IRM Design for Toronto Hydro-Electric System

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1. Introduction and Summary

1.1. Introduction

Toronto Hydro-Electric System ("Toronto Hydro" or "the Company") proposed a Custom Incentive Rate-setting ("IR") mechanism for its power distributor services in an August 2018 application.[1] A multiyear rate plan is proposed which is similar to that which the Ontario Energy Board ("OEB") approved for the Company in 2015.[2] Escalation of a Custom Price Cap Index ("PCI") would be slowed by an X factor. The Company retained Power System Engineering Inc. ("PSE") to prepare cost and reliability benchmarking research and testimony in support the proposed X factor. A C factor would ensure recovery of projected/proposed capital cost.[3] A capital-related revenue requirement variance account ("CRRRVA") would asymmetrically compensate customers for cumulative capex underspends but not overspends. An Externally Driven Capital Variance Account would adjust revenue for variations in the externally-driven capital costs of projects such as mass transit extensions.

Toronto Hydro is one of Ontario's largest electricity distributors. Its approach to Custom IR has provided a template for other utilities in the province. These considerations increase the value of careful appraisal of the Company's new incentive ratemaking ("IR") proposal and the supportive statistical cost research. Controversial technical work and IR provisions should be identified and, where warranted, challenged to avoid undesirable precedents for the Company and other Ontario utilities in the future. The OEB has constructively commented on plan design and statistical cost research methods in its decisions in past IR proceedings.

OEB staff retained Pacific Economics Group Research LLC ("PEG") to appraise and comment on PSE's benchmarking research and testimony and, if needed, to prepare an alternative study. We were also asked to consider other aspects of the Company's IR proposal. This is the report on our work.

The plan for the report is as follows. We begin by providing pertinent background information. There follow critiques of PSE's evidence and the presentation of some results using our preferred

[1] EB-2018-0165, Toronto Hydro-Electric System Limited Custom Incentive Rate-setting Application for 2020-2024 Electricity Distribution Rates and Charges, filed August 15, 2018.

[2] EB-2014-0116, OEB Decision and Order, Toronto Hydro-Electric System Limited, December 29, 2015.

[3] The capital cost in the C factor calculation is as much a proposal as it is a projection or forecast.

methods and data. We conclude by discussing other features of the Company's Custom IR proposal. An Appendix addresses some of the more technical issues in more detail.

1.2. Summary

X Factor

The X factor in Toronto Hydro's proposed PCI is the sum of a 0% base productivity trend and a 0.30% custom stretch factor. These proposals are supported by total cost benchmarking research and testimony by PSE. PSE found that the Company's costs were 18.6% below the model's benchmark prediction on average over the three most recent years for which historical data are available (2015-17). However, the Company's projected/proposed costs over the five years of the new plan (2020-2024) were 6.0% below the model's predictions on average. Cost performance deteriorated during the current plan and would continue to deteriorate under the proposed plan. Toronto Hydro maintained in its evidence that a 0% base productivity trend contains a material *implicit* stretch factor.

Mr. Fenrick, one of the PSE study leaders, is a former employee of PEG and his benchmarking methods are in some respects similar to ours. We nonetheless disagree with some of the methods PSE used in this study. Here are our biggest concerns.

- We acknowledge that the Company faces substantial urban challenges in the provision of distributor services but disagree with the model's treatment of these challenges. Moreover, the model doesn't capture rural challenges that some distributors face, unlike a previous total cost benchmarking model that PSE prepared for Hydro One Networks in another electricity distributor rate application.[4]
- In addition to numerous business condition variables, the model includes an unusually large number of quadratic and interaction terms for these variables which jeopardize the precision of all parameter estimates.[5]

[4] Fenrick, S., Power Systems Engineering, *Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network*, EB-2017-0049, Exhibit A-3-2, Attachment 2, June 7, 2017.

[5] These terms are explained in Section 3.1 and Appendix A.2.

- Generally speaking, we have found that the results of the PSE study are not robust with respect to changes in their methodology. Small changes in methodology produced large changes in the Company's ranking.
- The calculation of capital costs for the utilities in the econometric study sample is inaccurate.

We applaud the Company's willingness to present reliability benchmarking results and suggest some upgrades to their models. These models show that Toronto Hydro has substandard outage frequency but superior outage duration. PEG developed an alternative total cost benchmarking model using a longer sample period that includes 2017, more accurate capital cost data, and a better model specification. Using this model we found that Toronto Hydro's total cost was about 5.2% above the benchmark on average from 2015 to 2017. This is very close to an average performance. However, the Company's total cost performance has deteriorated steadily under the current Custom IRM and is forecasted to continue to deteriorate under the proposed new plan. The projected/proposed total cost is about 20.6% above our model's prediction on average in the five years from 2020 to 2024.

PEG also developed experimental models to evaluate Toronto Hydro's projected/ proposed operation, maintenance, and administrative ("OM&A") expenses, capital cost, and capital expenditures ("capex"). These models are sensible and generate results that should be informative to regulators and the Company alike. During the term of the proposed plan, the Company's projected/proposed OM&A expenses would be about 12.1% *below* the model's predictions whereas the Company's capital cost would be about 43.0% *above* the predictions and capex would be about 21.7% above predictions. The results of these studies are summarized in Figures 1 and 2.

We also wish to challenge the notion that a 0% base productivity target contains an implicit stretch factor. Ontario data have limitations for the accurate measurement of productivity trends. U.S. productivity trends are also germane to the consideration of the right X factors for Custom IR plans. Recent research on the cost of U.S. power distributors suggests that their multifactor productivity ("MFP") growth trend has been positive.

Figure 1

Benchmarking Results for Toronto Hydro's Proposed Reliability (2020-2024)

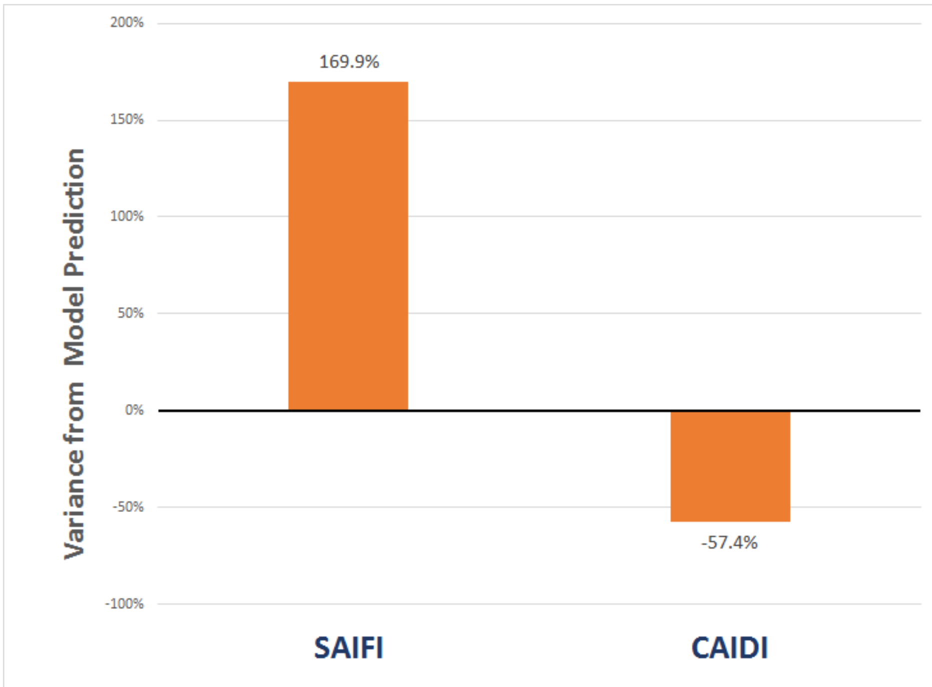
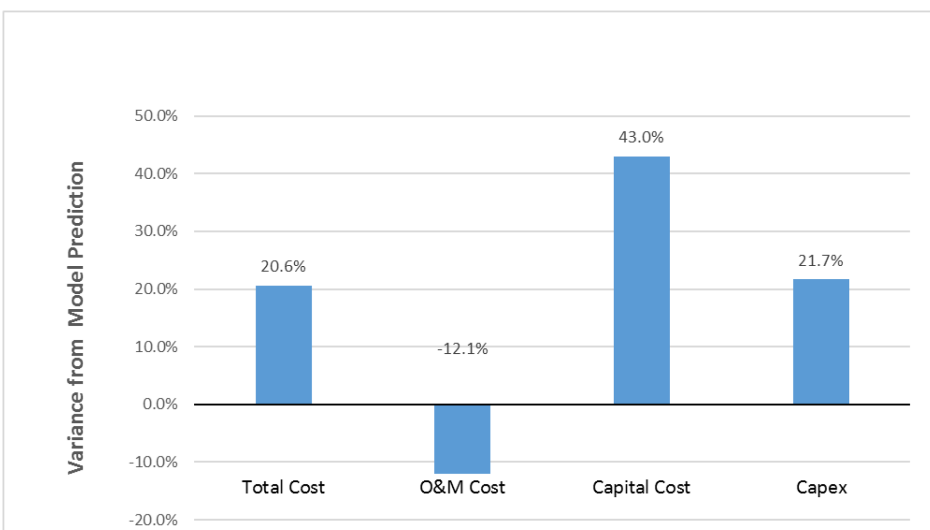


Figure 2

Benchmarking Results for Toronto Hydro's Proposed Costs (2020-2024)



On the basis of our research, we believe that a 0.45% stretch factor is indicated for Toronto Hydro provided that the Board is comfortable fixing the stretch factor for the full plan term. Combined with a 0% base productivity factor, this would yield an X factor of 0.45%. The PCI formula would then be Inflation - 0.45% exclusive of Z or growth factors.

In addition to the techniques used by PSE we have more general reservations about the use of benchmarking in this application.

- PSE's benchmarking suggests a continuation of the material decline in the cost performance of Toronto Hydro which occurred during its first Custom IR plan. It is possible that this is a rational response to special circumstances, such as the advanced age of some facilities and brisk load growth that strains capacity in some areas. However, no evidence has been provided that suggests that Toronto Hydro's cost performance has been and will be improving when these circumstances are accounted for. This violates the Board's Custom IR guidelines for cost efficiency evidence in our opinion. Taking better account of special circumstances should be a long-term goal in Custom IR benchmarking.
- Setting the stretch factor on the basis of a cost *forecast* rather than *actual achieved historical* cost reduces the incentive to cut costs during a plan since cutting cost cannot lower the stretch factor. Consideration should be paid to having the stretch factor reset annually during the years of its plan on the basis of whichever benchmarking model the Board prefers. The chosen model need not be updated.
- We believe that it desirable to go beyond total cost benchmarking in Custom IR proceedings by starting to consider performance in the management of the major cost subaggregates.

Other Plan Design Features

The IR plan proposed by Toronto Hydro is, in several respects, uncontroversial. We have noted that this plan is similar to that which the Board approved for the Company in EB-2014-0116. The proposed inflation factor and base productivity factor are in line with recent Board IR decisions. An earnings sharing mechanism would symmetrically share with customers earnings variances from non-capital causes outside a dead band.

We are nonetheless concerned about some features of Toronto Hydro's proposal. Here are our main concerns and suggested alternative plan provisions.

- The proposed ratemaking treatment of capital cost is problematic. Incentives to contain capex would be weakened by the CRRRVA and the Externally-Driven Capital Variance Account. The Company is perversely incented to spend excessive amounts on capital that slows growth of OM&A expenses. Notwithstanding the CRRRVA, the Company is still incentivized to exaggerate its need for supplemental revenue. The regulatory cost for the OEB and stakeholders is substantially raised and, ultimately, it is ratepayers who bear the burden of the capital cost increases.

- The kinds of capex accorded C factor and variance account treatment are, for the most part, conventional distribution capex that is similar to that incurred by distributors in studies used to calibrate the base productivity trend. The PCI would effectively apply chiefly to revenue for OM&A expenses and provide only a floor for price growth, even though it is designed to play neither of these roles. OM&A productivity growth in the United States has recently been positive.

We discuss several possible upgrades to the capital cost treatment. An extra stretch factor term for setting the C factor like that which the OEB recently approved for Hydro One Distribution is certainly one option.

1.3. PEG Credentials

PEG is an economic consulting firm with home offices on Capital Square in Madison, Wisconsin USA. We are a leading consultancy on IR and the measurement of energy utility performance. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. The University of Wisconsin has trained most of our staff and is renowned for its economic statistics program. Work for a mix of utilities, regulators, government agencies, and consumer and environmental organizations has given PEG a reputation for objectivity and dedication to good research methods. Our practice is international in scope and has included dozens of projects in Canada.

Mark Newton Lowry, the author of this report and principal investigator for the project, is the President of PEG. He has over thirty years of experience as an industry economist, most spent on energy utility issues. Author of numerous professional publications, Dr. Lowry has also chaired several conferences on performance measurement and utility regulation. He has provided productivity, benchmarking, and other statistical cost research and testimony in over 30 proceedings. His latest study on the productivity trends of U.S. power distributors was published in 2017 by Lawrence Berkeley

National Laboratory ("Berkeley Lab").[6] In Canada, Dr. Lowry has in recent years played a prominent role in IR proceedings in Alberta, British Columbia, and Québec as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin.

[6] Mark Newton Lowry, Matt Makos, and Jeff Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Lawrence Berkeley National Laboratory, July 2017.

