TORONTO HYDRO ELECTRIC SYSTEM LIMITED CUSTOM IR APPLICATION AND PSE REPORT

ECONOMETRIC BENCHMARKING OF TORONTO HYDRO'S HISTORICAL AND PROJECTED TOTAL COST AND RELIABILITY LEVELS

ASSESSMENT AND RECOMMENDATIONS

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Pacific Economics Group Research, LLC

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1 Introduction and Executive Summary

Pacific Economics Group Research LLC (PEG) and Dr. Lawrence Kaufmann advised Board Staff on the Custom Incentive Rate-Setting ("Custom IR") application submitted by Toronto Hydro-Electric System Limited ("THESL," "Toronto Hydro" or "the Company") in July 2014. PEG was retained to review the overall Custom IR application, to assess the design of the Custom IR plan, and to analyze the Company's proposed stretch factor and custom capital factor. PEG was also asked to evaluate the technical work of Power Systems Engineering ("PSE"), which undertook benchmarking analyses of THESL's past and projected cost and service reliability performance. Where relevant, PEG was also asked to provide alternate cost and reliability benchmarking evidence.

This report presents: 1) the findings of PEG's review of the PSE work; 2) a brief analysis of the Company's proposed stretch factor and custom capital factor; and 3) PEG's ratemaking recommendations for THESL in light of these conclusions. PEG reviewed the prefiled evidence, updated evidence, and responses to interrogatories and technical conference questions before finalizing this report.

Overview

PEG's review indicates that PSE's conclusions regarding Toronto Hydro's cost and reliability performance are largely, but not entirely, unfounded. Based on an econometric analysis of THESL and 85 US utilities, PSE's analysis indicated that THESL's 2010-2012 costs were 31.1% below the costs expected for an average electric utility operating under the Company's business conditions. PEG's review identified a number of areas in which the costs of THESL and the US were not comparably defined or measured. After correcting and/or controlling for these differences, and eliminating an unwarranted "urban core dummy" variable from PSE's econometric cost model, PEG found THESL's costs were 9.7% *above* its expected costs. The Company's total costs are projected to be 34.7% above its expected costs in 2019, the final year of its Custom IR plan.

PEG's review partly confirmed PSE's reliability benchmarking conclusions. Based on an econometric analysis of THESL and 46 US utilities, PSE found the Company's SAIFI performance was 73% above its expected value but found THESL's SAIDI was 50% below its expected SAIDI. PEG believes the data PSE used for its reliability benchmarking are not suitable for regulatory application, so we compiled an alternative SAIFI and SAIDI dataset and used it to estimate alternate SAIFI and SAIDI benchmarking models. Using these data and models, PEG confirms PSE's finding that THESL's SAIFI is far above its expected level, but we find the Company's SAIDI is not statistically different from its expected level.

Overall, PEG finds THESL has been a sub-par performer with respect to cost and reliability. Given these findings, the proposed stretch factor of 0.3% in the Company's Custom IR plan is not warranted. PEG believes a stretch factor between 0.6% and 1% is appropriate and consistent with Toronto Hydro's historical and projected cost performance. We recommend that a stretch factor within this range be applied to the Company's capital and OM&A costs. In addition, the Company's proposed C factor should include an adjustment for the growth in THESL billing determinants to prevent the C factor from over-recovering capital cost. PEG's recommended C factor adjustment will eliminate over-recovery of capital costs and reduce THESL's price growth by an estimated 1.5% per annum in 2016 through 2019.

PEG also believes there may be value to ratepayers in extending the period of THESL's capital spending program. Doing so is consistent with the RRFE principles of pacing and prioritization of capital spending, while at the same time managing the pace of rate increases for customers. PEG therefore recommends that the capital expenditures in THESL's Custom IR plan be spread out over eight years (2015-2022) rather than concentrated in five years (2015-2019).

Below we present a chronological, chapter-by-chapter summary of PEG's main findings.

Interpretation and Regulatory Application of PSE Benchmarking

PEG believes PSE's interpretation of its technical benchmarking analysis is problematic. PSE's interpretations of its benchmarking results are sometimes not consistent with the actual statistical hypotheses they are testing. The cost benchmarking models PSE applies are specifically designed to assess the efficiency of cost performance. This is also how the Board currently applies statistical benchmarking in Ontario regulation. Using these models to benchmark the "reasonableness" of THESL's cost forecasts is tantamount to benchmarking THESL's cost efficiency during the period being forecast. However, PSE does not accept this interpretation, but at times attempts to use its benchmarking models to draw unwarranted conclusions about the impact of THESL's cost management on its SAIFI performance. There is no logical or empirical basis for these conclusions in PSE's benchmarking work.

PEG also has concerns with the regulatory application of PSE's benchmarking results. PSE has employed inconsistent and contradictory standards for evaluating THESL's performance. This creates ambiguity that would be avoided if the analysis focused on the hypotheses the benchmarking models are designed to test. PEG also believes that PSE's view on aligning utilities with external, average performance standards represents a misapplication of benchmarking and is likely to be incompatible with the Board's objectives for incentive regulation.

PSE's Cost Benchmarking

PEG reviewed PSE's cost benchmarking work in three steps. The first step addressed PSE's measure of costs for THESL. The starting point for PEG's cost benchmarking work in 4^{th}GenIR study was the benchmark cost measure we developed for THESL and other Ontario utilities. However, PSE selected and used the more limited, TFP-based cost measure for THESL as the basis for its analysis. When the appropriate, benchmark-based costs for the Company are used in PSE's analysis, the difference between THESL's actual 2010-2012 costs and its predicted costs changes from the -31.1% reported by PSE to -21.3%.

THESL's costs were also not comparable to the costs of US utilities in several respects. PEG standardized the treatment of the costs of uncollectible accounts, DSM expenses, and contributions in aid of construction (CIAC) across THESL and the US sample. PEG also eliminated several US companies from PSE's US sample because of mergers during the sample period. When these changes are made, the difference between THESL's actual 2010-2012 cost and its predicted cost changes from -21.3% to -6.3%.

