is used in model estimation. For example, it may be possible to identify additional significant business conditions and/or to add more flexibility to the functional form.
- The University of Toronto and other Ontario universities can train the personnel needed for Board Staff, stakeholder groups, and larger utilities to upgrade their skills in the benchmarking area. The accuracy of benchmarking methods and the potential role of benchmarking in regulation should not be limited by the lowest common denominator of expertise in the current regulatory community.
- Given the substantial net benefits of econometric benchmarking, it is hard to imagine how it would be just and reasonable for the Board to make ratemaking decisions based on results from a simpler method when and if a good econometric benchmarking model yields results that are substantially different.

Notwithstanding these advantages of direct econometric benchmarking we believe that even if the Board should choose to continue this work, unit cost benchmarking should also continue as a useful point of reference. Managers and stakeholders alike will appreciate comparisons, using tangible metrics, to peer group benchmarks prepared with the aid of good cost research.

Regarding the role of benchmarking in regulation, we believe that the Board has upgraded its benchmarking capability greatly in the past year. Sophisticated cost models have been developed that shed considerable light on the drivers of distributor cost in Ontario. These models provide the basis for unit cost indexes and direct econometric benchmarking. Statistical tests of efficiency hypotheses are available. In the latest round of research we have improved upon earlier research by incorporating system age into the benchmarking program, including HON in the sample, developing more refined peer groups, and showing the potential for the inclusion of reliability in performance benchmarking. While data problems still impose impediments to accurate benchmarking, the Board has nonetheless developed a world class capability to benchmark OM&A expenses. Preliminary research also suggests that a capability to benchmark reliability can be developed eventually.

We therefore recommend that the Board proceed with more extensive use of benchmarking in the ratesetting process. At a minimum, benchmarking can be used to identify companies that --- thanks to favorable OM&A scores --- merit expedited processing of rate applications and those that --- due to poor scores --- should be scheduled for especially thorough rate reviews. Benchmarking results, such as the estimated OM&A surpluses and deficits, are also good enough now to serve as evidence of operating efficiency in rate reviews.

Consideration should also be paid to using benchmarking results to inform decisions concerning the X factor terms of rate adjustment mechanisms. Since research has focused primarily on the *level* of cost performance rather than its *trend*, it is not very useful in determining the productivity trend component of the X factor. However, it is potentially very relevant for determining the stretch factor component. If benchmarking is used to set stretch factors now, the range in stretch factors should not be too broad until more experience is gained with the methods and data refinements are made.

Benchmarking should extend to bridge year and test year costs in addition to recent historical costs. It is, after all, the latter costs that most affect rates and there is a temptation for companies to talk up the need for cost growth even if their historical costs are low. Statistical tests of efficiency hypotheses can help to ensure the reasonableness of regulatory outcomes. Rewards for superior performance should be considered as well as penalties for inferior performance.

Business conditions that are not properly controlled for with the current methodologies are valid concerns for parties to raise in rate cases. For example, a company with a poor performance score may argue that it is because it faces special business conditions (*e.g.* has a low load factor and high service quality) that have been excluded from our analysis.

With good methods, additional years of data, and reforms in the collection of data, benchmarking may reach a level of accuracy that will permit it in the future to play a larger role in Ontario ratemaking. Regulators may still undertake some traditional prudence reviews but can rely more extensively on benchmarking results to set initial rates and the escalation terms of rate adjustment mechanisms. This use of benchmarking in ratemaking can materially strengthen performance incentives and thus be considered a component of a broader scheme of incentive regulation.

Appendix

This appendix contains additional details of our benchmarking research for Board staff. Section A.1 discusses the econometric cost research. Section A.2 discusses our indexing research. Section A.3 provides supplemental data on the sampled companies.