2. Background

2.1. The Company's Proposal

Toronto Hydro has filed a Custom IR application for its electricity distributor services.[7] Under the proposal, a multiyear rate plan would set rates for the five-year 2020-2024 period. Rates for 2020 would be established by a conventional rebasing process that uses a forecasted test year. A Custom PCI applicable to years 2021-2024 of the plan would have a growth rate formula featuring an inflation factor ("I"), an X factor, a Custom Capital ("C") Factor, and a growth ("g") factor.

$$CPCI = I - X + C - g.$$

The Company has proposed to use the inflation measure that the OEB adopted in its 4th generation IRM ("GIRM") decision. The growth in this inflation measure would be a weighted average of the growth in two inflation indexes: Canada's gross domestic product implicit price index for final domestic demand ("$GDPIPIFDD^{Canada}$") and the average weekly earnings for all employees in Ontario ("$AWE^{Ontario}$"). Both of these indexes are calculated by Statistics Canada. The inflation measure would be updated annually as calculated and issued by the OEB.

The proposed X factor would be fixed as the sum of a 0% productivity factor and a 0.30% custom stretch factor. The 0% productivity factor would be based on the OEB's 4th GIRM decision, its most recent industry productivity determination for Ontario's power distributors. The 0.30% stretch factor is supported by total cost benchmarking research by PSE. Toronto Hydro claims that this X factor also includes an *implicit* stretch factor because of the difference between the -0.33% multifactor productivity trend found in the PEG study[8] that informed the OEB's 4th GIRM decision and the OEB's determination of a 0% MFP trend.[9]

[7] We use the term distributor services to encompass distribution and customer (e.g., billing and collection) services.

[8] PEG Research, *Productivity and Benchmarking Research in Support of Incentive Rate Setting In Ontario: Final Report To The Ontario Energy Board*, EB-2010-0379, November 21, 2013 and as corrected on December 19, 2013 and January 24, 2014.

[9] OEB EB-2010-0379, *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 and as corrected on December 4, 2013.

The C Factor would provide supplemental revenue for the difference between the growth in the Company's projected/proposed capital cost and the growth in its capital revenue that is otherwise yielded by the I Factor. The C Factor is calculated as $C_n - (S_{cap} *I)$, where

C_n = the percent change in forecast total revenue requirement attributable to changes in depreciation, return on equity, and payments in lieu of taxes/taxes; and

S_{cap} = the share of forecast capital-related revenue requirement in the forecast total revenue requirement.

The (S_{cap}*I) term reduces the possibility of double counting capital funding between C_n and the escalation provided by Inflation – X. By limiting the application of S_{cap} to the inflation measure rather than I - X, the C Factor would effectively be based on forecasted/proposed cost adjusted downward for the full 0.30% stretch factor. Based on Toronto Hydro's revenue requirement forecast, proposed X factor, and annual inflation of 1.2% for the CPCI term, the Company estimates that C_n will be a little higher than 3.5% for the CPCI term and S_{cap} will be about 73% on average. This results in an overall C factor averaging about 2.75% annually during the four indexing years of plan.

The g factor reduces growth in the PCI to reflect the Company's forecast of growth in its billing determinants during the four years that the CPCI would be operational. Toronto Hydro has proposed a g factor of 0.2% for each year of the plan which would not be trued up or reforecast.

Several costs would be addressed by variance accounts. These would include those for pension and other post-employment benefits, renewable enabling improvements not funded through provincial rate protection, and the gains or losses on asset derecognition (e.g., asset disposal). A lost revenue adjustment mechanism would compensate the Company for load losses due to conservation and demand management ("CDM") programs. Costs of CDM programs would continue to be funded by Ontario's Independent Electricity System Operator rather than through rates. An asymmetrical capital-related revenue requirement variance account ("CRRRVA") would reduce rates for cumulative plant addition underspends during the plan term. An Externally Driven Capital Variance Account would adjust rates for variation in the capital costs of external events such as facility relocations due to highway construction.

Toronto Hydro would continue to have the option to request Z factors if a qualifying event occurs, based on the OEB's existing Z factor policy. A qualifying event would need to result in a change in the revenue requirement of $1 million or more.

A symmetrical earnings-sharing mechanism ("ESM") would annually address variances between actual and allowed revenue requirements for OM&A expenses and revenue offsets that cause the Company's ROE to be outside of a dead band. Toronto Hydro has also proposed to apply the OEB's existing off-ramp policy. An off-ramp would be triggered if earnings variances exceed the OEB-approved rate of return on equity by more than 300 basis points in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This review would be prospective in nature and could result in modifications to the plan, the plan continuing without changes, or the termination of the plan.

The Company has proposed to add 15 metrics to its existing performance scorecard and service quality reporting requirements. Each of these metrics would be associated with a goal, which may be to monitor, improve, or maintain performance. For each metric associated with the goal of maintaining or improving performance, Toronto Hydro's recent historical average performance was provided. The Company states that these targets are calibrated based on its proposed capital spending and that any change to this spending may affect the proposed targets.

2.2. Custom IR Guidelines

The *Handbook for Utility Rate Applications* ("Rate Handbook") provides guidelines for energy utilities requesting Custom IR plans.[10] The OEB stated that

> The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).
>
> The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. **If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

[10] OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[11] [Emphasis added]

Benchmarking is a fundamental requirement of a Custom IR application, both 1) *external* benchmarking to analyze specific measures or programs by comparing year over year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group and 2) *internal* benchmarking to assess continuous improvement by the utility over time. Methodologies other than unit cost benchmarking are permitted in these studies. Utilities are expected to present objective, well researched benchmarking information supported by high quality and thorough analysis (using either third party or internal resources) which can be rigorously tested.

The OEB has also shown an interest in service quality benchmarking. The *2013 Report of the Board* outlining the final provisions of 4th GIRM stated that

> The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including total cost benchmarking for the 2014 rate year. Future work will involve comprehensive benchmarking [i.e., model(s) that combine standards for customer service, including distribution system reliability, and cost performance].[12]

The OEB mentioned the eventual adoption of reliability benchmarking again in its 2015 *Report of the Board on Electricity Distribution System Reliability Measures and Expectations.* Reliability benchmarking considerations also led the System Reliability Working Group to suggest the use of the IEEE 1366 approach to determining major event exclusions in reliability reporting. The OEB subsequently adopted the IEEE 1366 approach as its preferred option for identifying major events.

2.3. First Toronto Hydro Custom IR Proceeding

In its order approving the first Custom IR plan for Toronto Hydro, the OEB approved many of the basic features of future Custom IR plans, including the adoption and calculation of the C factor, the

[11] *Ibid*., pp. 25-26.

[12] OEB *Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, EB-2010-0379, *op. cit*., p. 23.

inclusion of an earnings sharing mechanism, and the refund of capital underspends at the end of the plan term. More specifically, the OEB approved a plan that had a 5-year term and escalated rates using the formula I – X + C, where I was the OEB's approved inflation measure, X was the sum of a 0% productivity trend and a 0.6% stretch factor, and C was a custom capital factor. A symmetric ESM addressed non-capital revenue requirement earnings variances outside of a 100-basis point deadband, while a variance account was developed to refund capex underspends to customers.

Despite approving much of Toronto Hydro's proposed Custom IR plan, the OEB appears to have expressed reservations about the quality of Toronto Hydro's filing.

> The OEB has determined that it cannot fully rely on Toronto Hydro's approach to establishing its spending proposals in determining if the outcome of that spending is desirable for ratepayers. It is not clear that Toronto Hydro's proposals are necessarily aligned with the interests of its customers, as they are largely supported by an asset condition analysis rather than the impact of the proposed work on the reliability of the system. The approach used by Toronto Hydro does not give a clear indication of how the overall spending is related to customer experience such as reliability.
>
> The Application lacks evidence of corporate policy guiding Toronto Hydro staff to focus on impacts on customers when developing spending proposals. The focus overall is on the need for work based on asset condition assessment without a clear understanding of the results expected to be achieved through the work. Continuous improvement measurements are lacking…
>
> There does not appear to be any measurement of units of activity and their costs that would allow for year over year assessment of improvement in Toronto Hydro's proposed metrics. The OEB agrees with the parties which suggested that reporting measures such as specific performance improvements sought and achieved per asset class, tie-ins of capital program spending to the dollar value of OM&A savings achieved and how program spending specifically impacts the reliability and quality of service are desirable under the RRFE. However, as the RRFE is relatively new, the OEB does not expect all such measures to be implemented at once….
>
> In the absence of these parameters, Toronto Hydro's rates have been set based on the OEB's assessment of Toronto Hydro's historic expenditures, and the OEB's expectations with respect to improved productivity informed by the external benchmarking evidence of the expert witnesses for OEB staff and Toronto Hydro. [13]

The OEB cut Toronto Hydro's proposed capex budget by 10% for the Custom IR term, without specifying which costs to cut. The Company was urged to find efficiencies during the term of the Custom IR plan. The OEB also expected Toronto Hydro to show improvements in reliability metrics due

[13] OEB, Decision and Order EB-2014-0116, *op. cit*., p. 6-7.

to increased capex and to be prepared to provide evidence on the relationship between capital investments and reliability performance at its next rebasing.

The Toronto Hydro Custom IR decision also provided general commentary on what the Board expected Custom IR plans to entail.

> The Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. However, this is an example, not a condition precedent, and the OEB will not make a decision as to whether it is the best option for any particular distributor. The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests….

Presumably, then the OEB was open to further innovation in the design of Custom IR plans. The OEB further stated that

> A Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.[14]

2.4. Hydro One Distribution Proceeding

Several aspects of the OEB's recent decision on Hydro One Networks ("HON") Distribution's Custom IR plan also suggest a wariness on the part of the Board with respect to multiyear capex forecasts and the related C factor. The first was to disallow $300 million (or 8.4%) from HON's capex forecast. The OEB provided several reasons for its disallowance including:

- There were perceived gaps and deficiencies in Hydro One's customer consultation and investment planning processes.
- Hydro One's historical performance has shown significant gaps between the planned capital work program and the work that was actually executed.
- Benchmarking studies involving Hydro One's capital program have shown that Hydro One's performance has been worse than its peers.
- Proposed significant increases in the test period compared to the previous five years have not been fully justified.

[14] OEB, Decision and Order EB-2014-0116, *op. cit.*, pp. 4-5.

- The impact of the new vegetation management strategy on the proposed capital program has not been taken into account.
- The timing of the smart meter replacement program has not been properly supported.[15]

In addition, the OEB ordered HON to provide reports on a variety of issues to show that the forecasts and expected efficiency gains it approved in this proceeding had been realized. For example, the OEB directed HON to report at the next rebasing that detailed actual performance on the capital program relative to the approved plan and improvements in performance in benchmarked areas (e.g., pole replacement) that resulted from discussing best practices with better performing peers. HON was also ordered to report on the achievement of forecasted productivity savings.

The OEB also adopted an additional 0.15% stretch factor to apply solely to HON's C-factor beyond the 0.45% stretch factor applied to the entire revenue requirement. This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[16] The OEB was also influenced by HON's prior capital overspending and a proposal by its expert advisor that a materiality threshold and deadband be added to the C Factor.

[15] EB-2017-0049, OEB Decision and Order, Hydro One Networks, March 7, 2019, p. 70.

[16] *Ibid*., p. 32.

3. PSE's Benchmarking Research

3.1. Summary of PSE's Work

PSE benchmarked the total cost of the Company's base rate inputs which it incurs in the provision of power distributor services. This study appraised Toronto Hydro's historical costs over the 13-year 2005-2017 period and its projected/proposed costs for the 2018-2024 period. The Company's component OM&A expenses, capital costs (e.g., depreciation and return on plant value), and capex were not separately benchmarked.

An econometric model provided the total cost benchmarks. PSE developed this model using data on power distributor operations of 83 investor-owned utilities ("IOUs") in the United States and of Toronto Hydro and six other Ontario distributors that serve urban areas. The model contains two scale variables, the number of customers served and ratcheted maximum peak demand. Differences in the wage levels utilities faced were calculated using detailed U.S. and Canadian government data on wage rates, for labor categories that electric utilities use, in cities that the sampled utilities serve. PSE used these levels in the construction of summary input price indexes that had other features discussed below.

The challenge posed by urbanization is a major issue when benchmarking Toronto Hydro's cost. PSE estimated the percentage of the service territory served by each sampled distributor which was highly urbanized. There are, additionally, first-order terms for the following five business condition variables:

- percentage of distribution plant (by value) that is underground;
- percentage of customers with advanced metering infrastructure ("AMI");
- share of electric customers in the sum of electric and gas customers served;
- share of the service territory that is forested; and
- standard deviation of service territory elevation.

The model also contains a trend variable and a binary variable that indicates whether the data in a panel is for an Ontario distributor.

With respect to the form of PSE's cost model, a full complement of quadratic and interaction terms (e.g., $Customers^2$ and Customers x Ratcheted Peak Demand) for the two scale variables is added to their first order terms (Customers and Ratcheted Peak Demand). This is common in econometric cost models, but PSE also adds an unusually large number of quadratic and interaction terms for the other business condition variables (e.g., forestation^2).[17]

PSE reported that the Company's total costs were well below the benchmarks yielded by its model in the early historical years considered. However, Toronto Hydro's cost advantage began a notable decline after 2006. Cost was 24.1% below the model's prediction in 2013, the last year before the start of Toronto Hydro's current IRM, and is forecasted to be 11.6% below the model's prediction in 2019, the last year of the plan. Projected/proposed costs would be only 6.0% below the model's predictions on average during the years of the new plan. On this basis, and in conformance with the OEB 4th GIRM rules, PSE has advocated and the Company has proposed a fixed 0.30% stretch factor during the full term of the plan.

