Report to the Ontario Energy Board

New Developments in Activities and Program Benchmarking

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1. Introduction and Summary

1.1. Introduction

In 2018, Ontario Energy Board ("OEB") staff began a project to benchmark granular costs that utilities incur at the activity level (e.g., reported right of way expenses) or program level (e.g., tree-trimming costs). This came to be called the activities and programs benchmarking ("APB") project. The project has focused on granular operation and maintenance ("O&M") expenses and capital expenditures ("capex") of power distributors. Pacific Economics Group Research LLC ("PEG") was chosen as project consultant.

PEG prepared a concept paper that discussed the challenges of granular cost benchmarking and considered alternative benchmarking methods. Several working group sessions were conducted to draw input from stakeholders and inform them of the state of the initiative. OEB staff prepared a discussion paper that identified 19 activities that were shortlisted to 10 activities for benchmarking. These categories included capital expenditures ("capex") as well as operation and maintenance ("O&M") expenses.

PEG prepared another paper that discussed promising activities for benchmarking, granular benchmarking precedents in other jurisdictions, and reported preliminary benchmarking results using alternative methods. Areas of data deficiency were noted and discussed. In the fall of 2019, PEG conducted exploratory benchmarking work and develop 10 preliminary models for the 10 activities. After a hiatus occasioned in part by the COVID-19 pandemic, PEG was authorized in the fall of 2020 to prepare a first-generation cost benchmarking study of staff's 10 short-listed activities aided with new data from distributors in December 2020.

This is a report on our new research. Following a summary of key results in Section 1, Section 2 discusses the cost areas benchmarked, our preliminary models for shortlisted costs, and their explanatory power. Section 3 discusses data collection and explanatory variables. Section 4 discusses the new benchmarking results. Section 5 discusses applications of the new models. Two appendices contain additional information.

1.2 Summary

The New Research

We added two years of data to the APB database and, in collaboration with OEB staff, gathered and processed data on new variables that were potentially useful for improving the accuracy of benchmarking. In addition to data on new business condition variables (e.g., the number of poles owned), improved capex data were gathered. The criteria used to identify what data should be requested were that it should be reasonably easy for distributors to access, not already provided to the OEB, and have a high probability of improving the models. The additional data provided were generally complete and distributors generally made a good effort to respond to the questions. The new, expanded sample contains data reported for 2018 and 2019 under the Reporting and Record-Keeping Requirements (RRR) as well as the additional data made possible by the questionnaire.

New benchmarking results were calculated for each of the ten cost categories that OEB staff had previously shortlisted using unit cost and econometric benchmarking. The relative explanatory power of each method was evaluated as well as the improvement in the econometric models. Many of the new business condition variables were found to be statistically significant cost drivers in the new econometric research which provides a basis to choose a scale variable or variables for unit cost benchmarking. There have been improvements in both the explanatory power of the models and their sophistication in linking benchmarks to cost drivers.

Conclusions

Our new APB research prompts several conclusions.

- The efficacy of APB is better for some cost categories than others. It may make sense to focus on categories where APB is more accurate. We found that the benchmarking results had high explanatory power in 8 of the ten models and lower explanatory power in two cases (poles O&M and station capex).
- Inconsistent allocation of OM&A expenses has been found to be a material problem with the available data reported.
- Supplemental data that we gathered in this phase of the project made APB more effective.

- Some of the new data gathered have materially improved the explanatory power of our cost models.
- Some of the data gathered has diagnostic value even if it was not used in the final version of the benchmarking work. Diagnostic variables can provide insights on good operating practices. An example is whether a particular distributor outsources billing operations. The data on which distributors outsource billing work can help determine if outsourcing appears to be a good operating practice. The business condition variables are intended to explain cost due to factors beyond management control. The remaining cost difference is attributed to management. Because operating practices are within the control of management, outsourcing should not be used to explain cost difference from choices within management control. However, it is useful to diagnose why some distributors had better performance than others (e.g., the reason why the distributor had good performance is because it chose to outsource billing). Explaining the performance is different from calculating the performance.

- Econometric cost modeling is a useful complement to unit cost metrics. For example, econometric modelling can more easily control for
    - Unusual cost allocations
    - Business conditions other than operating scale that influence cost (e.g., the vegetation challenge in right of way clearance)

Trend variables are useful when benchmarking future costs since they provide a reasonable productivity growth target.

Econometric models can be developed with various degrees of complexity. We were mindful to balance the cost of incremental complexity with the value of incremental explanatory power. We also sought consistency in how the equations were specified in each of the ten models.[1] Therefore,

[1] The equation used to relate cost to business conditions can take on various functional forms. These can include variables multiplied with themselves (i.e., "squared") or with other variables (i.e., "interaction"). One advantage to including these terms in the equation is that it provides a way to better account for the effect of scale of operation on cost. Without a squared term in the equation, the effect of scale on cost is assumed to be linear whereas a

we established and followed rules for econometric cost model development in the hope of reducing controversy.

Parties are nonetheless free to use either the simpler unit cost metrics or the more complex econometric results and we have facilitated such research.

Suggestions for Further Research

1. Continue to benchmark some (or all) of the ten costs that OEB staff shortlisted. Given the small sample of data currently available, re-estimation of the econometric models as data accumulate will enhance their precision. Further refinements to the data gathered may be warranted.

2. A number of improvements in benchmarking methods can be made. Here are some examples.

    - Ontario asset price indexes measure trends in price. Additional research to find a way to also make adjustments to reflect the difference in price levels in different cities in Ontario would be an improvement.

    - Alternative methods for parameter estimation merit consideration. These include exploring ways to deal with zero values present in the capex data.

3. Benchmark other granular cost categories that OEB staff shortlisted (i.e., the remaining nine programs identified in the preliminary short list of 19 programs). To accomplish this

    - data on some additional business condition variables may be needed; and

    - econometric models must then be developed, and results must be compared to those from simpler unit cost indexes.

squared term allows for a non-linear relationship. The number of terms in the equation to be estimated can quickly increase as squared and interaction terms are included. Two scale variables become five variables if both squared and interaction terms are included.

2. Cost Areas Benchmarked, Preliminary Models, and Explanatory Power

The OEB Staff discussion paper identified 10 areas of most interest to benchmark. They consist of the following six O&M cost areas

- distribution station equipment O&M;
- vegetation management;
- lines O&M;
- poles, towers, and fixtures maintenance;
- meters O&M;
- billing;

and four capex areas

- distribution station equipment;
- line transformers;
- pole, towers, and fixtures; and
- meters.

In the prior phase of the project, PEG developed econometric cost models for each of these costs. These models had varying levels of explanatory power. Explanatory power is the ability of data on relevant business conditions to correlate to differences in observed levels of cost (i.e., how much of the total variability in the cost is explained by the benchmarking model).

PEG employed two different measures of explanatory power. The first is an adjusted R-squared statistic. This is a commonly-used statistic in econometric research which summarizes how well the explanatory variables explain the variation in the cost being examined. The second is the percentage of distributors whose cost differed from the benchmark by more than 50% in either direction. This measure gives a notion of the dispersion of benchmarking outcomes. The cost performance is the difference between the distributor's cost level and that provided by the benchmark. For unit cost benchmarking this comparison is made with respect to the industry average or a group of distributors that are considered peers. For the econometric models, the benchmark is the cost level of a hypothetical distributor facing the exact same identified business conditions as the distributor.

Cost benchmarking is done to explain differences in cost levels. Each cost area will naturally have different amounts of variation in cost levels that benchmarking will attempt to explain. The benchmarking may be able to explain a good percentage of the variation (e.g., 80% or r-square of 0.80) and yet have a significant amount of cost variation that remains. The 50% ratios present a statistical metric to quantify how much variation remains. PEG uses the 50% threshold as an indication of whether a given company is an outlier in our more aggregated econometric models such as total distribution cost. In a total cost model, we will typically find that a very small proportion of the companies will have performance values outside of 50%. This will lead us to ask why this is happening and how the model may be improved or if the results are particularly sensitive to certain explanatory variables. In the context of these 10 APB models, it provides a notion of how much variation remains even after controlling for the effects of scale, prices, and other business conditions. Other more formal statistical tests to quantify the amount of dispersion could be considered, but PEG thought this simple metric would be more accessible. A potential use of this statistic is to help a user understand the context of a cost performance score. For example, if a distributor is a good performer as measured by a cost level that is 60% below expected, this will have a different context depending on the model. In a model in which a lot of distributors are within 50%, a 60% performance is more significant than in a model in which many distributors are outside of 50%.

A large amount of remaining variation can come from several sources. Distributors may have unique business conditions that are not included in the model, have different accounting treatment for the costs being benchmarked, or have high year-to-year variation. In the latter case results may need to be considered on a multi-year basis. Unexplained differences in cost are normally attributed to management performance. One might expect management to have some impact on cost through policies, practices, and human capital, but one would not expect the magnitude of such cost savings (or excessive spending) to be extremely large. Very large differences become more intuitively implausible the larger they become and suggest that other factors are needed to fully explain the observed differences.

The explanatory power of the preliminary econometric models as measured by these metrics is summarized in Table 1. As can be seen, some models had better explanatory power than others. Explanatory power was generally lower for the capex models than for the O&M models.

Table 1

Summary of Preliminary Models

Model	R-squared value	% of companies within 50%
	Previous Results	
Billing OM&A	0.870	79%
Metering OM&A	0.749	37%
Vegetation Management OM&A	0.818	69%
Line OM&A	0.867	49%
Station Equipment OM&A	0.680	30%
Poles, Towers, and Fixtures OM&A	0.462	52%
Meter Capex	0.594	37%
Station Capex	0.376	22%
Line Transformer Capex	0.813	22%
Poles, Towers, and Fixtures Capex	0.698	63%
Average	**0.693**	**46%**

Examples of reasons for low explanatory power include:

- Some of the models lacked variables that casual empiricism suggests should drive the cost to be benchmarked. For example, when considering the cost of pole maintenance, the number of poles in service would be an excellent start for explaining differences in cost. Because data on number of poles were not available, the preliminary models used other available, but less effective, measures of operating scale such as number of customers.
- Some costs may have a lot of inherent variation that cannot be readily modelled due to the nature of the activity. It is not surprising that an activity with less frequent or predictable cost such as distribution station capex has more variation than billing which is done on a regular basis.

- The equation used to predict cost used a form that does not adequately suit the reality of the relationship between cost and the explanatory variables. For example, if it were true that line maintenance cost tended to go up exponentially with the km of line, a model that only included km would only increase predicted cost by a fixed amount as km increases. The predicted cost for a larger distributor would only go up by a certain amount of $/km for each km it was larger than average.
- The small size of the available sample may result in less accurate model parameters. The lack of a sufficient number of distributors of all sizes and density can also result in less accurate parameters and predictions for distributors that are less typical. The number of medium to large distributors has increased over time as amalgamations have taken place.
- In an effort to increase the explanatory power of the models, PEG updated the models to incorporate additional years RRR data and additional data from the data request questionnaire. The next section will discuss the data collection and describe how the additional data were used to produce additional explanatory variables.

3. Rationale for the New Explanatory Variables

3.1. Overview

The data used in the new research were drawn from the RRR, the annual total cost benchmarking work that OEB staff commissions, and a questionnaire recently sent to all distributors ("data request"). PEG updated the APB sample using available data from the most recent total cost benchmarking work and adjusted for recent amalgamations of distributors as needed. Data from the questionnaire became available during the week of December 14, 2020. OEB staff provided a significant contribution to the processing of the data.

The additional data provided were generally complete and it is the opinion of PEG that the distributors generally made a good effort to respond to the questions. Most provided comments which were also helpful for the current work and future analysis of the results. Enough data were collected to be useful in model development. The models were developed using available data to determine if the additional information were improving the models. Because this work does not directly affect rates, some estimated values could be used in cases where data were not provided for variables that were improving the models. When a distributor does not provide appropriate data, a choice must be made between proceeding with estimates or not benchmarking the distributor missing the data.

3.2. New Data Gathered from Questionnaire

When developing econometric benchmarking models, an important consideration is to identify what business conditions will explain the cost being benchmarked. This is an exercise based on knowledge of electric utilities and economics in general. This is done regardless of whether appropriate data are available. The next step is to attempt to measure a business condition that is theoretically important to cost using available data. Variables constructed using available data can then be tested to determine if they provide additional explanatory power. The changes to the metric used and improvements in the underlying data can help further improve explanatory power. There are instances in which there is a clearly relevant business condition that should be important for which data exist and alternatives do not provide good explanatory power. An example of this is number of poles as being relevant for the cost of pole maintenance. Other measures such as number of customers or circuit-km of line did not appear to be good substitutes. PEG identified a list of business conditions that were theoretically important for improving explanatory power.

Gaining the ability to create new explanatory variables and test their explanatory power was the motivation behind requesting additional information from distributors. We found that in many cases the new variables had more explanatory power than what was available previously and these were featured in the final model. In some cases, the new data did not provide an improvement in explanatory power and these were not featured in the final models. In one case a variable was not featured in the final model but provided insight into why some distributors achieved better cost performance than others. The questionnaire was designed to collect data that were simultaneously relevant to the modelling with a low burden for distributors to provide from their existing records. Appendix 1 contains a copy of the data request questionnaire made to distributors. Below is a discussion of the rationale for each question and how the information was used to improve the models.

Question 1

Question 1 asked for information on the accounting treatment of pensions and benefits. There is a fundamental difference observed in all OM&A data because some distributors allocate pensions and benefits to O&M accounts while others report these expenses in the relevant general cost account. Distributing or allocating pensions and benefits is sometimes called "loading labor expenses" or "labor burden." The inconsistency causes problems for drawing conclusions about granular cost efficiency. To lower the reporting burden, a simple Yes or No response was requested. A binary (1 or 0) variable was constructed where 1 indicates that benefit expenses were allocated to O&M accounts.

This variable was statistically significant in all of the O&M cost models. It was expected to be more significant to the extent that a higher percentage of OM&A cost was labor. The binary nature of the variable assumes that a similar percentage of benefits were allocated to the account. The model will raise the predicted cost due to this accounting issue by an average amount. Therefore, distributors that have reason to believe that they had allocated a greater than typical level of benefits could argue that the model provides a slight downward bias to their measured performance. The reverse is true for distributors that allocated less than a typical amount. There are a lot of benefits that could be allocated to load labor cost. These include not only pensions, but sick time, vacation time, health insurance, and other miscellaneous benefits. A distributor that allocates all of these would have worse measured performance than one that only allocated some of them.

Question 2

Question 2 asked for information on whether billing work was done by the distributor or outsourced to companies providing billing services. The proposition was that there might be a difference between the costs of a distributor performing billing services versus those of distributors hiring others to do it for them. This information was ultimately not included in the benchmarking model due to a methodological reason related to whether a business condition is beyond the control of management. Benchmarking models will typically only include explanatory variables that reflect conditions beyond management control. In this case, because the choice of whether to outsource is a management choice, it should not be part of determining expected performance.

This information is still valuable to quantify the amount of potential saving from the outsourcing of billing. If the goal sought from the analysis is to determine efficiency in performing the billing function, it is necessary to know which distributors are performing this function. An application to the unit cost results could be to separate the distributors into two group depending upon who is outsourcing and see the average cost difference. Another would be for a distributor to identify peers and then separate the data. One of the goals of APB is to identify areas in which procedures, policies, and technology can be improved. Using billing as an example, the distributors identified as being the best at billing could be asked about what they are doing that makes them better. This information could be shared with others to allow them to adopt best practices. Identifying best practices is a primary goal of benchmarking work.

A distributor that outsources this work would not be a good source of information on best practices as only the billing company knows what policies, procedures, and other technology was used to achieve the outcome. This distributor's superior cost performance is attributed to getting a good deal on procured services or another factor that was not identified or controlled for in the model.

Question 3

Question 3 asked for outsourcing information on station maintenance. This information is only relevant for one of the models. In the station maintenance model, this variable had a statistically significant and negative sign which means that outsourcing results in lower than expected cost levels.

Interpretation of this information may require some context. Reasons for this statistical relationship may be due to better opportunities available to some distributors. One such beneficial opportunity may be distributors that have jointly-owned stations with Hydro One Networks ("HON"). Hydro One may be able to perform the task at lower cost either because of its greater economies of scale, the economies of scope available because it will be at the site anyways performing maintenance on its part of the station, or because it is especially efficient at substation maintenance for other reasons.

This relationship also suggests that an inquiry as to the accounting treatment of payments for station maintenance services rendered by others may be warranted. If for some reason these costs are bundled with other costs in the group of accounts that comprise this activity or are otherwise not part of the cost being evaluated, this will have an impact on how this result should be interpreted. If this is the case, the variable may be more of a correction for accounting classification issues than an estimate of expected efficiency gains from outsourcing station maintenance functions.

For these reasons, this variable was viewed as a measure of good opportunities beyond management control as opposed to a choice available to all distributors. This information on outsourcing may be useful in future refinements of this model.

Question 4

Question 4 asked for information about vegetation. It was a difficult question to ask and to answer. The goal was to measure the challenge each distributor faced from vegetation around its overhead lines. The approach that was adopted was to ask what percentage of line required clearance management over a long period of time. Five choices were offered (A being the lowest and E the highest percentages over the period to 2012). This was intended to serve as a proxy for what percentage potentially will need clearance.

Several variables were constructed that separated the responses into two groups above and below a threshold. The variable that grouped responses D and E (indicating larger vegetation challenges) separately from A, B, and C was more statistically significant than those that compared E vs. ABCD or CDE vs. AB. A version of the variable was constructed that assigned a percentage of vegetation based on the midpoint of the provided intervals. This was tested but did not have as much explanatory power as the binary version of the variable.

One limitation of this variable is that the question implicitly assumes the same type and growth in vegetation. To the extent that a distributor has vegetation that either grows faster or is more difficult to remove, the model will understate its cost performance. The reverse is true for distributors with an easier than average situation.

Question 5

Question 5 requested several items that indicate the scale of operation as represented by the quantity of assets in detailed areas of operation. These were used as variables in the models to replace the currently-available measures of operating scale such as number of customers served. As an example, number of customers was replaced by number of poles in the pole maintenance and vegetation management models.

The new scale variables gathered had statistically significant and plausibly signed (e.g., positive if increases in the variable should increase cost) parameter estimates in five of the six O&M models and in one of the four capex models and were able to supplement or replace the previously-used scale measures. All of the new scale variables proved statistically significant in some models even if they were not featured in the final models. Another variable that was not used was the number of line transformers. It was statistically significant, but the number of customers had superior explanatory power.

Question 6

Question 6 requested information on the type of pole (e.g., wood, steel, concrete). The theory is that there might be significant cost differences in pole construction and maintenance depending on the material used. If the additions were of more expensive materials (i.e., concrete) then the model will predict a cost that is too low relative to what was actually installed. The reverse is also true. The type of material used was not statistically significant in early versions of the pole capex model and was not included in the final model. PEG hoped that the easier-to-obtain data on the types of material for the entire system would be a good proxy for the types of poles added. The current evidence suggests that either the additions do not reflect the mix in types of poles or that the types of poles installed do not matter as much as anticipated. This issue could be revisited in the future if another round of data improvement is undertaken.

This variable was statistically significant in earlier versions of the vegetation management model, where wood construction tended to lower predicted cost. PEG suspects that wood poles may be a proxy for the height of the structure which could impact vegetation management cost. The construction material variable was not statistically significant in the pole maintenance model. It was not featured in the final version of the vegetation model, partially due to the uncertainty associated with its interpretation. Additional research in this area may be warranted.

Question 7

Question 7 requested that distributors provide capital continuity schedules for any years for which they have not already done so in previous rate applications. This request was different from the others in that accurate information on the *cost to be benchmarked* was not previously available. It is not an explanatory variable, but rather the cost to be explained by explanatory variables. The collection of this information is required to do capital expenditure benchmarking.

The data were compiled by OEB staff and the combination of previous data collection, information from previous rate filings, and supplemental information resulted in a database that contained enough data to perform capex benchmarking. Some distributors did not always report a value for plant additions in a given year, particularly for station equipment. These observations are not currently benchmarked. Modeling techniques to address these missing data such as calculating moving averages of additions could be considered in the future. The zero values would then be averaged with higher values from other years to smooth the level of investment and provide recognition of the lower levels of investment not previously benchmarked. Distributors that show poor cost performance in a particular year could use the zero values in other years not benchmarked as evidence that overall cost performance is not as bad as indicated by the model.

Question 8

Question 8 requested information on the age of various assets. It was expected that distributors could rely upon distribution system plans ("DSPs") required as a part of their rate applications as an accessible source of data to respond to this question.

In the context of O&M, older systems could be expected to have higher maintenance cost. In the context of capex, systems with an unusually large number of assets at or near replacement age will have a higher probability of needing replacement. The reason why age in an earlier year was requested is that the age in 2012 could be predictive of replacement capex (aka "repex") for subsequent years whereas information from 2019, for example, would not be as predictive of 2013 expenditures.

Unfortunately, not as many distributors as hoped provided information close to 2012 to be able to fully assess their effect on these hypotheses.

PEG constructed several age variables rom these data. Some of these were defined as the percentage of assets *below* a certain age cutoff, while others were defined as the percentage of assets *above* a certain age cutoff. Other variables that calculated an average age for each distributor based on the intervals provided with the questions were also constructed and tested. None of these variables was featured in the final capex models but two of the O&M models did feature age variables based on this information.

The problem encountered with the capex models is the offsetting effects of age. In the capex models, an older system should be indicative of *higher* capital expenditures for capex if the data provided are from *early* years. However, the same could be indicative of *lower* capex if the data provided are from *later* years. This is because a lack of investment will increase average system age over time. For example, a system that is older than average in 2019 may have been average age in 2012 with little investment since. These offsetting effects make it more difficult to model the effects of age. Variables that attempted to account for the year for which the data were provided were constructed and tested. These were generally either not statistically significant or had the wrong sign and were not able to improve the age variables.

PEG believes that additional information in this area could prove useful. The information already provided will also become more relevant over time because system age in 2019 should be predictive of future capex. Some distributors had noted that asset condition might be a preferable measure. PEG agrees that this would be desirable and should be considered for future data collection. The next section will present the updated model results and corresponding improvements in explanatory power.

4. New Research Results

4.1. Overview

New benchmarking work was undertaken for each of the ten granular cost categories that OEB staff shortlisted using samples that had been expanded to include 2018-2019 data and the new explanatory variables. A unit cost metric and an econometric model were developed for each area.

Each econometric model has a constant, one or more scale variables, a trend variable, and one or more other relevant business conditions. For example, if cost can be described by the equation $C = b_0 + b_1 \times Y$, where Y is an output variable, we use data for C and Y to estimate the values of b_0 and b_1. Once these estimates are available, the model can produce a predicted value for the cost of each distributor that is equal to $C = b_0 + b_1 \times Y$, given that distributor's data for Y. If the *actual* value for C for a given distributor in a given year is less that the *predicted* value $C = b_0 + b_1 \times Y_1$ then the distributor has performed well in the cost category. This is represented by a negative sign in the discussion and tables below. Any unexplained difference between actual and predicted cost is normally attributed to management performance in the absence of additional information.

The exact nature of the equation used to describe the relationship between cost and the explanatory variables to explain cost can take on many different forms. For example, additional terms can be added (e.g., $+ b_2 \times Y_2$), squared terms created (e.g., $+ b_3 \times Y_2 \times Y_2$), or interaction terms introduced [e.g., $+ b_4 \times (Y_1 \times Y_2)$]. Given the large number of possible variations of this equation, we created and followed some rules for making these choices. The goals we sought were to simultaneously improve explanatory power, minimize complexity, and reduce the dispersion of benchmarking results. A detailed discussion of the rules we followed is available in Appendix 2.

Table 2 compares the explanatory power of the new models to the power of those that we had previously developed. The Previous Results columns show the state of the econometric models prior to the collection of additional variables and 2018-2019 data. The Current Results columns show the current state of the models and the Improvement columns show the incremental change in explanatory power. As discussed above, two different types of explanatory power were used. The first is the R-squared statistic and the second is the dispersion of results as measured by the percent of distributors with actual cost within 50% of predicted cost.

Table 2

Overall Improvements to Updated Econometric Models

Model	Previous Results		Current Results		Improvement	
	R-squared value	% of companies within 50%	R-squared value	% of companies within 50%	R-squared value	% of companies within 50%
Billing O&M	0.870	79%	0.888	71%	0.018	-8%
Poles, Towers, and Fixtures O&M	0.462	52%	0.496	46%	0.034	-6%
Line O&M	0.867	49%	0.884	64%	0.017	15%
Metering O&M	0.749	37%	0.839	60%	0.090	23%
Vegetation Management O&M	0.818	69%	0.856	49%	0.038	-20%
Station Equipment O&M	0.680	30%	0.794	57%	0.114	27%
Poles, Towers, and Fixtures Capex	0.698	63%	0.851	67%	0.153	4%
Station Capex	0.376	22%	0.490	21%	0.114	-1%
Line Transformer Capex	0.813	22%	0.885	83%	0.072	61%
Meter Capex	0.594	37%	0.678	59%	0.084	22%
Average	**0.693**	**46%**	**0.766**	**58%**	**0.074**	**12%**

It can be seen that the R-squared statistics all the models were improved with the inclusion of the new data. The number of distributors with results within a 50% difference between actual and predicted cost was also improved in most of the new models. On this basis, it can be concluded that the additional data has improved the models. The improvements in explanatory power were generally more marked for the capex models than for the O&M cost models.

In addition to the econometric results, unit cost results were also calculated. Unit cost is defined as the ratio of cost to a unit of scale. If there is only one relevant scale variable, then the unit cost index will show the same relative performance as if it were expressed as a simple dollars per unit of output (e.g., dollars per pole). It is common for more than one scale variable to be relevant. As part of the rules we followed to simplify the models, the use of multiple scale variables is used only where necessary. Of the ten cost areas benchmarked, only the line maintenance O&M models used multiple scale variables.

Table 3 compares the unit cost results to the econometric results for each of the 10 cost areas. The Econometric Results columns have the same measures of explanatory power as Table 2. The Unit Cost Results columns have the same measures for the unit cost work. The percentage of distributors with scores within 50% is intended as a measure of the dispersion of benchmarking outcomes. It is possible to calculate something similar for the unit cost results. In this case, the number of unit cost values that were within 50% of average as a percentage of total observations was calculated. The last two columns compare this statistic for the two methods. Because the econometric work can address business conditions that the unit cost method cannot, one should expect better explanatory power from the econometric version of the benchmarking. As can be seen, some improvement can be seen in this statistic from using the econometric results instead of the unit cost results.

This can help guide the users of the APB models when faced with the choice of which set of results to feature. In the case of vegetation management, the econometric results show much less dispersion in results relative to the unit cost results. Therefore, if the unit cost results for a distributor are very atypical, one might check the econometric results to see the estimated cost impact of additional business conditions on the cost performance results. When examining distributor results for line transformer capex, however, there is little difference in the dispersion of results. Therefore, the econometric results are more likely to be similar and there is less harm in using the simpler method.

Table 3

Overall Econometric Benchmarking and Unit Cost Results

Model	Econometric Results % of companies within 50% of Predicted Cost	Unit Cost Results % of companies within 50% of Average Unit Cost
Billing O&M	71%	60%
Poles, Towers, and Fixtures O&M	46%	36%
Line O&M	64%	66%
Metering O&M	60%	66%
Vegetation Management O&M	49%	53%
Station Equipment O&M	57%	24%
Poles, Towers, and Fixtures Capex	67%	61%
Station Capex	21%	16%
Line Transformer Capex	83%	72%
Meter Capex	59%	63%
Average	**58%**	**52%**

4.2. O&M Research

For each of the O&M activities in this section, three tables are provided to show and discuss the results for unit cost and the econometric benchmarking.

Billing O&M

Table 4 summarizes the unit cost results for billing O&M. As can be seen, there is a fair amount of variation in the unit cost results. The number of distributors within 50% of average is 60% which is not as good as the econometric work (71%). A simple metric such as dollars per customer is unable to account for variations, between companies and over time, in business conditions other than scale of operations.

Our econometric work resulted in the model for billing O&M shown in Table 5. The model identified the number of customers as the relevant scale variable. For a distributor of average scale, a 1% increase in the number of customers results in a 0.897% increase in predicted cost. This suggests that a distributor of average scale should expect some additional scale economies from increasing its scale of operations because cost increases less than size.