A.1 Econometric Cost Research

A.1.1 Form of the Cost Model

Specific forms must be chosen for cost functions used in econometric research. Forms commonly employed by scholars include the linear, the double log and the translog. Here is a simple example of a linear cost model:

$$C_{h,t} = a_0 + a_1 \cdot N_{h,t} + a_2 \cdot W_{h,t} + e_{h,t} . \qquad [A1]$$

Here, for each firm h in year t, cost is a function of the number of customers served ($N_{h,t}$), the prevailing wage rate ($W_{h,t}$), and an error term ($e_{h,t}$). Here is an analogous cost model of double log form:

$$\ln C_{h,t} = a_0 + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln W_{h,t} + e_{h,t} . \qquad [A2]$$

Notice that in this model the dependent variable and both business condition variables have been logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, the a_1 parameter indicates the % change in cost resulting from 1% growth in the output quantity. It is also noteworthy that in a double log model, the elasticities are *constant* across every value that the cost and business condition variables might assume.[35]

[35] Cost elasticities are not constant in the linear model that is exemplified by equation 8a.

Here is an analogous cost function of translog form. This very flexible function is common in econometric cost research, and by some accounts the most reliable of several available flexible forms.[36] [37]

$$\begin{aligned} lnC_{h,t} &= a_0 + a_1 \cdot lnN_{h,t} + a_2 \cdot lnW_{h,t} + a_3 \cdot lnN_{h,t} \cdot lnN_{h,t} \\ &+ a_4 \cdot lnW_{h,t} \cdot lnW_{h,t} + a_5 \cdot lnW_{h,t} \cdot lnN_{h,t} + e_{h,t} \end{aligned} \qquad \text{[A3]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms such as $\ln N_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to differ at different values of the variable. Interaction terms like $\ln W_{h,t} \cdot \ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable.

The quadratic form used in our study has the following formula:

$$\begin{aligned} &ln\,C = \alpha_o + \sum_i \alpha_i lnY_i + \sum_j \alpha_j lnW_j + \sum_\ell \alpha_\ell lnZ_\ell + \alpha_t T \\ &+ \frac{1}{2}\left[\sum_i \gamma_i lnY_i lnY_i + \sum_j \gamma_j lnW_j lnW_j \right] \\ &+ \varepsilon. \end{aligned} \qquad \text{[A4]}$$

Here, Y_i denotes one of several variables that quantify output and W_j denotes one of several input prices. The *Z*s denote the additional business conditions, *T* is a trend variable, and ε denotes the error term.

A.2 Index Research

This section contains additional details of our index research. Sub-Section 2.1 discusses the formula for output quantity indexes. Sub-Section 2.2 discusses the formula for input quantity indexes.

A.2.1 Output Quantity Indexes

The output quantity index for each company *h* was defined by the formula

$$ln\,Output\,Quantity_{h,t} = \sum_i se_i \cdot (\ln Y_{i,h,t} - \overline{\ln Y_{i,t}}) \qquad \text{[A5]}$$

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[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.

Here for each company h in year *t*,

$Output\ Quantity_{h,t}$ = output quantity index

$Y_{i,h,t}$ = quantity of output dimension *i*

$\overline{\ln Y_{i,t}}$ = sample mean of the logged quantity of output dimension *i* provided by all utilities

se_i = share of output dimension *i* in the sum of the econometric estimates of the cost elasticities of the output quantities.

A.2.2 Unit Cost Indexes

Each unit cost index was computed using the ratio of a cost index to an output quantity index:

$$Unit\ Cost_{h,t} = Cost_{h,t} / Output\ Quantity_{h,t}. \qquad [A6]$$

Here for each company h in year t,

$Cost_{h,t}$ = *cost index* where the cost index is constructed as:

$\ln Cost_{h,t} = \ln C_{h,t} - \overline{\ln C_t}$

$\ln C_{h,t}$ = logged OM&A expenses

$\overline{\ln\ C}$ = sample mean of the logged OM&A expenses for all utilities.