PSE also benchmarked the Company's reliability. Econometric models were developed for the System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") using U.S. data. These models control for various business conditions, such as forestation and undergrounding, which can affect reliability. The models were developed using data from utility reports to state regulators as well as form EIA 861 data. Benchmarking work using these models suggests that the Company has long been an inferior SAIFI performer but a superior CAIDI performer and that these performances will not change much during the new plan.

The Company also submitted a unit cost benchmarking study prepared by UMS.[18] This study reviewed Toronto Hydro's cost performance for select capex and maintenance programs, including wood pole replacements, transformer replacements, breaker replacements, vegetation management, pole tests and treatments, overhead line patrols, and vault inspections. It is notable that this study uses an urban peer group and subjects the unit cost metrics to statistical adjustments to account for differences in cost reporting, input prices, and miscellaneous external business conditions. The study

[17] Functional forms are discussed further in the Appendix.

[18] Exhibit 1B/Tab 2/Schedule 1, Appendix B, and updated in Exhibit I/Tab 1B/Schedule 4 (response to OEB Staff 1B-4).

shows Toronto Hydro to be a 2nd quartile performer for most categories and programs studied relative to its peer group after normalization.

3.2. Critique

PSE Cost Benchmarking

Mr. Fenrick, one of the PSE study leaders, is a former employee of PEG and his benchmarking methods are in some respects similar to ours. For example, we both favor the econometric approach to benchmarking and believe that total cost benchmarking using a monetary approach to the measurement of capital cost is worthwhile. PSE has to its credit taken the time to develop a number of business condition variables that stand up to econometric scrutiny.

<u>Major Concerns</u>

We nonetheless disagree with some of the methods PSE used in its benchmarking study for Toronto Hydro. Our biggest concerns are addressed first to facilitate OEB review. We start by discussing our concerns about PSE's treatment of urban challenges. We agree that the provision of distribution services using facilities located under streets and buildings pose special cost challenges, especially in downtown areas where a high level of reliability is required. However, we do not believe that PSE has the urban challenge appropriately modelled.

PSE uses an urban congestion variable in its model. We prefer to call this an "urban challenge" variable because the cost of urban service is materially raised by high reliability requirements in office districts as well as by congestion problems. Our concerns about the variable that PSE developed include the following.

- It seems equally sensible to use the estimated urban area as the variable in a cost model since cost will clearly be higher the larger is the urban area served.
- Toronto Hydro and Consolidated Edison of New York ("Con Ed") have by far the highest values for PSE's urban challenge variable. If these two companies have unusually poor cost performances the variable's parameter estimate would reflect this. Con Ed is the worst cost performer in our replication of PSE's model. The parameter estimate for PSE's urban challenge variable is, in any event, very sensitive to the inclusion of Con Ed in the sample.

- PSE's model also has an interaction term between the share of assets that are undergrounded and its urban challenge variable. While undergrounding can increase the urban challenge, Toronto Hydro and many other utilities have assets that are undergrounded but are not located in congested areas or under streets and buildings. Some of these assets were directly buried. This practice is especially common in suburban areas, particularly those developed since the late 1970s, due in part to municipal requirements. The cost of direct-buried lines is considerably lower than the cost of underground vaulted lines.
- We are concerned about the sizable and unexplained value of the Ontario dummy variable.

Here are some other major concerns we have with PSE's benchmarking work in this proceeding.

- The model does not give balanced attention to the special challenges of serving rural areas, which Toronto Hydro does not face. PSE reports that it considered a rural challenge variable (total area/customer) but its parameter estimate was not quite statistically significant. PSE's total cost benchmarking model for Hydro One Distribution included this variable.[19]
- We are not convinced that an undergrounding variable is needed in a total cost model that includes an urban challenge variable. One reason is that the extent of system undergrounding is not fully exogenous, like the share of the service territory that is urban. Another is that the impact of undergrounding on capital cost varies with the type of undergrounding (e.g. vaulting vs. direct bury).
- The unusually large number of quadratic and interaction terms for the business condition variables in the model compromises the accuracy of all parameter estimates. There is even a quadratic version of the undergrounding/urban congestion interaction term. Quadratic interaction terms are rarely seen in econometric cost research.
- Power distributors use capital-intensive technologies, so the treatment of capital is a major issue when benchmarking their total cost or capital cost. PSE used a 1989 benchmark year to calculate the capital cost of *all* U.S. utilities in the econometric cost sample and a 2002 benchmark year for Toronto Hydro and the other Ontario distributors, even though a 1989

[19] Fenrick, S., EB-2017-0049, *op. cit*., p. 18.

benchmark year is feasible for all of the Ontario distributors in the sample, and a 1964 benchmark year is feasible for the U.S. distributors. The cost of gathering the requisite U.S. capital data for a 1964 benchmark year is non-negligible, but PSE has expended effort to develop several complicated business condition variables. Since capital cost typically accounts for more than half of the total cost of distributor base rate inputs in PSE's study, the recent benchmark year substantially reduces the accuracy of the benchmarking work.

- Research on the total cost of U.S. utilities usually uses a "monetary" approach to the calculation of capital cost.[20] This involves deflation of asset values that utilities report (e.g., their gross plant additions) using price indexes. PSE used an American Handy Whitman Electric Utility Construction Cost Index ("HWI") for power distribution in North Atlantic states to deflate the asset values of the included Ontario distributors. They attempted to make this index more relevant to Canada by adjusting each value for U.S./Canadian purchasing power parities ("PPPs") obtained from the Organization for Economic Cooperation and Development ("OECD").

  The appropriate asset price deflator to use in Ontario power distributor cost research is an issue of growing importance. One reason is that Statistics Canada stopped computing Electric Utility Construction Price Indexes ("EUCPIs") after 2014. These had been available for power distribution assets and substations. The trend in the EUCPIs in the decade prior to this was implausible.

  PEG spent considerable time and effort during the recent Hydro One distribution IR proceeding reviewing alternative asset price deflators.[21] We found that HWIs and EUCPIs both have drawbacks. Both indexes were designed many years ago and have some cost-share weights and inflation subindexes that are now quite dated. The labor price component of the distribution system EUCPI grew quite slowly in the later years of its calculation. However, trends in prices of labor and other construction inputs in the North Atlantic states may not be appropriate for Toronto Hydro and other Ontario utilities. For example, the HWI would be sensitive to a surge in power transmission capex that puts

[20] Monetary approaches to measuring capital cost are discussed further in Appendix Section A.1.

[21] EB-2017-0049, Exhibit L1, Tab 8, Schedule HONI-14 Attachment.

upward pressure on distribution construction costs. Purchasing power parities ("PPPs") calculated for the entire economy may not satisfactorily adjust for differences in Ontario and northeast U.S. construction cost trends.

Alternative asset price indexes are available. Based on our review, our professional opinion is that the most promising replacement for the EUCPI in Ontario distributor cost research is Statistics Canada's implicit price index for the capital stock of the Ontario utility sector.[22] This is readily computed from Statistics Canada's data on Flows and Stocks of Fixed Non-Residential Capital. This data collection program measures trends in the quantities of various capital assets using a monetary method. Statistics Canada generates this dataset by gathering investment data from various sources including the Capital Repair and Expenditures Survey. Our research showed that this index tracked the EUCPI in its good years better than the HWI with a PPP adjustment.

Smaller Concerns

Here are some smaller concerns we have with PSE's benchmarking study. We do not believe that these problems had a major impact on the benchmarking results. However, future benchmarking studies, by Toronto Hydro and other utilities, which steer clear of these problems will have more credibility.

- Fixed 70/30 weights were assigned to labor and material and service expenses in the OM&A price index for U.S. utilities, even though flexible weights are available for the American IOUs in the sample and the labor cost share is typically well below 70% for these companies. Thus, the OM&A input price indexes for American distributors were unnecessarily inaccurate.
- PSE used the U.S. gross domestic product price index, converted to Canadian dollars using PPPs, as the material and services ("M&S") price index for the Ontario utilities.

[22] Statistics Canada, 36-10-0096-01, Flows and Stocks of Fixed Non-Residential Capital, CANSIM. The implicit price index is calculated as the ratio of current value of net stock to the corresponding quantity index.

- PSE used the U.S. Employment Cost Index ("ECI") for *salaries and wages* as its labor price escalator even though an ECI for *total* compensation is available which would be more appropriate since its study includes pension and benefit expenses.

General Concerns

In addition to our comments above on specific techniques used by PSE, we have more general reservations about the use of benchmarking in this application.

- PSE's benchmarking suggests a continuation of the material decline in the cost performance of Toronto Hydro which occurred during its first Custom IR plan. It is possible that brisk cost growth is a rational response to special circumstances such as capacity constraints and advanced system age. However, no evidence has been provided that suggests that Toronto Hydro's cost performance is improving after taking account of such challenges. This arguably violates the Board's Custom IR guidelines that we discussed in Section 2.
- Setting the stretch factor on the basis of a cost forecast rather than the actual cost incurred during the plan removes a potential incentive benefit of stretch factors in that cost reductions cannot lower stretch factors. Consideration should be paid to having the stretch factor reset annually during the years of its plan on the basis of whichever benchmarking model the Board prefers.
- Total cost benchmarking does not shed light on the sources of high and low costs that utilities incur. Knowledge of strengths and weaknesses in more granular management of major cost categories such as OM&A expenses is useful to utilities and regulators alike.

Implicit Stretch Factor

We also wish to challenge the notion that a 0% base productivity target contains an *implicit* stretch factor. Ontario data have many limitations for the accurate measurement of multifactor productivity trends. These include the recent transition of many utilities to IFRS accounting.

PEG calculated the MFP trends of a large sample of U.S. power distributors in its recent study on multiyear rate plans for Berkeley Lab.[23] We reported MFP trends of 0.45% for the full 1980-2014 sample

[23] Lowry, Makos, and Deason, o*p. cit*., p. B.15.

period and of 0.39% for the more recent 1996-2014 sample period. In a fall 2017 presentation funded by LBNL which Dr. Lowry made to the New England Council of Public Utility commissions, Dr. Lowry reported that the MFP trend of sampled power distributors for the more recent 1996-2016 sample period was 0.43% per annum for the full U.S. sample and 0.31% for the Northeast U.S.

PSE Reliability Benchmarking

We believe that PSE has, with the Company's sponsorship, done a service to Ontario's regulatory community by making progress in the area of reliability benchmarking. Cost benchmarking should ideally be combined with reliability benchmarking, and reliability performance is germane when considering requests for supplemental capex funding. PSE has gathered a respectable sample of publicly available U.S. data that span the years 2010-2016. Major event days have been excluded, if not with fully consistent definitions. The models presented by PSE are a good starting point for further improvements. We present alternative models in Section 3.3. below.

3.3. Alternative Benchmarking Results Using PSE's Data

Alternative Cost Models

We tested the robustness of PSE's results by developing some alternative total cost benchmarking models using its dataset.

- Instead of using the estimated percentage of the total area served which was congested, we used the estimated area congested. We substituted this alternative in all of the variables that PSE constructed. Toronto Hydro's average score during the five years of its proposed plan declined from about 6% using PSE's model to about 52% over.
- We removed all of the translog terms for the non-scale business conditions from the model. The percentage urban variable had a highly significant and positive parameter estimate. However, PSE's average score for the 2020-24 period was about 39% over the model's prediction.
- Consolidated Edison of New York was removed from the sample. Toronto Hydro's average score during the five years of its proposed plan changed from about 6% under using PSE's model to 653% under.

These results provide strong evidence that PSE's total cost benchmarking results for Toronto Hydro are not robust.

Alternative Reliability Models

PEG developed alternative econometric reliability models using the data provided by PSE in its working papers. We modelled CAIDI and SAIFI using business condition variables obtained from PSE and an additional weather variable that are pertinent to power distributor reliability performance. The sampled companies were the same. We extended the sample period to include 2017.

Results of our reliability research can be found in Tables 1 and 2. Our SAIFI model indicates that SAIFI was higher the greater is the share of distribution assets overhead. The SAIFI impact of overheading was magnified by forestation. Our research also shows that SAIFI was greater

- the lower is the share of the service territory that was urban
- the greater were extreme temperatures in the service territory.
- the more extensive was forestation when more distribution plant is overhead
- the greater was precipitation
- the greater was the standard deviation of elevation
- when the IEEE major event day standard was used.

The parameter estimate for the trend variable suggests that the SAIFI of sampled utilities trended downward by 1.85% annually for reasons not explained by the model's business condition variables. The adjusted R-squared of the model was 0.30%. While this is much lower than in our cost models, it should be remembered that the SAIFI metric already controls for the number of customers served.

Our model for CAIDI indicates that CAIDI was higher

- the greater was the share of service territory area that was urban.
- the more extensive was forestation
- the greater was the area of the service territory per customer
- the greater was precipitation
- the greater was the standard deviation of elevation in the service territory.