The econometric work was able to account for other relevant business conditions such as customer density, the percentage distribution cost recorded as miscellaneous or supervision, the impact of pension accounting, and the overall trend in cost over time. The pension variable has a positive relationship with cost. Two allocation variables were included to measure the impact of suspected accounting issues with the itemization of expenses. One version is the ratio of supervision and engineering expense to total O&M. The second is the ratio of miscellaneous O&M to total O&M. To the extent that a distributor reported higher than average amounts in these broad categories, one may expect lower values in the billing account due to a lack of itemization of expenses. Both have negative signs and are statistically significant which suggests that some distributors may be putting less effort into itemizing O&M expenses as others.

The zero value of the trend variable parameter suggests that cost should not increase or decline for reasons other than measured by the business condition variables. These reasons include productivity growth. The impact of the scale variables is discussed above.

Table 4

Unit Cost Indexes by Distributor: Billing O&M

Distributor	Cost ($1,000) 2017	2018	2019	Average	Scale (1,000 customers) 2017	2018	2019	Average	Unit Cost ($ / customer) 2017	2018	2019	Average
Alectra Utilities Corporation	11,981	13,940	32,308	19,410	982.0	991.1	1,054.6	1009.2	$ 12.20	$ 14.06	$ 30.63	$ 18.97
Algoma Power Inc.	169	160	190	173	11.7	11.7	11.7	11.7	$ 14.39	$ 13.62	$ 16.21	$ 14.74
Atikokan Hydro Inc.	136	137	138	137	1.6	1.6	1.6	1.6	$ 82.92	$ 83.93	$ 84.88	$ 83.91
Bluewater Power Distribution	1,017	1,024	963	1,001	36.6	36.7	36.7	36.7	$ 27.79	$ 27.91	$ 26.20	$ 27.30
Brantford Power Inc.	972	960	1,005	979	39.6	39.9	40.1	39.9	$ 24.54	$ 24.05	$ 25.03	$ 24.54
Burlington Hydro Inc.	846	799	813	819	67.1	67.9	68.2	67.8	$ 12.61	$ 11.76	$ 11.92	$ 12.09
Canadian Niagara Power Inc.	441	474	423	446	29.1	29.2	29.5	29.3	$ 15.16	$ 16.20	$ 14.37	$ 15.25
Centre Wellington Hydro Ltd.	250	235	264	249	6.9	7.0	7.2	7.0	$ 36.08	$ 33.41	$ 36.88	$ 35.46
Chapleau Public Utilities Corporation	80	72	81	78	1.2	1.2	1.2	1.2	$ 64.79	$ 59.58	$ 66.64	$ 63.67
Cooperative Hydro Embrun Inc.	181	190	205	192	2.2	2.3	2.4	2.3	$ 80.87	$ 82.43	$ 86.79	$ 83.36
E.L.K. Energy Inc.	247	396	285	309	12.3	12.4	12.5	12.4	$ 20.04	$ 31.95	$ 22.86	$ 24.95
Elexicon Energy Inc.	4,997	4,735	3,650	4,461	163.0	164.7	167.7	165.1	$ 30.67	$ 28.74	$ 21.77	$ 27.06
Energy Plus	1,347	1,324	1,644	1,438	64.7	65.4	66.5	65.6	$ 20.81	$ 20.25	$ 24.71	$ 21.92
Entegrus Powerlines Inc.	2,160	2,349	2,057	2,189	58.7	59.2	59.8	59.2	$ 36.83	$ 39.68	$ 34.39	$ 36.97
ENWIN Utilities Ltd.	1,390	1,457	1,457	1,435	88.4	89.0	89.6	89.0	$ 15.72	$ 16.38	$ 16.27	$ 16.12
ERTH Power	1,221	1,224	1,382	1,276	22.8	23.1	23.4	23.1	$ 53.49	$ 52.98	$ 59.08	$ 55.19
Espanola Regional Hydro Distribution	184	188	187	186	3.3	3.3	3.3	3.3	$ 55.90	$ 56.84	$ 56.50	$ 56.42
Essex Powerlines Corporation	598	707	695	667	29.8	30.0	30.4	30.1	$ 20.10	$ 23.56	$ 22.87	$ 22.18
Festival Hydro Inc.	577	568	599	581	21.1	21.4	21.4	21.3	$ 27.34	$ 26.58	$ 28.01	$ 27.31
Fort Frances Power Corporation	192	183	167	181	3.7	3.7	3.8	3.8	$ 51.18	$ 48.93	$ 44.24	$ 48.11
Greater Sudbury Hydro Inc.	1,496	1,994	1,560	1,683	47.4	47.6	47.7	47.6	$ 31.55	$ 41.87	$ 32.69	$ 35.37
Grimsby Power Incorporated	466	459	423	449	11.4	11.6	11.6	11.5	$ 41.02	$ 39.76	$ 36.40	$ 39.06
Halton Hills Hydro Inc.	407	391	389	396	22.2	22.4	22.5	22.4	$ 18.36	$ 17.44	$ 17.27	$ 17.69
Hearst Power Distribution Company	213	201	207	207	2.7	2.7	2.7	2.7	$ 79.08	$ 74.70	$ 76.50	$ 76.76
Hydro One Networks	46,800	45,637	40,224	44,220	1,320.1	1,334.0	1,344.3	1332.8	$ 35.45	$ 34.21	$ 29.92	$ 33.19
Hydro 2000 Inc.	138	138	157	144	1.3	1.3	1.2	1.3	$ 109.75	$ 109.65	$ 125.97	$ 115.13
Hydro Hawkesbury Inc.	240	231	234	235	5.5	5.5	5.5	5.5	$ 43.36	$ 41.62	$ 42.23	$ 42.40
Hydro Ottawa Limited	8,620	8,531	8,224	8,459	331.8	335.3	339.8	335.6	$ 25.98	$ 25.44	$ 24.21	$ 25.21
Innpower Corporation	353	366	395	371	17.2	18.2	18.6	18.0	$ 20.50	$ 20.13	$ 21.22	$ 20.61
Kingston Hydro Corporation	352	326	357	345	27.6	27.7	27.8	27.7	$ 12.77	$ 11.80	$ 12.85	$ 12.48
Kitchener-Wilmot Hydro Inc.	1,890	2,122	2,297	2,103	95.8	96.8	97.7	96.8	$ 19.74	$ 21.92	$ 23.51	$ 21.72
Lakefront Utilities Inc.	223	210	232	222	10.3	10.5	10.5	10.4	$ 21.51	$ 20.13	$ 21.98	$ 21.21
Lakeland Power Distribution Ltd.	466	476	487	476	13.5	13.6	13.8	13.6	$ 34.56	$ 34.86	$ 35.39	$ 34.94
London Hydro Inc.	1,865	1,712	1,867	1,814	157.2	159.0	160.6	158.9	$ 11.86	$ 10.76	$ 11.62	$ 11.42
Milton Hydro Distribution Inc.	1,569	1,503	1,477	1,516	37.9	39.6	40.4	39.3	$ 41.39	$ 37.96	$ 36.56	$ 38.64
Newmarket-Tay Power Distribution	1,026	585	816	809	43.0	43.5	43.9	43.5	$ 23.87	$ 13.44	$ 18.57	$ 18.63
Niagara Peninsula Energy Inc.	3,070	2,928	3,147	3,048	54.9	55.6	56.1	55.5	$ 55.89	$ 52.67	$ 56.13	$ 54.90
Niagara-on-the-Lake Hydro Inc.	314	320	286	307	9.4	9.5	9.6	9.5	$ 33.45	$ 33.84	$ 29.97	$ 32.42
North Bay Hydro Distribution Limited	471	462	383	439	24.1	24.2	24.2	24.2	$ 19.53	$ 19.11	$ 15.83	$ 18.16
Northern Ontario Wires Inc.	243	250	234	243	6.0	5.9	6.0	6.0	$ 40.70	$ 42.22	$ 39.18	$ 40.70
Oakville Hydro Electricity Distribution	1,213	1,380	1,538	1,377	70.5	72.1	73.1	71.9	$ 17.21	$ 19.14	$ 21.03	$ 19.12
Orangeville Hydro Limited	357	369	338	355	12.4	12.6	12.7	12.5	$ 28.88	$ 29.29	$ 26.73	$ 28.30
Orillia Power Distribution	910	923	941	925	13.8	14.1	14.4	14.1	$ 65.79	$ 65.50	$ 65.53	$ 65.61
Oshawa PUC Networks Inc.	1,065	1,170	1,138	1,124	57.6	58.7	59.2	58.5	$ 18.50	$ 19.91	$ 19.24	$ 19.21
Ottawa River Power Corporation	439	427	441	436	11.1	11.2	11.3	11.2	$ 39.54	$ 37.97	$ 38.97	$ 38.82
Peterborough Distribution	761	735	833	777	37.3	37.1	37.3	37.2	$ 20.38	$ 19.80	$ 22.37	$ 20.85
PUC Distribution Inc.	550	446	476	491	33.6	33.6	33.6	33.6	$ 16.37	$ 13.28	$ 14.15	$ 14.60
Renfrew Hydro Inc.	279	293	312	295	4.3	4.3	4.3	4.3	$ 65.00	$ 68.01	$ 72.16	$ 68.39
Rideau St. Lawrence Distribution Inc.	349	368	383	367	5.9	5.9	5.9	5.9	$ 59.16	$ 62.29	$ 64.85	$ 62.10
Sioux Lookout Hydro Inc.	259	192	199	217	2.8	2.8	2.8	2.8	$ 91.02	$ 67.49	$ 69.98	$ 76.16
Synergy North Corporation	1,776	1,762	1,478	1,672	56.4	56.5	56.7	56.5	$ 31.48	$ 31.17	$ 26.07	$ 29.57
Tillsonburg Hydro Inc.	459	464	500	474	7.2	7.1	7.1	7.2	$ 63.70	$ 65.08	$ 70.13	$ 66.31
Toronto Hydro-Electric System	10,125	9,626	16,633	12,128	767.9	772.6	777.9	772.8	$ 13.18	$ 12.46	$ 21.38	$ 15.68
Wasaga Distribution Inc.	564	554	595	571	13.6	13.8	14.0	13.8	$ 41.49	$ 40.16	$ 42.52	$ 41.39
Waterloo North Hydro Inc.	1,646	1,637	1,731	1,671	57.0	57.5	57.9	57.5	$ 28.85	$ 28.49	$ 29.91	$ 29.08
Welland Hydro-Electric System Corp.	920	923	900	915	23.0	23.4	23.7	23.4	$ 39.92	$ 39.51	$ 38.05	$ 39.16
Wellington North Power Inc.	93	108	110	104	3.8	3.8	3.8	3.8	$ 24.67	$ 28.49	$ 28.73	$ 27.30
Westario Power Inc.	419	277	384	360	23.4	23.5	23.8	23.6	$ 17.92	$ 11.76	$ 16.14	$ 15.27
Distributor Average				**$ 2,206**				**88.84**				**$ 36.26**

Table 5

Econometric Model of Billing O&M

VARIABLE KEY

Scale Variables:

yn = Number of customers

Business Conditions:

custperkm = Customers per km of line
penload = Pensions allocated to O&M
pctmscbill = Percentage of O&M that is miscellaneous
pctsupbill = Percentage of O&M that is supervision
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.897	37.944	0.000
I(yn * yn/2)	0.152	12.339	0.000
custperkm	0.118	5.538	0.000
penload	0.508	10.469	0.000
pctmscbill	-0.062	-2.972	0.003
pctsupbill	-0.073	-4.030	0.000
trend	0.000	-0.096	0.924
Constant*	2.586	46.074	0.000
System Rbar-Squared	0.888		
Sample Period	2012-2019		
Number of Observations	462		

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 6 below. As can be seen there is a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%. There are several possible reasons to explain these differences. The first is that there is an unknown or unmeasurable business condition that affects billing O&M that is not included in the current model. The second is that there is an accounting issue that resulted in significantly more or less cost being recorded in the billing account. A third possible explanation is that the distributor is significantly better or worse at performing the billing function relative to other distributors. All three are of interest and will be discussed in more detail in Section 5 below.

There are several potential improvements that could be considered in this model should stakeholders find these models valuable and the OEB decides to commission improvements. A discussion of potential improvements is discussed below in Section 5.

PEG also tested several other business condition variables. In these cases, either the variable was not statistically significant or other combinations of other explanatory variables produced a better model. Additional or better data may produce better results in the future for these variables.

Conclusion: The billing O&M econometric models were improved by the inclusion of 2018-2019 data and the pension accounting variable made possible by the questionnaire. Continued monitoring of distributor accounting for pensions for compliance with OEB accounting guidance is recommended. The unit cost benchmarking provides an easier to understand alternative to the econometric model. In our opinion, both can be used for APB purposes.

Table 6

Cost Performance Results: Billing O&M

Distributor	Average Actual Cost	Average Predicted Cost	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 33,240,314	-53.8%
Algoma Power Inc.	$ 172,824	$ 308,054	-57.8%
Atikokan Hydro Inc.	$ 137,108	$ 170,335	-21.7%
Bluewater Power Distribution	$ 1,001,120	$ 844,610	17.0%
Brantford Power Inc.	$ 978,892	$ 728,088	29.6%
Burlington Hydro Inc.	$ 819,301	$ 1,574,120	-65.3%
Canadian Niagara Power Inc.	$ 445,939	$ 643,024	-36.6%
Centre Wellington Hydro Ltd.	$ 249,358	$ 288,267	-14.5%
Chapleau Public Utilities Corporation	$ 77,937	$ 105,520	-30.3%
Cooperative Hydro Embrun Inc.	$ 192,218	$ 141,547	30.6%
E.L.K. Energy Inc.	$ 309,443	$ 341,304	-9.8%
Elexicon Energy Inc.	$ 4,460,702	$ 3,408,615	26.9%
Energy Plus	$ 1,438,424	$ 1,196,676	18.4%
Entegrus Powerlines Inc.	$ 2,188,627	$ 1,093,381	69.4%
ENWIN Utilities Ltd.	$ 1,434,724	$ 1,979,754	-32.2%
ERTH Power	$ 1,275,736	$ 618,489	72.4%
Espanola Regional Hydro Distribution	$ 186,174	$ 198,479	-6.4%
Essex Powerlines Corporation	$ 666,785	$ 676,186	-1.4%
Festival Hydro Inc.	$ 581,358	$ 566,437	2.6%
Fort Frances Power Corporation	$ 180,648	$ 241,422	-29.0%
Greater Sudbury Hydro Inc.	$ 1,683,410	$ 973,188	54.8%
Grimsby Power Incorporated	$ 449,469	$ 380,341	16.7%
Halton Hills Hydro Inc.	$ 395,928	$ 574,921	-37.3%
Hearst Power Distribution Company	$ 207,091	$ 170,743	19.3%
Hydro One Networks	$ 44,220,101	$ 21,740,556	71.0%
Hydro 2000 Inc.	$ 144,241	$ 112,898	24.5%
Hydro Hawkesbury Inc.	$ 235,059	$ 223,148	5.2%
Hydro Ottawa Limited	$ 8,458,628	$ 7,808,298	8.0%
Innpower Corporation	$ 371,336	$ 386,877	-4.1%
Kingston Hydro Corporation	$ 345,236	$ 900,749	-95.9%
Kitchener-Wilmot Hydro Inc.	$ 2,103,214	$ 1,813,877	14.8%
Lakefront Utilities Inc.	$ 221,583	$ 320,472	-36.9%
Lakeland Power Distribution Ltd.	$ 476,292	$ 354,260	29.6%
London Hydro Inc.	$ 1,814,441	$ 3,227,725	-57.6%

Table 6 (continued)

Cost Performance Results: Billing O&M

Distributor	Average Actual Cost	Average Predicted Cost	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937	$ 886,950	53.6%
Newmarket-Tay Power Distribution	$ 808,922	$ 1,055,429	-26.6%
Niagara Peninsula Energy Inc.	$ 3,048,307	$ 1,017,742	109.7%
Niagara-on-the-Lake Hydro Inc.	$ 306,747	$ 355,322	-14.7%
North Bay Hydro Distribution Limited	$ 438,678	$ 649,865	-39.3%
Northern Ontario Wires Inc.	$ 242,501	$ 217,675	10.8%
Oakville Hydro Electricity Distribution	$ 1,376,904	$ 1,550,903	-11.9%
Orangeville Hydro Limited	$ 354,582	$ 447,618	-23.3%
Orillia Power Distribution	$ 924,782	$ 467,107	68.3%
Oshawa PUC Networks Inc.	$ 1,124,377	$ 1,616,445	-36.3%
Ottawa River Power Corporation	$ 435,782	$ 417,024	4.4%
Peterborough Distribution	$ 776,629	$ 1,010,259	-26.3%
PUC Distribution Inc.	$ 490,718	$ 875,565	-57.9%
Renfrew Hydro Inc.	$ 294,936	$ 279,991	5.2%
Rideau St. Lawrence Distribution Inc.	$ 366,644	$ 313,059	15.8%
Sioux Lookout Hydro Inc.	$ 216,533	$ 160,251	30.1%
Synergy North Corporation	$ 1,672,028	$ 1,363,476	20.4%
Tillsonburg Hydro Inc.	$ 474,090	$ 271,075	55.9%
Toronto Hydro-Electric System	$ 12,127,971	$ 22,931,568	-63.7%
Wasaga Distribution Inc.	$ 571,069	$ 460,131	21.6%
Waterloo North Hydro Inc.	$ 1,671,145	$ 1,176,459	35.1%
Welland Hydro-Electric System Corp.	$ 914,525	$ 699,527	26.8%
Wellington North Power Inc.	$ 103,820	$ 188,417	-59.6%
Westario Power Inc.	$ 359,825	$ 662,234	-61.0%
Average	**$ 2,206,040**	**$ 2,179,772**	**-0.7%**
Median	**$ 483,505**	**$ 630,756**	**3.5%**

Maintenance of Poles, Towers and Fixtures

Table 7 summarizes the unit cost results for pole maintenance. Values for each year are included as well as a three-year average for each distributor. The use of a three-year average is designed to smooth out the variation in cost performance and results in a measure that is typical of recent cost performance. This is the same method that is used in the econometric total cost benchmarking work done by PEG for the OEB each year.

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). A unit cost index is the ratio of a cost index to a scale index. Most of the unit cost measures in this report featured only one scale variable. In this simplified case, the cost index is presented in dollars and the scale in number of poles. The unit cost is just dollars per pole.

As can be seen, there is a fair amount of variation in the unit cost results. The number of distributors within 50% of average is only 36% which is not as good as the econometric work which had 46% within 50%. A simple metric such as dollars per pole is unable to account for other relevant business conditions such as the age of poles.

The econometric work was able to account for some other relevant business conditions including the percentage of poles over 50 years old, the impact of pension accounting, and the unexplained trend in cost over time. The model found a positive relationship between age and cost which suggests that older poles will tend to require more maintenance. The pension variable also has a positive relationship with cost. The negative value on the trend variable suggests that cost should decline by 1.5% per year for reasons other than measured by the business condition variables. The impact of the scale variables is discussed above.

Table 7

Unit Cost Indexes by Distributor: Pole Maintenance

Distributor	Cost ($1,000)				Scale (1,000 Poles)				Unit Cost ($ / pole)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	373.5	435.2	437.9	415.5	123.5	123.5	123.5	123.5	$ 3.02	$ 3.52	$ 3.55	$ 3.36
Algoma Power Inc.	121.2	101.8	142.2	121.7	30.2	30.4	30.5	30.3	$ 4.01	$ 3.35	$ 4.67	$ 4.01
Atikokan Hydro Inc.					1.3	1.3	1.3	1.3				
Bluewater Power Distribution	10.5	5.5	11.8	9.3	15.3	15.4	15.4	15.4	$ 0.68	$ 0.36	$ 0.76	$ 0.60
Brantford Power Inc.	40.5	34.6	43.5	39.5	10.0	10.0	10.0	10.0	$ 4.04	$ 3.45	$ 4.34	$ 3.94
Burlington Hydro Inc.	81.2	86.1	219.0	128.8	14.6	14.6	14.6	14.6	$ 5.55	$ 5.89	$ 14.96	$ 8.80
Canadian Niagara Power Inc.	81.9	93.5	124.4	99.9	24.5	24.5	24.4	24.5	$ 3.35	$ 3.82	$ 5.09	$ 4.09
Centre Wellington Hydro Ltd.	17.8	50.3	60.4	42.8	1.8	1.8	1.9	1.8	$ 10.08	$ 27.68	$ 32.51	$ 23.61
Chapleau Public Utilities Corporation		0.3		0.3	0.7	0.7	0.7	0.7		$ 0.42		$ 0.42
Cooperative Hydro Embrun Inc.	6.4	5.7	3.9	5.3	0.4	0.4	0.4	0.4	$ 14.90	$ 13.14	$ 9.06	$ 12.36
E.L.K. Energy Inc.	32.8	23.9	30.1	29.0	3.3	3.3	3.3	3.3	$ 9.99	$ 7.26	$ 9.12	$ 8.79
Elexicon Energy Inc.	229.6	196.0	153.5	193.0	36.5	34.8	36.5	36.0	$ 6.29	$ 5.63	$ 4.20	$ 5.37
Energy Plus	70.2	127.3	26.1	74.5	21.3	21.8	22.3	21.8	$ 3.29	$ 5.84	$ 1.17	$ 3.42
Entegrus Powerlines Inc.	70.1	60.1	152.2	94.1	14.7	20.1	20.7	18.5	$ 4.78	$ 2.99	$ 7.36	$ 5.10
ENWIN Utilities Ltd.		554.3	576.2	565.3	20.1	20.1	20.5	20.2		$ 27.63	$ 28.15	$ 27.96
ERTH Power	62.6	74.5	85.4	74.2	10.6	10.6	10.6	10.6	$ 5.93	$ 7.06	$ 8.09	$ 7.02
Espanola Regional Hydro Distribution	24.7	14.1	16.6	18.5	2.0	2.0	2.0	2.0	$ 12.41	$ 7.09	$ 8.33	$ 9.28
Essex Powerlines Corporation	82.3	32.1	85.2	66.5	6.3	6.3	6.2	6.3	$ 13.00	$ 5.14	$ 13.66	$ 10.61
Festival Hydro Inc.	55.7	34.2	58.9	49.6	6.0	6.0	6.0	6.0	$ 9.27	$ 5.70	$ 9.82	$ 8.26
Fort Frances Power Corporation	32.9	27.5	17.9	26.1	1.9	1.9	1.9	1.9	$ 17.54	$ 14.74	$ 9.59	$ 13.96
Greater Sudbury Hydro Inc.	260.4	242.7	190.1	231.1	12.1	12.0	12.0	12.0	$ 21.49	$ 20.16	$ 15.85	$ 19.18
Grimsby Power Incorporated	32.8	47.9	75.8	52.2	3.7	3.7	3.7	3.7	$ 8.94	$ 13.04	$ 20.65	$ 14.21
Halton Hills Hydro Inc.	28.8	24.0	1.7	18.2	9.1	9.2	9.4	9.2	$ 3.18	$ 2.60	$ 0.18	$ 1.97
Hearst Power Distribution Company	77.1	100.9	49.4	75.8	1.5	1.5	1.5	1.5	$ 50.42	$ 65.29	$ 31.98	$ 49.22
Hydro One Networks	18,515	19,297	22,361	20,058	1,604.1	1,608.0	1,609.9	1,607.4	$ 11.54	$ 12.00	$ 13.89	$ 12.48
Hydro 2000 Inc.	27.4	0.9	3.1	10.5	0.4	0.4	0.4	0.4	$ 74.47	$ 2.39	$ 8.38	$ 28.41
Hydro Hawkesbury Inc.	14.9	11.9	7.2	11.3	1.6	1.6	1.6	1.6	$ 9.55	$ 7.57	$ 4.54	$ 7.21
Hydro Ottawa Limited	710.8	691.6	600.6	667.7	49.5	48.5	48.9	49.0	$ 14.36	$ 14.26	$ 12.28	$ 13.63
Innpower Corporation	44.2	39.0	45.3	42.8	10.4	10.5	10.7	10.6	$ 4.24	$ 3.70	$ 4.21	$ 4.05
Kingston Hydro Corporation	100.3	72.3	65.7	79.5	3.5	3.5	3.5	3.5	$ 28.73	$ 20.63	$ 18.66	$ 22.66
Kitchener-Wilmot Hydro Inc.	364.2	296.7	347.1	336.0	23.1	23.1	23.2	23.1	$ 15.77	$ 12.83	$ 14.98	$ 14.53
Lakefront Utilities Inc.					3.1	3.1	3.1	3.1				
Lakeland Power Distribution Ltd.	0.2	3.6	27.1	10.3	6.4	6.3	6.3	6.4	$ 0.03	$ 0.57	$ 4.27	$ 1.61
London Hydro Inc.	565.8	695.6	640.1	633.8	27.0	27.0	27.0	27.0	$ 20.96	$ 25.78	$ 23.72	$ 23.49
Milton Hydro Distribution Inc.	157.3	360.2	334.3	283.9	9.7	9.7	9.7	9.7	$ 16.17	$ 37.11	$ 34.40	$ 29.22
Newmarket-Tay Power Distribution	54.6	53.2	112.5	73.4	8.5	8.5	8.5	8.5	$ 6.44	$ 6.27	$ 13.27	$ 8.66
Niagara Peninsula Energy Inc.	98.9	121.0	117.0	112.3	24.8	24.8	24.8	24.8	$ 3.99	$ 4.88	$ 4.71	$ 4.53
Niagara-on-the-Lake Hydro Inc.	79.9	52.5	63.5	65.3	4.8	4.8	4.8	4.8	$ 16.74	$ 10.99	$ 13.31	$ 13.68
North Bay Hydro Distribution Limited	43.4	18.7	158.6	73.6	10.4	10.4	10.4	10.4	$ 4.16	$ 1.79	$ 15.18	$ 7.05
Northern Ontario Wires Inc.	16.9	22.7	17.0	18.9	3.0	3.0	3.0	3.0	$ 5.60	$ 7.50	$ 5.59	$ 6.23
Oakville Hydro Electricity Distribution	52.4	33.8		43.1	8.4	8.4	8.5	8.4	$ 6.27	$ 4.01		$ 5.11
Orangeville Hydro Limited	28.8	5.5	5.4	13.2	1.7	1.7	1.7	1.7	$ 16.66	$ 3.17	$ 3.14	$ 7.67
Orillia Power Distribution	631.9	678.4	647.8	652.7	4.5	4.5	4.5	4.5	$ 139.18	$ 150.26	$ 144.34	$ 144.58
Oshawa PUC Networks Inc.	539.1	523.4	473.8	512.1	10.4	10.5	12.4	11.1	$ 51.87	$ 50.07	$ 38.27	$ 46.24
Ottawa River Power Corporation	27.1	6.4	4.6	12.7	4.1	4.1	4.1	4.1	$ 6.63	$ 1.56	$ 1.14	$ 3.11
Peterborough Distribution					11.2	11.2	11.2	11.2				
PUC Distribution Inc.	60.1	38.2	20.1	39.5	18.1	18.1	18.1	18.1	$ 3.32	$ 2.11	$ 1.11	$ 2.18
Renfrew Hydro Inc.	3.6	3.6	3.7	3.6	1.8	1.8	1.8	1.8	$ 2.02	$ 2.05	$ 2.08	$ 2.05
Rideau St. Lawrence Distribution Inc.	27.4	23.8	50.0	33.8	2.1	2.1	2.1	2.1	$ 12.98	$ 11.27	$ 23.57	$ 15.95
Sioux Lookout Hydro Inc.	42.2	39.1	25.1	35.5	2.7	2.7	2.7	2.7	$ 15.50	$ 14.32	$ 9.16	$ 12.99
Synergy North Corporation	302.5	363.3	363.7	343.2	23.2	23.3	23.4	23.3	$ 13.03	$ 15.58	$ 15.55	$ 14.72
Tillsonburg Hydro Inc.	23.6	15.7	16.1	18.4	2.4	2.4	2.4	2.4	$ 9.99	$ 6.54	$ 6.60	$ 7.69
Toronto Hydro-Electric System	512.6	580.6	1,160.9	751.3	178.8	179.4	180.3	179.5	$ 2.87	$ 3.24	$ 6.44	$ 4.19
Wasaga Distribution Inc.	25.3	13.2	9.8	16.1	5.2	5.2	5.2	5.2	$ 4.91	$ 2.55	$ 1.88	$ 3.11
Waterloo North Hydro Inc.	245.2	268.5	114.1	209.3	21.5	21.4	21.8	21.6	$ 11.41	$ 12.54	$ 5.23	$ 9.70
Welland Hydro-Electric System Corp.	227.6	279.2	143.5	216.8	7.8	7.8	7.9	7.9	$ 29.02	$ 35.58	$ 18.26	$ 27.62
Wellington North Power Inc.	9.5	10.0	18.1	12.5	1.9	1.9	1.9	1.9	$ 5.04	$ 5.28	$ 9.57	$ 6.64
Westario Power Inc.	211.6	126.5	170.2	169.4	10.4	10.4	10.3	10.4	$ 20.37	$ 12.17	$ 16.51	$ 16.35
Distributor Average				**$ 509**				**42.9**				**$ 14.05**

Our new econometric work resulted in the model for Poles, Towers and Fixtures Maintenance ("Poles Maintenance") shown in Table 8.