The third stage of PEG's review examined PSE's business condition variables. PEG made two necessary changes to PSE's selected business conditions. The first was adding a variable to reflect MVa of transformer capacity for stations with primary voltage levels at or above 50 kV. This variable is necessary to control for US utilities' costs of owning high voltage assets. The second was eliminating the urban core dummy variable from PSE's model because it is redundant, inappropriate in electricity distribution benchmarking, and appears to distort the estimated impact of other business condition variables (especially undergrounding). When these changes are made, the difference between THESL's actual and predicted costs changes from -6.3% to +9.7%. Over the term of the Company's Custom IR plan, the difference between THESL's projected and predicted costs rises further to 34.7% by 2019. The differences between the Company's projected and predicted costs are statistically significant.

PEG's review therefore finds that THESL is projected to be an inefficient cost performer when it is compared to US electric utilities. This differs from PSE's conclusion. However, making necessary changes to THESL cost data, modifying the data and business conditions to make THESL and US cost data more comparable, and eliminating an inappropriate urban core dummy variable changes the difference between the Company's actual and predicted costs from PSE's reported -31.1% to +9.7%. Most of this difference can be attributed to problems with the THESL and US utility data used by PSE. PEG's finding that THESL's projected costs exceed its expected, benchmark costs is consistent with PEG's benchmarking conclusion from Ontario, where THESL was an inferior cost performer compared with Ontario electricity distributors.

PSE's Reliability Benchmarking

PEG carefully reviewed the data that PSE assembled and used to estimate its reliability benchmarking models. We found that PSE could not identify the source of 22.1% of its SAIFI or SAIDI observations. PEG also found that 15.2% of PSE's SAIFI data and 17.6% of its SAIDI data were inaccurate.

PEG believes these are serious errors and omissions. Reliability benchmarking is still new in Ontario. The Board must have confidence in the data that are used to estimate reliability benchmarking models. This is particularly true since SAIFI and SAIDI data will differ among sampled companies for a variety of reasons. Because of its failure to document sources and data processing errors, PEG does not believe PSE's US dataset is suitable for regulatory application, and we recommend that the Board give no weight to PSE's reliability benchmarking.

PEG compiled its own reliability data and used these data to estimate SAIFI and SAIDI econometric models. Our sample period excluded the 2012 year because of the distorting impact of Hurricane Sandy. We found that measured SAIFI and SAIDI are both negatively related to the share of a utility's capital that is underground and are positively related to lighting strikes, variance in elevation, CDD and the amount of precipitation. SAIDI is also positively related to HDD and has a positive, statistically significant time trend.

PEG used these econometric models to benchmark THESL's SAIFI and SAIDI performance. In 2009-2011, we found THESL's SAIFI exceeded its benchmark value by 78.7%, and the difference was statistically significant. For SAIDI, we found THESL's SAIDI was below its benchmark by 20.6%, but the difference was not statistically significant.

Although PEG recommends that no weight be placed on PSE's reliability benchmarking, it is interesting to note that PEG and PSE both find THESL's SAIFI performance is far below what is expected. However, our findings differ somewhat with respect to SAIDI. PSE estimates that THESL's SAIDI is well below expected levels. PEG finds THESL's SAIDI is not statistically different from expected levels.

Simultaneous Cost and Reliability Benchmarking

Statistical analysis can be used to explore the relationship between electricity distributors' cost and reliability, instead of treating each as a stand-alone benchmarking exercise. Statistical tools can also quantify how this relationship is impacted by differences in business condition variables such as scale of outputs, customer density, and asset undergrounding. These are inherently empirical issues and therefore potentially amenable to statistical quantification and testing. While benchmarking cost and reliability simultaneously does pose a number of challenges, the simultaneous benchmarking of cost and reliability is in essence similar to the cost benchmarking analyses that the Board employed in 4thGenIR. Statistical methods and data sources are available to address the challenges involved with simultaneous cost and reliability benchmarking.

In fact, PSE has presented other evidence in this proceeding that addresses the cost-reliability relationship more directly. PSE has developed what it calls a "SAIDI impact benchmark model." This model was designed to address and evaluate the cost-effectiveness of reliability projects by examining the impact of utilities' capital spending on SAIDI, after controlling for the effects of other factors that influence SAIDI.

If the key result from the SAIDI impact benchmark model is applied to THESL, it shows that THESL's increase in capital spending is expected to lead to declines in SAIDI from 71.4 minutes in 2014 to 68.8 minutes in 2015, 66.4 minutes in 2016, 64 minutes in 2017, 61.7 minutes in 2018, and 59.5 minutes in 2019. In contrast, THESL projects smaller declines in SAIDI in each of these years. THESL's capital spending is therefore projected to lead to less SAIDI improvement than what PSE's SAIDI impact benchmark model predicts for an average utility investing the same amount as THESL.

PEG does not endorse the SAIDI impact benchmark model, but it is interesting because it shows statistical methods can be used to understand the interaction between distributors' cost and reliability performance. It is feasible to develop models that simultaneously benchmark cost and service reliability, and there may be merit in further research on this topic if the interaction between cost and reliability performance is expected to remain an important regulatory issue in Ontario.

THESL's Proposed Stretch Factor and C Factor

THESL and PSE both recommend a 0.3% stretch factor as part of the Price Cap Index in the Custom IR rate adjustment formula. This represents a reduction from the 0.6% stretch factor THESL would be assigned if it elected the Price Cap IR option. PSE explicitly bases this recommendation on the findings of its econometric research, since the difference between the Company's projected and expected costs under the Custom IR plan is within the +/- 10% band the Board established for the cohort of distributors that were assigned a 0.3% stretch factor.

PEG's review finds that PSE's recommendation is unwarranted. Our appraisal indicates that, in a US-only benchmarking study, THESL's costs are projected to be 34.7% above its expected costs under the Custom IR plan. A 34.7% difference between projected and benchmark costs would put THESL in the cohort of distributors assigned a 0.6% stretch factor in Price Cap IR. It is noteworthy that this finding supports PEG's conclusion regarding THESL's cost performance in our Ontario cost benchmarking study.