Table 1

Econometric Model of SAIFI

VARIABLE KEY

PCTCU =	% service territory congested urban
PCTPOH =	% of distribution plant overhead
EXTREME =	Sum of cooling degree hours above 30°C and heating degree hours below -15°C
PCP =	Annual average precipitation
PCTFOREST =	% service territory forested
ELEVSTD =	Elevation standard deviation
IEEE =	Binary variable indicating the IEEE standard
Trend =	Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
PCTCU	-39.913	-6.32	0.00
PCTPOH	1.236	14.66	0.00
EXTREME	0.056	7.52	0.00
PCP	0.131	6.37	0.00
PCTPOH*PCTFOREST	0.204	1.76	0.00
ELEVSTD	0.035	3.45	0.00
IEEE	0.111	5.62	0.00
Trend	-0.019	0.003	-5.821
Constant	0.128	4.121	0.000

Adjusted R^2 0.305

Sample Period 2010-2017

Number of Observations 496

Table 2

Econometric Model of CAIDI

VARIABLE KEY

PCTCU =	% service territory congested urban
PCTFOREST =	% service territory forested
AREAYN16 =	Square km of service territory per customer in 2016
PCP =	Annual average precipitation
ELEVSTD =	Elevation standard deviation
PCTAMI =	% of customers with AMI meters
IEEE =	Binary variable indicating the IEEE standard

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
PCTCU	18.924	9.095	0.000
PCTFOREST	0.055	10.167	0.000
AREAYN16	0.066	7.686	0.000
PCP	0.063	5.151	0.000
ELEVSTD	0.081	12.758	0.000
PCTAMI	-0.049	-2.908	0.004
IEEE	-0.031	-2.651	0.008
Constant	4.824	446.464	0.000

Adjusted R^2 0.232

Sample Period 2010-2017

Number of Observations 496

- the lower was the level of AMI penetration
- when the IEEE major event day standard was not used.

The parameter estimate for the trend variable suggests that the CAIDI of sampled utilities tended to fall over time by 3.14% annually for reasons not explained by the model's business condition variables. The adjusted R-squared of the model was modest 0.23%. Thus, CAIDI is less well explained by our modelling than SAIFI.

Benchmarking results for Toronto Hydro can be found in Tables 3 and 4. It can be seen that the Company's SAIFI was far above our model's prediction throughout the sample period. The results are quite sensitive to the inclusion of the urban variable. The Company's CAIDI tended to be well below the model's predictions throughout the sample period and improved noticeably from 2013 to 2018.

Table 3

Year by Year SAIFI Benchmarking Results

Year	Percent Difference[1]
2005	131.2%
2006	158.1%
2007	161.6%
2008	160.9%
2009	147.2%
2010	155.0%
2011	158.9%
2012	149.6%
2013	159.7%
2014	152.6%
2015	161.2%
2016	161.3%
2017	160.2%
2018	*164.3%*
2019	*164.8%*
2020	*166.5%*
2021	*168.1%*
2022	*169.9%*
2023	*171.7%*
2024	*173.5%*
Annual Averages	
2010-2017	**157.3%**
2015-2017	**160.9%**
2020-2024	**169.9%**

[1] Formula for benchmark comparison is $\ln(SAIFI^{THESL}/SAIFI^{Bench})$.

Note: Italicized numbers are projections/proposals.

Table 4

Year by Year CAIDI Benchmarking Results

Year	Percent Difference[1]
2005	-45.4%
2006	-62.0%
2007	-52.1%
2008	-58.4%
2009	-34.8%
2010	-42.2%
2011	-39.9%
2012	-54.3%
2013	-52.5%
2014	-60.8%
2015	-59.7%
2016	-66.1%
2017	-65.3%
2018	*-64.9%*
2019	*-58.0%*
2020	*-57.8%*
2021	*-57.6%*
2022	*-57.4%*
2023	*-57.2%*
2024	*-57.0%*
Annual Averages	
2010-2017	**-55.1%**
2015-2017	**-63.7%**
2020-2024	**-57.4%**

[1] Formula for benchmark comparison is $\ln(CAIDI^{THESL}/CAIDI^{Bench})$.

Note: Italicized numbers are projections/proposals.

4. PEG's Original Cost Benchmarking Work

4.1. Sources of Data on Cost, Price, and Operating Scale

Accurate statistical benchmarking is facilitated by abundant, high quality data on utility operations. In this section we discuss sources of the data we used in our study to benchmark the cost of Toronto Hydro.

Ontario

About seventy utilities provide power distribution services in Ontario today. These utilities also provide a wide range of customer services that include conservation and demand management ("CDM"). The largest distributor, Hydro One Networks, also provides most power transmission services in Ontario.

<u>Pros and Cons of Ontario Data</u>

Advantages of using data for other Ontario utilities to appraise the cost performance of Toronto Hydro include the following.

- Standardized, high quality data are publicly and electronically available on operations of numerous Ontario distributors for more than a decade. Thus, a large sample is available for econometric estimation of cost model parameters. Large samples of good data improve the accuracy of econometric model parameter estimates.
- Data are available for all distributors on peak loads and the total length of distribution lines (in circuit miles).
- There is no need for currency conversions in an Ontario benchmarking study, and adjustments are fairly straightforward if desired for differences between input prices in various parts of the province.

Disadvantages of Ontario data include the following.

- Many of the distributors serve small towns outside the larger metropolitan areas and hence face business conditions quite different than those of Toronto Hydro.

- Many distributors recently transitioned to Modified International Financial Reporting Standards ("MIFRS"). These new standards reduced capitalization of OM&A expenses for many companies.
- Itemized data on pension and benefit expenses of most Ontario distributors, including Toronto Hydro, are unavailable for lengthy sample periods. These costs are difficult to benchmark accurately, and the Company proposes to address these costs with a variance account rather than indexing. Canadian labor price indexes are available only for salaries and wages and not for comprehensive employment costs
- Data needed to calculate capital costs and quantities for most distributors using a monetary method are available only since 1989.[24] In addition, data on *gross* plant additions, which we normally use to calculate capital costs, are only available starting in 2013. It is necessary to impute gross plant additions in earlier years using data on changes in the gross (undepreciated) value of plant. Another problem in measuring Ontario capital costs is that itemized data on distribution and general plant are not readily available. Statistics Canada suspended calculation of its electric utility construction price indexes several years ago. These circumstances tend to reduce the accuracy of statistical research on the capital cost and total cost performance of Ontario utilities.
- Itemization of OM&A salary and wage and material and service expenses is not readily available for a lengthy sample period.
- PSE has, in any event, made its business condition data available in this proceeding only for six additional Ontario distributors.

Based on these considerations, the only observations for Ontario utilities that we use in our study are those for Toronto Hydro.

<u>Data Sources</u>

The primary source of data on the cost and operating scale of Ontario power distributors is the Regulatory Recordkeeping Requirements ("RRR") reports. The OEB has required each jurisdictional

[24] We believe that it is straightforward to interpolate plant additions over the few years for which gross plant value data are available before the year 2000.

power distributor to file this report since 2002. A uniform system of accounts called the *Accounting Procedures Handbook* has been established for the RRR reports. Most data on Canadian prices used in the study were obtained from Statistics Canada.

United States

Power distributor services in the United States are provided to most customers by investor-owned electric utilities ("IOUs") but are provided in some areas by cooperative or municipal utilities.[25] U.S. distributors typically provide several customer services (e.g., meter reading, billing, and collection) but varied levels of CDM services. Most IOUs also provide power transmission services in their service territory and many provide generation services.[26] The reported distribution costs of some companies include subtransmission lines and substations that receive power at subtransmission and higher voltages.

Pros and Cons of U.S. Data

U.S. data have numerous advantages in a Toronto Hydro total cost benchmarking study.

- The U.S. government has gathered detailed, standardized data for decades on the operations of dozens of IOUs.
- Most IOUs provide an array of distributor services that is similar to Toronto Hydro's.
- Many IOUs serve large urban areas.
- U.S. cost data are credibly itemized, permitting calculations of the cost of power distributor services even for vertically integrated utilities.
- Data on the net value of plant and the corresponding gross plant additions have been itemized for power distribution and general assets since 1964. Custom price indexes are available on the construction cost trends of power distributors. This makes U.S. data the best in the world for accurate calculation, using monetary methods, of the consistent capital

[25] Cities that are served by municipal utilities include Austin, Los Angeles, Memphis, Nashville, Sacramento, and Seattle.

[26] Examples of vertically integrated electric utilities ("VIEUs") include Duke Energy Carolinas, Florida Power and Light, Georgia Power, and Northern States Power.

cost, price, and quantity indexes that are needed to appraise the capital cost and total cost performances of power distributors.

There are, however, some downsides to using U.S. data in distributor cost research.

- Consistent data on *total* distribution line length, a potentially useful scale variable, are not publicly available for most major IOUs.[27]
- Peak load is another potentially relevant scale variable in a power distribution cost study. Available U.S. peak load data require adjustments to be comparable to the analogous Ontario data.
- Itemized data are available on administrative and general expenses and general plant but these are driven by the entirety of each IOU's operations and not just by the provision of distributor services. If these costs are to be considered in the research, it is necessary to assign a portion of them to distributor services by some arbitrary means.

U.S. Data Sources

The source of U.S. utility cost data used in our study is Federal Energy Regulatory Commission ("FERC") Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[28] More recently, these data have been available electronically in raw form from the FERC and in more processed forms from commercial vendors such as SNL Financial.

Data on the number of retail customers served by the utilities were drawn from Form EIA-861 (the *Annual Electric Power Industry Report*) for most years of the sample period and from FERC Form 1 for some early years. Customer data from these two sources are generally similar.

Data on U.S. labor prices were drawn from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate material and service expenses of U.S. distributors was obtained from the Bureau of Economic Analysis of

[27] Data on *overhead* pole (aka structure or route) miles are available for a considerably larger group of companies from surveys of an American data vendor.

[28] This publication series had several titles over the years. The most recent title is *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*.

the U.S. Department of Commerce. Data on levels of heavy construction costs in various U.S. and Canadian locations were purchased from R.S. Means. Data on U.S. electric utility construction cost *trends* were purchased from Whitman, Requardt and Associates.

U.S. data were eligible for inclusion in our sample from all major IOUs in the United States which filed Form 1 in 1964 (the benchmark year for our study, described further in the Appendix) and that, together with any important predecessor companies, have reported the data required for our calculations continuously since then. To be included in the study the data were also required to be of good quality and plausible.

To take advantage of some of the Z variable data that PSE have gathered, we have used data on the sizable number of American IOUs that PSE used in its studies. These utilities serve some of the largest urban areas in the United States, including Baltimore, Charlotte, Chicago, Cincinnati, Cleveland, Denver, Detroit, Indianapolis, Kansas City, Las Vegas, Miami, Minneapolis, New York, Philadelphia, Phoenix, Pittsburgh, Portland, San Diego, San Francisco, St. Louis, Tampa, and Washington.[29]

Sample Summary

Data from a total of 84 distributors were used in our econometric cost research. This is six companies fewer than in the PSE sample due to the exclusion of the other Ontario distributors. The sampled companies are listed in Table 5. We believe that these data form a good base for rigorous research on the cost performance of Toronto Hydro. The sample is large and varied enough to permit development of credible econometric cost models with several business condition variables. Most regions of the United States are well-represented.[30] The sample period for the econometric cost research was 1995 to 2017.[31]

[29] All of the cities mentioned have metropolitan areas with a population exceeding two million.

[30] However, the requisite data are not available for most Texas distributors.

[31] The sample period for the capex model was 1996-2017.

Table 5

Sample of Utilities Used in Econometric Cost Model Development

*Alabama Power	MDU Resources Group
*ALLETE (Minnesota Power)	Metropolitan Edison
*Appalachian Power	*Mississippi Power
*Arizona Public Service	Monongahela Power
Atlantic City Electric	*Nevada Power
Avista	New York State Electric & Gas
*Baltimore Gas & Electric	*Niagara Mohawk Power
*Black Hills Power	Northern Indiana Public Service
*Central Hudson Gas & Electric	Northern States Power - MN
*Central Maine Power	Northern States Power - WI
*Cleco Power	*Ohio Edison
*Cleveland Electric Illuminating	*Oklahoma Gas & Electric
*Commonwealth Edison	Orange & Rockland Utilities
Connecticut Light & Power	*Pacific Gas & Electric
Consolidated Edison of New York	*PECO Energy
*Consumers Energy	Pennsylvania Electric
*Delmarva Power & Light	Pennsylvania Power
*DTE Electric	*Portland General Electric
*Duke Energy Carolinas	*Potomac Electric Power
*Duke Energy Florida	*PPL Electric Utilities
*Duke Energy Indiana	*Public Service Company of Colorado
*Duke Energy Kentucky	Public Service Company of New Hampshire
*Duke Energy Ohio	*Public Service Company of Oklahoma
Duke Energy Progress	*Public Service Electric & Gas
*Duquesne Light	*Puget Sound Energy
El Paso Electric	*San Diego Gas & Electric
Empire District Electric	*South Carolina Electric & Gas
*Entergy Arkansas	*Southern California Edison
*Entergy Mississippi	Southern Indiana Gas & Electric
*Entergy New Orleans.	*Southwestern Public Service
*Florida Power & Light	*Tampa Electric Company
*Gulf Power	***Toronto Hydro**
*Idaho Power	Toledo Edison
*Indiana Michigan Power	*Tucson Electric Power
*Indianapolis Power & Light	Union Electric
Jersey Central Power & Light	*United Illuminating
*Kansas City Power & Light	*Virginia Electric & Power
*Kansas Gas & Electric	*West Penn Power
*Kentucky Power	Western Massachusetts Electric
*Kentucky Utilities	*Wisconsin Electric Power
*Louisville Gas & Electric	*Wisconsin Power & Light
*Madison Gas & Electric	Wisconsin Public Service

* These companies experienced AMI penetration during the sample period and therefore have non-NA values for PCTAMIGROWTH. These companies were the only companies to be included in the capex model.