A.3 Supplemental Data

Please see Table A for supplemental data on the operations of the sampled distributors.

Appendix Table A

Average Values of Variables Used in Econometric Research by LDC[1 2]

LDC	OM&A Cost	Retail Customers	Total Volume	Distribution Line Circuit Kilometers	Input Price Index	Canadian Shield	Percent Kilometers Underground	Customer Growth/Output Index[fn]
Sample Mean	**11,856,770**	**51,858**	**1,608,322,698**	**2,322**	**1.003**	**0.23**	**0.25**	**1,718**
Atikokan Hydro	736,022	1,762	42,547,962	92.3	0.974	1.00	0.01	-1,170
Barrie Hydro Distribution	8,310,599	63,624	1,416,784,410	1415.6	1.029	0.00	0.54	5,032
Bluewater Power Distribution	8,988,081	34,968	1,113,785,178	771.6	1.013	0.00	0.21	691
Brant County Power	3,030,541	8,897	225,439,261	409.8	0.981	0.00	0.07	1,913
Brantford Power	6,580,081	35,443	945,523,123	466.0	0.981	0.00	0.42	1,837
Burlington Hydro	10,803,147	58,168	1,661,478,784	1406.8	1.042	0.00	0.40	2,955
Cambridge and North Dumfries Hydro	7,271,054	46,512	1,535,392,742	1079.1	1.026	0.00	0.33	2,595
Centre Wellington Hydro	1,473,050	5,948	150,133,469	139.2	1.006	0.00	0.45	3,576
Chapleau Public Utilities	495,392	1,347	31,344,574	27.3	0.980	1.00	0.05	-1,604
Chatham-Kent Hydro	5,048,426	31,908	880,595,520	759.6	0.990	0.00	0.29	691
Clinton Power	402,506	1,618	30,450,733	21	0.993	0.00	0.19	452
COLLUS Power	2,664,812	13,688	355,639,686	314.8	0.958	0.00	0.30	2,341
Cooperative Hydro Embrun	314,954	1,684	28,384,285	27.8	1.061	0.00	0.43	4,815
Dutton Hydro	152,918	577	8,140,399	7.4	0.993	0.00	0.15	2,271
E.L.K. Energy	1,788,169	10,351	191,518,251	133.5	1.055	0.00	0.35	3,238
Eastern Ontario Power (CNP)	1,242,071	3,581	76,962,909	155.3	0.967	0.00	0.03	497
Enersource Hydro Mississauga	38,679,259	175,618	7,727,859,610	4979.6	1.066	0.00	0.66	2,666
ENWIN Powerlines	22,061,230	84,478	2,674,101,760	1171.0	1.117	0.00	0.35	1,750
Erie Thames Powerlines	3,942,840	13,579	401,146,560	255.8	0.993	0.00	0.21	1,232
Espanola Regional Hydro Distribution	852,381	3,319	64,494,533	134.9	0.980	1.00	0.08	805
Essex Powerlines	5,709,652	27,032	545,184,256	447.3	1.080	0.00	0.49	3,845
Festival Hydro	3,360,308	18,685	626,928,218	274.7	0.981	0.00	0.33	1,474
Fort Erie (CNP)	4,137,187	15,260	286,883,494	490.8	0.974	0.00	0.05	402
Fort Frances Power	994,871	3,937	81,846,989	82.8	0.974	1.00	0.10	1,073
Grand Valley Energy	187,929	677	9,184,276	8.3	1.047	0.00	0.18	1,724
Great Lakes Power	7,127,519	11,449	172,851,118	1830.8	0.946	1.00	0.00	248
Greater Sudbury Hydro	8,925,259	42,906	884,812,262	833.4	0.980	1.00	0.21	12
Grimsby Power	1,375,602	9,206	162,128,595	224.2	1.042	0.00	0.24	3,103
Guelph Hydro Electric Systems	8,667,372	44,459	1,553,265,254	948.1	1.006	0.00	0.56	3,713
Haldimand County Hydro	5,237,431	20,280	366,770,522	1650.8	0.981	0.00	0.05	828
Halton Hills Hydro	4,095,592	18,730	456,497,619	1282.5	1.054	0.00	0.30	2,535
Hearst Power Distribution	560,730	2,766	117,356,062	68.2	0.980	1.00	0.16	1,192
Horizon Utilities	35,004,222	228,700	5,744,667,443	3219.8	1.042	0.00	0.50	1,369
Hydro 2000	187,950	1,128	26,360,266	21.6	0.938	0.00	0.11	1,078
Hydro Hawkesbury	694,094	5,226	197,754,608	65.1	0.938	0.00	0.13	1,977
Hydro One Brampton Networks	14,751,317	109,315	3,536,972,442	2389.2	1.066	0.00	0.69	5,004
Hydro One Networks	358,035,024	1,145,917	39,519,488,000	119392.3	1.045	1.00	0.04	862
Hydro Ottawa	44,068,927	273,742	7,519,680,205	5078.6	1.061	0.00	0.37	2,478
Innisfil Hydro Distribution Systems	2,865,640	13,553	214,023,898	599.6	1.029	0.00	0.17	2,435
Kenora Hydro Electric	1,233,543	5,825	109,079,907	98.0	1.004	1.00	0.10	1,247
Kingston Electricity Distribution	5,590,800	26,390	725,074,160	347.9	0.948	0.00	0.31	267
Kitchener-Wilmot Hydro	10,767,670	77,261	1,968,665,805	1729.0	1.026	0.00	0.42	2,180
Lakefront Utilities	1,489,382	8,642	278,443,635	102.8	0.983	0.00	0.09	2,020
Lakeland Power Distribution	2,219,749	8,926	219,134,544	656.2	0.988	1.00	0.13	749