It should also be noted that the Company exhibits generally poor reliability performance. PSE and PEG agree that THESL's SAIFI is far greater than what is expected for a utility operating under its business conditions. PEG's analysis also indicates that THESL is an average SAIDI performer. Since THESL displays poor cost performance and average to poor reliability performance, PEG believes a stretch factor in excess of 0.6% may even be appropriate for THESL. There are precedents for stretch factors of 1% in North American incentive regulation. PEG therefore recommends that the stretch factor in THESL's Custom IR price cap index be no lower than 0.6% and no higher than 1%.

The C factor in THESL's Custom IR plan is designed to recover capital-related costs that exceed the funding for capital expenditures implicitly provided by the plan's "I – X" rate adjustment mechanism. THESL's C factor employs a sound method for ensuring that the C factor reflects only incremental capital spending, but the proposed C factor does not appropriately translate those cost changes into price changes. THESL's C factor will lead to revenue adjustments that exceed the change in capital costs because it does not account for the revenue growth resulting from changes in billing determinants. To ensure that the C factor recovers only the change in incremental capital spending, it should be modified to reduce the change in prices by the annual change in a revenue-share weighed average of THESL's billing determinants. This adjustment can be easily calculated and implemented using THESL billing data.

Concluding Remarks and Ratemaking Recommendations

Overall, PEG finds THESL has been a sub-par performer with respect to cost and reliability. Given these findings, and a broader review of the Company's Custom IR application and the record in this proceeding, PEG recommends the following changes to Toronto Hydro's Custom IR proposal:

1. Adopt a stretch factor of between 0.6% and 1% rather than THESL and PSE's recommended 0.3%
2. Apply the stretch factor to both OM&A and capital costs under the Custom IR plan
3. Apply an adjustment to the C_n factor in each year to net off the annual growth in billing determinants

4. Spread the Company's proposed capital expenditures over the eight year, 2015-2022 period rather than the proposed five year, 2015-2019 period

PEG's estimates that its recommendations will reduce growth in THESL prices over the 2016-2019 period from the Company's estimated 6.26% per annum to 2.07% per annum. About 40% of the reduction in THESL's price escalation can be attributed to the addition of the billing determinant adjustment. Just over 10% of the reduction in THESL's price escalation results from the increased stretch factor and the application of this stretch factor to capital as well as non-capital costs. The remainder is due to spreading the Company's capital expenditures over an eight-year period rather than a five-year period.

This report is structured as follows. After this introduction, Chapter Two discusses the interpretation and application of PSE's benchmarking results. Chapter Three presents our analysis of PSE's cost benchmarking work. Chapter Four discusses PSE's reliability benchmarking work and presents alternate results. Chapter Five considers the simultaneous benchmarking of cost and reliability. Chapter Six assesses THESL's proposed stretch factor and custom capital factor. Chapter Seven presents concluding remarks and recommendations.

There are also two appendices. Appendix One summarizes the data sources used in PEG reliability datasets. Appendix Two presents some technical details of PEG's econometric modeling.

2 Interpretation and Application of Benchmarking Results

Before addressing the technical details of PSE's benchmarking analysis, this chapter will consider how PSE has interpreted and applied its benchmarking results in THESL's Custom IR application. After briefly summarizing PSE's work, we assess how PSE has interpreted its findings. We then consider the application of PSE's results in light of the Board's objectives for incentive regulation.

2.1 Summary of PSE Benchmarking Results

PSE benchmarked Toronto Hydro's cost and reliability performance on a historical and forward-looking basis. For the cost benchmarking, PSE compared THESL's actual and forecast total costs to econometric projections of the Company's costs over the same periods. Similarly, PSE's reliability benchmarking compared THESL's actual and forecast values for SAIFI and SAIDI to econometric projections of those values.

PSE estimated its econometric models using samples from two broad jurisdictions. One was a "combined sample" of Ontario electricity distributors (including THESL) and US electric utilities. The second was a "US-Only" sample of US electric distributors plus THESL.[1] PSE expanded the sample beyond the Ontario database PEG used to benchmark costs in Fourth Generation Incentive Rate-setting ("4th Gen IR") because it claimed Toronto Hydro is an "extreme outlier" in the Province in size and because it serves Toronto's "urban core"/central business district.

PSE developed estimates of the "drivers" of cost performance, SAIFI performance, and SAIDI performance for the sampled utilities. Separate estimates of these cost and reliability drivers were developed using the combined sample and US-Only sample. Since PSE estimated three different econometric models using two different samples, the PSE report presents estimates for six different benchmarking models. The sample period in each model was 2002-2012.

[1] There were 85 US utilities and 71 Ontario utilities in the combined sample for the cost model, and 46 US utilities and 70 Ontario utilities in the combined sample for the SAIFI and SAIDI models. The US-Only samples therefore had 85 US utilities plus THESL for the cost model and 46 US utilities plus THESL for the SAIFI and SAIDI models. The number of US utilties differed across the cost and reliability models because fewer US utilities had available data on SAIFI and SAIDI.

For the combined sample, PSE finds that Toronto Hydro's historical costs are below those predicted by the econometric model.[2] PSE writes that "…prior to 2007 the company was consistently near 30% below benchmark expectations. This is suggestive that the company's capital was in need of investment."[3] In 2010-2012, PSE estimates that THESL's actual costs were 21.5% below the costs predicted by the econometric model, and the difference was statistically significant at the 10% level.

For the 2014 to 2019 period, PSE finds "the projected total cost levels during the Custom IR period remain below the benchmark predictions, although they do converge towards benchmark expectations, and the 'statistically below expectations' conclusion is no longer statistically significant at a 90% confidence level."[4] The fact that THESL's measured cost performance under the Custom IR plan is no longer significantly below expected cost is an indicator that its cost performance, as measured by PSE's "performance" definition and equation presented on p. 23 of its report, is deteriorating under the plan. PSE concludes that "nevertheless, they (the benchmarking models) indicate that the company's proposed spending levels are reasonable and well within the normal range of model expectations."[5]

For the reliability benchmarking, PSE finds that THESL's SAIFI values in 2010-2012 were 73% above those predicted by the econometric model. This indicates that the average THESL customer is experiencing about 73% more outages than would be expected for an average utility operating under the Company's business conditions. THESL's SAIDI, on the other hand, is 50% below the econometric prediction for the 2010-2012 period. Under THESL's Custom IR plan, SAIFI is projected to decline but still remain an average of 41% above the benchmark prediction for the 2015-2019 period. SAIDI is projected to decline even further under Custom IR and hence remain well below econometric forecasts for SAIDI.