Table 8

Econometric Model of Pole Maintenance O&M Cost

VARIABLE KEY

Scale Variables:

npoles = Number of poles

Business Conditions:

pctwood = Percent of poles tahat are wood
pctsteel = Percent of poles that are steel
oldpol50 = % poles over 50 years old
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
npoles	0.766	10.065	0.000
I(npoles * npoles/2)	0.024	0.590	0.556
pctwood	0.458	2.792	0.005
pctsteel	-0.162	-1.836	0.067
oldpol50	0.064	1.854	0.064
penload	0.854	4.325	0.000
trend	-0.040	-2.858	0.004
Constant*	0.149	0.605	0.545
System Rbar-Squared	0.496		
Sample Period	2012-2019		
Number of Observations	407		

The model identified the number of poles as the scale variables. For a distributor of average scale, a 1% increase in the number of poles results in an increase in predicted maintenance cost of 0.766%. This suggests that a distributor of average scale should expect some cost savings as a result of increasing its scale of operations because size increases more than cost. The 0.496 R-squared statistic is much lower than that for billing and the lowest by far of all of the new O&M cost models that we developed.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 9 below. As can be seen there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%.

The explanatory power of the model as measured by R-squared was 0.496 which is a little higher than the preliminary model. The percentage of distributors with cost performance within 50% was 46% which was a little *worse* than the preliminary model produced. While the improvement in explanatory power is small, the model specification is considerably improved.

There are several potential improvements that could be considered should stakeholders find these models valuable and the OEB decides to commission improvements. These improvements include more accurate information on the age and types of poles. The information on number of poles should be collected on an ongoing basis and any changes in how the distributor accounts for labor cost should also be monitored. In addition, several distributors changed their reporting for km of line so that they now include secondary lines. PEG estimated the historical values of km of line for these companies in earlier years so as to be more consistent with the most recently reported value. These distributors could improve the accuracy of their results if *actual* values are provided to replace our estimates. However, PEG does not believe that the difference between the actual and estimated values would have a significant impact on the overall explanatory power of the model.

Conclusion: The pole maintenance O&M econometric models were improved by the inclusion of 2018-2019 data and the pension accounting variable made possible by the questionnaire. The information on system age and type of construction also helped. Continued collection of this information is recommended. Although the econometric model provides good explanatory power, the amount of variation to be explained is large which results in a significant dispersion of cost performance results. The unit cost benchmarking provides an easier to understand alternative to the econometric model. In our opinion, both can be used for APB purposes.

Table 9

Cost Performance Results: Pole Maintenance O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 14,051,981	32.3%
Algoma Power Inc.	$ 172,824.38	$ 241,598.18	-33.5%
Atikokan Hydro Inc.			
Bluewater Power Distribution	$ 1,001,120.24	$ 12,294,101.77	-250.8%
Brantford Power Inc.	$ 978,892.37	$ 1,477,965.40	-41.2%
Burlington Hydro Inc.	$ 819,300.95	$ 736,899.47	10.6%
Canadian Niagara Power Inc.	$ 445,938.71	$ 741,875.57	-50.9%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 127,470.93	67.1%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 1,419,276.75	-290.2%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 212,646.48	-10.1%
E.L.K. Energy Inc.	$ 309,442.63	$ 105,295.71	107.8%
Elexicon Energy Inc.	$ 4,460,702.04	$ 5,802,600.40	-26.3%
Energy Plus	$ 1,438,423.87	$ 2,610,516.19	-59.6%
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 2,782,290.71	-24.0%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 296,998.78	157.5%
ERTH Power	$ 1,275,736.38	$ 988,589.17	25.5%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 147,773.62	23.1%
Essex Powerlines Corporation	$ 666,785.34	$ 576,784.18	14.5%
Festival Hydro Inc.	$ 581,357.64	$ 497,385.87	15.6%
Fort Frances Power Corporation	$ 180,647.65	$ 161,023.20	11.5%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 543,254.02	113.1%
Grimsby Power Incorporated	$ 449,469.02	$ 339,022.65	28.2%
Halton Hills Hydro Inc.	$ 395,928.02	$ 2,813,634.76	-196.1%
Hearst Power Distribution Company	$ 207,090.82	$ 43,127.35	156.9%
Hydro One Networks	$ 44,220,101.17	$ 426,211.09	464.2%
Hydro 2000 Inc.	$ 144,241.31	$ 148,040.77	-2.6%
Hydro Hawkesbury Inc.	$ 235,058.84	$ 262,128.77	-10.9%
Hydro Ottawa Limited	$ 8,458,627.80	$ 3,016,770.72	103.1%
Innpower Corporation	$ 371,335.51	$ 680,008.97	-60.5%
Kingston Hydro Corporation			
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 733,789.29	105.3%
Lakefront Utilities Inc.			
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 9,897,434.35	-303.4%
London Hydro Inc.	$ 1,814,441.18	$ 382,042.86	155.8%

Table 9 (continued)

Cost Performance Results: Pole Maintenance O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 426,148.98	126.9%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 729,750.16	10.3%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 3,613,172.55	-17.0%
Niagara-on-the-Lake Hydro Inc.	$ 306,746.94	$ 221,411.53	32.6%
North Bay Hydro Distribution Limited	$ 438,677.78	$ 626,259.71	-35.6%
Northern Ontario Wires Inc.	$ 242,500.80	$ 378,798.74	-44.6%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 1,447,498.99	-5.0%
Orangeville Hydro Limited	$ 354,582.13	$ 842,134.72	-86.5%
Orillia Power Distribution	$ 924,782.33	$ 51,756.93	288.3%
Oshawa PUC Networks Inc.	$ 1,124,377.29	$ 176,970.78	184.9%
Ottawa River Power Corporation	$ 435,782.42	$ 1,481,993.00	-122.4%
Peterborough Distribution			
PUC Distribution Inc.	$ 490,717.95	$ 1,426,343.60	-106.7%
Renfrew Hydro Inc.	$ 294,936.00	$ 2,058,552.58	-194.3%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 314,628.09	15.3%
Sioux Lookout Hydro Inc.	$ 216,533.10	$ 184,701.94	15.9%
Synergy North Corporation	$ 1,672,028.19	$ 688,002.63	88.8%
Tillsonburg Hydro Inc.	$ 474,089.51	$ 482,700.38	-1.8%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 19,658,591.23	-48.3%
Wasaga Distribution Inc.	$ 571,069.22	$ 1,561,669.03	-100.6%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 852,577.66	67.3%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 282,705.16	117.4%
Wellington North Power Inc.	$ 103,820.01	$ 186,729.06	-58.7%
Westario Power Inc.	$ 359,825.35	$ 63,536.77	173.4%

Average	**9.8%**
Median	**10.5%**

Lines O&M

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). A unit cost index is the ratio of a cost index to a scale index. The cost index is the ratio of pole cost for a given distributor to the average cost for all distributors (e.g., if cost is $150 vs. an average of $100 then the cost index is 1.50 = 150/100). Because both the number of poles and customers are considered important scale variables, the scale index calculation is a little more complicated. It is calculated as a weighted average of a pole index and a customer index. Each of these is calculated the same as for the cost index (i.e., ratio to the sample average). The weights used to create the scale index from the pole index and km index are taken from the econometric results. This is an example of how the econometrics work informs the development of multidimensional scale variables for unit costs to make them more precise. Because the cost impact of number of poles is 0.334 and customers is 0.691, it can be said that number of customers is responsible for 67% of the increase in cost [0.691/(0.691+0.334)] due to scale. For example, assume that a distributor has cost that is 10% above average (i.e., cost index = 1.10) and has 20% more poles than average and 10% more customers than average (i.e., poles index = 1.20 and customer index = 1.10). The scale index would be 1.20 x 0.31 + 1.10 x 0.69 = 1.131 (i.e., 13.1% higher than average). Because cost is 110% of average and scale is 113.1% of average, unit cost would be 1.10/1.131 or 0.9725. The 0.9725 value can be interpreted as unit cost being 2.75% below average (0.9725 – 1).

Table 10 summarizes the unit cost results for line O&M. As can be seen, there is a fair amount of variation in the unit cost measures. The 67% of companies within 50% of average is actually better than the current econometric work. Using Algoma Power as an example from Table 10, they have a cost level in 2019 that is 26% of the average. They also have two different scale variables that have been combined into a single scale index. These were combined into a scale index by taking a weighted average of the two ratios. The unit cost index for each year is the ratio of the cost index to the scale index. Rather than taking the ratio of cost to a unit of scale such as dollars per pole, here we take the ratio of relative cost to relative scale to get a similar measure. Because they have cost that is only 26% of the average but have scale that is 35% of the average, they have below average cost. This is indicated by having a unit cost index of 0.90 which is less than 1.00. This method is a simplified version of a more complex method that uses logarithms in the calculations. It will not be as accurate, but it will be easier to use which is important in an APB context.

Table 10

Unit Cost Indexes by Distributor: Lines O&M

Distributor	Cost Index (Cost / Average)				Scale Index				Unit Cost (Cost Index/Scale Index)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	8.41	8.66	13.39	10.15	10.70	10.66	11.20	10.85	0.79	0.81	1.20	0.93
Algoma Power Inc.	0.40	0.29	0.26	0.31	0.35	0.35	0.35	0.35	1.14	0.83	0.74	0.90
Atikokan Hydro Inc.	0.13	0.11	0.10	0.11	0.03	0.03	0.03	0.03	4.75	4.20	3.97	4.31
Bluewater Power Distribution	0.54	0.60	0.48	0.54	0.48	0.48	0.47	0.48	1.12	1.25	1.02	1.13
Brantford Power Inc.	0.34	0.34	0.36	0.35	0.47	0.08	0.47	0.34	0.73	4.47	0.77	1.99
Burlington Hydro Inc.	1.26	1.26	1.10	1.21	0.78	0.78	0.78	0.78	1.62	1.62	1.42	1.55
Canadian Niagara Power Inc.	0.37	0.40	0.32	0.37	0.48	0.47	0.47	0.47	0.78	0.84	0.68	0.77
Centre Wellington Hydro Ltd.	0.08	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.94	0.85	0.95	0.92
Chapleau Public Utilities Corporation	0.07	0.05	0.05	0.06	0.02	0.02	0.02	0.02	3.89	2.70	2.78	3.12
Cooperative Hydro Embrun Inc.	0.01	0.01	0.00	0.01	0.03	0.03	0.03	0.03	0.22	0.25	0.15	0.21
E.L.K. Energy Inc.	0.19	0.18	0.20	0.19	0.15	0.15	0.15	0.15	1.26	1.20	1.37	1.28
Elexicon Energy Inc.	1.48	1.59	1.04	1.37	1.90	1.88	1.91	1.90	0.78	0.85	0.55	0.72
Energy Plus	0.77	0.78	0.75	0.77	0.81	0.81	0.82	0.81	0.95	0.97	0.91	0.95
Entegrus Powerlines Inc.	0.39	0.39	0.46	0.41	0.52	0.73	0.74	0.66	0.74	0.53	0.63	0.63
ENWIN Utilities Ltd.	1.48	1.22	1.12	1.27	1.03	1.03	1.03	1.03	1.43	1.19	1.09	1.24
ERTH Power	0.15	0.17	0.19	0.17	0.31	0.31	0.31	0.31	0.50	0.57	0.60	0.56
Espanola Regional Hydro Distribution	0.08	0.09	0.09	0.09	0.05	0.05	0.05	0.05	1.60	1.91	1.85	1.79
Essex Powerlines Corporation	0.27	0.29	0.23	0.26	0.34	0.34	0.34	0.34	0.80	0.84	0.67	0.77
Festival Hydro Inc.	0.34	0.35	0.35	0.35	0.26	0.26	0.25	0.26	1.32	1.38	1.37	1.36
Fort Frances Power Corporation	0.02	0.01	0.01	0.01	0.05	0.05	0.05	0.05	0.34	0.22	0.24	0.26
Greater Sudbury Hydro Inc.	0.51	0.41	0.41	0.44	0.56	0.56	0.56	0.56	0.90	0.73	0.73	0.78
Grimsby Power Incorporated	0.07	0.07	0.07	0.07	0.14	0.14	0.14	0.14	0.46	0.46	0.50	0.48
Halton Hills Hydro Inc.	0.21	0.19	0.18	0.19	0.29	0.29	0.29	0.29	0.72	0.64	0.61	0.66
Hearst Power Distribution Company	0.06	0.05	0.06	0.06	0.04	0.04	0.04	0.04	1.44	1.40	1.71	1.52
Hydro One Networks	18.72	17.65	18.74	18.37	25.49	25.36	25.35	25.40	0.73	0.70	0.74	0.72
Hydro 2000 Inc.	0.01	0.00	0.00	0.01	0.02	0.02	0.01	0.02	0.50	0.33	0.22	0.35
Hydro Hawkesbury Inc.	0.03	0.04	0.02	0.03	0.07	0.07	0.07	0.07	0.51	0.55	0.24	0.44
Hydro Ottawa Limited	2.01	1.96	1.83	1.94	3.68	3.66	3.68	3.67	0.55	0.54	0.50	0.53
Innpower Corporation	0.20	0.13	0.12	0.15	0.25	0.26	0.26	0.26	0.78	0.51	0.47	0.58
Kingston Hydro Corporation	0.29	0.29	0.24	0.27	0.30	0.30	0.30	0.30	0.97	0.98	0.80	0.92
Kitchener-Wilmot Hydro Inc.	1.43	1.55	1.47	1.48	1.13	1.13	1.13	1.13	1.27	1.37	1.31	1.32
Lakefront Utilities Inc.	0.12	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.95	1.15	1.13	1.08
Lakeland Power Distribution Ltd.	0.23	0.24	0.18	0.22	0.18	0.18	0.18	0.18	1.23	1.30	1.01	1.18
London Hydro Inc.	1.48	1.53	1.36	1.46	1.77	1.76	1.77	1.77	0.84	0.86	0.77	0.82
Milton Hydro Distribution Inc.	0.26	0.24	0.26	0.26	0.45	0.46	0.47	0.46	0.58	0.53	0.56	0.56
Newmarket-Tay Power Distribution	0.40	0.34	0.36	0.37	0.42	0.49	0.49	0.47	0.96	0.69	0.74	0.79
Niagara Peninsula Energy Inc.	0.71	0.69	0.72	0.71	0.74	0.73	0.73	0.74	0.96	0.95	0.98	0.96
Niagara-on-the-Lake Hydro Inc.	0.11	0.13	0.12	0.12	0.13	0.13	0.13	0.13	0.83	0.97	0.94	0.91
North Bay Hydro Distribution Limited	0.30	0.29	0.30	0.30	0.32	0.32	0.32	0.32	0.93	0.91	0.96	0.93
Northern Ontario Wires Inc.	0.13	0.13	0.12	0.13	0.08	0.08	0.08	0.08	1.60	1.61	1.42	1.55
Oakville Hydro Electricity Distribution	0.47	0.44	0.29	0.40	0.76	0.77	0.78	0.77	0.62	0.57	0.37	0.52
Orangeville Hydro Limited	0.07	0.04	0.05	0.05	0.14	0.14	0.14	0.14	0.48	0.31	0.39	0.40
Orillia Power Distribution	0.10	0.08	0.07	0.08	0.17	0.17	0.17	0.17	0.55	0.47	0.42	0.48
Oshawa PUC Networks Inc.	0.23	0.26	0.19	0.23	0.65	0.66	0.67	0.66	0.35	0.40	0.29	0.35
Ottawa River Power Corporation	0.09	0.02	0.07	0.06	0.14	0.14	0.14	0.14	0.63	0.11	0.49	0.41
Peterborough Distribution	0.39	0.39	0.35	0.38	0.46	0.45	0.45	0.45	0.85	0.87	0.79	0.84
PUC Distribution Inc.	0.58	0.67	0.66	0.64	0.47	0.47	0.47	0.47	1.23	1.43	1.43	1.36
Renfrew Hydro Inc.	0.03	0.03	0.02	0.03	0.06	0.06	0.06	0.06	0.47	0.60	0.43	0.50
Rideau St. Lawrence Distribution Inc.	0.09	0.07	0.08	0.08	0.07	0.07	0.07	0.07	1.18	0.92	1.05	1.05
Sioux Lookout Hydro Inc.	0.15	0.13	0.14	0.14	0.05	0.05	0.05	0.05	3.04	2.70	2.78	2.84
Synergy North Corporation	1.12	1.12	1.06	1.10	0.74	0.73	0.73	0.73	1.51	1.53	1.45	1.50
Tillsonburg Hydro Inc.	0.03	0.03	0.03	0.03	0.09	0.09	0.09	0.09	0.35	0.33	0.34	0.34
Toronto Hydro-Electric System	9.02	10.33	6.25	8.54	9.01	8.94	8.94	8.96	1.00	1.16	0.70	0.95
Wasaga Distribution Inc.	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.88	0.89	0.91	0.89
Waterloo North Hydro Inc.	0.58	0.54	0.47	0.53	0.73	0.73	0.73	0.73	0.79	0.74	0.64	0.72
Welland Hydro-Electric System Corp.	0.48	0.45	0.52	0.48	0.29	0.29	0.29	0.29	1.65	1.56	1.79	1.67
Wellington North Power Inc.	0.03	0.02	0.01	0.02	0.05	0.05	0.05	0.05	0.49	0.37	0.27	0.38
Westario Power Inc.	0.38	0.30	0.26	0.31	0.31	0.31	0.31	0.31	1.20	0.95	0.85	1.00
Distributor Average				$ 1.00				1.1971				1.011

The econometric work was able to account for other relevant business conditions such as the percentage of transformers less than 20 years old. Variables to adjust for accounting issues were also included. The impact of pension accounting and the propensity for distributors to not itemize but rather record expenses as supervision or miscellaneous were also considered. The model found a positive relationship between older age and cost which suggests that younger systems will tend to require less maintenance. The pension variable also has a positive relationship with cost. This reflects the average additional cost that is included in the maintenance cost because the distributor chose to include more than just salaries and wages. The variables that measured the percent of distribution O&M recorded as supervision or miscellaneous respectively each had negative signs. This means that the more distributors tended to record expenses in these general categories, the less cost was observed in the more itemized account being benchmarked. The negative value on the trend variable suggest that cost should increase by 0.3% per year for reasons other than measured by the business condition variables. The impact of the scale variables is discussed above.

The econometric work resulted in the model for Lines O&M cost shown in Table 11. The explanatory power of the model as measured by R-squared was 0.884 which is almost identical to the preliminary model. The percentage of distributors with cost performance within 50% was 57% which was also a little better than the preliminary work. While the improvement in explanatory power is small, the model specification is more sophisticated and includes more relevant and intuitive scale variables.

There are several potential improvements that could be considered. These improvements include more accurate information on the age and types of poles. The information on number of poles should be collected on an ongoing basis and any changes in how the distributor accounts for labor cost should also be monitored.

Conclusion: The lines O&M econometric models were improved by the inclusion of 2018-2019 data and the pension, age, and number of poles information made possible by the questionnaire. Continued collection of these data is recommended. The econometric model has good explanatory power. The unit cost benchmarking provides an easier to understand alternative to the econometric model. Both methods resulted in reasonable levels of dispersion. In our opinion, both can be used for APB purposes.

Table 11

Econometric Model of Lines O&M

VARIABLE KEY

Scale Variables:

yn = Number of customers
ypol = Number of poles

Business Conditions:

agetrf20 = % line transformers under 20 years old
pctmscdx = % distribution O&M miscellaneous
pctsupdx = % distribution O&M supervision
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.691	14.866	0.000
I(yn * yn/2)	0.143	5.019	0.000
ypol	0.334	5.893	0.000
I(ypol * ypol/2)	-0.157	-5.030	0.000
agetrf20	-0.227	-3.860	0.000
pctmscdx	-0.357	-9.807	0.000
pctsupdx	-0.189	-4.791	0.000
penload	0.933	5.330	0.000
trend	0.003	0.639	0.523
Constant*	3.268	22.229	0.000
System Rbar-Squared	0.884		
Sample Period	2012-2019		
Number of Observations	447		

Table 12

Cost Performance Results: Lines O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 23,377,252	-18.6%
Algoma Power Inc.	$ 172,824.38	$ 223,917.10	-25.9%
Atikokan Hydro Inc.	$ 137,108.02	$ 36,589.78	132.1%
Bluewater Power Distribution	$ 1,001,120.24	$ 686,684.47	37.7%
Brantford Power Inc.	$ 978,892.37	$ 718,683.95	30.9%
Burlington Hydro Inc.	$ 819,300.95	$ 582,571.24	34.1%
Canadian Niagara Power Inc.	$ 445,938.71	$ 659,301.89	-39.1%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 142,720.52	55.8%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 11,598.81	190.5%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 236,898.33	-20.9%
E.L.K. Energy Inc.	$ 309,442.63	$ 90,267.07	123.2%
Elexicon Energy Inc.	$ 4,460,702.04	$ 5,727,654.80	-25.0%
Energy Plus	$ 1,438,423.87	$ 1,343,862.56	6.8%
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 2,998,987.06	-31.5%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 976,259.12	38.5%
ERTH Power	$ 1,275,736.38	$ 1,671,169.30	-27.0%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 101,563.23	60.6%
Essex Powerlines Corporation	$ 666,785.34	$ 672,813.49	-0.9%
Festival Hydro Inc.	$ 581,357.64	$ 308,082.04	63.5%
Fort Frances Power Corporation	$ 180,647.65	$ 645,192.32	-127.3%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 1,332,186.72	23.4%
Grimsby Power Incorporated	$ 449,469.02	$ 630,218.71	-33.8%
Halton Hills Hydro Inc.	$ 395,928.02	$ 619,698.11	-44.8%
Hearst Power Distribution Company	$ 207,090.82	$ 105,441.62	67.5%
Hydro One Networks	$ 44,220,101.17	$ 1,733,564.10	323.9%
Hydro 2000 Inc.	$ 144,241.31	$ 368,886.01	-93.9%
Hydro Hawkesbury Inc.	$ 235,058.84	$ 345,100.57	-38.4%
Hydro Ottawa Limited	$ 8,458,627.80	$ 13,173,232.92	-44.3%
Innpower Corporation	$ 371,335.51	$ 476,327.67	-24.9%
Kingston Hydro Corporation	$ 345,235.52	$ 198,984.49	55.1%
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 1,353,192.52	44.1%
Lakefront Utilities Inc.			
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 261,133.26	60.1%
London Hydro Inc.	$ 1,814,441.18	$ 1,262,100.67	36.3%

Table 12 (continued)

Cost Performance Results: Lines O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 1,678,723.58	-10.2%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 568,330.00	35.3%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 1,961,258.20	44.1%
Niagara-on-the-Lake Hydro Inc.	$ 306,746.94	$ 284,013.88	7.7%
North Bay Hydro Distribution Limited	$ 438,677.78	$ 529,411.04	-18.8%
Northern Ontario Wires Inc.	$ 242,500.80	$ 77,246.76	114.4%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 1,554,007.74	-12.1%
Orangeville Hydro Limited	$ 354,582.13	$ 285,413.78	21.7%
Orillia Power Distribution	$ 924,782.33	$ 1,825,407.25	-68.0%
Oshawa PUC Networks Inc.	$ 1,124,377.29	$ 2,517,406.90	-80.6%
Ottawa River Power Corporation			
Peterborough Distribution	$ 776,628.65	$ 839,630.83	-7.8%
PUC Distribution Inc.	$ 490,717.95	$ 360,636.14	30.8%
Renfrew Hydro Inc.	$ 294,936.00	$ 496,090.51	-52.0%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 228,238.53	47.4%
Sioux Lookout Hydro Inc.	$ 216,533.10	$ 68,493.81	115.1%
Synergy North Corporation	$ 1,672,028.19	$ 1,145,724.71	37.8%
Tillsonburg Hydro Inc.	$ 474,089.51	$ 539,906.59	-13.0%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 15,157,787.94	-22.3%
Wasaga Distribution Inc.	$ 571,069.22	$ 685,062.74	-18.2%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 1,397,254.19	17.9%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 505,933.14	59.2%
Wellington North Power Inc.	$ 103,820.01	$ 204,109.92	-67.6%
Westario Power Inc.	$ 359,825.35	$ 428,212.16	-17.4%

Average	**16.6%**
Median	**7.3%**

Meter O&M

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). The number of customers was used as the scale variable due to its close association with number of meters. Although number of poles is also a measure of scale, in this model it serves as a proxy for service territory size and customer density (i.e., holding customers constant, more lines implies lower density and higher cost). Table 13 summarizes the unit cost results for meter O&M. As can be seen, there is a fair amount of variation in the unit cost evaluations. The percent of companies with scores that are within 50% of average is 57% which is not as good as the econometric work. A simple metric such as dollars per customer is unable to account for business conditions other than scale.

The econometric work was able to account for other relevant business conditions such as the percentage distribution cost recorded as miscellaneous, the impact of pension accounting, and the unexplained trend in cost over time. As in the other models, there was a negative relationship between the cost allocation variable and cost which suggests that distributors that have more cost recorded in the miscellaneous account will tend to have less cost recorded in the accounts we are benchmarking. The pension variable once again had a positive relationship with cost. The negative value on the trend variable suggests that cost should decline by 3.0% per year for reasons other than measured by the business condition variables. The impact of the scale variables is discussed above.

Our econometric work resulted in the model for Meter O&M cost shown in Table 14. The model identified the number of poles and the number of customers as relevant scale variables. The number of poles is presumably a proxy for the geographical dispersion of meters. The results suggest that the long-run impact of customers is similar to that of poles. For a distributor of average scale, a 1% increase in the number of customers results in an increase in predicted cost of 0.402% whereas a 1% increase in number of poles results in an increase of 0.483%. A 1% increase in overall scale (i.e., 1% increase in both poles and customers) results in an expected cost increase of 0.885%. This suggests that a distributor of average scale should expect some cost savings as a result of increasing its scale of operations because size increases more than cost.