4.2. Definition of Variables

Costs

The major tasks in power distribution are the local delivery of power, the reduction of its voltage, and the metering of quantities delivered. Most power is delivered to customers at the voltage at which it is consumed. This requires distributors to step down the voltage of power from the voltage at which they receive it from the transmission sector.[32] All distributors use transformers near the point of delivery to reduce voltage to the level at which it is consumed. Some also own and operate substations.

Distributors also typically provide various customer services. In North America, these typically include metering, meter reading, customer account, and customer service and information ("CS&I") services. In the United States, reported expenses for CS&I services include those for CDM programs. These expenses vary widely between utilities and are not itemized for easy removal. We accordingly follow the path of PSE by excluding all CS&I expenses from the costs of US utilities in our study.

Pension and benefit expenses are often excluded from utility cost performance studies because they are sensitive to volatile external business conditions such as stock prices. In Canada, an additional problem with including pension and benefit expenses in econometric cost research is the lack of federal labor price indexes that encompass them. Pension and benefit expenses can be removed from the data for Toronto Hydro and American IOUs. We have therefore excluded these expenses from this study.

The O&M expenses we used in the study for U.S. utilities included those for power distribution, customer accounts, metering, and meter reading. We also included a sensible share of A&G expenses.[33] We excluded all reported O&M expenses incurred by sampled U.S. utilities for generation, power procurement, transmission, customer service and information, franchise fees, and gas services. The capital costs we included were those for distribution plant and a sensible share of the cost of general plant.

[32] Some large industrial customers take delivery of power directly from the transmission system.

[33] The particular method chosen for allocating general costs is theoretically arbitrary but has little impact on results.

Like PSE we excluded expenses for CDM from the costs of sampled Canadian distributors. All reported administrative and general expenses were included. The capital costs we considered were those for distribution plant and all reported general plant.

The total cost of power distributor services considered in our study was therefore the sum of capital costs and *applicable* O&M expenses. We employed a monetary approach to capital cost, price, and quantity measurement which featured geometric decay. Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains.[34] Further details of our capital cost calculations are provided in Appendix Section A.1.

Input Price Indexes

OM&A

Summary OM&A input price indexes were constructed by PEG which were weighted averages of price subindexes for labor and material and service ("M&S") inputs. Calculation of these indexes used 70/30 labor/M&S weights for Toronto Hydro and company-specific, time-varying cost share weights for the U.S. utilities. The cost shares were calculated from FERC Form 1 OM&A expense data.

Methods for constructing the price subindexes used in these calculations differed somewhat for for Ontario and the United States.

Ontario We used the indexes that PSE calculated to compare the levels of U.S. and Canadian salaries and wages in particular years. Labor price index values for earlier and later years were then established by trending these levels using Statistics Canada's $AWE^{Ontario}$ in Ontario. The $GDPPIFDD^{Canada}$ was our proxy for a Canadian M&S price trend index.

United States The labor price levels for U.S. utilities that we obtained from PSE were escalated by regionalized BLS Employment Cost Indexes for salaries and wages. M&S prices were escalated by the U.S. gross domestic product price index. This is the U.S. government's featured index of inflation in prices of the economy's final goods and services. Final goods and services include business equipment and exports as well as consumer products.

[34] Capital gains are included due to the geometric decay capital cost treatment that we employ, which like other monetary methods values capital at replacement cost.

Capital

Construction cost indexes and rates of return on capital are required in the capital cost research. We calculated weighted averages of rates of return for debt and equity.[35] For Toronto Hydro we took the weighted average cost of capital approved by the OEB. This takes an average of the allowed return on equity and long-term and short-term debt rates. For the United States we calculated for each sample year a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data, and the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric Institute.[36]

We used the Statistics Canada implicit price index for the capital stock of Ontario utilities to deflate the value of plant additions of Toronto Hydro. Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution. For the United States we used the applicable regional Handy Whitman Indexes of Public Utility Construction Costs for Total Electric Utility Distribution Plant.

Multifactor

The summary *multifactor* input price index for each U.S. and Ontario utility in our sample was constructed by combining the capital and summary O&M price indexes using company-specific, time-varying cost share weights for all companies. The ratio of cost to this index was the dependent variable in the econometric total cost research.[37]

U.S./Canada Price Patch

Since transnational data were used in the study, it was necessary to adjust for differences in currencies of distributors in different countries. M&S prices were patched using purchasing power parities ("PPPs") computed by the Organization for Economic Cooperation and Development ("OECD"). Labor prices did not require a patch because they were based on average salaries and wages stated in

[35] This calculation was made solely for the purpose of measuring productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities.

[36] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

[37] The dependent variables in the econometric models for OM&A, capital, and capex costs were, similarly, cost divided by the corresponding input price index.

nominal U.S. or Canadian dollars. Construction cost indexes did not require a patch since data on heavy construction cost levels in the U.S. and Canada were drawn from the same source and are stated in nominal U.S. and Canadian dollars.

Scale Variables

Two measures of distributor operating scale were used in all four of our econometric cost models: ratcheted peak demand and the number of retail electric customers served. The ratcheted peak demand in a given year is the highest value of peak demand that has thus far been achieved by the utility during the sample period. This is a better measure of the *expected* maximum peak demand that typically drives distribution cost. The U.S. peak demand data were adjusted to remove the estimated amount that was due to required sales for resale since these are not distributor loads.

All four costs that we modelled should be higher the higher are the values of both of these scale variables. To provide some flexibility to the model's functional form we added quadratic and interaction terms to each model for these variables.[38] This is a common practice in econometric cost research. The expected signs for the parameters for these variables are indeterminate.

Other Business Condition Variables

Several other business condition variables were used in one or more of our econometric cost models. One of these variables was the estimated share of area served by the utility that was urban. This variable, developed by PSE, should have a positive parameter estimate in the total cost, capital cost, and capex models. Its sign is indeterminate in the OM&A cost model.

The OM&A model has a variable indicating the share of distribution assets that are overhead. This makes sense because undergrounding is an attribute of the capital quantity, which is a variable in an OM&A cost function.[39] We expect this variable to have a negative sign.

The challenge of low customer density is captured by the estimated area served that is non urban. We expect cost to be higher the higher is the value of this variable in all four models.

[38] Quadratic terms and other functional form issues are discussed in Appendix Section A.2.

[39] In a restricted or short-run cost function, cost depends on the prices of *included* inputs, output, miscellaneous other external business conditions, and the quantity of *other* inputs that a utility uses. In the context of an OM&A cost function the quantities and attributes of capital inputs are pertinent.

The cost of serving non-urban areas is generally raised by forestation. We therefore included in our models PSE's variable for the percentage of area forested in the service territory. We expect the parameter for this variable to have a positive sign in the OM&A and total cost models. Its expected sign is indeterminate in the capital cost and capex models.

The models also contain a variable indicating the share of customers that have AMI. We expect this variable to have a positive sign in the total cost and capital cost models. Its expected sign is indeterminate in the OM&A model since AMI reduces meter reading expenses but raises costs of processing and analyzing the copious data that AMI gathers.

The models also have a variable indicating the standard deviation of elevation in the service territory. As the value of this variable increases, roads between destinations become less direct and work off the road tends to be more difficult. We therefore expect this variable's parameter estimate to have a positive sign in all four models.

The models also have a variable indicating the share of electric customers in the sum of electric and gas customers. We expect this variable's parameter estimate to have a positive sign in all four models since higher values mean less opportunities to realize economies of scope from the joint provision of gas and electric service.

The capex models also have variables indicating the *growth* in operating scale and AMI. We expect the parameter estimates for these variables to have positive signs.

The models also have trend variables. These variables permit predicted cost to shift over time for reasons other than changes in the specified business conditions. Trend variables thereby capture the net effect on cost of diverse conditions, such as technical change, which are otherwise excluded from the models. Parameters for such variables have often had negative signs in econometric research on utility cost. However, the expected signs of trend variable parameters in cost models are nonetheless indeterminate.

How Does PEG's Cost Benchmarking Differ?

- Fewer Ontario utilities in the sample, but longer sample period that includes 2017 data
- Alternative urban and rural challenge specifications
- Fewer interaction and quadratic terms
- Pension and benefit expenses excluded
- Better capital cost specification
- Better Ontario input price indexes
- Experimental benchmarking models for OM&A expenses, capital cost, and capital expenditures were also developed

We generally tried to use as many business condition variables with statistically significant and sensibly signed parameter estimates as we could in each cost model. If a variable appears in one model and not another, it is either because the variable does not belong in one of the models or because it did not have a correctly signed and statistically significant parameter estimate. It makes sense that some variables matter more for OM&A expenses than they do for capital cost and vice versa. We were more sparing in the use of extra quadratic and interaction terms than PSE was out of concern that too many variables reduce the precision of parameter estimates.

4.3. Econometric Research

Like PSE we developed an econometric model of the total cost of power distributor base rate inputs. We also developed experimental econometric models of three major components of total cost: OM&A expenses ("opex"), capital cost, and capital expenditures ("capex"). Estimation results for all four models are reported in Tables 6-11. These tables include parameter estimates and their associated asymptotic t values and p-statistics. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. These significance tests were used in model development. A t test requires selection of a critical value for the asymptotic t ratio. We employed a critical value that is appropriate for a 90% confidence level.[40] In all of these models, all of the parameter estimates for the first-order terms of the business condition variables are statistically significant and plausible as to sign and magnitude.

Total Cost

Results for the total cost model are presented in Table 6. Here are some salient results.

- The parameter estimates for the number of customers and ratcheted peak demand are highly significant and positive. The parameter estimates for the additional quadratic and interaction terms associated with these scale variables are also highly significant. This suggests that the relationship of cost to the scale variables is nonlinear.
- Total cost was higher the higher was the share of the service territory that was urban but also higher the greater was the area of the remainder of the service territory.
- Total cost was also raised by forestation, the greater was AMI penetration, the standard deviation of elevation, and the share of gas and electric customers that were electric.
- The estimate of the trend variable parameter suggests that cost was falling by about 0.4% annually over the sample period for reasons other than changes in the values of the included business condition variables.

The adjusted R^2 for the model was 0.970. This suggests that the model has a high level of explanatory power.

[40] A one-tailed test was appropriate for most first order terms in the model. Two-tailed tests were appropriate for the quadratic and interaction terms associated with the scale variables.

Table 6

Econometric Model of Total Cost

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
AREA_OTHER = Service territory area multiplied by (1-PCTCU)
PCTFOREST = % service territory forested
PCTELEC = % electric customers
PCTAMI = % of customers with AMI meters
ELEVSTD = Elevation standard deviation
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.601	28.701	0.000
N*N	0.487	6.246	0.000
D	0.351	16.501	0.000
D*D	0.561	6.807	0.000
D*N	-0.507	-6.508	0.000
PCTCU	15.198	8.243	0.000
AREA_OTHER	0.019	3.072	0.002
PCTFOREST	0.042	13.604	0.000
PCTELEC	0.088	4.881	0.000
PCTAMI	0.030	2.834	0.005
ELEVSTD	0.032	6.469	0.000
Trend	-0.004	-7.751	0.000
Constant	19.776	2074.167	0.000

Adjusted R^2	0.970
Sample Period	1995-2017
Number of Observations	1907

OM&A Expenses

Results for the opex cost model are presented in Table 7.

- The parameter estimates for the number of customers and ratcheted peak demand were both significant and positive.[41] Notice that the number of customers served has a greater cost impact than in the total cost model. This is as we might expect since OM&A expenses include many customer related expenses such as those for metering and billing.
- The parameter estimates for the additional quadratic and interaction terms associated with these scale variables are also highly significant. This suggests that the relationship of cost to the scale variables is nonlinear.
- Opex was higher the greater was the share of the service territory that was urban and the higher was the extent of system overheading. Overheading had a greater cost impact the larger was the non-urban area served.
- Cost was, somewhat surprisingly, higher when more customers had AMI.
- Opex was also higher the greater was forestation, the standard deviation of elevation, and the share of electric customers in the sum of gas and electric customers.

The estimate of the trend variable parameter indicates a 0.7% annual decline in opex for reasons other than changes in the values of included business condition variables. This decline is considerably more rapid than that in the total cost model. Table 7 also reports the adjusted R^2 statistic for the opex model. Its 0.927 value was considerably lower than that of the total cost model.

[41] Ratcheted peak demand was significant using a one-tailed test.

Table 7

Econometric Model of OM&A Expenses

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
PCTPOH = % of plant overhead
AREA_OTHER = Service territory area multiplied by (1-PCTCU)
PCTFOREST = % service territory forested
PCTELEC = % electric customers
PCTAMI = % of customers with AMI meters
ELEVSTD = Elevation standard deviation
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.903	25.120	0.000
N*N	1.239	10.398	0.000
D	0.061	1.631	0.103
D*D	0.921	6.705	0.000
D*N	-1.045	-8.359	0.000
PCTCU	9.542	2.260	0.024
PCTPOH	0.772	10.591	0.000
AREA_OTHER*PCTPOH	0.151	2.616	0.009
PCTFOREST	0.053	12.757	0.000
PCTELEC	0.106	3.735	0.000
PCTAMI	0.042	2.153	0.031
ELEVSTD	0.038	5.431	0.000
Trend	-0.007	-8.228	0.000
Constant	18.848	1275.331	0.000

Adjusted R^2 0.927

Sample Period 1995-2017

Number of Observations 1907

Capital Cost

Econometric results for the capital cost model are presented in Table 8.