Because THESL's total costs under Custom IR remain within benchmark projections, PSE concludes that THESL's spending under the Custom IR plan is reasonable from a benchmarking perspective. PSE also finds THESL's plan to address SAIFI is reasonable from a benchmarking perspective because SAIFI is projected to decline. Bringing these

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[2] Although the quantiative values are different, PSE's analysis and conclusions for the combined sample also apply to its results from the US-Only sample.

[3] Power System Engineering (PSE), *Econometric Benchmarking of Toronto Hydro's Historical and Projected Total Cost and Reliabiilty Levels*, Report prepared on behalf of Toronto Hydro-Electric System Limited, p. 33.

[4] PSE, *op cit*, p. 5.

[5] PSE, *op cit*, p. 33.

conclusions together, PSE finds that "from a benchmark perspective, the projections to 2019 show that Toronto Hydro's spending forecasts will converge the company's SAIFI and total costs towards the benchmark expectations (red dot in Figure 6). SAIDI is projected to remain at a very strong level. Based on the projections, the projected spending will result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective."[6] Given PSE's previously-stated conclusions that THESL's costs and SAIFI under Custom IR are both reasonable from a benchmarking perspective, it follows logically that PSE believes "a utility more aligned with its externally-derived benchmark values" for total cost and SAIFI is also a reasonable outcome from a benchmarking perspective.

2.2 Interpretation of Benchmarking Results

PEG believes PSE's interpretation of its technical benchmarking analysis is problematic. There are two main problems with these interpretations, both primarily stemming from PSE's attempt to evaluate two aspects of THESL's performance - cost and reliability - simultaneously. The first is PSE's interpretations are sometimes not consistent with the actual statistical hypotheses they are testing. A second, related problem is that PSE draws conclusions that have no empirical basis in the benchmarking analysis it performs.

On the first issue, it must be recognized that PSE undertakes statistical cost benchmarking that, by its nature, is designed to address a specific hypothesis. The hypothesis addresses the difference between THESL's actual (or projected) cost in a specific time period and the costs predicted for THESL. Predicted costs are equivalent to the costs of a utility with a sample-average level of cost efficiency operating under the same business conditions as THESL. The econometric benchmarking model is designed to test whether the subject utility's cost is significantly different from its predicted cost. If so, the analyst has a rigorous basis for inferring that the subject utility is either a good cost performer (if cost is below predicted cost and the difference is statistically significant) or a bad cost performer (if cost is above predicted cost and the difference is statistically significant). This is equivalent to inferring that the subject utility exhibits efficiency with respect to cost management that is, respectively, above or below the average level of cost efficiency in the sample.

[6] PSE, *op cit*, pp. 8-9.

Analogous points apply to reliability benchmarking. When benchmarking SAIFI, the hypothesis is whether there is a statistically significant difference between THESL's actual (or projected) values for SAIFI and the values predicted for THESL. If so, there is a rigorous basis for inferring that THESL is either a good or bad performer with respect to managing its SAIFI performance. The same is true for SAIDI benchmarking.

PSE often draws conclusions from its benchmarking results that are not consistent with these hypotheses. For example, PSE's claim that THESL costs 30% below predicted costs are "suggestive that the company's capital was in need of investment" is not an appropriate inference. There is nothing in the structure of the statistical exercise or the hypothesis being tested that supports this conclusion. In fact, if PSE's statement is correct, an equally reasonable inference would be that the Company had been an *inefficient* rather than an efficient cost performer in recent years. The failure to invest when investment is needed could be an example of inefficient cost deferment, which the Board should want to discourage, rather than cost savings from efficiency gains. In addition, if PSE believes THESL has been inefficiently deferring costs, its benchmarking study provides no quantitative basis for discerning whether capital or OM&A expenditures are the costs that had been deferred. PSE's conclusion that "the company's capital was in need of investment" is simply speculation; this conclusion does not follow logically or empirically from the benchmarking studies it has presented.

It is also worth noting that PSE does not acknowledge that the purpose of its statistical cost benchmarking is to make inferences on THESL's cost efficiency. PSE instead claims that the purpose of its analysis "has been to evaluate the reasonableness of Toronto Hydro's historical and projected total cost amounts and system reliability metrics."[7] Indeed, PSE even says it "was not tasked with explicitly evaluating Toronto Hydro's efficiency."[8]

These interpretations are insupportable. PSE's statistical benchmarking model is similar in form and technical detail to the model PEG developed in 4thGen IR, although PSE has applied this model to other datasets and used different independent variables. The Board is using PEG's benchmarking model to assign stretch factors for Ontario distributors in 4thGenIR. The November 4, 2013 *Report of the Board: Ratesetting Parameters and*

[7] PSE, *op cit*, p. 1.
[8] Responses to Ontario Energy Board Staff Interrogatories, PSE response to Interrogatory 17 c).

Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors describes the Board's decision to use PEG's model for this purpose as follows:

> "the Board has determined that distributors will be assigned to one of five groups with stretch factors based on their efficiency as determined through PEG's econometric total cost benchmarking model."[9]

The Board's finding in 4thGenIR that efficiency is "determined through PEG's total cost benchmarking model" also applies logically to PSE's cost benchmarking model, because this model is identical in substance to the PEG model even though it differs in empirical implementation.

In sum, PSE's interpretation of its benchmarking results is often problematic. The cost benchmarking models PSE applies are specifically designed to assess the efficiency of cost performance. This is also how the Board currently applies statistical benchmarking in Ontario regulation. Using these models to benchmark the "reasonableness" of THESL's cost forecasts is tantamount to benchmarking THESL's cost efficiency during the period being forecast. PSE does not accept this interpretation, but instead attempts (at times) to use its benchmarking models to draw unwarranted conclusions about the impact of THESL's cost management on its SAIFI performance.

These are not pedantic issues or immaterial distinctions. It is important for analytical and statistical tools to be "fit for purpose" and for technical results to be interpreted appropriately. The relationship between THESL's cost and reliability performance may be relevant to the Custom IR application, but PSE would have to develop different benchmarking models to provide evidence on this topic. The statistical benchmarking models PSE employed are variants of PEG's cost benchmarking model, and PEG's cost benchmarking model has not been designed to explore this issue. Chapter Five will discuss some modelling issues associated with assessing cost and reliability simultaneously.