Table 13

Unit Cost Indexes by Distributor: Meter Maintenance

Distributor	Cost ($1,000)				Scale (1,000 customers)				Unit Cost ($ per customer)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	13,909	15,665	9,045	12,873	982.0	991.1	1,054.6	1,009.2	$ 14.16	$ 15.81	$ 8.58	$ 12.85
Algoma Power Inc.	966.8	877.3	829.7	891.3	11.7	11.7	11.7	11.7	$ 82.46	$ 74.85	$ 70.72	$ 76.01
Atikokan Hydro Inc.	81.2	86.2	85.2	84.2	1.6	1.6	1.6	1.6	$ 49.60	$ 52.66	$ 52.32	$ 51.53
Bluewater Power Distribution	764.0	813.2	759.3	778.8	36.6	36.7	36.7	36.7	$ 20.88	$ 22.16	$ 20.67	$ 21.24
Brantford Power Inc.	823.3	886.9	874.3	861.5	39.6	39.9	40.1	39.9	$ 20.78	$ 22.23	$ 21.79	$ 21.60
Burlington Hydro Inc.	956.1	745.1	693.3	798.2	67.1	67.9	68.2	67.8	$ 14.24	$ 10.97	$ 10.17	$ 11.79
Canadian Niagara Power Inc.	949.8	798.3	866.8	871.6	29.1	29.2	29.5	29.3	$ 32.69	$ 27.29	$ 29.43	$ 29.80
Centre Wellington Hydro Ltd.	186.1	202.3	213.2	200.5	6.9	7.0	7.2	7.0	$ 26.91	$ 28.81	$ 29.79	$ 28.50
Chapleau Public Utilities Corporation	48.0	41.6	41.9	43.9	1.2	1.2	1.2	1.2	$ 38.71	$ 34.45	$ 34.31	$ 35.82
Cooperative Hydro Embrun Inc.	2.5		12.0	7.3	2.2	2.3	2.4	2.3	$ 1.13		$ 5.06	$ 3.10
E.L.K. Energy Inc.	222.1	244.6	246.4	237.7	12.3	12.4	12.5	12.4	$ 17.99	$ 19.75	$ 19.75	$ 19.16
Elexicon Energy Inc.	1,879.9	1,744.0	1,211.1	1,611.6	163.0	164.7	167.7	165.1	$ 11.54	$ 10.59	$ 7.22	$ 9.78
Energy Plus	1,319.5	1,373.9	1,344.3	1,345.9	64.7	65.4	66.5	65.6	$ 20.39	$ 21.01	$ 20.21	$ 20.53
Entegrus Powerlines Inc.	499.4	551.6	389.1	480.0	58.7	59.2	59.8	59.2	$ 8.51	$ 9.32	$ 6.51	$ 8.11
ENWIN Utilities Ltd.	1,255.2	1,301.2	1,422.3	1,326.2	88.4	89.0	89.6	89.0	$ 14.20	$ 14.62	$ 15.88	$ 14.90
ERTH Power	266.8	329.8	433.9	343.5	22.8	23.1	23.4	23.1	$ 11.69	$ 14.27	$ 18.56	$ 14.84
Espanola Regional Hydro Distribution	71.2	76.9	108.9	85.7	3.3	3.3	3.3	3.3	$ 21.65	$ 23.29	$ 32.90	$ 25.95
Essex Powerlines Corporation	351.2	388.8	346.8	362.3	29.8	30.0	30.4	30.1	$ 11.80	$ 12.95	$ 11.41	$ 12.05
Festival Hydro Inc.	680.1	626.9	615.2	640.7	21.1	21.4	21.4	21.3	$ 32.22	$ 29.34	$ 28.77	$ 30.11
Fort Frances Power Corporation	64.5	62.9	98.6	75.3	3.7	3.7	3.8	3.8	$ 17.21	$ 16.81	$ 26.13	$ 20.05
Greater Sudbury Hydro Inc.	826.0	769.5	809.7	801.8	47.4	47.6	47.7	47.6	$ 17.42	$ 16.16	$ 16.97	$ 16.85
Grimsby Power Incorporated	259.1	303.4	230.4	264.3	11.4	11.6	11.6	11.5	$ 22.82	$ 26.26	$ 19.81	$ 22.96
Halton Hills Hydro Inc.	151.4	97.6	116.7	121.9	22.2	22.4	22.5	22.4	$ 6.82	$ 4.35	$ 5.18	$ 5.45
Hearst Power Distribution Company	27.9	38.9	34.4	33.7	2.7	2.7	2.7	2.7	$ 10.35	$ 14.41	$ 12.75	$ 12.50
Hydro One Networks	25,304	31,447	28,775	28,509	1,320.1	1,334.0	1,344.3	1,332.8	$ 19.17	$ 23.57	$ 21.41	$ 21.38
Hydro 2000 Inc.	18.0	15.6	8.1	13.9	1.3	1.3	1.2	1.3	$ 14.32	$ 12.38	$ 6.49	$ 11.06
Hydro Hawkesbury Inc.	44.3	46.0	34.8	41.7	5.5	5.5	5.5	5.5	$ 8.01	$ 8.30	$ 6.27	$ 7.53
Hydro Ottawa Limited	2,793.1	2,535.6	2,355.3	2,561.3	331.8	335.3	339.8	335.6	$ 8.42	$ 7.56	$ 6.93	$ 7.64
Innpower Corporation	294.2	307.9	291.1	297.7	17.2	18.2	18.6	18.0	$ 17.07	$ 16.95	$ 15.62	$ 16.55
Kingston Hydro Corporation	532.2	623.2	659.2	604.8	27.6	27.7	27.8	27.7	$ 19.29	$ 22.53	$ 23.73	$ 21.85
Kitchener-Wilmot Hydro Inc.	1,536.9	1,490.6	1,685.3	1,570.9	95.8	96.8	97.7	96.8	$ 16.05	$ 15.39	$ 17.25	$ 16.23
Lakefront Utilities Inc.	287.2	293.1	282.4	287.6	10.3	10.5	10.5	10.4	$ 27.76	$ 28.04	$ 26.77	$ 27.52
Lakeland Power Distribution Ltd.	162.7	176.6	168.8	169.3	13.5	13.6	13.8	13.6	$ 12.06	$ 12.94	$ 12.26	$ 12.42
London Hydro Inc.	2,892.4	3,028.3	3,309.7	3,076.8	157.2	159.0	160.6	158.9	$ 18.40	$ 19.04	$ 20.61	$ 19.35
Milton Hydro Distribution Inc.	656.0	679.7	636.6	657.4	37.9	39.6	40.4	39.3	$ 17.31	$ 17.17	$ 15.76	$ 16.75
Newmarket-Tay Power Distribution	897.3	789.3	925.6	870.7	43.0	43.5	43.9	43.5	$ 20.88	$ 18.13	$ 21.07	$ 20.03
Niagara Peninsula Energy Inc.	929.7	989.6	984.1	967.8	54.9	55.6	56.1	55.5	$ 16.93	$ 17.80	$ 17.55	$ 17.43
Niagara-on-the-Lake Hydro Inc.	175.9	189.9	183.2	183.0	9.4	9.5	9.6	9.5	$ 18.76	$ 20.07	$ 19.17	$ 19.33
North Bay Hydro Distribution Limited	579.1	530.1	578.3	562.5	24.1	24.2	24.2	24.2	$ 24.01	$ 21.93	$ 23.90	$ 23.28
Northern Ontario Wires Inc.	224.1	255.8	269.7	249.9	6.0	5.9	6.0	6.0	$ 37.48	$ 43.22	$ 45.12	$ 41.94
Oakville Hydro Electricity Distribution	583.5	1,247.8	1,362.1	1,064.5	70.5	72.1	73.1	71.9	$ 8.28	$ 17.30	$ 18.62	$ 14.74
Orangeville Hydro Limited	242.0	242.3	268.7	251.0	12.4	12.6	12.7	12.5	$ 19.57	$ 19.26	$ 21.24	$ 20.02
Orillia Power Distribution	256.1	290.0	279.0	275.0	13.8	14.1	14.4	14.1	$ 18.52	$ 20.58	$ 19.42	$ 19.51
Oshawa PUC Networks Inc.	864.5	896.5	1,093.2	951.4	57.6	58.7	59.2	58.5	$ 15.01	$ 15.26	$ 18.47	$ 16.25
Ottawa River Power Corporation	156.0	166.7	198.1	173.6	11.1	11.2	11.3	11.2	$ 14.04	$ 14.82	$ 17.50	$ 15.45
Peterborough Distribution	399.7	321.9	356.7	359.4	37.3	37.1	37.3	37.2	$ 10.70	$ 8.67	$ 9.58	$ 9.65
PUC Distribution Inc.	748.2	727.4	722.1	732.6	33.6	33.6	33.6	33.6	$ 22.28	$ 21.64	$ 21.46	$ 21.79
Renfrew Hydro Inc.	127.9	36.0	30.2	64.7	4.3	4.3	4.3	4.3	$ 29.75	$ 8.34	$ 6.98	$ 15.03
Rideau St. Lawrence Distribution Inc.	89.2	98.5	72.4	86.7	5.9	5.9	5.9	5.9	$ 15.14	$ 16.67	$ 12.25	$ 14.69
Sioux Lookout Hydro Inc.	88.7	73.7	96.3	86.3	2.8	2.8	2.8	2.8	$ 31.21	$ 25.97	$ 33.82	$ 30.34
Synergy North Corporation	471.6	497.3	593.4	520.8	56.4	56.5	56.7	56.5	$ 8.36	$ 8.80	$ 10.47	$ 9.21
Tillsonburg Hydro Inc.	126.2	123.2	62.4	103.9	7.2	7.1	7.1	7.2	$ 17.52	$ 17.30	$ 8.75	$ 14.52
Toronto Hydro-Electric System	4,490.0	5,193.3	5,556.2	5,079.9	767.9	772.6	777.9	772.8	$ 5.85	$ 6.72	$ 7.14	$ 6.57
Wasaga Distribution Inc.	182.6	224.9	232.2	213.3	13.6	13.8	14.0	13.8	$ 13.44	$ 16.31	$ 16.59	$ 15.44
Waterloo North Hydro Inc.	777.7	791.7	867.4	812.2	57.0	57.5	57.9	57.5	$ 13.63	$ 13.77	$ 14.99	$ 14.13
Welland Hydro-Electric System Corp.	426.2	273.0	291.4	330.2	23.0	23.4	23.7	23.4	$ 18.49	$ 11.68	$ 12.31	$ 14.16
Wellington North Power Inc.	156.7	147.2	160.4	154.7	3.8	3.8	3.8	3.8	$ 41.56	$ 38.68	$ 41.87	$ 40.71
Westario Power Inc.	520.3	547.0	562.8	543.4	23.4	23.5	23.8	23.6	$ 22.26	$ 23.23	$ 23.67	$ 23.05
Distributor Average				**$ 1,337**				**88.8**				**$ 19.67**

Pacific Economics Group Research, LLC

Table 14

Econometric Model of Meter O&M Cost

VARIABLE KEY

Scale Variables:

yn = Number of customers
npoles= Number of poles

Business Conditions:

pctmscdx = Percent of distribution O&M that is miscellaneous
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.402	11.190	0.000
I(yn * yn/2)	-0.050	-4.030	0.000
npoles	0.483	14.789	0.000
pctmscdx	-0.168	-5.004	0.000
penload	1.092	5.855	0.000
trend	-0.030	-5.019	0.000
Constant*	2.371	16.179	0.000
System Rbar-Squared	0.839		
Sample Period	2012-2019		
Number of Observations	459		

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 15.

The explanatory power of the model as measured by R-squared was 0.839 which is a little higher than the preliminary model. The percentage of distributors with a cost performance less than 50% was 60% which was significantly better than the preliminary work.

Table 15

Cost Performance Results: Meter O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 9,251,294	74.1%
Algoma Power Inc.	$ 172,824.38	$ 91,037.90	64.1%
Atikokan Hydro Inc.	$ 137,108.02	$ 73,095.67	62.9%
Bluewater Power Distribution	$ 1,001,120.24	$ 885,254.25	12.3%
Brantford Power Inc.	$ 978,892.37	$ 640,610.54	42.4%
Burlington Hydro Inc.	$ 819,300.95	$ 1,174,328.15	-36.0%
Canadian Niagara Power Inc.	$ 445,938.71	$ 449,071.24	-0.7%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 133,071.73	62.8%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 16,893.06	152.9%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 701,086.35	-129.4%
E.L.K. Energy Inc.	$ 309,442.63	$ 124,433.66	91.1%
Elexicon Energy Inc.	$ 4,460,702.04	$ 6,960,881.80	-44.5%
Energy Plus	$ 1,438,423.87	$ 1,226,970.32	15.9%
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 4,726,923.58	-77.0%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 1,502,263.19	-4.6%
ERTH Power	$ 1,275,736.38	$ 1,758,609.71	-32.1%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 171,516.85	8.2%
Essex Powerlines Corporation	$ 666,785.34	$ 830,865.69	-22.0%
Festival Hydro Inc.	$ 581,357.64	$ 333,741.29	55.5%
Fort Frances Power Corporation	$ 180,647.65	$ 197,265.09	-8.8%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 1,350,968.50	22.0%
Grimsby Power Incorporated	$ 449,469.02	$ 383,779.02	15.8%
Halton Hills Hydro Inc.	$ 395,928.02	$ 1,813,896.25	-152.2%
Hearst Power Distribution Company	$ 207,090.82	$ 371,354.61	-58.4%
Hydro One Networks	$ 44,220,101.17	$ 22,179,744.52	69.0%
Hydro 2000 Inc.	$ 144,241.31	$ 154,854.77	-7.1%
Hydro Hawkesbury Inc.	$ 235,058.84	$ 384,074.24	-49.1%
Hydro Ottawa Limited	$ 8,458,627.80	$ 11,136,042.97	-27.5%
Innpower Corporation	$ 371,335.51	$ 489,363.71	-27.6%
Kingston Hydro Corporation	$ 345,235.52	$ 184,976.14	62.4%
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 1,852,371.36	12.7%
Lakefront Utilities Inc.	$ 221,582.58	$ 65,614.41	121.7%
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 801,136.10	-52.0%
London Hydro Inc.	$ 1,814,441.18	$ 870,034.45	73.5%

Table 15 (continued

Cost Performance Results: Meter O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 1,244,873.27	19.7%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 504,063.49	47.3%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 3,409,570.08	-11.2%
Niagara-on-the-Lake Hydro Inc.	$ 306,746.94	$ 369,822.48	-18.7%
North Bay Hydro Distribution Limited	$ 438,677.78	$ 426,565.17	2.8%
Northern Ontario Wires Inc.	$ 242,500.80	$ 105,848.10	82.9%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 1,080,946.70	24.2%
Orangeville Hydro Limited	$ 354,582.13	$ 185,850.02	64.6%
Orillia Power Distribution	$ 924,782.33	$ 924,782.33	0.0%
Oshawa PUC Networks Inc.	$ 1,124,377.29	$ 1,098,811.74	2.3%
Ottawa River Power Corporation	$ 435,782.42	$ 606,159.46	-33.0%
Peterborough Distribution	$ 776,628.65	$ 1,585,987.17	-71.4%
PUC Distribution Inc.	$ 490,717.95	$ 505,157.13	-2.9%
Renfrew Hydro Inc.	$ 294,936.00	$ 513,247.60	-55.4%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 512,034.13	-33.4%
Sioux Lookout Hydro Inc.	$ 216,533.10	$ 242,679.93	-11.4%
Synergy North Corporation	$ 1,672,028.19	$ 4,047,248.93	-88.4%
Tillsonburg Hydro Inc.	$ 474,089.51	$ 470,782.47	0.7%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 20,790,880.55	-53.9%
Wasaga Distribution Inc.	$ 571,069.22	$ 799,119.44	-33.6%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 1,871,067.31	-11.3%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 1,390,480.34	-41.9%
Wellington North Power Inc.	$ 103,820.01	$ 48,943.11	75.2%
Westario Power Inc.	$ 359,825.35	$ 334,493.94	7.3%

Average	**2.6%**
Median	**-0.4%**

Several potential improvements in the research could be considered. The information on the number of poles should be collected on an ongoing basis and any changes in how the distributor accounts for labor cost should also be monitored. An examination of the use of the miscellaneous distribution O&M accounts might also be considered.

Conclusion: The meter O&M econometric models were improved by the inclusion of 2018-2019 data and as well as the pension and poles information provided by the questionnaire. Continued monitoring of this information is recommended. If a distributor changes their accounting treatment, their cost benchmarking would be impacted because cost being benchmarked will be higher or lower depending on if pensions are being included. The econometric model has good explanatory power. The unit cost benchmarking provides an easier to understand alternative to the econometric model. Both methods resulted in reasonable levels of dispersion. In our opinion, both can be used for APB purposes.

Vegetation Management

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). Table 16 summarizes the unit cost results for vegetation management O&M. As can be seen, there is a fair amount of variation in the unit cost measures. The number of distributors within 50% of average is 53% which is as good as the econometric work.

The econometric work was able to account for other relevant business conditions such as overhead lines per pole, real overhead line cost per km, whether the percentage of the system with vegetation challenges exceeded 60%, the percentage distribution cost recorded as supervision, the impact of pension accounting, and the overall trend in cost over time. The real overhead line cost per km is intended to address a possible accounting issue associated with right of way and line maintenance. To the extent that line maintenance cost is high, right-of-way expenses might be low due to where these expenses are recorded. The percentage of right of way in the total of right of way and line maintenance was statistically significant in earlier versions of the model. The variable used in the final version was developed to avoid problems with using the right-of-way cost in a variable to explain right-of-way cost.

Our econometric work resulted in the model for vegetation management cost shown in Table 17. The model identified the number of poles as the relevant scale variable. For a distributor of average scale, a 1% increase in the number of poles results in an increase in predicted cost of 1.063%. This suggests that a distributor of average scale should not expect cost savings from increasing its scale of operations because size increases less than cost.

Table 16

Unit Cost Indexes by Distributor: Vegetation Management O&M Cost

Distributor	Cost ($1,000)				Scale (1,000 Poles)				Unit Cost ($ per Pole)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	5,074	5,363	5,027	5,155	123.5	123.5	123.5	123.5	$ 41.09	$ 43.43	$ 40.71	$ 41.74
Algoma Power Inc.	3,409	3,616	3,620	3,548	30.2	30.4	30.5	30.3	$ 112.88	$ 119.15	$ 118.80	$ 116.95
Atikokan Hydro Inc.	61	42	53	52	1.3	1.3	1.3	1.3	$ 45.63	$ 31.34	$ 40.30	$ 39.09
Bluewater Power Distribution					15.3	15.4	15.4					
Brantford Power Inc.	361	380	426	389	10.0	10.0	10.0	10.0	$ 35.96	$ 37.91	$ 42.46	$ 38.78
Burlington Hydro Inc.	579	487	596	554	14.6	14.6	14.6	14.6	$ 39.58	$ 33.25	$ 40.74	$ 37.86
Canadian Niagara Power Inc.	443	478	530	484	24.5	24.5	24.4	24.5	$ 18.08	$ 19.55	$ 21.69	$ 19.77
Centre Wellington Hydro Ltd.	64	47	43	51	1.8	1.8	1.9	1.8	$ 36.50	$ 26.00	$ 23.00	$ 28.50
Chapleau Public Utilities Corporation					0.7	0.7	0.7					
Cooperative Hydro Embrun Inc.	12	17	10	13	0.4	0.4	0.4	0.4	$ 28.04	$ 39.65	$ 22.17	$ 29.95
E.L.K. Energy Inc.	65	60	54	60	3.3	3.3	3.3	3.3	$ 19.71	$ 18.09	$ 16.38	$ 18.06
Elexicon Energy Inc.	1,647	1,260	896	1,268	36.5	34.8	36.5	36.0	$ 45.12	$ 36.18	$ 24.52	$ 35.27
Energy Plus	504	516	545	522	21.3	21.8	22.3	21.8	$ 23.63	$ 23.68	$ 24.50	$ 23.94
Entegrus Powerlines Inc.	278	280	271	276	14.7	20.1	20.7	18.5	$ 18.99	$ 13.96	$ 13.09	$ 15.35
ENWIN Utilities Ltd.	868	941	1,045	951	20.1	20.1	20.5	20.2	$ 43.16	$ 46.88	$ 51.03	$ 47.02
ERTH Power	179	205	144	176	10.6	10.6	10.6	10.6	$ 16.94	$ 19.45	$ 13.66	$ 16.68
Espanola Regional Hydro Distribution	62	52	92	69	2.0	2.0	2.0	2.0	$ 31.23	$ 26.07	$ 45.95	$ 34.41
Essex Powerlines Corporation	401	477	461	446	6.3	6.3	6.2	6.3	$ 63.45	$ 76.33	$ 73.86	$ 71.21
Festival Hydro Inc.	167	114	128	136	6.0	6.0	6.0	6.0	$ 27.77	$ 18.97	$ 21.37	$ 22.70
Fort Frances Power Corporation	107	98	70	92	1.9	1.9	1.9	1.9	$ 56.98	$ 52.47	$ 37.46	$ 48.97
Greater Sudbury Hydro Inc.	433	507	625	522	12.1	12.0	12.0	12.0	$ 35.71	$ 42.10	$ 52.15	$ 43.32
Grimsby Power Incorporated	65	61	91	72	3.7	3.7	3.7	3.7	$ 17.62	$ 16.54	$ 24.79	$ 19.65
Halton Hills Hydro Inc.	231	237	203	223	9.1	9.2	9.4	9.2	$ 25.42	$ 25.74	$ 21.69	$ 24.28
Hearst Power Distribution Company	10	3	14	9	1.5	1.5	1.5	1.5	$ 6.22	$ 1.66	$ 9.12	$ 5.67
Hydro One Networks	128,156	133,674	157,782	139,871	1,604.1	1,608.0	1,609.9	1,607.4	$ 79.89	$ 83.13	$ 98.00	$ 87.01
Hydro 2000 Inc.	8	7	5	7	0.4	0.4	0.4	0.4	$ 21.42	$ 18.88	$ 13.59	$ 17.96
Hydro Hawkesbury Inc.	76	59	32	56	1.6	1.6	1.6	1.6	$ 48.97	$ 37.71	$ 19.95	$ 35.55
Hydro Ottawa Limited	4,394	3,960	2,796	3,717	49.5	48.5	48.9	49.0	$ 88.81	$ 81.62	$ 57.17	$ 75.86
Innpower Corporation	156	106	197	153	10.4	10.5	10.7	10.6	$ 15.00	$ 10.05	$ 18.35	$ 14.47
Kingston Hydro Corporation	351	295	306	318	3.5	3.5	3.5	3.5	$ 100.53	$ 84.24	$ 86.98	$ 90.58
Kitchener-Wilmot Hydro Inc.					23.1	23.1	23.2					
Lakefront Utilities Inc.	46	48	53	49	3.1	3.1	3.1	3.1	$ 14.79	$ 15.40	$ 16.83	$ 15.68
Lakeland Power Distribution Ltd.	147	194	180	174	6.4	6.3	6.3	6.4	$ 22.88	$ 30.51	$ 28.47	$ 27.29
London Hydro Inc.	954	1,091	1,112	1,052	27.0	27.0	27.0	27.0	$ 35.35	$ 40.42	$ 41.19	$ 38.99
Milton Hydro Distribution Inc.	260	374	325	320	9.7	9.7	9.7	9.7	$ 26.68	$ 38.49	$ 33.47	$ 32.88
Newmarket-Tay Power Distribution	172	106	218	165	8.5	8.5	8.5	8.5	$ 20.27	$ 12.52	$ 25.75	$ 19.51
Niagara Peninsula Energy Inc.	417	347	371	378	24.8	24.8	24.8	24.8	$ 16.84	$ 13.98	$ 14.95	$ 15.25
Niagara-on-the-Lake Hydro Inc.	28	75	76	60	4.8	4.8	4.8	4.8	$ 5.83	$ 15.67	$ 15.96	$ 12.49
North Bay Hydro Distribution Limited	516	516	550	528	10.4	10.4	10.4	10.4	$ 49.43	$ 49.41	$ 52.70	$ 50.52
Northern Ontario Wires Inc.	91	93	94	93	3.0	3.0	3.0	3.0	$ 30.04	$ 30.72	$ 31.08	$ 30.61
Oakville Hydro Electricity Distribution	384	536	396	439	8.4	8.4	8.5	8.4	$ 45.98	$ 63.53	$ 46.45	$ 51.99
Orangeville Hydro Limited	123	118	144	128	1.7	1.7	1.7	1.7	$ 71.08	$ 68.37	$ 84.34	$ 74.60
Orillia Power Distribution					4.5	4.5	4.5					
Oshawa PUC Networks Inc.					10.4	10.5	12.4					
Ottawa River Power Corporation	145	168	217	177	4.1	4.1	4.1	4.1	$ 35.52	$ 41.18	$ 53.21	$ 43.30
Peterborough Distribution	41	44	36	40	11.2	11.2	11.2	11.2	$ 3.65	$ 3.89	$ 3.25	$ 3.60
PUC Distribution Inc.	677	622	617	639	18.1	18.1	18.1	18.1	$ 37.37	$ 34.32	$ 34.06	$ 35.25
Renfrew Hydro Inc.	50	70	105	75	1.8	1.8	1.8	1.8	$ 28.17	$ 39.22	$ 59.16	$ 42.19
Rideau St. Lawrence Distribution Inc.	103	76	70	83	2.1	2.1	2.1	2.1	$ 48.77	$ 36.19	$ 32.92	$ 39.29
Sioux Lookout Hydro Inc.	79	84	88	84	2.7	2.7	2.7	2.7	$ 28.80	$ 30.92	$ 32.17	$ 30.63
Synergy North Corporation	1,051	839	825	905	23.2	23.3	23.4	23.3	$ 45.27	$ 35.98	$ 35.27	$ 38.84
Tillsonburg Hydro Inc.	5	61	69	45	2.4	2.4	2.4	2.4	$ 2.13	$ 25.68	$ 28.35	$ 18.72
Toronto Hydro-Electric System	3,332	3,309	2,826	3,156	178.8	179.4	180.3	179.5	$ 18.63	$ 18.44	$ 15.67	$ 17.58
Wasaga Distribution Inc.	168	181	181	177	5.2	5.2	5.2	5.2	$ 32.55	$ 34.84	$ 34.84	$ 34.08
Waterloo North Hydro Inc.	218	313	371	301	21.5	21.4	21.8	21.6	$ 10.14	$ 14.64	$ 17.00	$ 13.93
Welland Hydro-Electric System Corp.	214	206	247	223	7.8	7.8	7.9	7.9	$ 27.27	$ 26.30	$ 31.49	$ 28.35
Wellington North Power Inc.	58	78	51	62	1.9	1.9	1.9	1.9	$ 30.97	$ 41.11	$ 26.91	$ 33.00
Westario Power Inc.	146	126	153	142	10.4	10.4	10.3	10.4	$ 14.10	$ 12.11	$ 14.86	$ 13.69
Distributor Average				**$ 3,183**				**45.9**				**$ 35.15**

Table 17

Econometric Model of Vegetation Management O&M Cost

VARIABLE KEY

Scale Variables:

ypol = Number of poles

Business Conditions:

ykmohperypol = km per pole
vegDE = 60% or more vegetation
pctsupdx = Percent of distribution O&M that is miscellaneous
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
ypol	1.063	47.716	0.000
I(ypol * ypol/2)	0.067	4.163	0.000
ykmohperypol	0.129	2.996	0.003
vegDE	0.187	2.822	0.005
pctsupdx	-0.295	-5.339	0.000
penload	0.971	6.912	0.000
trend	-0.007	-0.998	0.319
Constant*	1.802	10.289	0.000
System Rbar-Squared	0.856		
Sample Period	2012-2019		
Number of Observation:	419		

The model once again found a negative relationship between the cost allocation variable and cost which suggests that distributors that have more cost recorded in supervision and engineering will tend to have less cost recorded in the accounts we are benchmarking. The pension variable also has a positive relationship with cost. The negative value on the trend variable suggests that cost should decline by 0.7% per year for reasons other than those measured by the model's business condition variables. The impact of the scale variables is discussed above.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 18.

The explanatory power of the model as measured by R-squared was 0.856 which is a little higher than the preliminary model. The percentage of distributors with cost performance less than 50% was 49% which was a little worse than the preliminary work. Overall, the small improvement in explanatory power is justified by the availability of much more relevant and intuitive scale variables.

There are several potential improvements that could be considered. These improvements include more accurate and consistent information on the vegetation management challenges faced by the distributors. The vegetation question posed to the distributors was more difficult to address than anticipated. Because the responses provided to a less-than-optimal question are yielding statistically significant explanatory power, PEG would expect that improvements would also be significant and more consistent across distributors. A discussion of other potential improvements can be found in the previous PEG report. The information on the number of poles should be collected on an ongoing basis and any changes in how the distributor accounts for labor cost should also be monitored. An examination of the use of the supervision and engineering account might also be considered.

PEG also tested many alternative models featuring other potentially relevant variables. In each of these cases either the variable was not statistically significant or other combinations of explanatory variables produced a better model. Additional or better data may produce better results in the future for these variables.

<u>Conclusion</u>: The vegetation management econometric models were improved by the inclusion of 2018-2019 data as well as the pension, vegetation, and pole information provided by the questionnaire. Continued monitoring of this information is recommended. Future benchmarking results will be sensitive to changes in pension allocation or the vegetation challenge faced by distributors. The pole information is required for future benchmarking in several cost areas. The econometric model has good explanatory power. The unit cost benchmarking provides an easier to understand alternative to the econometric model. The econometric method provided a more reasonable level of dispersion than the unit cost method. In our opinion, both can be used for APB purposes.