- The parameter estimates for the number of customers and ratcheted peak demand are both highly significant and positive. Note that ratcheted peak demand is a bigger cost driver in this model than in the total cost model whereas the number of customers served is a smaller driver. Most of the parameter estimates for the extra quadratic and interaction terms for these variables are significant.
- Capital cost was higher the greater was the *share* of the area served that was urban but also higher the greater was the area served that was non-urban.
- Capital cost was also greater the greater was forestation, AMI penetration, the standard deviation of elevation, and the ratio of electric customers to the sum of gas and electric customers.

The estimate of the trend variable parameter indicates a 0.54% annual decline in capital cost for reasons other than changes in the values of the model's business condition variables.

Capex

Results for the capex model are presented in Table 9.

- The parameter estimates for the number of customers and ratcheted peak demand were both highly significant and positive. The parameter estimates for the extra quadratic and interaction terms were insignificant.
- Capex was higher the more rapid was growth in customers, ratcheted peak demand, and AMI penetration.
- Capex was also greater the higher was the share of service territory area that was urban and the standard deviation of service territory elevation.
- The estimate of the trend variable parameter suggests that capex was declining by about 0.32% annually during the sample period for reasons other than changes in the values of the included business condition variables.

Table 8

Econometric Model of Capital Cost

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
AREA_OTHER = Service territory area multiplied by (1-PCTCU)
PCTFOREST = % service territory forested
PCTELEC = % electric customers
PCTAMI = % of customers with AMI meters
ELEVSTD = Elevation standard deviation
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.526	39.417	0.000
N*N	-0.121	-2.157	0.031
D	0.427	30.934	0.000
D*D	0.118	2.006	0.045
D*N	0.018	0.321	0.748
PCTCU	25.921	13.495	0.000
AREA_OTHER	0.069	15.091	0.000
PCTFOREST	0.037	14.580	0.000
PCTELEC	0.046	5.165	0.000
PCTAMI	0.028	5.029	0.000
ELEVSTD	0.017	4.837	0.000
Trend	-0.005	-15.722	0.000
Constant	17.415	2735.360	0.000

Adjusted R^2 0.964
Sample Period 1995-2017
Number of Observations 1907

Table 9

Econometric Model of Capex

VARIABLE KEY

N = Number of customers
D = Ratcheted maximum peak demand
PCTCU = % service territory congested urban
ELEVSTD = Elevation standard deviation
NGROWTH = % change in number of customers over last ten years
PCTAMIGROWTH = % change in PCTAMI from 2002 to 2017
DGROWTH = % change in D over sample period
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.494	9.229	0.000
N*N	0.271	1.090	0.276
D	0.567	9.744	0.000
D*D	0.374	1.372	0.170
D*N	-0.245	-0.964	0.335
PCTCU	48.166	9.341	0.000
ELEVSTD	0.056	4.499	0.000
NGROWTH	0.572	2.983	0.003
PCTAMIGROWTH	0.020	3.453	0.001
DGROWTH	0.313	2.415	0.016
Trend	-0.003	-1.704	0.089
Constant	14.493	505.654	0.000

Adjusted R^2	0.869
Sample Period	1996-2017
Number of Observations	1306

The 0.869 adjusted R^2 for the capex model is the lowest of the four models that we developed. The lack of a system age specification in the model is likely one reason why its explanatory power isn't higher.

4.4. Business Conditions of Toronto Hydro

The external business conditions faced by Toronto Hydro should be considered in fashioning benchmarks for the company. The Company is an electric utility based in Toronto. It distributes power in the City of Toronto and is owned by the city. The service territory includes one of North America's largest downtown office districts and high reliability is expected there. Exclusive of Hamilton, the Toronto metropolitan area is the ninth largest in the U.S. and Canada. Salaries and wages tend to be well above the U.S./Canadian norm.

The territory also includes several other areas of high density where office and residential high rises are concentrated. Many of these areas are located near mass transit stations. However, the sizable "horseshoe area" surrounding Toronto's central business district is for the most part suburban in character. Undergrounding of the distribution system is quite extensive in Toronto but many undergrounded facilities do not lie beneath streets and buildings.

The Company does not provide generation, power transmission, or natural gas services. This limits its opportunities to realize scope economies. All customers now have AMI. The service territory lies along the shore of Lake Ontario and has little variation in elevation.

4.5. Econometric Benchmarking Results

We benchmarked the opex, capital cost, total cost, and capex of Toronto Hydro in each year of the historical 2005-2017 period as well as in the 2018-2024 period for which the Company has provide proposals/projections. These benchmarks were based on our econometric model parameter estimates and the values for the business condition variables which are appropriate for the Company in each historical and future year.

Tables 10-13 and Figures 3-6 report results of this benchmarking work. For each cost considered, we provide results for each year as well as average results for the last three historical years of the sample period (2015-2017).[42] We also provide average benchmarking results for the five years of the proposed new Custom IR plan (2020-24).

[42] Recollecting the recent benchmark years for estimating capital cost in Ontario, the capital cost and total cost benchmarking results are likely to be more accurate in these three years.

Table 10 and Figure 3 show results of our econometric *total* cost benchmarking. It can be seen that the company's total cost was well below the model's predictions in the early years of the sample period but declined steadily. Cost efficiency will decline substantially under the current Custom IR plan and is projected to continue declining substantially during the next plan. On average, projected/proposed total cost during the new plan exceed the benchmarks by a substantial 20.6%.

Table 11 and Figure 4 show results of our econometric opex benchmarking. It can be seen that Toronto Hydro's expenses tended to be well below the model's predictions in the early years of the sample period. While opex performance has been worse since 2009, the Company's opex continues to be less than the model's predictions. Proposed/projected opex will be 12.1% below the model's predictions on average during the five years of the proposed plan.

Table 12 and Figure 5 show results of our econometric *capital* cost benchmarking. It can be seen that the Company's capital cost was well below the model's projections at the beginning of the sample period. However, capital cost performance has steadily declined. Over the five years of the new plan, proposed/projected capital cost will exceed the model's predictions by 43.0% on average.

Table 13 and Figure 6 show results of our econometric *capex* benchmarking. It can be seen that that the Company's capex was far *below* the model's predictions in most years from 2005 to 2009 and well *above* the model's predictions in most years since. Over the five years of the new plan, proposed/projected capex will exceed the model's predictions by 21.7% on average.

Table 10

Year by Year Total Cost Benchmarking Results

Year	Percent Difference[1]
2005	-30.3%
2006	-29.7%
2007	-25.3%
2008	-23.2%
2009	-21.2%
2010	-13.9%
2011	-6.2%
2012	-7.7%
2013	-2.8%
2014	-1.0%
2015	1.1%
2016	5.8%
2017	8.7%
2018	*12.5%*
2019	*13.7%*
2020	*16.5%*
2021	*18.4%*
2022	*20.9%*
2023	*22.8%*
2024	*24.5%*
Annual Averages	
2005-2017	**-11.21%**
2015-2017	**5.2%**
2020-2024	**20.6%**

[1] Formula for benchmark comparison is $\ln(Cost^{THESL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 3

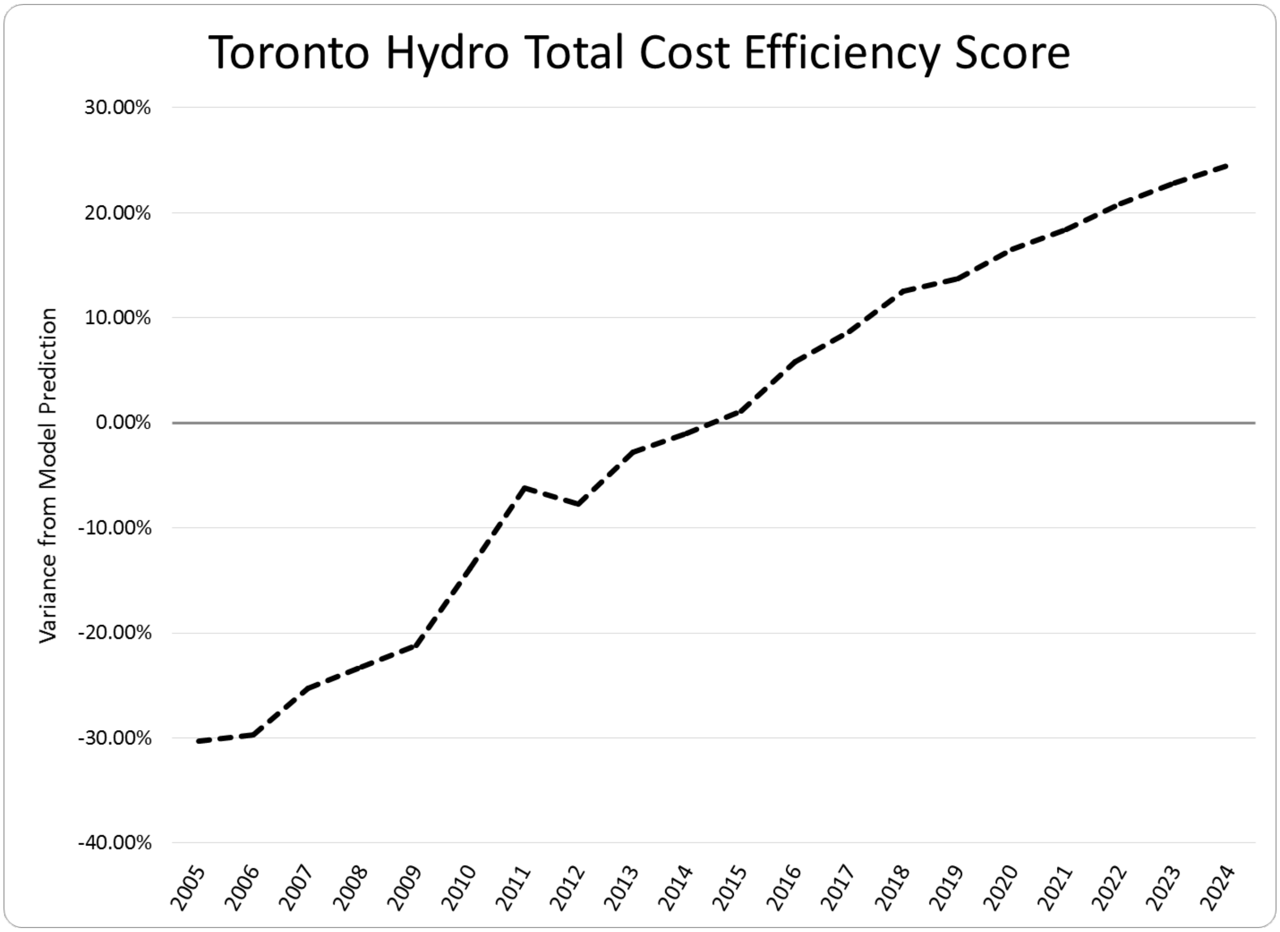

Toronto Hydro Total Cost Efficiency Score
Variance from Model Prediction
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
-40.00%
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

Table 11

Year by Year OM&A Cost Benchmarking Results

Year	Percent Difference[1]
2005	-29.9%
2006	-33.5%
2007	-25.8%
2008	-28.9%
2009	-24.6%
2010	-12.1%
2011	-5.5%
2012	-12.9%
2013	-4.9%
2014	-10.7%
2015	-11.1%
2016	-12.5%
2017	-13.1%
2018	*-14.0%*
2019	*-13.2%*
2020	*-11.6%*
2021	*-11.3%*
2022	*-11.9%*
2023	*-12.5%*
2024	*-13.0%*
Annual Averages	
2005-2017	**-17.3%**
2015-2017	**-12.2%**
2020-2024	**-12.1%**

[1] Formula for benchmark comparison is $\ln(Cost^{THESL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 4