[9] November 4, 2013 *Report of the Board: Ratesetting Parameters and Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 19.

2.3 Application of Benchmarking Results

PEG believes the regulatory application of PSE's results is problematic in at least two respects. First, PSE uses different criteria rather than a single standard to judge the "reasonableness" of THESL's cost and reliability performance under Custom IR. Second, PSE's application of "externally-derived benchmark values" is inappropriate and appears to be incompatible with the Board's objectives for incentive regulation.

On the first point, there is an inconsistency, and contradiction, in how PSE assesses the reasonableness of THESL's cost performance and its SAIFI performance. PSE finds THESL's costs to be reasonable because they are less than benchmark costs, even though THESL's costs under Custom IR are increasing over time relative to predicted costs. Conversely, PSE finds THESL's SAIFI to be reasonable because it is declining under Custom IR, even though SAIFI exceeds its benchmark level in every year of the plan. PSE's judgment on the reasonableness of THESL's cost therefore depends entirely on the *level* of cost compared to its benchmark; PSE's judgment on THESL's SAIFI depends entirely on the *change* in SAIFI relative to its benchmark.

There is no logical reason to judge the reasonableness of cost by one standard and the reasonableness of SAIFI by another. Doing so creates confusion and, more fundamentally, leads to ambiguities and contradictions in how performance is evaluated. For example, suppose PSE applied the "level" standard to both cost and SAIFI under Custom IR; its conclusion would now be that THESL's cost was reasonable but its SAIFI not. Alternatively, suppose PSE applied the "change" standard to both cost and SAIFI under Custom IR; now SAIFI would be deemed reasonable but cost would not. Finally, suppose PSE reversed the criteria, and cost under Custom IR was judged by the "change" standard and SAIFI by the "level" standard; in this case, neither cost nor SAIFI would be considered reasonable.

This ambiguity can be avoided by focusing directly on the hypotheses the benchmarking models are designed to test. Conclusions on the reasonableness of costs and reliability would then be determined by statistical tests that lead to rigorous inferences on whether THESL is an average, superior, or inferior performer with respect to cost and reliability performance. The temporal pattern of these test results can then be examined to evaluate how the Company's cost and reliability performance is (or is not) changing over time.

Instead of taking this approach, however, PSE's summary conclusion is that THESL's Custom IR plan will "result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective." As previously discussed, PSE's statements preceding this conclusion imply that it views such an outcome as reasonable. PEG disagrees. We believe PSE's conclusion represents a misapplication of benchmarking models and is likely to be incompatible with the Board's objectives for incentive regulation.

It is important to remember that PSE's benchmark predictions for THESL reflect the average performance standards for cost and reliability within the samples used to estimate the econometric models. In general, incentive regulation should be designed to encourage superior performance by subject utilities, not average performance. Good incentive regulation also clearly encourages performance *improvements* by utilities subject to IR plans.

The desirability of a utility becoming "more aligned with its externally-derived benchmark values" therefore depends critically on the utility's performance at the outset of the plan. If the utility is a superior performer before the plan starts, then becoming more aligned with the average performance standards inherent in the econometric benchmark would represent a degradation in performance. Such an outcome is obviously contrary to good regulatory practice.

However, if PSE's cost benchmarking is (for now) taken at face value, it projects that this outcome would result from THESL's Custom IR plan. PSE finds THESL is a superior cost performer in 2010-2012, when its actual costs were 21.5% below benchmark costs (determined using the combined sample). This difference was statistically significant at the 10% level. The Custom IR plan is to take effect in 2015, and at its conclusion in 2019 PSE projects that THESL will be an average cost performer, with no statistically significant difference between THESL's projected and predicted costs. This trend is evident in Table 6 (millions of $ for actual and predicted cost) of the PSE report.

Year	Projected THESL Cost	Predicted THESL Cost	% Difference
2014	730	845	14.7%
2015	823	884	7.1%

2016	887	935	5.3%
2017	947	985	3.8%
2018	1001	1037	3.5%
2019	1064	1092	2.6%

The data in Table 6 can be re-expressed to show why THESL's cost performance declines under the Custom IR plan. If we examine the annual changes in THESL's projected costs, annual changes in benchmark costs, and the dollar value of this difference over the term of the IR plan, PSE's results (again, taken for now at face value) show the following:

Year	Change THESL Cost	Change Predicted THESL Cost	$ Difference
2015	93	39	-54
2016	64	51	-13
2017	60	50	-10
2018	54	52	- 2
2019	63	55	- 8
Cumulative			- 88

This table shows THESL's projected change in costs exceeds the Company's predicted change in costs in every year of the plan. PSE's results therefore imply THESL costs are growing more rapidly than the cost changes expected for a utility with average cost efficiency which faced the same projected business conditions as the Company in 2014-2019. As a result, PSE estimates that THESL's measured efficiency will decline (from 21.5% below the benchmark in 2010-12 to 2% below in 2019) under its Custom IR plan.

Even for a sub-par cost performer, the desired objective is not to become "aligned" with the average performance benchmark but instead move continuously in the direction of better performance each year. Benchmarking can support these incentives in various ways. For example, benchmarking models can set "stretch" goals that are embodied in regulation, with declining stretch factors as utilities become increasingly efficient.[10] The Board's

[10] This approach is consistent with establishing objective, above-average performance standards (but not "frontier" efficiency standards) for all utilities in the industry.

4thGenIR decision is an example of a well-designed regulatory framework that appropriately integrates benchmarking in this manner. Allowing superior cost performers simply to become "aligned" with externally-derived benchmarks is incompatible with the spirit and architecture of 4th Gen IR.

PSE's view is also likely to be inconsistent with the Board's desire to encourage continuous performance improvement in the RRFE.[11] This is evident from Figure 6 of the PSE report, which PSE references when it says "projections to 2019 show that Toronto Hydro's spending forecasts will converge the company's SAIFI and total costs towards the benchmark expectations (red dot in Figure 6)…Based on the projections, the projected spending will result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective." Figure One below replicates PSE's Figure 6, but adds an arrow showing the movement from THESL's current cost and SAIFI performance to projected 2019 performance that "converge the company's SAIFI and total costs towards the benchmark expectations."