Table 18

Cost Performance Results: Vegetation Management

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 17,971,073	7.7%
Algoma Power Inc.	$ 172,824.38	$ 49,071.38	125.9%
Atikokan Hydro Inc.	$ 137,108.02	$ 192,822.31	-34.1%
Bluewater Power Distribution			
Brantford Power Inc.	$ 978,892.37	$ 485,617.70	70.1%
Burlington Hydro Inc.	$ 819,300.95	$ 863,895.21	-5.3%
Canadian Niagara Power Inc.	$ 445,938.71	$ 872,341.98	-67.1%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 287,979.21	-14.4%
Chapleau Public Utilities Corporation			
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 173,578.69	10.2%
E.L.K. Energy Inc.	$ 309,442.63	$ 220,693.03	33.8%
Elexicon Energy Inc.	$ 4,460,702.04	$ 4,675,359.98	-4.7%
Energy Plus	$ 1,438,423.87	$ 1,454,333.87	-1.1%
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 4,097,080.25	-62.7%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 700,453.54	71.7%
ERTH Power	$ 1,275,736.38	$ 1,992,765.88	-44.6%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 156,441.40	17.4%
Essex Powerlines Corporation	$ 666,785.34	$ 349,487.63	64.6%
Festival Hydro Inc.	$ 581,357.64	$ 636,743.00	-9.1%
Fort Frances Power Corporation	$ 180,647.65	$ 105,694.03	53.6%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 952,963.90	56.9%
Grimsby Power Incorporated	$ 449,469.02	$ 775,158.03	-54.5%
Halton Hills Hydro Inc.	$ 395,928.02	$ 534,446.93	-30.0%
Hearst Power Distribution Company	$ 207,090.82	$ 1,531,736.66	-200.1%
Hydro One Networks	$ 44,220,101.17	$ 10,893,643.60	140.1%
Hydro 2000 Inc.	$ 144,241.31	$ 252,771.95	-56.1%
Hydro Hawkesbury Inc.	$ 235,058.84	$ 93,021.99	92.7%
Hydro Ottawa Limited	$ 8,458,627.80	$ 4,455,712.42	64.1%
Innpower Corporation	$ 371,335.51	$ 815,748.42	-78.7%
Kingston Hydro Corporation	$ 345,235.52	$ 138,272.57	91.5%
Kitchener-Wilmot Hydro Inc.			
Lakefront Utilities Inc.	$ 221,582.58	$ 205,366.33	7.6%
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 457,158.81	4.1%
London Hydro Inc.	$ 1,814,441.18	$ 1,140,854.48	46.4%

Table 18 (continued)

Cost Performance Results: Vegetation Management O&M

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 1,979,875.04	-26.7%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 1,251,004.66	-43.6%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 5,604,591.70	-60.9%
Niagara-on-the-Lake Hydro Inc.	$ 306,746.94	$ 963,934.27	-114.5%
North Bay Hydro Distribution Limited	$ 438,677.78	$ 276,376.80	46.2%
Northern Ontario Wires Inc.	$ 242,500.80	$ 233,692.24	3.7%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 550,370.95	91.7%
Orangeville Hydro Limited	$ 354,582.13	$ 126,714.94	102.9%
Orillia Power Distribution			
Oshawa PUC Networks Inc.			
Ottawa River Power Corporation	$ 435,782.42	$ 308,938.76	34.4%
Peterborough Distribution	$ 776,628.65	$ 5,286,767.67	-191.8%
PUC Distribution Inc.	$ 490,717.95	$ 383,703.27	24.6%
Renfrew Hydro Inc.	$ 294,936.00	$ 259,500.44	12.8%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 267,038.08	31.7%
Sioux Lookout Hydro Inc.	$ 216,533.10	$ 378,321.14	-55.8%
Synergy North Corporation	$ 1,672,028.19	$ 943,685.22	57.2%
Tillsonburg Hydro Inc.	$ 474,089.51	$ 1,251,873.03	-97.1%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 26,377,581.28	-77.7%
Wasaga Distribution Inc.	$ 571,069.22	$ 551,979.23	3.4%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 3,288,754.82	-67.7%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 1,056,170.10	-14.4%
Wellington North Power Inc.	$ 103,820.01	$ 84,915.67	20.1%
Westario Power Inc.	$ 359,825.35	$ 895,711.85	-91.2%

Average	**-2.2%**
Median	**3.7%**

Distribution Station Equipment O&M

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). Table 19 summarizes the unit cost results for substation O&M. As can be seen, there is a fair amount of variation in the unit cost measures. 57% of companies have a score within 50% of the average.

The econometric work resulted in the model for distribution station O&M cost shown in Table 20. The model identified the number of substations as the most important scale variable. For a distributor of average scale, a 1% increase in the number of substations results in an increase in predicted cost of 1.088%. This suggests that a distributor of average scale should expect no additional scale economies from increasing the scale its substation operations.

The econometric work was able to account for other relevant business conditions such as the number of transformers per station, average station capacity (in MVA), whether company outsourced station maintenance, the percentage of distribution cost reported as miscellaneous, the impact of pension accounting, and the unexplained trend in cost over time. The model found a negative relationship between the cost allocation variable and cost which suggests that distributors that have more cost recorded in supervision and engineering will tend to have less cost reported as substation O&M. The pension variable once again had a positive relationship with reported substation cost. The 0.023 estimate of the trend variable parameter indicates that cost should increase by 2.3% each year for reasons other than measured by the business condition variables.

Table 19

Unit Cost Indexes by Distributor: Station Maintenance

Distributor	Cost (Dollars)				Scale (number of stations)				Unit Cost ($ per station)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	4,229,180	5,307,263	8,516,544	6,017,662	174	173	167	171	$ 24,306	$ 30,678	$ 50,997	$ 35,327
Algoma Power Inc.	74,603	114,825	87,029	92,153	9	9	11	10	$ 8,289	$ 12,758	$ 7,912	$ 9,653
Atikokan Hydro Inc.	13,234	23,054	12,874	16,387	4	4	4	4	$ 3,309	$ 5,764	$ 3,218	$ 4,097
Bluewater Power Distribution	66,438	102,421	190,254	119,704	17	17	17	17	$ 3,908	$ 6,025	$ 11,191	$ 7,041
Brantford Power Inc.	2,125	100,544	118,637									
Burlington Hydro Inc.	925,826	821,383	1,007,848	918,353	32	32	32	32	$ 28,932	$ 25,668	$ 31,495	$ 28,699
Canadian Niagara Power Inc.	283,640	165,320	129,344	192,768	11	11	11	11	$ 25,785	$ 15,029	$ 11,759	$ 17,524
Centre Wellington Hydro Ltd.	35,040	47,381	82,997	55,139	6	6	6	6	$ 5,840	$ 7,897	$ 13,833	$ 9,190
Chapleau Public Utilities Corporation	2,080	2,331	2,454	2,289	1	1	1	1	$ 2,080	$ 2,331	$ 2,454	$ 2,289
Cooperative Hydro Embrun Inc.	4,306	6,847	3,633	4,929	2	2	2	2	$ 2,153	$ 3,423	$ 1,817	$ 2,464
E.L.K. Energy Inc.	620	8,567										
Elexicon Energy Inc.	816,296	1,145,402	555,747	839,149	64	63	64	64	$ 12,755	$ 18,181	$ 8,684	$ 13,206
Energy Plus		263,870	158,408		1							
Entegrus Powerlines Inc.	309,286	320,085	314,868	314,746	15	21	19	18	$ 20,619	$ 15,242	$ 16,572	$ 17,478
ENWIN Utilities Ltd.	51,816	648,808	465,580	388,735	5	5	5	5	$ 10,363	$129,762	$ 93,116	$ 77,747
ERTH Power	49,231	59,797	136,844	81,957	9	9	11	10	$ 5,470	$ 6,644	$ 12,440	$ 8,185
Espanola Regional Hydro Distribution	37,974	37,481	30,317	35,257	4	4	4	4	$ 9,494	$ 9,370	$ 7,579	$ 8,814
Essex Powerlines Corporation												
Festival Hydro Inc.		144,195	117,200	130,698	2	2	2	2		$ 72,098	$ 58,600	$ 65,349
Fort Frances Power Corporation		76,602	113,584	95,093	1	1	1	1		$ 76,602	$113,584	$ 95,093
Greater Sudbury Hydro Inc.	735,267	733,691	821,940	763,633	30	30	30	30	$ 24,509	$ 24,456	$ 27,398	$ 25,454
Grimsby Power Incorporated	2,919	133,481	90,519									
Halton Hills Hydro Inc.	225,426	221,165	232,576	226,389	12	12	12	12	$ 18,785	$ 18,430	$ 19,381	$ 18,866
Hearst Power Distribution Company												
Hydro One Networks	22,632,811	14,466,957	14,840,027	17,313,265	913	908	906	909	$ 24,789	$ 15,933	$ 16,380	$ 19,034
Hydro 2000 Inc.					2	2	2					
Hydro Hawkesbury Inc.	16,885	33,809	66,585	39,093	2	2	2	2	$ 8,442	$ 16,905	$ 33,293	$ 19,547
Hydro Ottawa Limited	692,635	1,970,799	1,687,424	1,450,286	56	57	58	57	$ 12,368	$ 34,575	$ 29,094	$ 25,346
Innpower Corporation	30,869	131,568	78,460	80,299	10	10	10	10	$ 3,087	$ 13,157	$ 7,846	$ 8,030
Kingston Hydro Corporation	370,243	345,861	314,613	343,572	17	17	16	17	$ 21,779	$ 20,345	$ 19,663	$ 20,596
Kitchener-Wilmot Hydro Inc.	103,117	1,775,008	1,836,335	1,238,154	7	7	6	7	$ 14,731	$253,573	$306,056	$191,453
Lakefront Utilities Inc.	36,667	43,534	65,255	48,485	7	7	7	7	$ 5,238	$ 6,219	$ 9,322	$ 6,926
Lakeland Power Distribution Ltd.	91,412	55,272	67,325	71,336	11	11	10	11	$ 8,310	$ 5,025	$ 6,732	$ 6,689
London Hydro Inc.	819,209	980,975	1,010,299	936,828	40	40	39	40	$ 20,480	$ 24,524	$ 25,905	$ 23,637
Milton Hydro Distribution Inc.	59,666	37,960	42,166	46,597	4	4	4	4	$ 14,917	$ 9,490	$ 10,542	$ 11,649
Newmarket-Tay Power Distribution	96,894	111,154	161,650	123,233	17	17	17	17	$ 5,700	$ 6,538	$ 9,509	$ 7,249
Niagara Peninsula Energy Inc.	27,993	209,974	235,484	157,817	18	18	16	17	$ 1,555	$ 11,665	$ 14,718	$ 9,313
Niagara-on-the-Lake Hydro Inc.		15,550	30,341									
North Bay Hydro Distribution Limited	109,792	92,171	127,362	109,775	16	17	17	17	$ 6,862	$ 5,422	$ 7,492	$ 6,592
Northern Ontario Wires Inc.	27,961	22,406	27,752	26,039	5	5	5	5	$ 5,592	$ 4,481	$ 5,550	$ 5,208
Oakville Hydro Electricity Distribution	298,900	466,589	340,250	368,580	19	19	19	19	$ 15,732	$ 24,557	$ 17,908	$ 19,399
Orangeville Hydro Limited	44,469	34,548	45,092	41,370	4	4	3	4	$ 11,117	$ 8,637	$ 15,031	$ 11,595
Orillia Power Distribution	264,396	235,716	194,800	231,637	9	9	9	9	$ 29,377	$ 26,191	$ 21,644	$ 25,737
Oshawa PUC Networks Inc.	126,945	203,155	222,637	184,246	8	9	9	9	$ 15,868	$ 22,573	$ 24,737	$ 21,059
Ottawa River Power Corporation	108,040	149,395	112,998	123,478	11	11	11	11	$ 9,822	$ 13,581	$ 10,273	$ 11,225
Peterborough Distribution	358,540	390,081	378,408	375,676	16	16	16	16	$ 22,409	$ 24,380	$ 23,650	$ 23,480
PUC Distribution Inc.	81,598	352,967	387,578	274,048	15	14	14	14	$ 5,440	$ 25,212	$ 27,684	$ 19,445
Renfrew Hydro Inc.	66,174	64,564	51,973	60,904	5	5	5	5	$ 13,235	$ 12,913	$ 10,395	$ 12,181
Rideau St. Lawrence Distribution Inc.	41,320	41,046	41,393	41,253	9	9	9	9	$ 4,591	$ 4,561	$ 4,599	$ 4,584
Sioux Lookout Hydro Inc.												
Synergy North Corporation	327,530	432,016	425,320	394,955	14	13	12	13	$ 23,395	$ 33,232	$ 35,443	$ 30,690
Tillsonburg Hydro Inc.	19,750	25,675	20,006	21,810	1	1	1	1	$ 19,750	$ 25,675	$ 20,006	$ 21,810
Toronto Hydro-Electric System	11,462,666	13,934,968	9,354,625	11,584,086	188	181	180	183	$ 60,972	$ 76,989	$ 51,970	$ 63,310
Wasaga Distribution Inc.	23,157	19,337	20,005	20,833	5	5	5	5	$ 4,631	$ 3,867	$ 4,001	$ 4,167
Waterloo North Hydro Inc.	301,655	581,246	672,460	518,454	10	9	6	8	$ 30,166	$ 64,583	$112,077	$ 68,942
Welland Hydro-Electric System Corp.	192,633	206,117	236,976	211,909	13	13	13	13	$ 14,818	$ 15,855	$ 18,229	$ 16,301
Wellington North Power Inc.	32,290	23,212	42,384	32,628	6	6	6	6	$ 5,382	$ 3,869	$ 7,064	$ 5,438
Westario Power Inc.	214,962	194,539	236,087	215,196	27	27	27	27	$ 7,962	$ 7,205	$ 8,744	$ 7,970
Distributor Average				**$ 958,794**				**38.17**				**$ 23,981**

Table 20

Econometric Model of Station Maintenance O&M Cost

VARIABLE KEY

Scale Variables:

nstation = Number of stations

Business Conditions:

mvaperstat = Station capacity
statyes = Affirmed outsourcing
pctmscdx = Percent of distribution O&M that is miscellaneous
penload = Pensions allocated to O&M
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
nstation	1.088	38.721	0.000
I(nstation * nstation/2)	0.043	1.618	0.107
mvaperstat	0.360	7.064	0.000
statyes	-0.462	-8.926	0.000
pctmscdx	-0.211	-3.266	0.001
penload	0.783	2.665	0.008
trend	0.023	2.377	0.018
Constant*	1.433	6.160	0.000
System Rbar-Squared	0.794		
Sample Period	2012-2019		
Number of Observations	390		

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 21. As can be seen there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%.

The explanatory power of the model as measured by R-squared was 0.794, a little higher than the result for the preliminary model. The percentage of distributors with cost performance less than 50% was 53%, which was much better than the result from the preliminary work. The model specification is, additionally, much more sophisticated.

There are several potential improvements that could be considered. These improvements include more accurate and consistent information on the station maintenance challenges faced by the distributors. The information on number of stations and transformers should be collected on an ongoing basis and any changes in how the distributor accounts for labor cost should also be monitored. An examination of the use of the supervision and engineering account might also be considered.

Conclusion: The distribution station econometric models were improved by the inclusion of 2018-2019 data as well as the pension, station count, station capacity, and outsourcing information made possible by the questionnaire. Continued monitoring of this information is recommended. The status of pension accounting and outsourcing will have an impact on future benchmarking work. The station count and capacity data are used in the model and are required for future work. The econometric model has good explanatory power. The unit cost benchmarking provides an easier to understand alternative to the econometric model. Both methods provided reasonable levels of dispersion. In our opinion, both can be used for APB purposes.

Table 21

Cost Performance Results: Station Maintenance

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 23,190,980	-17.8%
Algoma Power Inc.	$ 172,824.38	$ 373,260.26	-77.0%
Atikokan Hydro Inc.	$ 137,108.02	$ 560,466.28	-140.8%
Bluewater Power Distribution	$ 1,001,120.24	$ 1,199,757.70	-18.1%
Brantford Power Inc.			
Burlington Hydro Inc.	$ 819,300.95	$ 679,564.04	18.7%
Canadian Niagara Power Inc.	$ 445,938.71	$ 570,310.83	-24.6%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 211,006.37	16.7%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 443,147.51	-173.8%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 508,584.34	-97.3%
E.L.K. Energy Inc.			
Elexicon Energy Inc.	$ 4,460,702.04	$ 4,368,004.03	2.1%
Energy Plus			
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 1,768,752.66	21.3%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 1,557,329.92	-8.2%
ERTH Power	$ 1,275,736.38	$ 1,081,688.84	16.5%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 127,827.48	37.6%
Essex Powerlines Corporation			
Festival Hydro Inc.	$ 581,357.64	$ 87,651.27	189.2%
Fort Frances Power Corporation	$ 180,647.65	$ 29,890.73	179.9%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 1,029,241.11	49.2%
Grimsby Power Incorporated			
Halton Hills Hydro Inc.	$ 395,928.02	$ 383,842.55	3.1%
Hearst Power Distribution Company			
Hydro One Networks	$ 44,220,101.17	$ 211,913,773.53	-156.7%
Hydro 2000 Inc.			
Hydro Hawkesbury Inc.	$ 235,058.84	$ 100,568.18	84.9%
Hydro Ottawa Limited	$ 8,458,627.80	$ 7,926,304.90	6.5%
Innpower Corporation	$ 371,335.51	$ 411,210.81	-10.2%
Kingston Hydro Corporation	$ 345,235.52	$ 325,781.48	5.8%
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 249,940.26	213.0%
Lakefront Utilities Inc.	$ 221,582.58	$ 150,474.76	38.7%
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 556,146.00	-15.5%
London Hydro Inc.	$ 1,814,441.18	$ 857,081.32	75.0%

Table 21 (continued)

Cost Performance Results: Station Maintenance

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 1,964,099.22	-25.9%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 1,236,082.31	-42.4%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 4,360,497.73	-35.8%
Niagara-on-the-Lake Hydro Inc.			
North Bay Hydro Distribution Limited	$ 438,677.78	$ 1,271,261.70	-106.4%
Northern Ontario Wires Inc.	$ 242,500.80	$ 567,933.89	-85.1%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 766,314.39	58.6%
Orangeville Hydro Limited	$ 354,582.13	$ 183,266.25	66.0%
Orillia Power Distribution	$ 924,782.33	$ 623,630.72	39.4%
Oshawa PUC Networks Inc.	$ 1,124,377.29	$ 2,008,181.05	-58.0%
Ottawa River Power Corporation	$ 435,782.42	$ 614,705.37	-34.4%
Peterborough Distribution	$ 776,628.65	$ 556,664.27	33.3%
PUC Distribution Inc.	$ 490,717.95	$ 349,278.47	34.0%
Renfrew Hydro Inc.	$ 294,936.00	$ 300,292.92	-1.8%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 1,054,045.91	-105.6%
Sioux Lookout Hydro Inc.			
Synergy North Corporation	$ 1,672,028.19	$ 999,037.84	51.5%
Tillsonburg Hydro Inc.	$ 474,089.51	$ 83,212.38	174.0%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 7,145,726.28	52.9%
Wasaga Distribution Inc.	$ 571,069.22	$ 1,396,201.23	-89.4%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 273,216.44	181.1%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 826,669.13	10.1%
Wellington North Power Inc.	$ 103,820.01	$ 117,525.90	-12.4%
Westario Power Inc.	$ 359,825.35	$ 356,245.02	1.0%

Average	**6.6%**
Median	**3.1%**

4.3. Capital Expenditure Research

Overview

The next four cost areas considered are related to capital expenditures ("capex"). Relative to OM&A expenses, capital expenditures are more variable and harder to predict. In some cases, such as distribution station equipment, investment can be very "lumpy" in that infrequent large investments can be observed. This reflects in part the smaller number of assets involved. The magnitude and timing of such investments may not correlate well with other explanatory variables. Despite these challenges, some models that we developed have fairly high explanatory power.

A known deficiency with these models is that, unlike the O&M models, the input prices do not include different price levels for the distributors. Difficulty in determining relative prices for construction labor for all Ontario distributors combined with the unknown proportion of labor cost in the total cost of new construction contributed to the decision to not attempt the calculation of price indexes where construction price levels vary by distributor.

Another methodological concern (that was the topic of discussion in a working group meeting) was what a capex model would be measuring. Using poles capex as an example, one candidate would be that the model would measure the efficiency of a distributor in performing the task of installing poles. This notion of efficiency is somewhat limited in that it implicitly assumes that a new pole was required. A broader notion of capex efficiency would also evaluate the need for the new poles. The models developed here encompass both considerations. The specification of these models could include scale variables such as number of poles or another scale variable correlated with the investment being made (e.g., customers are correlated with number meters). This will tend to lend itself to the narrow interpretation that the total number of poles is used to explain why investment in additional poles took place. However, additional variables such as customer growth are also included that attempt to estimate the need to increase the number of poles. Including variables to estimate the demand for capital investment (e.g., customer growth) instead of including the quantity of investment made (e.g., number of new poles installed) is more consistent with the broader notion of capex cost efficiency. In this sense the models contain elements of both notions of capex cost efficiency. A discussion of each of the four capital expenditures follows. Three tables are provided for each of the capex programs to show the results for unit cost and the econometric benchmarking.

Capital Expenditures: Poles, Towers, and Fixtures

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). In the context of capex, the interpretation is also a little different than for O&M expenses. Here the unit cost is expressed as dollars per unit of total scale and not dollars per added scale (e.g., dollars per pole vs dollars per new pole). Table 22 summarizes the unit cost results for pole capex.

As can be seen, there is a fair amount of variation in the unit cost measures. The number of companies within 50% of average is 61% which is similar to the 67% for the econometric work.

The econometric work was able to account for other relevant business conditions such as the percentage of line that is overhead, the km of line per pole, the age of poles, customer growth and the overall trend in cost over time. The model found a positive relationship between each these variables and cost. A more overhead system implies greater above ground investment. Higher values of km per pole are associated with more fixtures and possibly correlated with more structures made of steel instead of wood. Higher values of the percent of poles over 50 years old will imply a greater probability that poles will need to be replaced. Higher customer growth is correlated with an expansion of the area served which increases the number of poles needed. The positive value on the trend variable suggests that cost should increase by 0.21% per year for reasons not measured by the included business condition variables.

The econometric work resulted in the model for Poles, Towers and Fixtures Capital Expenditures ("poles capex")[2] shown in Table 23. The model identified the number of poles as the relevant scale variable. In the context of capital investment, the interpretation of scale is a little different than for O&M. For O&M an above average number of poles should imply that cost will be higher than average assuming an average level of O&M per pole. For capital expenditures, the source of demand can come from several sources which include system replacement as well as system augmentation. Assuming that a certain percentage of system assets reach the end of their useful life and need to be replaced each year, a scale measure such as number of customers or km of line measures the need for pole

[2] The data used for capital expenditure is plant additions from the capital continuity schedules provided by distributors. It is technically a little different from capital expenditures because of timing. The capital expenditure comes first when the asset is being constructed and is later recognized as plant in service when completed.

Table 22

Unit Cost Indexes by Distributor: Poles, Towers, and Fixtures Capex

Distributor	Cost ($1,000)				Scale (1,000 poles)				Unit Cost ($ per pole)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	15,695	30,224	54,862	33,593	123.5	123.5	123.5	123.5	$ 127.09	$ 244.75	$ 444.27	$ 272.04
Algoma Power Inc.	2,194	2,587	3,160	2,647	30.2	30.4	30.5	30.3	$ 72.64	$ 85.22	$ 103.71	$ 87.19
Atikokan Hydro Inc.	268	331	247	282	1.3	1.3	1.3	1.3	$ 201.79	$ 249.41	$ 186.27	$ 212.49
Bluewater Power Distribution	1,880	2,138	2,363	2,127	15.3	15.4	15.4	15.4	$ 122.66	$ 138.97	$ 153.38	$ 138.34
Brantford Power Inc.	653	722	850	742	10.0	10.0	10.0	10.0	$ 65.07	$ 72.01	$ 84.71	$ 73.93
Burlington Hydro Inc.	1,247	1,519	1,851	1,539	14.6	14.6	14.6	14.6	$ 85.18	$ 103.76	$ 126.44	$ 105.13
Canadian Niagara Power Inc.	2,073	2,373	2,163	2,203	24.5	24.5	24.4	24.5	$ 84.69	$ 97.02	$ 88.46	$ 90.06
Centre Wellington Hydro Ltd.	157	168	185	170	1.8	1.8	1.9	1.8	$ 89.16	$ 92.65	$ 99.36	$ 93.72
Chapleau Public Utilities Corporation	27	29	41	32	0.7	0.7	0.7	0.7	$ 36.51	$ 39.10	$ 56.30	$ 43.97
Cooperative Hydro Embrun Inc.	19	33	17	23	0.4	0.4	0.4	0.4	$ 44.13	$ 76.21	$ 38.95	$ 53.09
E.L.K. Energy Inc.	48	47	49	48	3.3	3.3	3.3	3.3	$ 14.75	$ 14.38	$ 14.70	$ 14.61
Elexicon Energy Inc.	8,963	7,385	6,732	7,693	36.5	34.8	36.5	36.0	$ 245.57	$ 212.13	$ 184.23	$ 213.98
Energy Plus	4,743	2,103	3,487	3,444	21.3	21.8	22.3	21.8	$ 222.29	$ 96.45	$ 156.63	$ 158.45
Entegrus Powerlines Inc.	1,176	1,601	2,165	1,647	14.7	20.1	20.7	18.5	$ 80.24	$ 79.73	$ 104.69	$ 88.22
ENWIN Utilities Ltd.	6,798	5,638	5,900	6,112	20.1	20.1	20.5	20.2	$ 338.02	$ 281.02	$ 288.21	$ 302.42
ERTH Power	579	506	700	595	10.6	10.6	10.6	10.6	$ 54.84	$ 47.88	$ 66.28	$ 56.33
Espanola Regional Hydro Distribution	147	150	187	161	2.0	2.0	2.0	2.0	$ 73.97	$ 75.19	$ 93.78	$ 80.98
Essex Powerlines Corporation	844	653	675	724	6.3	6.3	6.2	6.3	$ 133.36	$ 104.46	$ 108.24	$ 115.36
Festival Hydro Inc.	486	469	496	484	6.0	6.0	6.0	6.0	$ 80.92	$ 78.08	$ 82.56	$ 80.52
Fort Frances Power Corporation	52	55	32	46	1.9	1.9	1.9	1.9	$ 27.80	$ 29.49	$ 17.09	$ 24.79
Greater Sudbury Hydro Inc.	1,751	1,842	2,080	1,891	12.1	12.0	12.0	12.0	$ 144.51	$ 153.03	$ 173.46	$ 157.00
Grimsby Power Incorporated	159	167	211	179	3.7	3.7	3.7	3.7	$ 43.38	$ 45.61	$ 57.52	$ 48.84
Halton Hills Hydro Inc.	2,795	2,449	1,670	2,305	9.1	9.2	9.4	9.2	$ 308.29	$ 265.88	$ 178.54	$ 250.91
Hearst Power Distribution Company	80	90	98	89	1.5	1.5	1.5	1.5	$ 52.51	$ 58.50	$ 63.14	$ 58.05
Hydro One Networks	196,333	211,333	258,667	222,111	1,604.1	1,608.0	1,609.9	1,607.4	$ 122.40	$ 131.42	$ 160.67	$ 138.16
Hydro 2000 Inc.	18	23	29	23	0.4	0.4	0.4	0.4	$ 49.40	$ 63.16	$ 78.11	$ 63.56
Hydro Hawkesbury Inc.	74	71	89	78	1.6	1.6	1.6	1.6	$ 47.41	$ 45.51	$ 56.53	$ 49.82
Hydro Ottawa Limited	12,350	11,539	10,283	11,391	49.5	48.5	48.9	49.0	$ 249.58	$ 237.84	$ 210.24	$ 232.56
Innpower Corporation	1,293	1,021	1,776	1,363	10.4	10.5	10.7	10.6	$ 123.96	$ 96.83	$ 165.42	$ 128.73
Kingston Hydro Corporation	1,404	1,507	1,178	1,363	3.5	3.5	3.5	3.5	$ 402.05	$ 429.67	$ 334.36	$ 388.69
Kitchener-Wilmot Hydro Inc.	3,241	3,091	3,250	3,194	23.1	23.1	23.2	23.1	$ 140.38	$ 133.61	$ 140.31	$ 138.10
Lakefront Utilities Inc.	420	443	416	426	3.1	3.1	3.1	3.1	$ 133.77	$ 141.16	$ 132.64	$ 135.86
Lakeland Power Distribution Ltd.	715	716	822	751	6.4	6.3	6.3	6.4	$ 111.50	$ 112.84	$ 129.76	$ 118.03
London Hydro Inc.	1,587	1,674	1,575	1,612	27.0	27.0	27.0	27.0	$ 58.79	$ 62.04	$ 58.34	$ 59.72
Milton Hydro Distribution Inc.	708	913	1,231	951	9.7	9.7	9.7	9.7	$ 72.80	$ 94.06	$ 126.65	$ 97.84
Newmarket-Tay Power Distribution	2,589	2,488	1,051	2,043	8.5	8.5	8.5	8.5	$ 305.38	$ 293.51	$ 123.96	$ 240.95
Niagara Peninsula Energy Inc.	2,354	2,421	2,205	2,327	24.8	24.8	24.8	24.8	$ 95.05	$ 97.55	$ 88.82	$ 93.81
Niagara-on-the-Lake Hydro Inc.	256	465	493	405	4.8	4.8	4.8	4.8	$ 53.69	$ 97.46	$ 103.20	$ 84.79
North Bay Hydro Distribution Limited	1,082	1,043	1,121	1,082	10.4	10.4	10.4	10.4	$ 103.63	$ 99.85	$ 107.32	$ 103.60
Northern Ontario Wires Inc.	230	257	265	251	3.0	3.0	3.0	3.0	$ 76.10	$ 84.93	$ 87.22	$ 82.75
Oakville Hydro Electricity Distribution	1,800	1,703	2,392	1,965	8.4	8.4	8.5	8.4	$ 215.42	$ 201.76	$ 280.41	$ 232.53
Orangeville Hydro Limited	116	148	180	148	1.7	1.7	1.7	1.7	$ 67.32	$ 85.71	$ 105.26	$ 86.10
Orillia Power Distribution	899	801	688	796	4.5	4.5	4.5	4.5	$ 198.10	$ 177.44	$ 153.28	$ 176.27
Oshawa PUC Networks Inc.	2,895	1,678	3,357	2,643	10.4	10.5	12.4	11.1	$ 278.51	$ 160.58	$ 271.19	$ 236.76
Ottawa River Power Corporation	178	201	160	180	4.1	4.1	4.1	4.1	$ 43.60	$ 49.12	$ 39.16	$ 43.96
Peterborough Distribution	1,526	1,258	1,142	1,309	11.2	11.2	11.2	11.2	$ 136.30	$ 112.39	$ 102.02	$ 116.90
PUC Distribution Inc.	1,693	1,656	1,809	1,719	18.1	18.1	18.1	18.1	$ 93.42	$ 91.39	$ 99.79	$ 94.87
Renfrew Hydro Inc.	183	196	227	202	1.8	1.8	1.8	1.8	$ 103.22	$ 109.94	$ 127.50	$ 113.55
Rideau St. Lawrence Distribution Inc.	83	99	104	95	2.1	2.1	2.1	2.1	$ 39.08	$ 46.92	$ 49.18	$ 45.06
Sioux Lookout Hydro Inc.	202	200	180	194	2.7	2.7	2.7	2.7	$ 74.11	$ 73.31	$ 65.89	$ 71.11
Synergy North Corporation	4,173	4,239	3,754	4,055	23.2	23.3	23.4	23.3	$ 179.71	$ 181.76	$ 160.47	$ 173.98
Tillsonburg Hydro Inc.	153	273	371	266	2.4	2.4	2.4	2.4	$ 64.81	$ 113.97	$ 151.63	$ 110.14
Toronto Hydro-Electric System	33,036	27,337	26,764	29,046	178.8	179.4	180.3	179.5	$ 184.77	$ 152.37	$ 148.44	$ 161.86
Wasaga Distribution Inc.	392	416	391	400	5.2	5.2	5.2	5.2	$ 75.95	$ 80.04	$ 75.33	$ 77.10
Waterloo North Hydro Inc.	4,543	4,851	4,497	4,630	21.5	21.4	21.8	21.6	$ 211.41	$ 226.56	$ 206.23	$ 214.73
Welland Hydro-Electric System Corp.	675	672	680	676	7.8	7.8	7.9	7.9	$ 86.06	$ 85.63	$ 86.50	$ 86.07
Wellington North Power Inc.	115	110	160	128	1.9	1.9	1.9	1.9	$ 60.99	$ 58.39	$ 84.54	$ 67.97
Westario Power Inc.	721	895	986	867	10.4	10.4	10.3	10.4	$ 69.43	$ 86.16	$ 95.63	$ 83.74
Distributor Average			$	**6,336**				**42.9**			$	**123.62**