[1] This metric is used to measure system age. High values like those for Barrie Hydro Distribution and Whitby Hydro Electric are indicative of a younger system. Since the output index is the denominator of the metric, large values should not be expected for large systems.
[2] These are the average values of the entire sample period, 2002-2006. Bad observations have been excluded.

Appendix Table A, continued

LDC	OM&A Cost	Retail Customers	Total Volume	Distribution Line Circuit Kilometers	Input Price Index	Canadian Shield	Percent Kilometers Underground	Customer Growth/Output Index[fn]
Sample Mean	**11,856,770**	**51,858**	**1,608,322,698**	**2,322**	**1.003**	**0.23**	**0.25**	**1,718**
London Hydro	21,699,822	136,319	3,369,441,997	2508.4	0.993	0.00	0.50	2,099
Middlesex Power Distribution	1,434,565	6,751	172,450,726	106.7	0.990	0.00	0.24	2,196
Midland Power Utility	1,717,835	6,414	226,026,170	110.6	0.949	0.00	0.30	1,007
Milton Hydro Distribution	3,808,125	17,659	603,913,472	744.3	1.042	0.00	0.29	3,979
Newbury Power	44,795	189	4,008,167	4.0	1.004	0.00	0.38	636
Newmarket Hydro	5,012,128	25,323	663,889,114	632.1	1.047	0.00	0.63	3,326
Niagara Falls Hydro	7,608,934	33,728	823,246,707	784.0	0.974	0.00	0.41	1,127
Niagara-on-the-Lake Hydro	1,433,664	7,258	171,981,939	326.5	0.974	0.00	0.22	2,276
Norfolk Power Distribution	4,021,081	17,935	359,426,234	761.2	0.981	0.00	0.10	2,966
North Bay Hydro Distribution	5,317,468	23,457	583,971,661	567.6	0.948	1.00	0.13	424
Northern Ontario Wires	1,770,570	6,253	136,750,606	370.0	0.998	1.00	0.01	-17
Oakville Hydro Electricity Distribution	11,068,949	53,560	1,621,643,930	1315.0	1.054	0.00	0.60	3,319
Orangeville Hydro	1,730,421	9,760	233,210,112	149.7	1.047	0.00	0.41	4,110
Orillia Power Distribution	2,995,205	12,307	318,343,795	293.1	1.029	0.00	0.17	1,166
Oshawa PUC Networks	9,311,374	48,888	1,140,257,075	1754.1	1.066	0.00	0.35	1,365
Ottawa River Power	1,950,505	10,114	198,881,485	146.8	0.913	1.00	0.13	990
Parry Sound Power	910,256	3,237	84,144,309	128.0	1.004	1.00	0.09	212
Peninsula West Utilities	4,006,776	14,388	341,120,019	1274.6	1.042	0.00	0.11	245
Peterborough Distribution	5,632,561	33,306	806,210,406	533.4	0.954	0.00	0.29	1,303