It can be seen that PSE projects THESL's performance will move in a northwest direction in this Figure. This is towards what PSE calls the "reliability better, cost worse" quadrant. The reason THESL moves in this direction is that, according to PSE's analysis, the company is in fact projected to display "reliability better, cost worse" performance under the Custom IR plan.

However, if THESL was exhibiting continuous improvement in its reliability and cost performance, it would be moving in a *southwest* direction on PSE's Figure 6, towards the "reliability better, cost better" quadrant. Indeed, it is straightforward to construct a "Zone of Continuous Improvement" for THESL relative to the Company's initial performance levels presented in PSE's Figure 6. This Zone of Continuous Improvement is incorporated into Figure Two below.

Figure Two illustrates why "converging towards benchmark expectations" is not a reasonable regulatory objective. Incentive regulation should be designed to encourage ongoing performance improvements. Encouraging continuous performance improvement is

[11] Chapter Four of the RRFE report is titled "Performance Measurement and Continuous Improvement." Page 57 of the RRFE report also outlines performance outcomes that it expects distributors to achieve in four distinct areas. One of these outcomes is "continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives."

Figure One

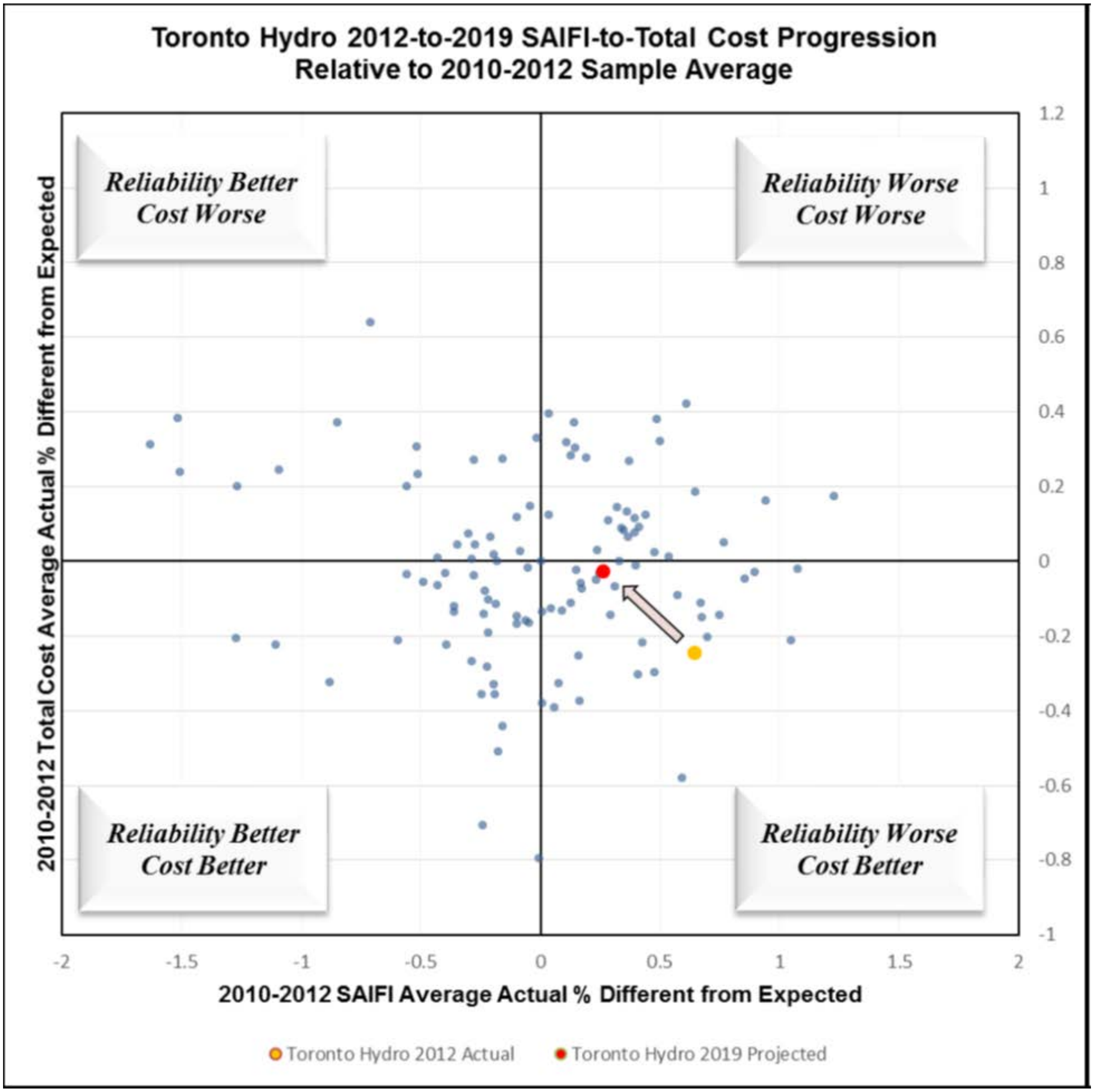
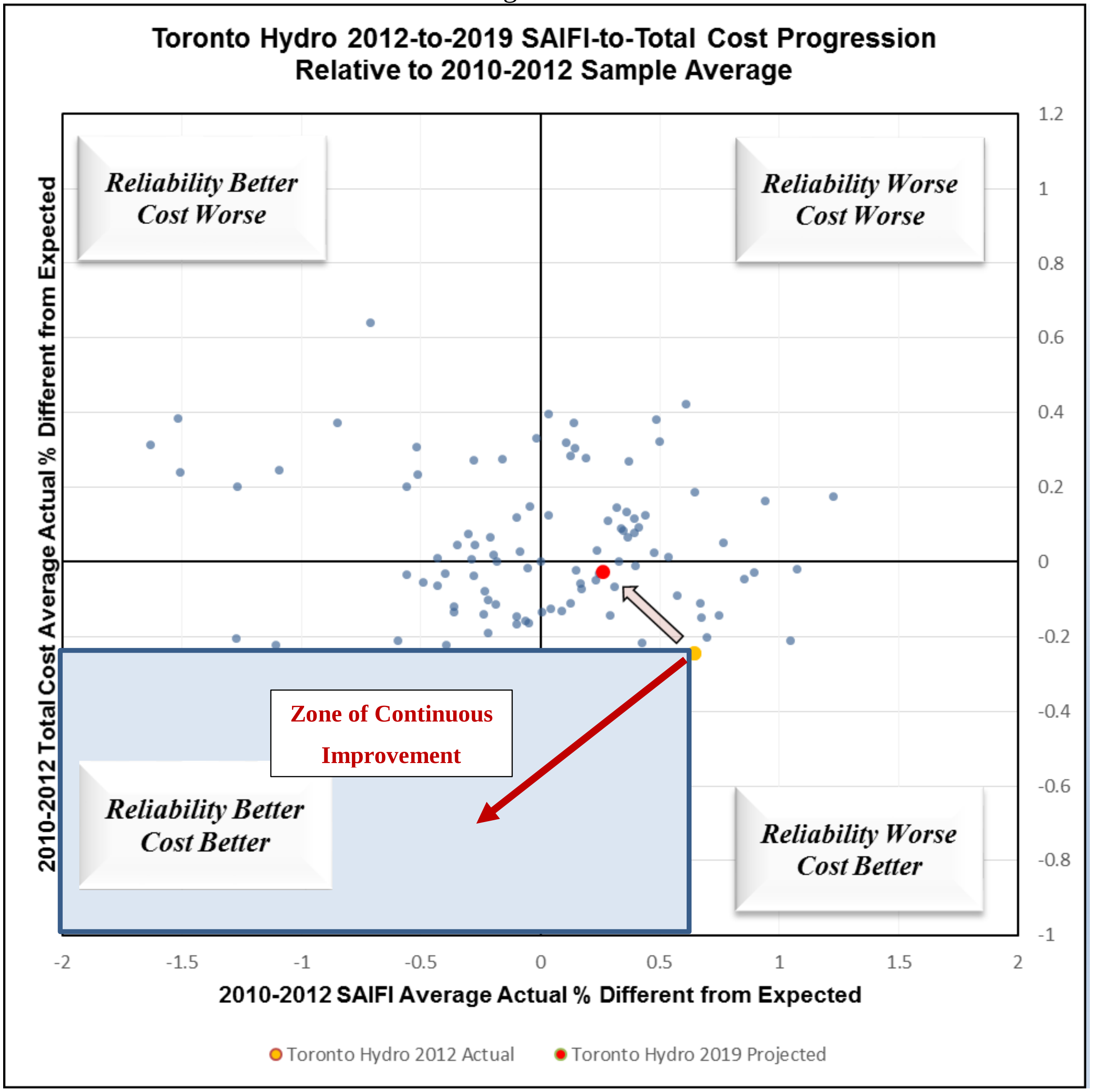