Table 23

Econometric Model of Poles, Towers and Fixtures Capex

VARIABLE KEY

Scale Variables:

npoles = Number of poles

Business Conditions:

ykmohperypol = km per pole
oldpol50 = % poles over 50 years old
ynaddavg = Average number of customers added
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
npoles	0.961	24.536	0.000
I(npoles * npoles/2)	-0.101	-6.507	0.000
ykmpernpol	1.700	3.926	0.000
oldpol50	0.081	2.200	0.028
ynaddavg	0.335	4.664	0.000
trend	0.021	2.270	0.024
Constant*	10.276	128.186	0.000
System Rbar-Squared	0.851		
Sample Period	2012-2019		
Number of Observations	436		

replacement because customers and km should be correlated with poles. A larger number of poles will need to be replaced on larger systems than on smaller systems. The same is true for system augmentation. To the extent that a system gets larger or needs to be reinforced by a certain percentage, a larger than average scale variable will imply more investment.

In the context of pole capex, the model indicates that, for a distributor or average scale, a 1% increase in the number of poles results in an increase in predicted cost of 0.961%. This suggests that a distributor of average scale should expect some economies from increasing its scale of operations because cost increases less than size.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 24. As can be seen that there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%. The percentage of distributors with cost performance less than 50% was 67% which was a little better than the preliminary work. The explanatory power of the model as measured by R-squared was 0.851 which is a higher than the preliminary model.

Several potential improvements could be considered in the substation capex model. These improvements include more detailed and consistent age data.

Conclusion: The poles capex econometric model was improved by the inclusion of 2018-2019 data, as well as the age and poles information made possible by the questionnaire. Continued collection of this information is recommended. The econometric model has good explanatory power. The unit cost benchmarking provides an easier to understand alternative to the econometric model. Both methods provided reasonable levels of dispersion. In our opinion, both can be used for APB purposes.

Table 24

Cost Performance Results: Poles, Towers and Fixtures Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 20,020,633	-3.1%
Algoma Power Inc.	$ 172,824.38	$ 181,685.27	-5.0%
Atikokan Hydro Inc.	$ 137,108.02	$ 53,451.20	94.2%
Bluewater Power Distribution	$ 1,001,120.24	$ 667,723.99	40.5%
Brantford Power Inc.	$ 978,892.37	$ 1,189,658.65	-19.5%
Burlington Hydro Inc.	$ 819,300.95	$ 831,683.10	-1.5%
Canadian Niagara Power Inc.	$ 445,938.71	$ 611,663.03	-31.6%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 173,797.06	36.1%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 131,617.86	-52.4%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 283,902.56	-39.0%
E.L.K. Energy Inc.	$ 309,442.63	$ 1,786,069.57	-175.3%
Elexicon Energy Inc.	$ 4,460,702.04	$ 3,586,964.00	21.8%
Energy Plus	$ 1,438,423.87	$ 1,077,397.03	28.9%
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 2,659,862.91	-19.5%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 727,582.97	67.9%
ERTH Power	$ 1,275,736.38	$ 2,202,346.89	-54.6%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 140,848.03	27.9%
Essex Powerlines Corporation	$ 666,785.34	$ 1,055,181.60	-45.9%
Festival Hydro Inc.	$ 581,357.64	$ 646,366.14	-10.6%
Fort Frances Power Corporation	$ 180,647.65	$ 1,011,862.98	-172.3%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 1,010,880.51	51.0%
Grimsby Power Incorporated	$ 449,469.02	$ 899,704.99	-69.4%
Halton Hills Hydro Inc.	$ 395,928.02	$ 267,262.80	39.3%
Hearst Power Distribution Company	$ 207,090.82	$ 234,664.64	-12.5%
Hydro One Networks	$ 44,220,101.17	$ 15,520,775.22	104.7%
Hydro 2000 Inc.	$ 144,241.31	$ 68,066.67	75.1%
Hydro Hawkesbury Inc.	$ 235,058.84	$ 285,955.41	-19.6%
Hydro Ottawa Limited	$ 8,458,627.80	$ 7,997,963.62	5.6%
Innpower Corporation	$ 371,335.51	$ 349,361.08	6.1%
Kingston Hydro Corporation	$ 345,235.52	$ 92,224.60	132.0%
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 2,251,207.26	-6.8%
Lakefront Utilities Inc.	$ 221,582.58	$ 137,798.90	47.5%
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 327,023.11	37.6%
London Hydro Inc.	$ 1,814,441.18	$ 5,082,369.19	-103.0%

Table 24 (continued)

Cost Performance Results: Poles, Towers and Fixtures Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 2,328,056.34	-42.9%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 881,568.08	-8.6%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 5,215,245.73	-53.7%
Niagara-on-the-Lake Hydro Inc.	$ 306,746.94	$ 327,675.28	-6.6%
North Bay Hydro Distribution Limited	$ 438,677.78	$ 399,320.82	9.4%
Northern Ontario Wires Inc.	$ 242,500.80	$ 248,888.50	-2.6%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 874,447.72	45.4%
Orangeville Hydro Limited	$ 354,582.13	$ 276,701.69	24.8%
Orillia Power Distribution	$ 924,782.33	$ 533,552.99	55.0%
Oshawa PUC Networks Inc.	$ 1,124,377.29	$ 981,404.43	13.6%
Ottawa River Power Corporation	$ 435,782.42	$ 1,088,050.76	-91.5%
Peterborough Distribution	$ 776,628.65	$ 851,468.34	-9.2%
PUC Distribution Inc.	$ 490,717.95	$ 482,446.25	1.7%
Renfrew Hydro Inc.	$ 294,936.00	$ 142,844.75	72.5%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 534,531.83	-37.7%
Sioux Lookout Hydro Inc.	$ 216,533.10	$ 390,623.20	-59.0%
Synergy North Corporation	$ 1,672,028.19	$ 1,072,548.27	44.4%
Tillsonburg Hydro Inc.	$ 474,089.51	$ 224,392.36	74.8%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 17,505,488.41	-36.7%
Wasaga Distribution Inc.	$ 571,069.22	$ 741,377.86	-26.1%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 955,528.22	55.9%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 1,103,679.12	-18.8%
Wellington North Power Inc.	$ 103,820.01	$ 93,098.56	10.9%
Westario Power Inc.	$ 359,825.35	$ 384,759.62	-6.7%

Average	**-0.3%**
Median	**-2.9%**

Capital Expenditures: Distribution Station Equipment

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). The number of stations was chosen as the sole scale variable for these calculations. Table 25 summarizes the unit cost results for station capex.

As can be seen, there is a fair amount of variation in the unit cost measures. The number of distributors within 50% of average is only 21% which is similar to the econometric work. The econometric work did not feature business conditions other than scale. The positive value on the trend variable suggests that cost should increase by 4.7% per year for reasons other than measured by the scale variables. It should also be noted that many distributors either do not have stations or occasionally did not have any plant additions which accounts for the blank performance values in the table.

Table 25

Unit Cost Indexes by Distributor: Stations Capex

Distributor	Cost ($1,000)				Scale (number of stations)				Unit Cost ($ per station)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	4,618.6	7,071.5	7,586.2	6,425.4	174	173	167	171	$ 26,544	$ 40,875	$ 45,426	$ 37,615
Algoma Power Inc.	1,314.9	278.1	95.3	562.8	9	9	11	10	$146,099	$ 30,905	$ 8,667	$ 61,891
Atikokan Hydro Inc.	5.4	4.6			4	4	4		$ 1,360	$ 1,150	$ -	$ 837
Bluewater Power Distribution	251.4	311.7	305.9	289.7	17	17	17	17	$ 14,791	$ 18,334	$ 17,993	$ 17,039
Brantford Power Inc.	227.5											
Burlington Hydro Inc.	70.2	123.6	121.8	105.2	32	32	32	32	$ 2,195	$ 3,863	$ 3,805	$ 3,288
Canadian Niagara Power Inc.	1,493.0	1,101.7	1,145.2	1,246.6	11	11	11	11	$135,725	$100,151	$104,112	$113,330
Centre Wellington Hydro Ltd.	673.2	414.4	288.5	458.7	6	6	6	6	$112,208	$ 69,059	$ 48,087	$ 76,451
Chapleau Public Utilities Corporation	1.7	18.5	17.7	12.6	1	1	1	1	$ 1,710	$ 18,522	$ 17,667	$ 12,633
Cooperative Hydro Embrun Inc.	536.7	535.9	532.2	535.0	2	2	2	2	$268,368	$267,958	$266,102	$267,476
E.L.K. Energy Inc.	0.2											
Elexicon Energy Inc.	3,213.3	3,434.1	5,946.6	4,198.0	64	63	64	64	$ 50,208	$ 54,510	$ 92,916	$ 65,878
Energy Plus					1							
Entegrus Powerlines Inc.	51.9	50.9	77.0	59.9	15	21	19	18	$ 3,458	$ 2,422	$ 4,053	$ 3,311
ENWIN Utilities Ltd.	586.0	566.0	200.6	450.9	5	5	5	5	$117,205	$113,198	$ 40,126	$ 90,176
ERTH Power	3.5	3.5	3.5	3.5	9	9	11	10	$ 392	$ 392	$ 321	$ 368
Espanola Regional Hydro Distribution					4	4	4					
Essex Powerlines Corporation												
Festival Hydro Inc.	11.6	18.8	24.6	18.3	2	2	2	2	$ 5,782	$ 9,406	$ 12,319	$ 9,169
Fort Frances Power Corporation					1	1	1					
Greater Sudbury Hydro Inc.	379.4	1,395.8	1,870.3	1,215.2	30	30	30	30	$ 12,646	$ 46,528	$ 62,343	$ 40,506
Grimsby Power Incorporated												
Halton Hills Hydro Inc.	492.2	409.0	528.9	476.7	12	12	12	12	$ 41,016	$ 34,083	$ 44,073	$ 39,724
Hearst Power Distribution Company												
Hydro One Networks	60,667	42,667	41,667	48,333.3	913	908	906	909	$ 66,448	$ 46,990	$ 45,990	$ 53,142
Hydro 2000 Inc.					2	2	2					
Hydro Hawkesbury Inc.	117.7	10.3	6.3	44.8	2	2	2	2	$ 58,860	$ 5,171	$ 3,134	$ 22,388
Hydro Ottawa Limited	14,967	11,339	13,365	13,223.6	56	57	58	57	$267,260	$198,939	$230,425	$232,208
Innpower Corporation	884.4	743.9	636.0	754.8	10	10	10	10	$ 88,442	$ 74,394	$ 63,596	$ 75,477
Kingston Hydro Corporation	221.1	302.1	781.9	435.0	17	17	16	17	$ 13,003	$ 17,772	$ 48,871	$ 26,549
Kitchener-Wilmot Hydro Inc.	891.7	894.3	832.4	872.8	7	7	6	7	$127,387	$127,752	$138,737	$131,292
Lakefront Utilities Inc.	773.0	659.7	296.5	576.4	7	7	7	7	$110,429	$ 94,247	$ 42,355	$ 82,344
Lakeland Power Distribution Ltd.	290.8	67.0	27.9	128.6	11	11	10	11	$ 26,435	$ 6,095	$ 2,789	$ 11,773
London Hydro Inc.	178.1	152.8	177.7	169.5		40	39	40		$ 3,820	$ 4,557	$ 4,188
Milton Hydro Distribution Inc.		0.3	0.3	0.3	4	4	4	4		$ 82	$ 82	$ 82
Newmarket-Tay Power Distribution	2,773			2,773	17	17	17	17	$163,136			$163,136
Niagara Peninsula Energy Inc.	79.3	84.1	134.0	99.1	18	18	16	17	$ 4,403	$ 4,672	$ 8,375	$ 5,817
Niagara-on-the-Lake Hydro Inc.	40.0	30.7	21.0	30.6								
North Bay Hydro Distribution Limited	1,333.8	1,577.4	1,744.4	1,551.9	16	17	17	17	$ 83,363	$ 92,789	$102,611	$ 92,921
Northern Ontario Wires Inc.	36.2	61.5	48.0	48.6	5	5	5	5	$ 7,233	$ 12,308	$ 9,606	$ 9,716
Oakville Hydro Electricity Distribution	111.2	362.5	518.4	330.7	19	19	19	19	$ 5,853	$ 19,077	$ 27,284	$ 17,405
Orangeville Hydro Limited	42.0	34.1	20.9	32.3	4	4	3	4	$ 10,496	$ 8,513	$ 6,953	$ 8,654
Orillia Power Distribution	1,154.4	1,206.2	1,051.5	1,137.4	9	9	9	9	$128,265	$134,024	$116,832	$126,373
Oshawa PUC Networks Inc.	1,245.7	1,834.2	1,552.4	1,544.1	8	9	9	9	$155,714	$203,797	$172,485	$177,332
Ottawa River Power Corporation	122.0	119.6	28.1	89.9	11	11	11	11	$ 11,091	$ 10,869	$ 2,552	$ 8,171
Peterborough Distribution	608.2	87.4	61.2	252.3	16	16	16	16	$ 38,013	$ 5,461	$ 3,828	$ 15,767
PUC Distribution Inc.	609.6	400.7	291.9	434.0	15	14	14	14	$ 40,640	$ 28,619	$ 20,848	$ 30,035
Renfrew Hydro Inc.	8.2	47.1	164.2	73.2	5	5	5	5	$ 1,639	$ 9,419	$ 32,846	$ 14,635
Rideau St. Lawrence Distribution Inc.	214.1	130.7	109.2	151.3	9	9	9	9	$ 23,787	$ 14,521	$ 12,136	$ 16,814
Sioux Lookout Hydro Inc.												
Synergy North Corporation					14	13	12					
Tillsonburg Hydro Inc.					1	1	1					
Toronto Hydro-Electric System	24,727	32,560	35,581	30,956	188	181	180	183	$131,528	$179,888	$197,670	$169,695
Wasaga Distribution Inc.	12.1	6.4	6.4	8.3	5	5	5	5	$ 2,417	$ 1,290	$ 1,290	$ 1,666
Waterloo North Hydro Inc.	347.8	113.3	113.3	191.4	10	9	6	8	$ 34,779	$ 12,584	$ 18,876	$ 22,079
Welland Hydro-Electric System Corp.	155.8	185.9	148.6	163.4	13	13	13	13	$ 11,984	$ 14,299	$ 11,427	$ 12,570
Wellington North Power Inc.	9.7	7.7	3.3	6.9	6	6	6	6	$ 1,623	$ 1,281	$ 544	$ 1,149
Westario Power Inc.	1,671.0	1,837.1	1,440.2	1,649.4	27	27	27	27	$ 61,889	$ 68,039	$ 53,340	$ 61,089
Distributor Average				$ 2,714				42				$ 54,092

The econometric work resulted in the model for Distribution Station Equipment Capex ("station capex") shown in Table 26.

Table 26

Econometric Model of Distribution Station Capex

VARIABLE KEY

Scale Variables:

numstat = Number of stations

numtrf = Number of transformers

Business Conditions:

trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
numstat	4.031	7.762	0.000
I(numstat * numstat/2)	-1.897	-8.900	0.000
numtrf	0.620	4.775	0.000
trend	0.047	1.654	0.099
Constant*	7.161	17.211	0.000
System Rbar-Squared	0.490		
Sample Period	2012-2019		
Number of Observations	296		

The model identified number of stations and number of transformers as potentially relevant scale variables. Because each distributor does not have as many stations as other assets such as number of poles, examining the results in terms for a 1% change is not as useful. To the extent that the number of stations and transformers is relatively constant, the model will tend to have higher values associated with scale variable parameters and a lower value for the constant.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 27.

Table 27

Cost Performance Results: Distribution Station Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 132,789,266	-192.3%
Algoma Power Inc.	$ 172,824.38	$ 2,090,745.36	-249.3%
Atikokan Hydro Inc.	$ 137,108.02	$ 822,023.58	-179.1%
Bluewater Power Distribution	$ 1,001,120.24	$ 1,116,411.60	-10.9%
Brantford Power Inc.			
Burlington Hydro Inc.	$ 819,300.95	$ 8,522,384.71	-234.2%
Canadian Niagara Power Inc.	$ 445,938.71	$ 111,852.55	138.3%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 106,153.73	85.4%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 98,484.85	-23.4%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 56,015.65	123.3%
E.L.K. Energy Inc.			
Elexicon Energy Inc.	$ 4,460,702.04	$ 3,258,627.72	31.4%
Energy Plus			
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 9,027,491.97	-141.7%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 692,098.33	72.9%
ERTH Power	$ 1,275,736.38	$ 13,511,262.03	-236.0%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 878,909.14	-155.2%
Essex Powerlines Corporation	$ 666,785.34	$ 17,145,107.93	-324.7%
Festival Hydro Inc.	$ 581,357.64	$ 1,377,969.24	-86.3%
Fort Frances Power Corporation			
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 740,686.18	82.1%
Grimsby Power Incorporated			
Halton Hills Hydro Inc.	$ 395,928.02	$ 251,698.62	45.3%
Hearst Power Distribution Company			
Hydro One Networks	$ 44,220,101.17	$ 1,257,567.71	356.0%
Hydro 2000 Inc.			
Hydro Hawkesbury Inc.	$ 235,058.84	$ 1,132,107.12	-157.2%
Hydro Ottawa Limited	$ 8,458,627.80	$ 5,339,793.39	46.0%
Innpower Corporation	$ 371,335.51	$ 148,726.05	91.5%
Kingston Hydro Corporation	$ 345,235.52	$ 123,621.79	102.7%
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 9,407,117.97	-149.8%
Lakefront Utilities Inc.	$ 221,582.58	$ 14,437.01	273.1%
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 246,418.39	65.9%
London Hydro Inc.	$ 1,814,441.18	$ 16,147,698.45	-218.6%

Table 27 (continued)

Cost Performance Results: Distribution Station Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 221,857,155.18	-498.6%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 15,925,903.82	-298.0%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 10,996,600.81	-128.3%
Niagara-on-the-Lake Hydro Inc.			
North Bay Hydro Distribution Limited	$ 438,677.78	$ 54,042.20	209.4%
Northern Ontario Wires Inc.	$ 242,500.80	$ 384,139.21	-46.0%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 1,169,805.19	16.3%
Orangeville Hydro Limited	$ 354,582.13	$ 831,257.82	-85.2%
Orillia Power Distribution	$ 924,782.33	$ 116,811.13	206.9%
Oshawa PUC Networks Inc.	$ 1,124,377.29	$ 154,931.74	198.2%
Ottawa River Power Corporation	$ 435,782.42	$ 383,808.25	12.7%
Peterborough Distribution	$ 776,628.65	$ 3,842,822.16	-159.9%
PUC Distribution Inc.	$ 490,717.95	$ 689,433.00	-34.0%
Renfrew Hydro Inc.	$ 294,936.00	$ 99,659.40	108.5%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 215,592.77	53.1%
Sioux Lookout Hydro Inc.			
Synergy North Corporation			
Tillsonburg Hydro Inc.	$ 474,089.51	$ 2,488,402.30	-165.8%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 8,859,713.74	31.4%
Wasaga Distribution Inc.	$ 571,069.22	$ 1,529,215.94	-98.5%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 622,201.69	98.8%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 2,051,660.06	-80.8%
Wellington North Power Inc.	$ 103,820.01	$ 842,740.17	-209.4%
Westario Power Inc.	$ 359,825.35	$ 66,328.44	169.1%

Average	**-32.2%**
Median	**-17.2%**

As can be seen there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%. There are several possible reasons to explain these differences. The first is that there is an unknown or unmeasurable business condition that affects distribution station capex that is not included in the current model. The second is that there is an accounting issue that resulted in significantly more or less cost being recorded in this account. A third possible explanation is that the distributor is significantly better or worse at performing this function relative to other distributors.

The explanatory power of the model as measured by R-squared was 0.490 which is a little higher than the preliminary model. The percentage of distributors with cost performance less than 50% was 21% which was similar to the preliminary work. The small improvement in explanatory power still justifies the continued gathering of the scale variables because they are relevant and intuitive.

There are several potential improvements that could be considered. These improvements include more detailed and consistent age data. The information on number of stations and station transformers should be collected on an ongoing basis.

Conclusion: The station capex econometric models were improved by the inclusion of 2018-2019 data and the information on number of stations and transformers made possible by the questionnaire. Continued collection of this information is recommended. The number of stations and transformers will be required for future benchmarking using this model. Despite these improvements, the econometric model continues to have poor explanatory power. The unit cost benchmarking provides an easier to understand alternative to the econometric model. Both methods result in very large dispersion in benchmarking outcomes. In our opinion, the usefulness of these models for APB purposes is limited. Future work in this area could include modeling techniques to benchmark investment over multi-year periods which should reduce the amount of variation in cost that needs to be explained by the models. Additional information on station age, ages of station equipment, or condition of such equipment may provide additional explanatory power. Comments from distributors on important business conditions and other drivers of capex cost could help inform future model development.

Capital Expenditures: Line Transformers

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). Number of customers was chosen as the sole scale variable for these calculations. In the context of capex, the interpretation of unit cost is a little different than for O&M expenses. Here the unit cost is expressed as dollars per unit of total scale and not dollars per added scale (e.g., dollars per customer vs dollars per transformer added).

Table 28 summarizes the unit cost results for transformer capex. As can be seen, there is a fair amount of variation in the unit cost scores. The number of companies within 50% of average is 83%.