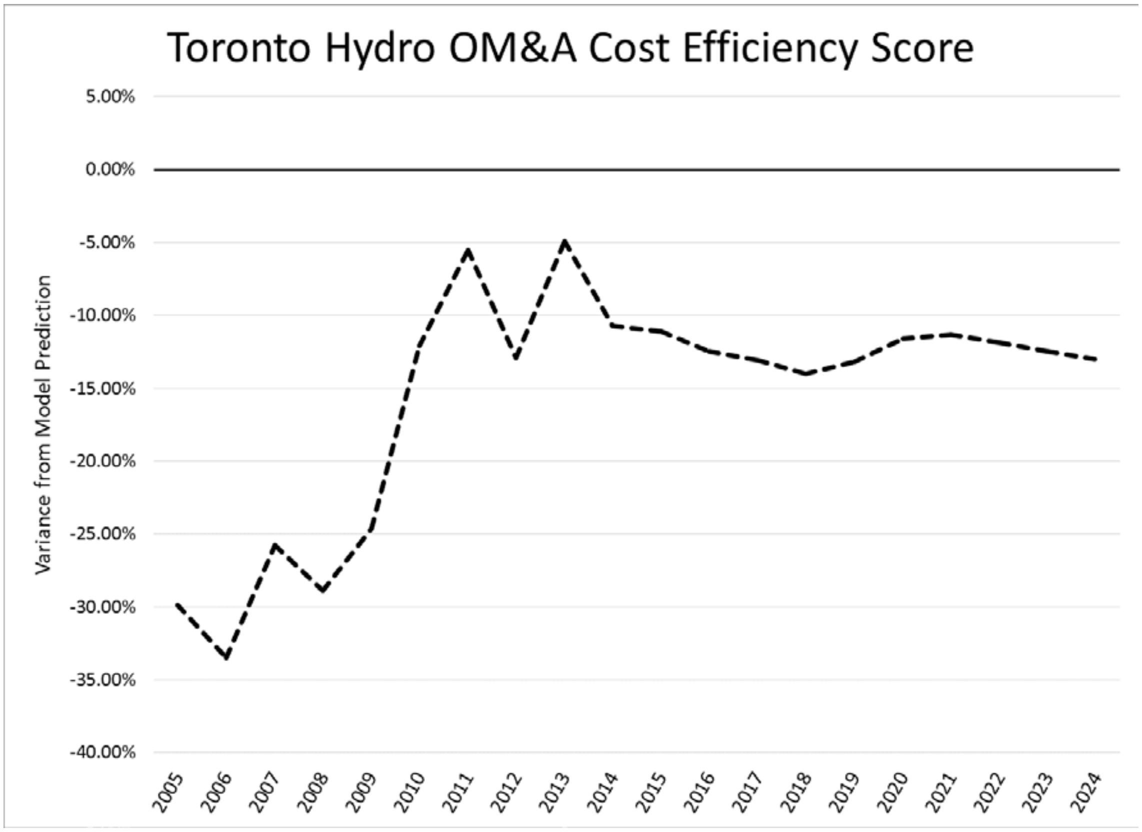

Toronto Hydro OM&A Cost Efficiency Score
Variance from Model Prediction
5.00%
0.00%
-5.00%
-10.00%
-15.00%
-20.00%
-25.00%
-30.00%
-35.00%
-40.00%
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

Table 12

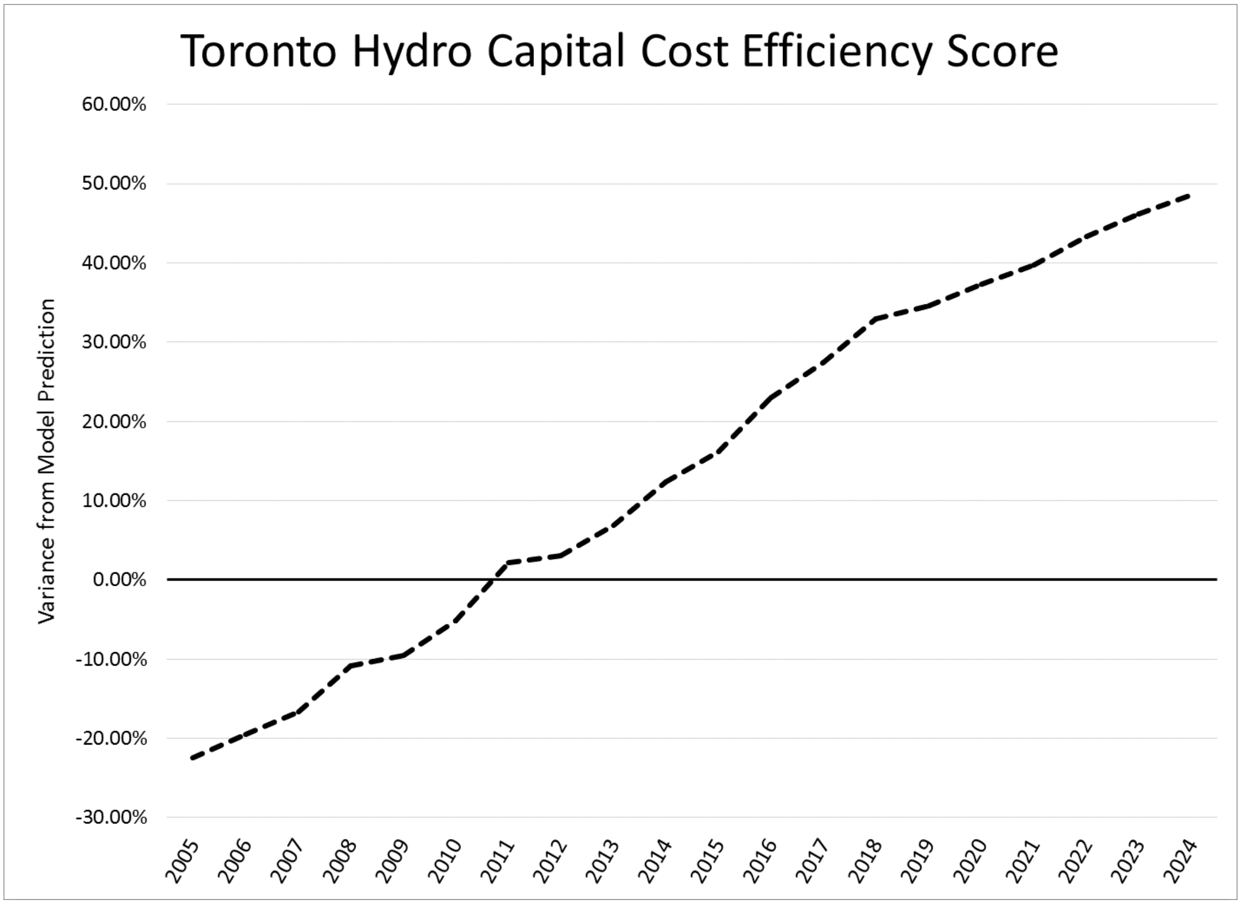
Year by Year Capital Cost Benchmarking Results

Year	**Percent Difference**[1]
2005	-22.5%
2006	-19.5%
2007	-16.6%
2008	-10.9%
2009	-9.5%
2010	-5.2%
2011	2.2%
2012	3.0%
2013	6.9%
2014	12.4%
2015	16.2%
2016	23.0%
2017	27.5%
2018	*32.9%*
2019	*34.6%*
2020	*37.3%*
2021	*39.7%*
2022	*43.3%*
2023	*46.2%*
2024	*48.6%*
Annual Averages	
2005-2017	**0.5%**
2015-2017	**22.2%**
2020-2024	**43.0%**

[1] Formula for benchmark comparison is $\ln(Cost^{THESL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 5


Toronto Hydro Capital Cost Efficiency Score
Variance from Model Prediction
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
-10.00%
-20.00%
-30.00%
2005
2006
2007
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2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

Table 13

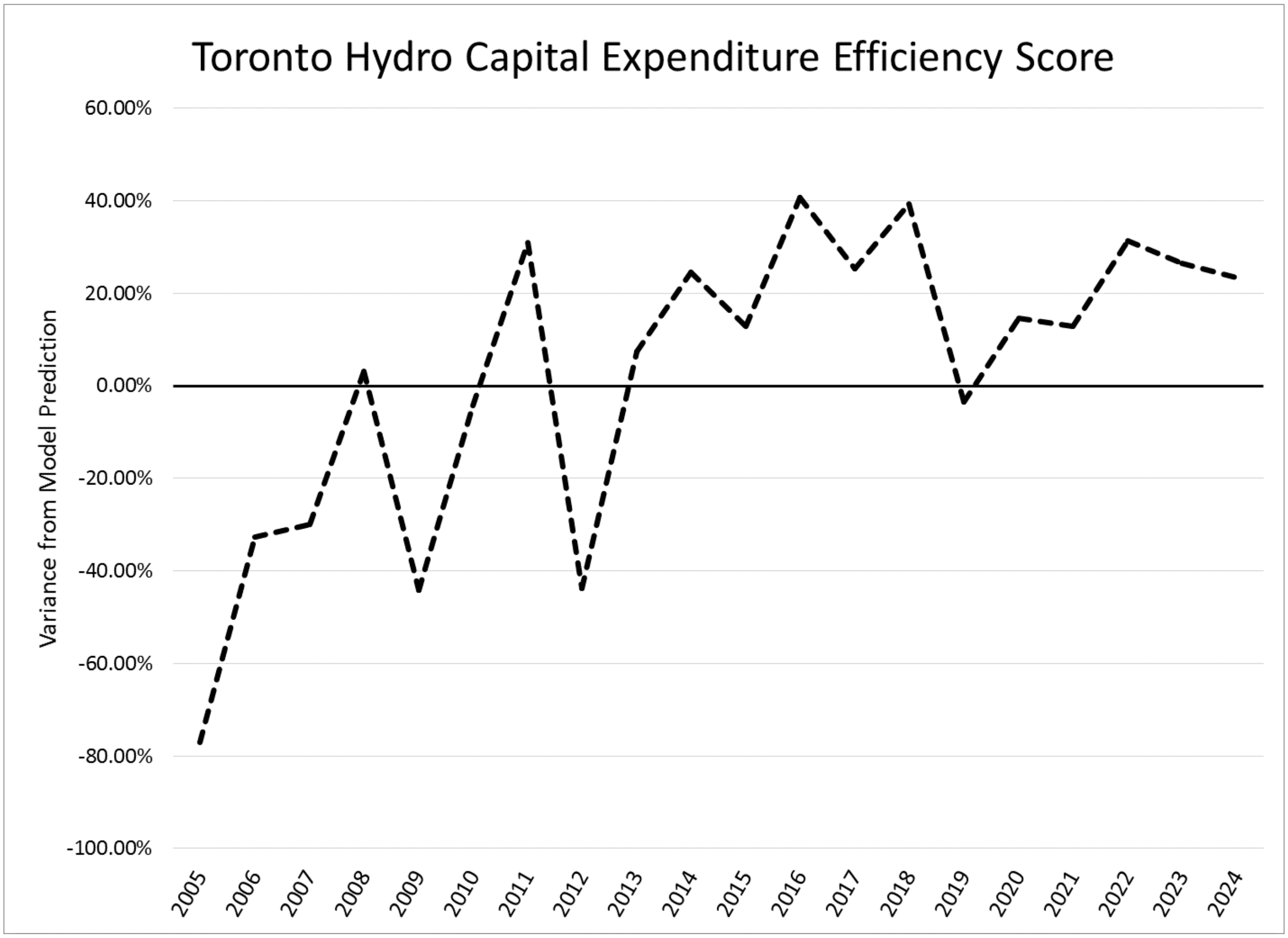
Year by Year Capex Benchmarking Results

Year	Percent Difference[1]
2005	-77.1%
2006	-32.6%
2007	-29.9%
2008	3.2%
2009	-44.2%
2010	-4.2%
2011	31.0%
2012	-43.7%
2013	7.4%
2014	24.5%
2015	12.8%
2016	40.6%
2017	25.2%
2018	*39.4%*
2019	*-3.5%*
2020	*14.5%*
2021	*12.9%*
2022	*31.4%*
2023	*26.5%*
2024	*23.4%*
Annual Averages	
2005-2017	**-6.7%**
2015-2017	**26.2%**
2020-2024	**21.7%**

[1] Formula for benchmark comparison is $\ln(Cost^{THESL}/Cost^{Bench})$.

Note: Italicized numbers are projections/proposals.

Figure 6



4.6. Conclusions

On the basis of our research, we believe that a 0.45% stretch factor is indicated for Toronto Hydro provided that the Board is comfortable fixing the stretch factor for the full plan term. A 0% base productivity trend is reasonable given the evidence in the panel's possession but does not include an implicit stretch factor. A 0% base X factor and a 0.45% stretch factor would yield an X factor of 0.45%. The PCI formula would then be growth Inflation - 0.45% net of Y, Z, or growth factors as discussed below.

5. Other Plan Design Issues

The other provisions of the IRM proposed by Toronto Hydro are in some respects uncontroversial. We have noted that the plan is similar to Custom IR plans the Board has previously approved for the Company and other distributors. Some provisions are also consistent with other Board decisions. We are nonetheless concerned about some features of the Company's proposal.

The proposed ratemaking treatment of capital is our chief concern. The C factor would ensure that the Company recovers its projected/proposed capital cost less a perfunctory stretch factor markdown. Any cumulative capex underspend would be returned to the ratepayer. Externally-driven capex such as that due to highway construction would be addressed by a variance account. Hence, capital revenue would chiefly be established on a cost of service basis.

Despite the proposed clawback of capex underspends, Toronto Hydro would still have some incentive to exaggerate capex needs since exaggerations strengthen the case for a C Factor and reduce the pressure on the Company to contain capex. Exaggeration of capex needs may reduce the credibility of Toronto Hydro's forecasts in future proceedings. However, the Company can always claim that it "discovered" ways to economize. British distributors operating under several generations of IR with revenue requirements based on cost forecasts have repeatedly spent less on capex than they forecasted. Toronto Hydro would also be incentivized to "bunch" its deferrable capex in ways that increase supplemental revenue. If, for example, the Company somehow managed to change the timing of its capex so that the $I – X + g$ escalation was compensatory it would obtain no supplemental revenue.

The full clawback of capex underspends and the variance account treatment of externally driven capex would greatly reduce the Company's incentive to contain capex. Incentives to contain capex and OM&A expenses would be imbalanced, creating a perverse incentive to incur excessive capex in order to reduce OM&A costs.

Another problem with the proposal is that while customers must fully compensate Toronto Hydro for expected capital revenue *shortfalls* when capex is high, for reasons beyond its control the Company need not reduce its capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control. Slow capital cost growth in the future may very well occur, and not just because of good capital cost management. For example, depreciation of recent and prospective surge capex will tend to slow capital cost growth in the future. Customers therefore would never receive the full benefit of the industry's multifactor productivity trend, even in the long run and even when it is achievable.