Toronto Hydro 2012-to-2019 SAIFI-to-Total Cost Progression
Relative to 2010-2012 Sample Average
Reliability Better
Cost Worse
Reliability Worse
Cost Worse
Reliability Better
Cost Better
Reliability Worse
Cost Better
1.2
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
-2
-1.5
-1
-0.5
0
0.5
1
1.5
2
2010-2012 Total Cost Average Actual % Different from Expected
2010-2012 SAIFI Average Actual % Different from Expected
Toronto Hydro 2012 Actual
Toronto Hydro 2019 Projected

Figure Two


Toronto Hydro 2012-to-2019 SAIFI-to-Total Cost Progression
Relative to 2010-2012 Sample Average
Reliability Better
Cost Worse
Reliability Worse
Cost Worse
Zone of Continuous
Improvement
Reliability Better
Cost Better
Reliability Worse
Cost Better
1.2
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
-2
-1.5
-1
-0.5
0
0.5
1
1.5
2
2010-2012 Total Cost Average Actual % Different from Expected
2010-2012 SAIFI Average Actual % Different from Expected
Toronto Hydro 2012 Actual
Toronto Hydro 2019 Projected

also an explicit Board objective. As the two figures below show, converging to cost and reliability benchmarks is not necessarily consistent with continuous improvement. PEG therefore finds that PSE's summary conclusion that such an outcome is reasonable is both unwarranted and likely to be incompatible with the Board's policy objectives.

In sum, PEG has significant concerns with how PSE applied its technical benchmarking results in this regulatory setting. PSE has employed inconsistent and contradictory standards for evaluating THESL's performance. This creates ambiguity that would be avoided if the analysis focused on the hypotheses the benchmarking models are designed to test. PEG also believes that PSE's view on aligning utilities with external, average performance standards represents a misapplication of benchmarking and is likely to be incompatible with the Board's objectives for incentive regulation.

3 Review of PSE Cost Benchmarking

This Chapter summarizes PEG's evaluation of PSE's cost benchmarking work. As part of 4thGen IR, PEG undertook a cost benchmarking study of Ontario distributors for the same 2002-2012 period examined by PSE. The Board is currently using PEG's benchmarking results to set stretch factors for distributors who choose the Annual IR and Price Cap IR options in the RRFE.

The most notable aspect of PSE's cost benchmarking work for THESL is the expansion of its sample to include US utilities. PEG therefore confines our review to PSE results derived from the US-Only sample. This focus will streamline our review without any loss of substance, because PSE employed very similar benchmarking tools and obtained qualitatively similar results for its combined Ontario-US and US-only samples.

3.1 Data Issues

PEG's review identified significant concerns with the data used in PSE's cost benchmarking studies. In Section 3.1.1 we discuss data problems associated with PSE's cost measure for THESL. Section 3.1.2 considers problems with the cost measures for the US utilities in PSE's sample and their comparability with THESL costs.

3.1.1 Data Toronto Hydro

In our 4thGenIR work for Staff, PEG developed two different cost measures for each Ontario distributor. One cost measure was used to estimate TFP trends for the electricity distribution industry in the Province. The other cost measure was used to benchmark the cost performance of Ontario electricity distributors. The starting point for the latter, benchmarking cost measure was the total cost used in our TFP analysis. However, PEG undertook several cost adjustments in order to make the costs to be benchmarked more comparable across distributors.