Table 28

Unit Cost Indexes by Distributor: Line Transformer Capex

Distributor	Cost ($1,000)				Scale (1,000 customers)				Unit Cost ($ per customer)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	12,071	24,984	42,574	26,543	982.0	991.1	1,054.6	1,009.2	$ 12.29	$ 25.21	$ 40.37	$ 25.96
Algoma Power Inc.	362	385	357	368	11.7	11.7	11.7	11.7	$ 30.90	$ 32.84	$ 30.41	$ 31.38
Atikokan Hydro Inc.	2	6	30	13	1.6	1.6	1.6	1.6	$ 1.40	$ 3.42	$ 18.72	$ 7.85
Bluewater Power Distribution	1,071	947	1,082	1,033	36.6	36.7	36.7	36.7	$ 29.27	$ 25.80	$ 29.44	$ 28.17
Brantford Power Inc.	815	1,072	1,145	1,010	39.6	39.9	40.1	39.9	$ 20.56	$ 26.87	$ 28.52	$ 25.32
Burlington Hydro Inc.	1,910	1,783	1,667	1,787	67.1	67.9	68.2	67.8	$ 28.45	$ 26.25	$ 24.44	$ 26.38
Canadian Niagara Power Inc.	994	1,376	1,238	1,203	29.1	29.2	29.5	29.3	$ 34.21	$ 47.05	$ 42.03	$ 41.10
Centre Wellington Hydro Ltd.	127	171	145	147	6.9	7.0	7.2	7.0	$ 18.32	$ 24.29	$ 20.20	$ 20.94
Chapleau Public Utilities Corporation	3	2	4	3	1.2	1.2	1.2	1.2	$ 2.05	$ 2.02	$ 3.54	$ 2.54
Cooperative Hydro Embrun Inc.	66	58	65	63	2.2	2.3	2.4	2.3	$ 29.25	$ 24.96	$ 27.51	$ 27.24
E.L.K. Energy Inc.	204	218	264	229	12.3	12.4	12.5	12.4	$ 16.56	$ 17.61	$ 21.16	$ 18.44
Elexicon Energy Inc.	3,213	3,434	5,947	4,198	163.0	164.7	167.7	165.1	$ 19.72	$ 20.85	$ 35.47	$ 25.35
Energy Plus	2,847	2,965	3,384	3,065	64.7	65.4	66.5	65.6	$ 43.98	$ 45.33	$ 50.87	$ 46.73
Entegrus Powerlines Inc.	957	1,152	1,208	1,105	41.1	59.2	59.8	53.4	$ 23.25	$ 19.46	$ 20.19	$ 20.97
ENWIN Utilities Ltd.	2,644	2,432	2,531	2,536	88.4	89.0	89.6	89.0	$ 29.90	$ 27.33	$ 28.26	$ 28.50
ERTH Power	541	443	685	556	22.8	23.1	23.4	23.1	$ 23.71	$ 19.15	$ 29.31	$ 24.06
Espanola Regional Hydro Distribution	32	32	42	36	3.3	3.3	3.3	3.3	$ 9.81	$ 9.79	$ 12.72	$ 10.77
Essex Powerlines Corporation	732	924	1,071	909	29.8	30.0	30.4	30.1	$ 24.62	$ 30.78	$ 35.22	$ 30.21
Festival Hydro Inc.	412	378	414	401	21.1	21.4	21.4	21.3	$ 19.53	$ 17.69	$ 19.35	$ 18.86
Fort Frances Power Corporation	57	54	44	52	3.7	3.7	3.8	3.8	$ 15.28	$ 14.35	$ 11.70	$ 13.78
Greater Sudbury Hydro Inc.	1,669	2,051	2,105	1,942	47.4	47.6	47.7	47.6	$ 35.20	$ 43.07	$ 44.11	$ 40.79
Grimsby Power Incorporated	262	301	373	312	11.4	11.6	11.6	11.5	$ 23.05	$ 26.08	$ 32.06	$ 27.06
Halton Hills Hydro Inc.	1,731	2,120	1,319	1,724	22.2	22.4	22.5	22.4	$ 78.00	$ 94.48	$ 58.57	$ 77.02
Hearst Power Distribution Company	17	21	22	20	2.7	2.7	2.7	2.7	$ 6.28	$ 7.64	$ 8.06	$ 7.32
Hydro One Networks	108,000	95,000	62,000	88,333	1,320.1	1,334.0	1,344.3	1,332.8	$ 81.81	$ 71.22	$ 46.12	$ 66.38
Hydro 2000 Inc.	12	13	31	19	1.3	1.3	1.2	1.3	$ 9.65	$ 9.95	$ 25.26	$ 14.95
Hydro Hawkesbury Inc.	9	11	12	11	5.5	5.5	5.5	5.5	$ 1.67	$ 2.04	$ 2.12	$ 1.94
Hydro Ottawa Limited	8,672	8,405	8,774	8,617	331.8	335.3	339.8	335.6	$ 26.14	$ 25.07	$ 25.82	$ 25.68
Innpower Corporation	728	587	751	689	17.2	18.2	18.6	18.0	$ 42.29	$ 32.30	$ 40.33	$ 38.30
Kingston Hydro Corporation	348	397	430	392	27.6	27.7	27.8	27.7	$ 12.63	$ 14.37	$ 15.46	$ 14.15
Kitchener-Wilmot Hydro Inc.	3,363	3,442	3,093	3,300	95.8	96.8	97.7	96.8	$ 35.12	$ 35.55	$ 31.66	$ 34.11
Lakefront Utilities Inc.	128	152	151	144	10.3	10.5	10.5	10.4	$ 12.35	$ 14.54	$ 14.32	$ 13.74
Lakeland Power Distribution Ltd.	477	520	530	509	13.5	13.6	13.8	13.6	$ 35.38	$ 38.11	$ 38.49	$ 37.33
London Hydro Inc.	5,208	5,103	4,860	5,057	157.2	159.0	160.6	158.9	$ 33.13	$ 32.09	$ 30.26	$ 31.83
Milton Hydro Distribution Inc.	1,383	1,896	1,780	1,687	37.9	39.6	40.4	39.3	$ 36.50	$ 47.91	$ 44.08	$ 42.83
Newmarket-Tay Power Distribution	631	345	507	494	35.7	43.5	43.9	41.1	$ 17.67	$ 7.94	$ 11.54	$ 12.38
Niagara Peninsula Energy Inc.	1,978	1,886	2,223	2,029	54.9	55.6	56.1	55.5	$ 36.01	$ 33.93	$ 39.66	$ 36.53
Niagara-on-the-Lake Hydro Inc.	464	530	343	446	9.4	9.5	9.6	9.5	$ 49.53	$ 56.07	$ 35.89	$ 47.16
North Bay Hydro Distribution Limited	628	653	731	671	24.1	24.2	24.2	24.2	$ 26.06	$ 27.03	$ 30.23	$ 27.77
Northern Ontario Wires Inc.	64	76	90	77	6.0	5.9	6.0	6.0	$ 10.72	$ 12.84	$ 14.98	$ 12.85
Oakville Hydro Electricity Distribution	1,982	2,166	2,348	2,165	70.5	72.1	73.1	71.9	$ 28.11	$ 30.04	$ 32.11	$ 30.09
Orangeville Hydro Limited	390	382	377	383	12.4	12.6	12.7	12.5	$ 31.55	$ 30.36	$ 29.81	$ 30.57
Orillia Power Distribution	341	338	253	311	13.8	14.1	14.4	14.1	$ 24.65	$ 24.02	$ 17.60	$ 22.09
Oshawa PUC Networks Inc.	1,508	1,317	2,677	1,834	57.6	58.7	59.2	58.5	$ 26.18	$ 22.41	$ 45.22	$ 31.27
Ottawa River Power Corporation	138	296	350	261	11.1	11.2	11.3	11.2	$ 12.42	$ 26.30	$ 30.93	$ 23.22
Peterborough Distribution	1,160	1,130	1,173	1,154	37.3	37.1	37.3	37.2	$ 31.06	$ 30.42	$ 31.48	$ 30.99
PUC Distribution Inc.	1,161	1,026	899	1,029	33.6	33.6	33.6	33.6	$ 34.59	$ 30.53	$ 26.73	$ 30.62
Renfrew Hydro Inc.	69	78	52	66	4.3	4.3	4.3	4.3	$ 16.07	$ 18.06	$ 11.96	$ 15.36
Rideau St. Lawrence Distribution Inc.	83	108	102	98	5.9	5.9	5.9	5.9	$ 14.15	$ 18.25	$ 17.19	$ 16.53
Sioux Lookout Hydro Inc.	61	64	77	67	2.8	2.8	2.8	2.8	$ 21.34	$ 22.53	$ 27.16	$ 23.68
Synergy North Corporation	1,740	1,648	1,349	1,579	56.4	56.5	56.7	56.5	$ 30.84	$ 29.16	$ 23.80	$ 27.93
Tillsonburg Hydro Inc.	161	212	379	251	7.2	7.1	7.1	7.2	$ 22.42	$ 29.81	$ 53.14	$ 35.12
Toronto Hydro-Electric System	60,766	63,875	69,416	64,686	767.9	772.6	777.9	772.8	$ 79.13	$ 82.67	$ 89.24	$ 83.68
Wasaga Distribution Inc.	196	211	313	240	13.6	13.8	14.0	13.8	$ 14.42	$ 15.32	$ 22.38	$ 17.37
Waterloo North Hydro Inc.	3,427	3,248	3,466	3,380	57.0	57.5	57.9	57.5	$ 60.08	$ 56.51	$ 59.91	$ 58.83
Welland Hydro-Electric System Corp.	343	328	471	381	23.0	23.4	23.7	23.4	$ 14.90	$ 14.04	$ 19.92	$ 16.28
Wellington North Power Inc.	58	72	75	68	3.8	3.8	3.8	3.8	$ 15.48	$ 18.85	$ 19.59	$ 17.97
Westario Power Inc.	460	530	474	488	23.4	23.5	23.8	23.6	$ 19.69	$ 22.50	$ 19.93	$ 20.71
Distributor Average			$	4,141				88.7			$	27.88

The econometric work resulted in the model for Line Transformer Capital Expenditures ("transformer capex") shown in Table 29.

Table 29

Econometric Model of Line Transformer Capex

VARIABLE KEY

Scale Variables:

yn = Number of customers
ykmtot = Total km of line

Business Conditions:

ynaddavg = Average number of customers added
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.732	14.267	0.000
I(yn * yn/2)	-0.164	-7.183	0.000
ykmtot	0.326	11.547	0.000
ynaddavg	0.186	2.483	0.013
trend	0.025	2.951	0.003
Constant	9.957	133.543	0.000
System Rbar-Squared	0.885		
Sample Period	2012-2019		
Number of Observations	433		

The research identified the number of customers and km of line as the potentially relevant scale variables. For a distributor of average scale, a 1% increase in the number of customers increases predicted capex by 0.732% whereas a 1% increase in km of line increases predicted capex by 0.326%.

The econometric work was able to account for other relevant business conditions such as customer growth. The model found a positive relationship between customer growth and cost. Higher customer growth implies system expansion which increases the number of transformers required. The 0.025 value on the trend variable suggest that capex should increase by 2.5% per year for reasons other than the changes in the model's business condition variables.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 30.

As can be seen there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%. The percentage of distributors with cost performance less than 50% was 83% which was much better than the preliminary work. The explanatory power of the model as measured by R-squared was 0.885 which is higher than the preliminary model.

There are several potential improvements that could be considered. These improvements include more detailed and consistent age data. PEG also tested several other potential explanatory variables including number of transformers. In each of these cases either the variable was not statistically significant or other combinations of explanatory variables produced a better model. The number of line transformers was statistically significant in several models but not featured in the final model. Additional or better data may produce better results in the future for these variables. The current evidence suggests that number of customers is an adequate alternative to the number of transformers such that the value of additional collection of this information may not provide enough value to justify the incremental reporting burden.

<u>Conclusion</u>: The transformer capex econometric models were improved by the inclusion of 2018-2019 data. The information made possible by the questionnaire was tested but not was not featured in the final models. The econometric model has good explanatory power. The unit cost benchmarking provides an easier to understand alternative to the econometric model. Both methods provided reasonable levels of dispersion. In our opinion, both can be used for APB purposes.

Table 30

Cost Performance Results: Line Transformers Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 21,047,113	-8.1%
Algoma Power Inc.	$ 172,824.38	$ 231,198.33	-29.1%
Atikokan Hydro Inc.	$ 137,108.02	$ 61,483.51	80.2%
Bluewater Power Distribution	$ 1,001,120.24	$ 943,762.83	5.9%
Brantford Power Inc.	$ 978,892.37	$ 819,276.55	17.8%
Burlington Hydro Inc.	$ 819,300.95	$ 1,038,415.71	-23.7%
Canadian Niagara Power Inc.	$ 445,938.71	$ 391,968.52	12.9%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 197,727.20	23.2%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 120,892.62	-43.9%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 51,092.16	132.5%
E.L.K. Energy Inc.	$ 309,442.63	$ 260,283.84	17.3%
Elexicon Energy Inc.	$ 4,460,702.04	$ 5,292,581.70	-17.1%
Energy Plus	$ 1,438,423.87	$ 931,040.95	43.5%
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 4,442,754.58	-70.8%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 2,181,412.86	-41.9%
ERTH Power	$ 1,275,736.38	$ 1,178,831.35	7.9%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 221,335.91	-17.3%
Essex Powerlines Corporation	$ 666,785.34	$ 746,554.16	-11.3%
Festival Hydro Inc.	$ 581,357.64	$ 649,606.07	-11.1%
Fort Frances Power Corporation	$ 180,647.65	$ 185,777.26	-2.8%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 1,044,796.10	47.7%
Grimsby Power Incorporated	$ 449,469.02	$ 378,443.55	17.2%
Halton Hills Hydro Inc.	$ 395,928.02	$ 255,502.56	43.8%
Hearst Power Distribution Company	$ 207,090.82	$ 320,908.95	-43.8%
Hydro One Networks	$ 44,220,101.17	$ 65,246,960.54	-38.9%
Hydro 2000 Inc.	$ 144,241.31	$ 39,745.14	128.9%
Hydro Hawkesbury Inc.	$ 235,058.84	$ 1,497,924.68	-185.2%
Hydro Ottawa Limited	$ 8,458,627.80	$ 10,871,959.61	-25.1%
Innpower Corporation	$ 371,335.51	$ 345,193.80	7.3%
Kingston Hydro Corporation	$ 345,235.52	$ 476,861.87	-32.3%
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 2,211,048.05	-5.0%
Lakefront Utilities Inc.	$ 221,582.58	$ 326,619.33	-38.8%
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 270,164.45	56.7%
London Hydro Inc.	$ 1,814,441.18	$ 2,015,319.07	-10.5%

Table 30 (continued)

Cost Performance Results: Line Transformers Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$ 1,515,937.00	$ 1,571,504.95	-3.6%
Newmarket-Tay Power Distribution	$ 808,921.79	$ 2,624,648.43	-117.7%
Niagara Peninsula Energy Inc.	$ 3,048,306.55	$ 3,406,162.22	-11.1%
Niagara-on-the-Lake Hydro Inc.	$ 306,746.94	$ 195,590.48	45.0%
North Bay Hydro Distribution Limited	$ 438,677.78	$ 357,367.67	20.5%
Northern Ontario Wires Inc.	$ 242,500.80	$ 342,751.27	-34.6%
Oakville Hydro Electricity Distribution	$ 1,376,903.63	$ 1,560,236.22	-12.5%
Orangeville Hydro Limited	$ 354,582.13	$ 235,083.32	41.1%
Orillia Power Distribution	$ 924,782.33	$ 1,239,617.81	-29.3%
Oshawa PUC Networks Inc.	$ 1,124,377.29	$ 805,920.13	33.3%
Ottawa River Power Corporation	$ 435,782.42	$ 374,331.99	15.2%
Peterborough Distribution	$ 776,628.65	$ 622,013.82	22.2%
PUC Distribution Inc.	$ 490,717.95	$ 481,001.08	2.0%
Renfrew Hydro Inc.	$ 294,936.00	$ 319,181.01	-7.9%
Rideau St. Lawrence Distribution Inc.	$ 366,643.98	$ 302,593.79	19.2%
Sioux Lookout Hydro Inc.	$ 216,533.10	$ 177,637.22	19.8%
Synergy North Corporation	$ 1,672,028.19	$ 2,007,795.54	-18.3%
Tillsonburg Hydro Inc.	$ 474,089.51	$ 149,067.04	115.7%
Toronto Hydro-Electric System	$ 12,127,971.21	$ 4,685,695.96	95.1%
Wasaga Distribution Inc.	$ 571,069.22	$ 594,374.99	-4.0%
Waterloo North Hydro Inc.	$ 1,671,145.00	$ 931,004.68	58.5%
Welland Hydro-Electric System Corp.	$ 914,524.75	$ 1,211,245.60	-28.1%
Wellington North Power Inc.	$ 103,820.01	$ 83,902.78	21.3%
Westario Power Inc.	$ 359,825.35	$ 457,885.32	-24.1%

Average	**3.5%**
Median	**-3.2%**

Capital Expenditures: Meters

Unit cost calculations were done for each distributor for each of the most recent three years for which data are available (2017, 2018, 2019). Number of customers was chosen as the sole scale variable for the unit cost calculations. The km of line in this model serves as a measure of service territory size similar to the role it had in the meter maintenance model. In the context of capex, the interpretation is also a little different than for O&M expenses. Here the unit cost is expressed as dollars per unit of total scale and not dollars per added scale (e.g., dollars per customer vs dollars per meter added). Table 31 summarizes the unit cost results for meter capex.

As can be seen, there is a fair amount of variation in the unit cost measures. The number of companies within 50% of average is 63%. A simple metric such as dollars per customer is unable to account for business conditions other than scale.

The econometric work resulted in the model for Meter Capital Expenditures ("meter capex") shown in Table 32. The model identified the number of customers and km of line as the relevant scale variables. The relationship between number of customers and number of installed meters should be close. The km of line serves as a measure of service territory size and works better than area. The model indicates that, for a distributor of average scale, a 1% increase in the number of customers results in an increase in predicted meter capex of 0.637% whereas a 1% increase in the km of line results in an increase in predicted capex of 0.406%.

The econometric work was able to account for other relevant business conditions. A positive relationship was found between customer growth and cost. Higher customer growth implies system expansion which increases the number of meters required. The -0.024 value of the trend variable parameter suggests that capex should fall by 2.4% annually for reasons other than changes in the values of the model's business condition variables.

The econometric model produced cost predictions for each year for each distributor. The average difference between actual cost and that predicted by the model is presented in Table 33. As can be seen there are a fair number of distributors with actual cost that differs from that predicted by the model by more than 50%.

Table 31

Unit Cost Indexes by Distributor: Meter Capex

Distributor	Cost ($1,000)				Scale (1,000 customers)				Unit Cost ($ per customer)			
	2017	2018	2019	Average	2017	2018	2019	Average	2017	2018	2019	Average
Alectra Utilities Corporation	4,207	8,682	14,259	9,049.5	982.0	991.1	1,054.6	1,009.2	$ 4.28	$ 8.76	$ 13.52	$ 8.86
Algoma Power Inc.	97.9	112.2	97.9	102.7	11.7	11.7	11.7	11.7	$ 8.35	$ 9.57	$ 8.34	$ 8.76
Atikokan Hydro Inc.	9.5	8.9	13.9	10.8	1.6	1.6	1.6	1.6	$ 5.77	$ 5.44	$ 8.56	$ 6.59
Bluewater Power Distribution	406.1	280.9	313.0	333.3	36.6	36.7	36.7	36.7	$ 11.10	$ 7.66	$ 8.52	$ 9.09
Brantford Power Inc.	166.0	174.6	202.0	180.9	39.6	39.9	40.1	39.9	$ 4.19	$ 4.38	$ 5.04	$ 4.53
Burlington Hydro Inc.	585.6	605.5	572.7	587.9	67.1	67.9	68.2	67.8	$ 8.72	$ 8.91	$ 8.40	$ 8.68
Canadian Niagara Power Inc.	314.7	267.5	290.6	290.9	29.1	29.2	29.5	29.3	$ 10.83	$ 9.15	$ 9.86	$ 9.95
Centre Wellington Hydro Ltd.	31.7	42.1	68.4	47.4	6.9	7.0	7.2	7.0	$ 4.58	$ 6.00	$ 9.56	$ 6.71
Chapleau Public Utilities Corporation	7.1	10.5	10.2	9.3	1.2	1.2	1.2	1.2	$ 5.69	$ 8.70	$ 8.33	$ 7.57
Cooperative Hydro Embrun Inc.	12.2	14.4	16.5	14.4	2.2	2.3	2.4	2.3	$ 5.45	$ 6.26	$ 6.96	$ 6.23
E.L.K. Energy Inc.	144.3	50.5	57.4	84.0	12.3	12.4	12.5	12.4	$ 11.69	$ 4.08	$ 4.60	$ 6.79
Elexicon Energy Inc.	1,262.0	1,446.2	1,314.4	1,340.9	163.0	164.7	167.7	165.1	$ 7.74	$ 8.78	$ 7.84	$ 8.12
Energy Plus	579.8	529.5	683.7	597.7	64.7	65.4	66.5	65.6	$ 8.96	$ 8.10	$ 10.28	$ 9.11
Entegrus Powerlines Inc.	852.6	1,015.2	1,170.0	1,012.6	41.1	59.2	59.8	53.4	$ 20.72	$ 17.15	$ 19.56	$ 19.15
ENWIN Utilities Ltd.	572.2	652.3	612.6	612.4	88.4	89.0	89.6	89.0	$ 6.47	$ 7.33	$ 6.84	$ 6.88
ERTH Power	311.6	308.3	337.2	319.0	22.8	23.1	23.4	23.1	$ 13.65	$ 13.34	$ 14.42	$ 13.80
Espanola Regional Hydro Distribution	7.4	6.7	5.6	6.6	3.3	3.3	3.3	3.3	$ 2.24	$ 2.04	$ 1.69	$ 1.99
Essex Powerlines Corporation	1,689.5	668.7	420.7	926.3	29.8	30.0	30.4	30.1	$ 56.78	$ 22.28	$ 13.84	$ 30.97
Festival Hydro Inc.	95.7	153.1	243.3	164.0	21.1	21.4	21.4	21.3	$ 4.53	$ 7.17	$ 11.38	$ 7.69
Fort Frances Power Corporation	33.3	33.3	47.4	38.0	3.7	3.7	3.8	3.8	$ 8.89	$ 8.90	$ 12.55	$ 10.12
Greater Sudbury Hydro Inc.	133.9	120.3	110.8	121.7	47.4	47.6	47.7	47.6	$ 2.82	$ 2.53	$ 2.32	$ 2.56
Grimsby Power Incorporated	112.0	113.2	135.8	120.3	11.4	11.6	11.6	11.5	$ 9.87	$ 9.80	$ 11.68	$ 10.45
Halton Hills Hydro Inc.	224.7	218.9	423.6	289.0	22.2	22.4	22.5	22.4	$ 10.12	$ 9.75	$ 18.80	$ 12.89
Hearst Power Distribution Company	2.0	9.3	8.1	6.5	2.7	2.7	2.7	2.7	$ 0.76	$ 3.45	$ 3.02	$ 2.41
Hydro One Networks	40,333	54,000	64,333	52,888.9	1,320.1	1,334.0	1,344.3	1,332.8	$ 30.55	$ 40.48	$ 47.86	$ 39.63
Hydro 2000 Inc.	4.6	5.1	10.8	6.8	1.3	1.3	1.2	1.3	$ 3.65	$ 4.05	$ 8.69	$ 5.47
Hydro Hawkesbury Inc.	18.1	20.2	22.6	20.3	5.5	5.5	5.5	5.5	$ 3.27	$ 3.64	$ 4.07	$ 3.66
Hydro Ottawa Limited	2,174.2	2,412.3	3,506.9	2,697.8	331.8	335.3	339.8	335.6	$ 6.55	$ 7.19	$ 10.32	$ 8.02
Innpower Corporation	252.3	315.7	278.9	282.3	17.2	18.2	18.6	18.0	$ 14.64	$ 17.38	$ 14.97	$ 15.67
Kingston Hydro Corporation	233.1	258.2	280.5	257.3	27.6	27.7	27.8	27.7	$ 8.45	$ 9.33	$ 10.10	$ 9.29
Kitchener-Wilmot Hydro Inc.	580.0	888.0	882.0	783.3	95.8	96.8	97.7	96.8	$ 6.06	$ 9.17	$ 9.03	$ 8.09
Lakefront Utilities Inc.	68.0	108.3	132.9	103.1	10.3	10.5	10.5	10.4	$ 6.57	$ 10.37	$ 12.60	$ 9.84
Lakeland Power Distribution Ltd.	202.5	250.4	261.8	238.2	13.5	13.6	13.8	13.6	$ 15.01	$ 18.35	$ 19.03	$ 17.46
London Hydro Inc.	1,659.8	1,649.8	1,635.3	1,648.3	157.2	159.0	160.6	158.9	$ 10.56	$ 10.37	$ 10.18	$ 10.37
Milton Hydro Distribution Inc.	745.4	1,103.4	1,244.4	1,031.1	37.9	39.6	40.4	39.3	$ 19.67	$ 27.88	$ 30.81	$ 26.12
Newmarket-Tay Power Distribution	226.6	173.8	207.7	202.7	35.7	43.5	43.9	41.1	$ 6.35	$ 3.99	$ 4.73	$ 5.02
Niagara Peninsula Energy Inc.	596.5	838.8	1,063.4	832.9	54.9	55.6	56.1	55.5	$ 10.86	$ 15.09	$ 18.97	$ 14.97
Niagara-on-the-Lake Hydro Inc.	87.7	109.4	107.6	101.6	9.4	9.5	9.6	9.5	$ 9.35	$ 11.56	$ 11.26	$ 10.73
North Bay Hydro Distribution Limited	236.4	192.8	143.1	190.7	24.1	24.2	24.2	24.2	$ 9.80	$ 7.97	$ 5.91	$ 7.90
Northern Ontario Wires Inc.	5.1	7.7	5.5	6.1	6.0	5.9	6.0	6.0	$ 0.85	$ 1.29	$ 0.91	$ 1.02
Oakville Hydro Electricity Distribution	911.3	1,121.4	1,369.4	1,134.0	70.5	72.1	73.1	71.9	$ 12.93	$ 15.55	$ 18.72	$ 15.73
Orangeville Hydro Limited	61.1	101.7	108.5	90.4	12.4	12.6	12.7	12.5	$ 4.95	$ 8.08	$ 8.58	$ 7.20
Orillia Power Distribution	47.3	90.7	83.9	74.0	13.8	14.1	14.4	14.1	$ 3.42	$ 6.44	$ 5.84	$ 5.23
Oshawa PUC Networks Inc.	552.0	604.3	705.2	620.5	57.6	58.7	59.2	58.5	$ 9.59	$ 10.29	$ 11.92	$ 10.60
Ottawa River Power Corporation	15.4	50.1	82.7	49.4	11.1	11.2	11.3	11.2	$ 1.38	$ 4.45	$ 7.31	$ 4.38
Peterborough Distribution	324.7	358.2	395.8	359.6	37.3	37.1	37.3	37.2	$ 8.69	$ 9.65	$ 10.62	$ 9.65
PUC Distribution Inc.	76.2	107.2	104.8	96.0	33.6	33.6	33.6	33.6	$ 2.27	$ 3.19	$ 3.12	$ 2.86
Renfrew Hydro Inc.	201.3	217.8	219.7	212.9	4.3	4.3	4.3	4.3	$ 46.82	$ 50.52	$ 50.79	$ 49.37
Rideau St. Lawrence Distribution Inc.	18.3	45.7	66.4	43.5	5.9	5.9	5.9	5.9	$ 3.11	$ 7.74	$ 11.23	$ 7.36
Sioux Lookout Hydro Inc.	4.3	6.8	17.0	9.4	2.8	2.8	2.8	2.8	$ 1.52	$ 2.39	$ 5.98	$ 3.30
Synergy North Corporation	451.8	446.2	572.6	490.2	56.4	56.5	56.7	56.5	$ 8.01	$ 7.89	$ 10.10	$ 8.67
Tillsonburg Hydro Inc.	23.8	54.1	96.4	58.1	7.2	7.1	7.1	7.2	$ 3.31	$ 7.60	$ 13.52	$ 8.14
Toronto Hydro-Electric System	19,688	21,989	20,932	20,869.6	767.9	772.6	777.9	772.8	$ 25.64	$ 28.46	$ 26.91	$ 27.00
Wasaga Distribution Inc.	78.5	94.1	132.1	101.6	13.6	13.8	14.0	13.8	$ 5.78	$ 6.82	$ 9.44	$ 7.35
Waterloo North Hydro Inc.	771.1	724.6	917.5	804.4	57.0	57.5	57.9	57.5	$ 13.52	$ 12.61	$ 15.86	$ 13.99
Welland Hydro-Electric System Corp.	64.3	80.8	79.1	74.7	23.0	23.4	23.7	23.4	$ 2.79	$ 3.46	$ 3.34	$ 3.20
Wellington North Power Inc.	79.7	140.5	152.4	124.2	3.8	3.8	3.8	3.8	$ 21.15	$ 36.92	$ 39.79	$ 32.62
Westario Power Inc.	247.1	270.2	233.9	250.4	23.4	23.5	23.8	23.6	$ 10.57	$ 11.48	$ 9.84	$ 10.63
Distributor Average				**$ 1,776**				**88.7**				**$ 11.04**

Table 32

Econometric Model of Meter Capex

VARIABLE KEY

Scale Variables:

yn = Number of customers
ykmtot = Total km of line

Business Conditions:

ynaddavg = Average number of customers added
trend = Time trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC	P-VALUE
yn	0.637	5.291	0.000
I(yn * yn/2)	-0.040	-0.886	0.376
ykmtot	0.406	5.225	0.000
ynaddavg	0.193	1.188	0.236
trend	-0.024	-1.256	0.210
Constant	9.200	57.364	0.000
System Rbar-Squared	0.678		
Sample Period	2012-2019		
Number of Observations	422		

Pacific Economics Group Research, LLC

Table 33

Cost Performance Results: Meter Capex

Distributor	Average Actual	Average Predicted	Average Actual Less Predicted 2017-2019
Alectra Utilities Corporation	$ 19,409,515	$ 36,225,504	-62.4%
Algoma Power Inc.	$ 172,824.38	$ 501,837.28	-106.6%
Atikokan Hydro Inc.	$ 137,108.02	$ 121,118.46	12.4%
Bluewater Power Distribution	$ 1,001,120.24	$ 983,261.29	1.8%
Brantford Power Inc.	$ 978,892.37	$ 1,418,594.25	-37.1%
Burlington Hydro Inc.	$ 819,300.95	$ 900,951.54	-9.5%
Canadian Niagara Power Inc.	$ 445,938.71	$ 547,948.62	-20.6%
Centre Wellington Hydro Ltd.	$ 249,357.67	$ 198,519.69	22.8%
Chapleau Public Utilities Corporation	$ 77,937.15	$ 116,851.36	-40.5%
Cooperative Hydro Embrun Inc.	$ 192,218.18	$ 116,936.50	49.7%
E.L.K. Energy Inc.	$ 309,442.63	$ 469,079.71	-41.6%
Elexicon Energy Inc.	$ 4,460,702.04	$ 6,496,776.70	-37.6%
Energy Plus	$ 1,438,423.87	$ 1,448,528.16	-0.7%
Entegrus Powerlines Inc.	$ 2,188,627.39	$ 1,389,959.46	45.4%
ENWIN Utilities Ltd.	$ 1,434,724.39	$ 2,900,759.98	-70.4%
ERTH Power	$ 1,275,736.38	$ 655,421.70	66.6%
Espanola Regional Hydro Distribution	$ 186,173.96	$ 4,585,624.24	-320.4%
Essex Powerlines Corporation	$ 666,785.34	$ 575,631.77	14.7%
Festival Hydro Inc.	$ 581,357.64	$ 357,940.27	48.5%
Fort Frances Power Corporation	$ 180,647.65	$ 57,199.69	115.0%
Greater Sudbury Hydro Inc.	$ 1,683,410.42	$ 6,591,768.97	-136.5%
Grimsby Power Incorporated	$ 449,469.02	$ 416,575.17	7.6%
Halton Hills Hydro Inc.	$ 395,928.02	$ 293,604.15	29.9%
Hearst Power Distribution Company	$ 207,090.82	$ 438,411.27	-75.0%
Hydro One Networks	$ 44,220,101.17	$ 15,183,046.80	106.9%
Hydro 2000 Inc.	$ 144,241.31	$ 75,225.31	65.1%
Hydro Hawkesbury Inc.	$ 235,058.84	$ 373,469.33	-46.3%
Hydro Ottawa Limited	$ 8,458,627.80	$ 10,424,793.53	-20.9%
Innpower Corporation	$ 371,335.51	$ 377,702.18	-1.7%
Kingston Hydro Corporation	$ 345,235.52	$ 207,105.20	51.1%
Kitchener-Wilmot Hydro Inc.	$ 2,103,213.96	$ 2,438,703.71	-14.8%
Lakefront Utilities Inc.	$ 221,582.58	$ 124,436.48	57.7%
Lakeland Power Distribution Ltd.	$ 476,291.87	$ 204,185.90	84.7%
London Hydro Inc.	$ 1,814,441.18	$ 1,825,360.55	-0.6%

Table 33 (continued)

Cost Performance Results: Meter Capex

Distributor	Average Actual		Average Predicted		Average Actual Less Predicted 2017-2019
Milton Hydro Distribution Inc.	$	1,515,937.00	$	685,253.61	79.4%
Newmarket-Tay Power Distribution	$	808,921.79	$	1,734,895.11	-76.3%
Niagara Peninsula Energy Inc.	$	3,048,306.55	$	2,253,729.07	30.2%
Niagara-on-the-Lake Hydro Inc.	$	306,746.94	$	244,697.59	22.6%
North Bay Hydro Distribution Limited	$	438,677.78	$	618,171.02	-34.3%
Northern Ontario Wires Inc.	$	242,500.80	$	4,518,814.79	-292.5%
Oakville Hydro Electricity Distribution	$	1,376,903.63	$	777,895.74	57.1%
Orangeville Hydro Limited	$	354,582.13	$	294,400.18	18.6%
Orillia Power Distribution	$	924,782.33	$	1,290,207.57	-33.3%
Oshawa PUC Networks Inc.	$	1,124,377.29	$	825,496.18	30.9%
Ottawa River Power Corporation	$	435,782.42	$	638,513.67	-38.2%
Peterborough Distribution	$	776,628.65	$	534,302.58	37.4%
PUC Distribution Inc.	$	490,717.95	$	1,374,533.28	-103.0%
Renfrew Hydro Inc.	$	294,936.00	$	92,921.81	115.5%
Rideau St. Lawrence Distribution Inc.	$	366,643.98	$	225,065.46	48.8%
Sioux Lookout Hydro Inc.	$	216,533.10	$	1,005,000.59	-153.5%
Synergy North Corporation	$	1,672,028.19	$	1,502,360.25	10.7%
Tillsonburg Hydro Inc.	$	474,089.51	$	260,185.84	60.0%
Toronto Hydro-Electric System	$	12,127,971.21	$	6,325,027.96	65.1%
Wasaga Distribution Inc.	$	571,069.22	$	665,481.22	-15.3%
Waterloo North Hydro Inc.	$	1,671,145.00	$	1,124,691.77	39.6%
Welland Hydro-Electric System Corp.	$	914,524.75	$	2,253,871.16	-90.2%
Wellington North Power Inc.	$	103,820.01	$	22,301.61	153.8%
Westario Power Inc.	$	359,825.35	$	304,484.07	16.7%

Average	**-5.4%**
Median	**9.2%**

The explanatory power of the model as measured by R-squared was 0.678 which is higher than the preliminary model. The percentage of distributors with cost performance less than 50% was 59% which was much better than the preliminary work.