A related problem is that most of the capex addressed by the C factor and the externally-driven capex variance account would be conventional distributor capex that is similar in kind to that incurred by distributors in past and future productivity research samples are used to calibrate X factors.[43] Utilities can then be compensated twice for the same capex: once via the C factor and then again by low X factors in past, present, and future IRMs.

Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, Toronto Hydro's weak incentive to contain capex, and the Company's incentive to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Company's capex proposal.[44] This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals greatly complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews distribution system plans --- a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB staff and stakeholders are often hard-pressed to effectively challenge distributor capex proposals. In essence, the OEB's Custom IR rules have sanctioned British (forecast-based) approaches to determining multiyear capital revenue requirements without making the same investment that the British and Australian regulators have made in the capability for appraising and ruling on capex proposals.[45]

The substantial compensation for full funding of capital revenue shortfalls that has been permitted by the OEB under Custom IR may be more remunerative than that available under the incremental capital modules ("ICMs") in 4th GIRM. ICMs, after all, feature a materiality threshold including a 10% deadband before funding projected capital revenue shortfalls. These thresholds are rationalized on the grounds of reducing regulatory cost. This encourages distributors to choose Custom IR instead of the 4th GIRM. Some distributors may have chosen Custom IR, with its weaker performance

[43] Toronto Hydro would not, however, be compensated during the plan for unexpected capex overruns.

[44] Proposed programs that raise capex and reduce OM&A expenses merit close examination. An example is the proposition to reduce backyard overheard facilities.

[45] Ofgem's own view of a power distributor's required cost growth is assigned a 75% weight in IRM proceedings. This view is supported by independent engineering and benchmarking research.

incentives and higher regulatory cost, even though efficient and compensatory operation under 4th GIRM was feasible.

In pondering this quandary, the following remarks of the OEB in its decision approving Toronto Hydro's last Custom IR plan resonate.

> The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application.[46]

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient distributors.

The Alberta Utilities Commission ("AUC") faced a similar challenge following an unhappy experience with capital cost trackers in their first-generation IRMs for provincial gas and electricity distributors. A number of possible reforms to the ratemaking treatment of capital were discussed in the AUC's generic proceeding on second generation IRMs. Based on the record, the AUC eventually chose a means for providing supplemental capital revenue which was much less dependent on distributor capex forecasts.[47] Regulatory cost was reduced thereby, and capex containment incentives were strengthened.

Informed by our research and testimony for a party to that proceeding, as well as by our familiarity with Custom IR, we believe that the following alternatives to Toronto Hydro's proposed ratemaking treatment of capital merit consideration.

- An obvious candidate for a different approach is that chosen by the OEB in the recent Hydro One Dx decision.[48] A special stretch factor would apply only to the calculation of the C factor. A variant on this theme is to calculate the C factor using the (typically slower) productivity growth trend of capital, while the X factor for OM&A revenue could reflect the

[46] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

[47] PEG is not recommending this ratemaking treatment for Toronto Hydro.

[48] OEB, *Decision and Order*, EB-2017-0049, March 7, 2019.

(typically faster) productivity trend of OM&A. This would reduce the need for C factors and make escalation of OM&A revenue more reflective of industry OM&A cost trends. Unfortunately, there is no conclusive research available to the panel in this proceeding on OM&A and capital productivity trends of power distributors.

- The C factor could alternatively, like ICMs, be subject to materiality thresholds and dead zones. For example, a company would not be eligible for a C factor unless its capital cost growth exceeded growth in capital revenue by a certain percent. A percentage of the underfunding would not be eligible for supplemental funding. Dead zones could also be added to the materiality thresholds for externally-driven capex.
- The X factor could be raised, in this and the Company's future IRMs, to reduce expected double dipping and give customers a better chance of receiving the benefits of industry productivity growth in the long run. This would be tantamount to having the Company borrow revenue escalation privileges from future plans. Knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Toronto Hydro's capex containment incentives.
- Capital costs that occasion supplemental revenue could be subject to continued tracking in later plans. Customers would then receive the benefit of depreciation of the surge capex between plans. Once again, knowledge that there is a price to be paid in the long run for asking for extra revenue now would strengthen Toronto Hydro's capex containment incentives. The IRMs for the Fortis companies in British Columbia track the cost of all older capital.
- Eligibility of capex for supplemental C factor revenue could be scaled back. For example, capex in the last year of the plan term could be declared ineligible for supplemental revenue because this involves only one year of underfunding.
- The proposed capex budget could be reduced by a material amount, as in the OEB's decisions in the last Toronto Hydro proceeding and the Hydro One distribution IRM proceeding.

- Toronto Hydro could be permitted to keep a share of the value of capex underspends. This would strengthen the Company's incentive to contain capex but also its incentive to exaggerate its capex needs.

If the OEB is prepared to deviate from Toronto Hydro's proposed C factor treatment, we note that the establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans has many advantages. This could be done in such a manner that the *first* A% of unfunded capital cost (after the X factor markdown) is ineligible for C factoring. However, the materiality threshold and dead zones need not be modelled on those in the ICMs used in 4th GIRM. For example, if proposed capital cost exceeded the materiality threshold, a possibly lower set percentage of *all* unfunded capital cost could be declared ineligible for C factoring. This would strengthen the Company's incentive to contain capital cost *at the margin*. The kind of adjustment to the C factor formula that the Board approved in the Hydro One distribution IRM proceeding has less incentive impact.

Appendix

A.1 Measuring Capital Cost

Monetary Approaches to Capital Cost Measurement

Monetary approaches to the measurement of capital costs and prices have been widely used in statistical cost research. The main components of capital cost are depreciation expenses, the return on investment, and certain taxes. These approaches decompose the growth in capital cost into the growth in consistent capital price and quantity indexes such that

$$Cost^{Capital} = Price^{Capital} \cdot Quantity^{Capital}. \qquad [A1]$$

Capital prices are calculated using data on construction costs and the rate of return on capital. The capital price index is sometimes called the “rental” or “service” price index because, in a competitive market, the trend in the price of rentals would tend to reflect the trend in the cost per unit of capital.

Several monetary methods are well established for measuring capital quantity trends. A key issue in the choice of a monetary method is whether plant is valued in historic or replacement dollars. Another issue is the pattern of decay in the quantity of capital resulting from plant additions. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and obsolescence.

Three monetary methods have been used in statistical research on utility costs.

- The geometric decay (“GD”) method assumes a replacement (i.e., *current* dollar) valuation of plant and a constant rate of decay. Replacement valuation differs from the historical (aka “book”) valuation used in North American utility accounting and requires consideration of capital gains. The GD specification involves formulae for capital price and quantity indexes that are mathematically simple and easy to code and review.

Academic research has supported use of the GD method to characterize depreciation in many industries. [49] GD has also been widely used in productivity studies, including X factor calibration studies. The U.S. Bureau of Economic Analysis ("BEA") and Statistics Canada both use geometric decay as the default approach to the measurement of capital stocks in the national income and product accounts.[50] PEG has used the GD method in most of its productivity research for the Board, including the research for 4th Generation IRM.

- The one hoss shay method assumes that the quantity of capital from plant additions in a given year does not decay gradually but, rather, all at once as the assets reach the end of their service lives. Plant is once again valued at replacement cost. The one hoss shay method has been used occasionally in research intended to calibrate utility X factors.
- The cost of service ("COS") method is designed to approximate the way that capital cost is calculated in utility regulation. This approach is based on the assumptions of straight-line depreciation and historic valuation of plant. The capital price and quantity formulas are complicated, making them more difficult to code and review. PEG has used this approach in several X factor calibration studies, including two for the OEB.[51]

Benchmark Year Adjustments

Utilities have diverse methods for calculating depreciation expenses that they report to regulators. It is therefore desirable when calculating capital quantities using a monetary method to rely on the reporting companies chiefly for the value of *gross* plant additions and then use a standardized

[49] See, for example, C, Hulten, and F. Wykoff (1981), "The Measurement of Economic Depreciation," in *Depreciation, Inflation, and the Taxation of Income From Capital*, C. Hulten ed., Washington D.C. Urban Institute and C. Hulton, "Getting Depreciation (Almost) Right", University of Maryland working paper, 2008.

[50] The BEA states on p. 2 its November 2018 "Updated Summary of NIPA Methodologies" that "The perpetual-inventory method is used to derive estimates of fixed capital stock, which are used to estimate consumption of fixed capital—the economic depreciation of private and government fixed capital. This method is based on investment flows and a geometric depreciation formula."

[51] See Lowry, et. al., *Rate Adjustment Indexes for Ontario's Natural Gas Utilities, op. cit.;* Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., and Moren, A., *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, in EB-2007-0673, (2008); and Lowry, M., Hovde, D., and Rebane, K., *X Factor Research for Fortis PBR Plans,* in BCUC Project 3698719, for Commercial Energy Consumers of British Columbia (2013).

depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. It is then customary to consider the value of all plant at the end of the limited-data period and to estimate the quantity of capital it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the "benchmark year" of the capital quantity index. Since the estimate of the capital cost in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

Capital Cost and Quantity Specification

A monetary approach was used in this study to calculate the capital cost of each utility. Geometric decay was assumed.

Data available and previously processed by PEG permitted us to use 1964 as the benchmark year for the U.S. capital cost and quantity calculations. The benchmark year was 1989 for Toronto Hydro. The value of the capital quantity index for each utility in the benchmark year depends on the net value of its plant. We estimated the benchmark year quantity of capital by dividing this book value by a triangularized weighted average of 40 values of an index of power distribution construction cost for a period ending in the benchmark year. The construction cost index ("WKA_t") for each U.S. utilities was the applicable regional Handy-Whitman indexes of cost trends of electric utility distribution construction.[52] A triangularized weighted average places a greater weight on more recent values of the construction cost index. This makes sense intuitively since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value.

The following GD formula was used to compute values of each capital quantity index in subsequent years.

$$XK_t=(1\text{-}d)\cdot XK_{t\text{-}1}+\frac{VI_t}{WKA_t}. \qquad [A2]$$

[52] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_t=d\cdot WKA_t+WKA_{t-1}\left[r_t-\frac{(WKA_t-WKA_{t-1})}{WKA_{t-1}}\right]. \quad [A3]$$

The first term in the expression corresponds to taxes and franchise fees. The second term corresponds to the cost of depreciation. The third term corresponds to the real rate of return on capital. This term was smoothed to reduce capital cost volatility.

A.2 Econometric Research

This section provides additional and more technical details of our econometric research. We begin by discussing the choice of a form for the econometric benchmarking models. There follow discussions of econometric methods.

Form of the Econometric Cost Model

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

$$C_{h,t}=a_0+a_1\cdot N_{h,t}+a_2\cdot V_{h,t}. \quad [A4]$$

Here is an analogous cost model of *double log* form:

$$\ln C_{h,t}=a_0+a_1\cdot\ln N_{h,t}+a_2\cdot\ln V_{h,t}. \quad [A5]$$

The double log model is so-called because the right- and left-hand side variables are all logged. This specification makes the parameter corresponding to each business condition variable the elasticity of cost with respect to the variable. For example, parameter a_1 indicates the percentage change in cost resulting from 1% growth in the number of customers. Elasticity estimates are useful and make it easier to assess the reasonableness of model results. It is also noteworthy that, in a double log model, elasticities are *constant* in the sense that they are the same for every value that the cost and business condition variables might assume. This model specification is restrictive and may be inconsistent with the true form of the cost relationship we are trying to model.

Here is an analogous model of *translog* form:

$$\ln C_{h,t} = a_o + a_1 \cdot \ln N_{h,t} + a_2 \cdot \ln V_{h,t} + a_3 \cdot \ln N_{h,t} \cdot \ln N_{h,t} + a_4 \cdot \ln V_{h,t} \cdot \ln V_{h,t} + a_5 \cdot \ln V_{h,t} \cdot \ln N_{h,t} \qquad \text{[A6]}$$

This form differs from the double log form in the addition of quadratic and interaction terms. Quadratic terms like $ln N_{h,t} \cdot ln N_{h,t}$ permit the elasticity of cost with respect to each business condition variable to vary with the value of the variable. The elasticity of cost with respect to a scale variable may, for example, be lower for a small utility than for a large utility. Interaction terms like $ln V_{h,t} \cdot ln N_{h,t}$ permit the elasticity of cost with respect to one business condition variable to depend on the value of another such variable. For example, the elasticity of cost with respect to growth in peak load may depend on the length of a transmitter's transmission lines.

The translog form is an example of a "flexible" functional form. Flexible forms can accommodate a greater variety of possible functional relationships between cost and the business condition variables. A disadvantage of the translog form is that it involves many more variables than simpler forms like the double log. As the number of variables accorded translog treatment increases, the precision of a model's parameter estimates and cost predictions falls. It is therefore common in econometric cost research to limit the number of variables accorded translog treatment.

In our econometric work for this proceeding, we have chosen a functional form that is logarithmic only with respect to the two scale variables. This preserves degrees of freedom but permits the model to recognize some nonlinearities. All of the quadratic terms in our model had statistically significant parameter estimates.

Econometric Model Estimation

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

Note, finally, that the model specification was determined using data for all sampled companies. However, estimation of parameters and appropriate standard errors for the cost model actually used for benchmarking required that the utility of interest be dropped from the sample. The parameter estimates used in developing the cost model and reported in the various econometric cost model tables above therefore vary slightly from those in the models used for benchmarking.

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