Port Colborne (CNP)	2,563,660	9,216	179,960,720	284.0	0.974	0.00	0.03	658
PowerStream	37,278,669	212,283	6,477,840,589	5729.2	1.066	0.00	0.65	4,245
PUC Distribution	6,635,505	32,397	715,995,098	713.6	0.946	1.00	0.15	263
Renfrew Hydro	788,525	4,066	94,476,520	67.0	0.913	1.00	0.03	556
Rideau St. Lawrence Distribution	1,260,786	5,772	123,563,549	85.7	0.976	0.00	0.11	531
Sioux Lookout Hydro	896,628	2,741	91,619,251	209.9	0.974	1.00	0.03	73
St. Thomas Energy	2,898,593	14,956	366,733,574	238.8	0.993	0.00	0.27	2,299
Tay Hydro Electric Distribution	745,300	3,955	42,667,114	354.3	1.029	0.00	0.04	949
Terrace Bay Superior Wires	291,723	947	19,174,764	20.3	0.964	1.00	0.02	86
Thunder Bay Hydro Electricity Distribution	11,131,307	49,299	1,044,844,480	1343.3	0.974	1.00	0.33	660
Tillsonburg Hydro	1,420,170	6,266	218,594,576	142.5	1.009	0.00	0.31	1,941
Toronto Hydro-Electric System	158,049,664	672,325	25,859,628,237	16754.5	1.066	0.00	0.48	424
Veridian Connections	20,402,350	102,396	2,466,949,837	1790.6	1.069	0.00	0.30	2,614
Wasaga Distribution	1,414,721	10,125	100,097,611	209.3	1.029	0.00	0.43	6,154
Waterloo North Hydro	8,686,499	46,688	1,268,598,528	1319.6	1.026	0.00	0.29	2,892
Welland Hydro-Electric System	3,849,528	21,221	486,944,474	421.6	0.974	0.00	0.23	1,026
Wellington North Power	909,794	3,362	88,862,582	127.1	0.979	0.00	0.08	743
West Coast Huron Energy	1,223,792	3,759	145,413,206	65.1	1.026	0.00	0.19	1,005
West Nipissing Energy Services	698,622	3,085	61,957,593	37.2	0.948	1.00	0.05	647
West Perth Power	485,790	1,940	63,704,152	33.8	0.981	0.00	0.20	1,463
Westario Power	4,460,753	20,502	437,833,392	417.6	0.929	0.00	0.21	818
Whitby Hydro Electric	7,013,847	34,506	807,022,221	951.8	1.069	0.00	0.51	5,054
Woodstock Hydro Services	2,975,665	14,051	409,574,682	251.0	1.008	0.00	0.40	1,552

[1] This metric is used to measure system age. High values like those for Barrie Hydro Distribution and Whitby Hydro Electric are indicative of a younger system. Since the output index is the denominator of the metric, large values should not be expected for large systems.

[2] These are the average values of the entire sample period, 2002-2006. Bad observations have been excluded.

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