There are several potential improvements that could be considered. These improvements could include more detailed and consistent age data. This new technology was mandated and the benefits from a long history of maintaining analog meters was not available to help inform repair vs. replace decisions. This is an area of large potential improvement from the identification of best practices. PEG also tested several other potential explanatory variables including number of meters. In each of these cases either the variable was not statistically significant or other combinations of explanatory variables produced a better model. The number of meters variable was statistically significant in several models but not featured in the final model. Additional or better data may produce better results in the future for these variables. The current evidence suggests that number of customers is an adequate alternative to number of meters.

Conclusion: The meter capex econometric models were improved by the inclusion of 2018-2019 data. The information made possible by the questionnaire was tested but not was not featured in the final models. The number of meters was statistically significant but did not have explanatory power that was better than number of customers. Despite these improvements, the econometric model had lower explanatory power than many other models. The unit cost benchmarking provides an easier to understand alternative to the econometric model. The econometric model provided a more reasonable amount of dispersion of benchmarking outcomes than the unit cost work. In our opinion, both methods have limited usefulness for APB purposes. Future work in this area could include modeling techniques to benchmark investment over multi-year periods which should reduce the amount of variation in cost that needs to be explained by the models. Other data collection could be considered regarding age and expected service life of smart meters. Input from distributors could be valuable because of the service life of these assets might differ from what was anticipated. Other business conditions related meters including challenges in determining repair vs. replace decisions could be taken into account in future work once these are better understood.

5. Potential Applications of Results

5.1. Noteworthy Limitations

The unit cost metrics and econometric models that we have developed have several potential applications. These tools also have limitations which the users of these results should consider. Although some of these models have significant explanatory power, no statistical model will be perfect and cannot replace sound judgement. In general, statistical models can be important tools the regulatory community can use in the discovery process to help determine just and reasonable rates. In addition to being a regulatory tool, the models can also be used as part of a process to discover best practices which leads to better productivity and cost efficiency.

Economic cost models will have some limitations that should be noted. The first is that the measurement of input prices may differ from the actual experience of distributors. The O&M price indexes are taken from PEG's total cost benchmarking work for OEB staff and contain assignments of distributors to cities with available data. It also assumes that labor cost is a substantial 75% of OM&A cost. The capital expenditure models assume that all distributors face the same construction costs which assumes that crews doing such construction operate regionally and are not necessarily based near where the work is being done.

The accuracy of reported data could also be an issue. In some cases, estimated values were used when they were not provided by distributors. The difference between actual values and what has been assumed can also be considered. To the extent that a distributor provided information that is based on estimates, improvements might impact the interpretation of results. The models contain variables that attempt to capture the average impact of accounting issues associated with the classification of expenses. To the extent that the actual impact of accounting differs, the impact on the results could be considered. Although the inclusion of estimated data provides a good basis for the estimation of an econometric model, some care should be exercised when interpreting particular results based on estimates.

A final factor that should be considered is that some business conditions will not be measured in the models. Some are difficult or impossible to model. Additional analysis to quantify the cost impact should be considered to explain differences between actual and predicted cost that is currently interpreted as management performance. For example, some distributors were asked to physically move a significant amount of assets to allow for highway projects. This is a case in which there is a clearly relevant business condition beyond the control of management that has an impact on cost. A distributor facing questions related to benchmarking results in a rate case could undertake to provide an estimate of the incremental cost of this unmeasured business condition. It could be used to explain the cost performance results, thereby reducing the amount of any cost performance deficiency that is attributed to management performance.

5.2. Increasing the Effectiveness of Regulation

A major goal of APB is to provide tools to the regulatory community that will help focus a limited amount of attention and other resources to areas that appear to deserve additional inquiry. Results are useful for identifying chronically good and bad cost performance and notable declines in performance in test years that could indicate strategic behavior.

The models presented in this report can assist this effort. Examining the results of the unit cost and econometric models for a particular cost area could act as a screening tool to help determine where to focus effort. PEG prefers to characterize this screening as identifying areas that are *not* worth spending much effort. Should APB suggest that a distributor has average or below-average cost in a certain area, this should provide some evidence that additional time spent examining this cost area would be unlikely to uncover a significant cost control problem by management. Unless there is relevant information not addressed by the model, it would be reasonable for a reviewer to ignore this area and presume that management is doing an acceptable job. Hypothetically, if all distributors had simultaneous rate cases and the standard for not reviewing a cost area was for a distributor to rank in the top half of cost performance, then this work could provide the basis for eliminating half of all inquiries by OEB staff and stakeholders.

As for areas in which a distributor is performing significantly worse than predicted by the model, some might contend that this is the end of the process because the model indicates that the distributor is a bad cost performer. There are many reasons why a distributor might perform poorly in a statistical model and only one reason is poor management performance. Other reasons include:

- Differences in accounting arising from inconsistent application of the OEB's accounting guidance in the Accounting Procedures Handbook (APH)

- Measurable business conditions of significant explanatory power not included in the econometric model
- Other random, exogenous events that are difficult or impossible to measure for all distributors

The availability of models that make cross-distributor comparisons can facilitate dialog in that it provides a tangible frame of reference. This dialog can contribute to more efficiently discussing areas where the reasons for poor measured performance are unknown. The process may start with a stakeholder asking why measured cost performance of a distributor appears to be worse than for other distributors. The response could be that a highway expansion forced the distributor to move facilities, a serious storm affected only a few distributors, or that the distributor faces less favorable labor market conditions than is recognized in the models. A stakeholder could then respond by asking for the company to quantify the cost impact of the proposed reason for the poor performance. The unexplained difference between actual and predicted cost is normally attributed to management performance in the absence of additional information. Additional information provides the basis to shift a portion of presumed poor management performance to other reasons such as business conditions not considered by the model.

5.3. Other Applications of APB Models

A major goal of benchmarking done in the world is the identification of best practices. Several organizations can contribute information to a researcher that uses the information to perform a benchmarking study. A large organization can conduct internal benchmarking to compare the relative efficiency of different divisions or store locations. The goal of the benchmarking is to use performance indicators to determine who is doing a task most efficiently and why. The first step is to determine who appears to be doing the task most efficiently. In the context of APB, cost performance is the performance indicator that starts the process but does not finish it. Unit cost might be the first metric to consider. Differences in unit cost can be partially explained through econometric work that addresses other identifiable and measurable reasons for cost differences. The process of identifying other reasons why the models may not be accurately measuring management performance as discussed above can then be done. Once this stage is reached, the distributors that are the best performers in an activity can be asked how they approach these activities. Examining how distributors differ in how they approach a given activity is how best practices are identified. These best practices can then be adopted by others, accelerating the diffusion of good practices. Adopting better methods should lead to cost reductions which are in the interest of all distributors and ratepayers. PEG is an expert at statistical cost benchmarking but not an expert at identifying best practices. The models in this report can provide a start towards identifying best practices.

5.4. Continuous Improvement in Existing and New APB Models

Just as the APB models presented here are a starting point for analysis and not an end in themselves, the models themselves can also be improved and additional cost areas considered. With a detailed benchmarking program such as APB, the areas that could be potentially benchmarked were too numerous. The near-term goal of APB was to make a set of relevant models available. A major objective of the working groups and Staff report was to narrow the scope of the benchmarking to be more manageable. The size of the cost categories and the potential for benchmarking accuracy were both considered. The end of this process resulted in the identification of 10 cost areas for PEG to benchmark.

Several further steps merit consideration. The first is to aid the regulatory community in better understanding and applying what is presented in this report. The second is to respond to feedback and identify areas in which the models on the 10 cost areas can be improved. A third is to identify other cost areas that would be valuable to benchmark. This could include less granular costs that are routinely reported in rate applications. The improvement of these models and the creation of additional models will require additional data which is discussed next.

5.5. Suggested New Data Requirements

The improved models were made possible by the supplemental data required by the data request. To continue the APB work, some of the data used in the upgraded models will need to be collected in the future. Requests for continued reporting of information fall into four categories:

- Information requiring annual filing under the RRR.
- Information that due to their static nature can be collected less frequently.
- Data that would benefit from additional clarification before another request is made.
- Data that did not provide explanatory power and are less promising do not need to be collected.

Data from the following data request questions were used in the analysis and would be useful to have for future work. They are organized according to suggested future collection.

Annual Filing:

- Question 5: Many but not all of the scale variables were featured in the final models. The numbers of substations and poles in particular had plausible and highly significant parameter estimates. The number of meters and line transformers were not found to be as valuable because number of customers was a good substitute. PEG noted a lack of variation over time in some of these data that may not be plausible. The data were sufficient to obtain good models, but should this information be collected on the RRR in the future, distributor input would be valuable to establish clear reporting guidance.
- Question 7: All the continuity schedule (Appendix 2-BA) data were used in the analysis and PEG recommends that distributors be required to provide these as part of the RRR each year. These data have been collected by the US FERC since at least 1948 and prove very valuable for statistical cost research.

Collected less frequently:

- Question 1: The pension variable had plausible and highly significant parameter estimates in all of the O&M cost models. The question on pensions is easy to answer.
- Question 2: The billing outsourcing information is valuable to identify which distributors are doing their own billing. This can aid in choosing peers and selecting just those distributors that are actually performing the billing function. The question on billing outsourcing is easy to answer.
- Question 3: The station maintenance outsourcing variable is more exogenous than that for billing in that jointly-owned stations provide better opportunities for outsourcing. The parameter estimate for this variable was plausible and highly significant. The question on billing outsourcing is easy to answer.

Additional Clarification Required:

- Question 4: The vegetation management data collected resulted in a statistically significant variable. Because the nature of vegetation is unlikely to change much over time, PEG sees no need for annual reporting of information in its current form. As discussed above, improvements in how this business condition is measured might be worthwhile. Distributor input on how to measure this is required to improve the accuracy of this information. Once clarification is achieved this would be moved to the less frequent collection category.

- Question 8: Information should be sought on the age and condition of assets. The questionnaire was formulated in a way to facilitate low-cost compliance by distributors. A survey of distribution system plans or other information provided by distributors could be done to assess how information has been provided and what form has proved most valuable. Such a survey could reveal best practices in reporting which could then be provided as guidance for future reporting. The resulting standardization will streamline review of this information as well as facilitate future benchmarking work. Rather than have broad requirements that can be subject to interpretation and presented in many different formats, a standardized form could be developed. For capex benchmarking purposes, broad measures of average age are not as valuable as knowing the number and type of very old assets. Therefore, reporting the number of assets by age cohorts is valuable. The types of assets for which this information is collected can be guided by the cost areas identified in the OEB Staff discussion paper. The detail at which assets are classified (e.g., poles and fixtures reported separately) should take into consideration the cost of compliance.

<u>Did not provide explanatory power:</u>

- Question 6: The information on type of construction for poles and towers was marginally significant in a few models and not featured in any final model. PEG believes that any current or future benefits of this information may not justify the additional reporting burden.

For all proposed continued data collection, the language used and existing distributor comments should be reviewed to determine how the language and guidance could be improved. Improved wording and guidance should make the data requests more clear and easier to provide.

Longer-term suggested data collection would include items that were either not expected to be as easy for distributors to provide or the impact they were expected to have on the models was less likely to improve explanatory power. The data request sent to distributors only requested information that was known to be easy to gather and very likely to improve the models.

PEG discussed new variables to consider in its December 18, 2018 report to the OEB titled "Activity and Program Benchmarking of Ontario Electricity Distributors". Tables 4, 5, and 6 as well as Appendix table A-5 list variables to consider for benchmarking. Each of these tables lists possible cost drivers.

Data for many of the identified cost drivers have been available on the RRR. Others were gathered from the data request to distributors. Most of the identified O&M cost drivers have been tested. Those that have not are in two groups. The first is additional information related to metering and billing. The second group is service quality.

The metering cost driver not yet considered is the type of smart meter. PEG does not know how many different brands of smart meters are in use and if some are easier to install and maintain than others. If there is a belief among distributors that the particular type of smart meter in use could matter for cost, then it might be reasonable to perform a survey to request the predominate type of meter installed. This information could then be put in the models to determine if the effect is statistically significant. If a particular type of meter was more expensive to maintain, this could help explain some observed cost performance differences. It is possible to have a legitimate trade-off between O&M and capital cost that would be cost efficient. For example, if a particular type of smart meter had a lower installation cost, O&M could be higher without affecting total cost.

There were also a number of billing cost drivers listed on the tables. These are related to number of languages spoken and income levels. Producing bills in multiple languages should be more costly and those distributors that have a higher proportion of low-income customers could expect higher billing cost. Electronic billing and those choosing budget plans with fixed payments may also affect billing cost. Another effect could be customer turnover. High levels of customer turnover should raise billing costs. This effect could be observed in territories with a high number of college students. The expected incremental explanatory power of additional information should be considered before additional work is done. This will come over time as the model results are used. If an unmeasured business condition such as customer turnover is frequently cited as a reason for differences in cost performance, then the model could be improved to quantify this effect. Due to the explanatory power of the current model, PEG does not see a need to collect these data at this time.

Data regarding service quality would also be valuable. Investments in better maintenance should help with service quality. Distributors that have maintained higher levels of service quality could use this as a means to explain higher costs. Service quality is also potentially relevant for the capital expenditure models. Information on system service investments is explicitly requested as part of each distributor's distribution system plan. One might expect that improved service quality may be correlated with higher levels of capital expenditures and lower levels of capital expenditures on an older system to be correlated with deteriorating service quality.

When considering what was reasonable to request from distributors for the data request, the type of meter and detailed information on types of customers were not a high priority. PEG recalls that the existing service quality data may not be sufficiently standardized for the definition of major event days which lowers the probability of getting meaningful model improvements. Differing methodologies do not pose a problem for tracking changes in service quality over time, but it does cause problems for making comparisons among distributors. Although the incorporation of service quality into the APB benchmarking would be valuable, the existing data may not be sufficient. Asking all distributors to standardize their data for the sake of testing its impact in APB does not appear to be justified by expected improvements in model performance. However, service quality benchmarking would be valuable apart from APB. Should the OEB decide that a service quality benchmarking program would be valuable, the reporting would need to be standardized. In this case, data relevant to APB would become available as a byproduct of service quality benchmarking.

An improvement that could be considered for the capital expenditure models would be to make use of the categories requested in the distribution system plans. The four classifications of capital expenditures (system access, system renewal, system service, and general) is a good separation of investments according to its purpose. This classification lends itself to different models with different explanatory variables. PEG was working with the RRR plant additions data by type of asset but not by purpose. In the current models, meter capex is a decent match for system access and general was not considered in the first 10 models. However, the other models attempt to simultaneously consider both the system renewal and the system service cost drivers. The age variables attempted to measure additional investment from system renewal. Customers, customer growth, capacity, transformers, and peak demand attempted to measure system service. If the four categories presented in the distribution system plans could be collected annually in a consistent manner, the resulting database over time could form the basis for benchmarking these areas separately and perhaps with greater explanatory power.

Which of the longer-term data collection projects to pursue depends upon which models the OEB wishes to prioritize and which of the existing models have the greatest need for improvement. Input from stakeholders that use these results would be valuable. In the end, APB is designed to be useful for OEB staff and other stakeholders and it makes sense that their needs should drive future investment in the APB program.

Table 34

Investment Categories and Example Drivers and Projects/Programs

	Example Drivers	Example Projects / Programs
system access	Customer service requests	– New customer connections – Modifications to existing customer connections – Expansions for customer connections or property development
	Other 3rd party infrastructure development requirements	– System modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
	Mandated service obligations (DSC; Cond. of Serv.; etc.)	– Metering – Long term load transfer
system renewal	Assets/asset systems at end of service life due to: – Failure – Failure risk – Substandard performance – High performance risk – Functional obsolescence	– Programs to refurbish/replace assets or asset systems; e.g.: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	Expected changes in load that will constrain the ability of the system to provide consistent service delivery	– Property acquisition – Capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – Line extensions
	System operational objectives: – Safety – Reliability – Power quality – System efficiency – Other performance/functionality	– Protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – Automation (new/upgrades) by device type/function – Supervisory control and data acquisition (SCADA) – Distribution loss reduction
general plant[1]	– System capital investment support – System maintenance support – Business operations efficiency – Non-system physical plant	– Land acquisition – Structures & depreciable improvements – Equipment and tools – Supplies – Finance/admin/billing software & systems – Rolling stock – Intangibles (e.g. land rights; capital contributions to other utilities)

Appendix 1

Data Request Made to Distributors

Figure 1 below shows the questions sent to distributors. The full copy of the questionnaire can be found here on the OEB website https://www.oeb.ca/industry/policy-initiatives-and-consultations/activity-and-program-based-benchmarking-apb.

Figure 1

Distributor Data Questionnaire for Activities/Program Benchmarking (APB) Initiative
Ontario Energy Board | October XX, 2020

Note: The information collected in this questionnaire will be used for the purposes of the APB initiative

Distributor Name	
Submitted by	
Contact Telephone No.	
Contact Email	
Date	

The purpose of this questionnaire is for electricity distributors to provide data for the OEB's activities and program-based benchmarking (APB) initiative. OEB staff is undertaking a detailed review of benchmarking a select set of activities/programs with its consultant, Pacific Economics Group Research, LLC (PEG). PEG has developed preliminary benchmarking models for the activities/programs using existing RRR reported data and data filed in rate applications by distributors. The specified data from this request will be used to advance improvements to these models.

This questionnaire is designed to provide information mostly through questions that require either "yes" or "no" responses, or the selection of the age distributions of specified plant and equipment. The provision of data is limited to five asset types, total station transformer MVA, and a "Fixed Asset Continuity Schedule" (Appendix 2-BA), if this schedule was not filed in a cost of service (CoS) or custom IR (CIR) rate application, or if data were not provided in the schedule on actual basis for the recent years (2019-2012).

To complete the questionnaire, please click on the applicable responses to the questions and populate the data fields with the specified data requested. Note that you can "copy and paste" information from other documents (e.g., Word) into the input data fields of the questionnaire using "Ctrl+V". For the fixed asset continuity schedule, complete the schedule (or the applicable years required) in Excel format as done for a rate application filing. Please submit the completed questionnaire and schedule, if applicable, by September XX, 2020 to the following email address performance_reporting@oeb.ca.

For clarifications on the contents of this questionnaire, please contact Shahdil Alibhai at Shahdil.Alibhai@oeb.ca.

Q1

Does the company assign pension and other benefit expenses to various non-Administrative and General Expense (A&G) accounts (i.e. fully loaded labor cost)? If the accounting for this has changed since 2012 please explain.

◉ Yes ○ No

Please provide a comment below:

Q2

Does the company outsource the majority of its billing function to independent vendors?

◉ Yes ○ No

Please provide a comment below:

Q3

Is maintenance work on company-owned station equipment performed by other parties, including joint owners? If so, does their work account for a majority of the total station maintenance cost?

◉ Yes, the company outsources the majority of station maintenance functions
○ No, the company does its own station maintenance
○ Neither, the company only outsources a minority of station maintenance functions

Please provide a comment below:

Figure 1 (continued)

Q4

Which of the following best describes the company's situation regarding vegetation management:

- (selected) a) Under 20% of the spans between distribution poles have required maintenance since 2012
- b) Between 20% to 40% of the spans between distribution poles have required maintenance since 2012
- c) Between 40% and 60% of the spans between distribution poles have required maintenance since 2012
- d) Between 60% and 80% of the spans between distribution poles have required maintenance since 2012
- e) Over 80% of the spans between distribution poles have required maintenance since 2012

Please provide a comment below:

Q5

Please provide the number of distribution stations, station transformers and total nameplate rated maximum capacity of the company's stations transformers in MVA. The station data are in relation to costs generally reported in Account 1820, Distribution Station Equipment - Normally Primary Below 50 kV, and not Account 1815, Transformer Station Equipment - Normally Primary Above 50 kV (high voltage).
Please also provide the total number of poles and towers, line transformers and meters. The costs of these items are generally reported in Accounts 1830, 1850 and 1860, respectively.

	Station			Number of:		
Year	Number of Stations	Number of Transformers	Total MVA (Maximum)	Poles & Towers	Line Transformers	Meters
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						

Please provide a comment below:

Q6

Please provide available information on the number of distribution poles and towers by type of material for a recent year (e.g., 2018 or 2019).

Year of Data	
Wood	
Steel	
Concrete	
Other (please explain)	

Please provide a comment below:

Q7

Please provide in Excel format any readily available Appendix 2-BA "Fixed Asset Continuity Schedule" (per Filing Requirements For Electricity Distribution Rate Applications) that have not already been provided as part of a cost of service (CoS) or Custom IR rate application filed in the 2020-2012 period.

In addition, if Appendix 2-BA was filed, but it did not contain data for the recent years (2019 to 2012) on an actual basis, please update and provide the schedule with the data for the applicable year(s).

For example, if a company filed a 2018 CoS rate application that included 2018 forecast and 2017 bridge year data, it should provide both 2018 and 2017 data and the most recent subsequently completed year 2019 on an actual basis in the schedule (i.e., 2017 to 2019). Companies that have merged should provide actual data on a consolidated basis for the current year(s), if applicable.

Please provide a comment below:

Pacific Economics Group Research, LLC

Figure 1 (continued)

Q4

Which of the following best describes the company's situation regarding vegetation management:

- (selected) a) Under 20% of the spans between distribution poles have required maintenance since 2012
- b) Between 20% to 40% of the spans between distribution poles have required maintenance since 2012
- c) Between 40% and 60% of the spans between distribution poles have required maintenance since 2012
- d) Between 60% and 80% of the spans between distribution poles have required maintenance since 2012
- e) Over 80% of the spans between distribution poles have required maintenance since 2012

Please provide a comment below:

Q5

Please provide the number of distribution stations, station transformers and total nameplate rated maximum capacity of the company's stations transformers in MVA. The station data are in relation to costs generally reported in Account 1820, Distribution Station Equipment - Normally Primary Below 50 kV, and not Account 1815, Transformer Station Equipment - Normally Primary Above 50 kV (high voltage).
Please also provide the total number of poles and towers, line transformers and meters. The costs of these items are generally reported in Accounts 1830, 1850 and 1860, respectively.

	Station			Number of:		
Year	Number of Stations	Number of Transformers	Total MVA (Maximum)	Poles & Towers	Line Transformers	Meters
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						

Please provide a comment below:

Q6

Please provide available information on the number of distribution poles and towers by type of material for a recent year (e.g., 2018 or 2019).

Year of Data	
Wood	
Steel	
Concrete	
Other (please explain)	

Please provide a comment below:

Q7

Please provide in Excel format any readily available Appendix 2-BA "Fixed Asset Continuity Schedule" (per Filing Requirements For Electricity Distribution Rate Applications) that have not already been provided as part of a cost of service (CoS) or Custom IR rate application filed in the 2020-2012 period.

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For example, if a company filed a 2018 CoS rate application that included 2018 forecast and 2017 bridge year data, it should provide both 2018 and 2017 data and the most recent subsequently completed year 2019 on an actual basis in the schedule (i.e., 2017 to 2019). Companies that have merged should provide actual data on a consolidated basis for the current year(s), if applicable.

Please provide a comment below:

Appendix 2

Rules for Econometric Models

In all of the models, cost was divided by an input price index to produce an inflation-adjusted ("real") cost level. For O&M expenses, we used a weighted average of average weekly earnings and an implicit price index for gross domestic product. For capex costs we used an implicit price index for gross domestic product. The O&M price features a factor that provides for a price level that varies by distributor whereas the capex price does not. Both prices are consistent with the current methodology used in PEG's total cost benchmarking work.

The total cost benchmarking model uses a standard form for the cost equation based on scholarly literature called a translog cost function which has many desirable theoretical properties. This equation has many squared and interaction terms that make it superior but complex. In an effort to simplify the APB econometric models and avoid controversy over model specifications, we used the following rules in model development.

- No interaction terms (e.g., customers x number of poles) were permitted.
- Quadratic terms are desirable to capture scale economies since the companies in the sample have wide variations in operating scale. However, quadratic terms (e.g., customers x customers) were permitted only for scale variables.
- Only one scale variable was used unless a strong argument could be made that two were needed.
- To be included in the model, most variables had to have a plausible parameter estimate with at least 75% statistical significance. However, no significance requirements were imposed on the quadratic and trend variables and some were insignificant.

This approach likely limited the explanatory power of some of the models.

Many econometric models were developed for each cost area and the models presented here represent the best specification available in the opinion of PEG. In developing the econometric models PEG considered other specifications and additional explanatory variables. In each of these cases either the variable was not statistically significant or other combinations of explanatory variables produced a better model. Additional or better data may produce better results in the future for these variables.

To estimate model parameters, we used an econometric method which corrects for first-order autocorrelation. According to econometric theory, this method improves the precision of unbiased parameter estimates, a trait known as efficiency. This method was implemented using the AR1 option in the widely-used R econometric software package. Variables were logged, so that each parameter estimate was an estimate of the corresponding cost elasticity.