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

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

One other adjustment was made to make costs more comparable across distributors. PEG included some charges for low voltage (LV) services that were paid by distributors to their "host" distributors. These charges are regulated separately by the OEB but not included in the RRRs. The necessary data were obtained from two sources: (a) Hydro One provided a summary of LV Charges to distributors from 2002 to 2012, and (b) the Board's supplementary data request.[12]

PEG also included contributions in aid of construction (CIAC) and smart meter capital additions in the capital cost measure, as well as incremental OM&A associated with smart meters in the OM&A used in each distributor's benchmarking cost measure. CIAC payments are outside of the Board's IR rate adjustment formula, so it would not be appropriate to include them in the cost measure used to determine industry TFP trends that will be used to adjust allowed rates. However, CIAC additions are part of the capital stock that distributors use to provide service to their customers. Similarly, smart meters are part of this capital stock. Table 5 in PEG's November 2013 report to the Board summarizes the differences between the cost measures that PEG used to estimate TFP and to benchmark distributors' total costs.

The benchmark cost measure from PEG's earlier study should be used to benchmark THESL costs vis-a-vis US distributors. However, PEG's review indicated that PSE actually selected the more limited, TFP-based cost measure for THESL as the basis for its analysis.

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

As a first step, PEG therefore updated PSE's analysis to reflect THESL's correct, benchmark-based cost. We did not modify any data for the US utilities in PSE's sample, nor did we change any of PSE's selected independent variables or any aspect of the estimation procedure. PEG simply re-ran PSE's econometric model with the corrected THESL cost data, obtained new estimates of the econometric cost function parameters, and benchmarked THESL using this new cost model and THESL's corrected, benchmark cost. The first step of PEG's updated analysis therefore reflects the correction of THESL data errors only.

The econometric coefficients from this updated analysis are presented in Table One. PEG used the model in Table One to benchmark THESL's benchmark-based cost. For 2010-2012, PEG found that THESL's actual cost was 21.3% below its predicted cost. Using the same model but the incorrect cost measure for THESL, PSE found that THESL's 2010-2012 cost was 31.1% below its predicted cost. PEG therefore concludes that using the correct, benchmark-based costs for THESL reduces PSE's estimate of the difference between THESL's actual, 2010-2012 costs and its predicted costs from a reported -31.1% to -21.3%.

3.1.2 Data US Sample

PEG's review also identified several data concerns in PSE's US utility sample. One issue was that several sampled utilities underwent mergers during the 2002-2012 period. Mergers can impact a utility's reported cost data. Unless the business conditions are similarly updated to reflect those of the merged company, the statistical relationship between a utility's costs and business conditions can therefore be impacted. Appropriately controlling for mergers is often critical for obtaining accurate inferences on utilities' cost performance.

PEG's review indicated that PSE did not control for the impact of mergers that took place between 2002 and 2012 for seven of its sampled companies: Georgia Power; Green Mountain Power; Ohio Power; Potomac Edison; Public Service of New Mexico; Sierra Pacific Power; and Southwestern Electric Power. To avoid potential data errors associated with these utilities, PEG therefore eliminated these seven utilities from PSE's US sample.

PEG also identified several differences in the definition of costs for THESL and the US utilities. The benchmark cost measure for THESL excluded the costs of uncollectible accounts, while PSE's cost measure for the US utilities included the costs of uncollectible accounts. The benchmark cost measure for THESL also does not contain CDM expenses.

Table One

Econometric Cost Benchmarking Results:
Corrected THESL Data

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
UD= Urban Core Dummy
PRV= Percent Residential Deliveries in Total Deliveries
PCE= Percent Electric Customers in Gas & Electric Customers
PDE= Percent Distribution Plant in Total Electric Plant
UG= Percent Distribution Plant Underground
ED= Elevation Standard Deviation
PF= Percent Forestation
Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.5591	143.028	0.0000
N*	0.7583	26.469	0.0000
D*	0.2075	7.494	0.0000
KxK*	0.0767	4.490	0.0000
NxN*	0.2993	3.282	0.0011
DxD*	0.2723	2.743	0.0062
KxN	-0.0191	-1.914	0.0559
KxD	0.0163	1.611	0.1075
NxD*	-0.2363	-2.572	0.0103
UD*	0.0211	6.417	0.0000
PRV	0.0130	1.217	0.2238
PCE*	0.2359	7.920	0.0000
PDE*	0.1038	5.590	0.0000
UG	0.0018	0.125	0.9006
ED*	0.0234	3.209	0.0014
PF*	0.0351	5.570	0.0000
Trend	-0.0015	-1.128	0.2596
Constant*	13.2016	910.034	0.0000
System Rbar-Squared	0.940		
Sample Period	2000-2012		
Number of Observations	880		

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

PSE's cost measure for US utilities does include DSM expenses, which are considerable for many US utilities. Both of these differences tend to raise the cost of the US sample compared with THESL. All else equal, this lack of cost comparability leads to a more favorable benchmarking evaluation for THESL. To enhance cost comparability, PEG eliminated two sources of expenses from US utilities' cost measure: uncollectible bills, and customer service and information expenses (for which CDM often constitutes the largest single expense).

PEG also standardized the treatment of contributions in aid of construction (CIAC) across the sample. The benchmark-based costs for THESL and the other Ontario distributors include CIAC in the capital costs. The data PSE used to construct capital costs for the US distributors excluded CIAC. PEG therefore eliminated CIAC from THESL's costs to ensure greater comparability of costs between THESL and the US electric utilities.

PEG incorporated these changes into the dataset that includes the corrected THESL data. We then re-ran PSE's econometric model, obtained new estimates of the econometric cost function parameters, and benchmarked the Company using the new cost model and corrected/more comparable data for THESL and the US utilities. There were no changes to PSE's selected independent variables or the econometric estimation procedure. The second step of PEG's updated analysis therefore reflects corrected and/or more comparably-defined cost measures for both THESL and the US sample.

These results are presented in Table Two. Compared to Table One, it can be seen that these changes raise the estimated coefficient on the capital service price WK from 0.559 to 0.701. This is expected, because this coefficient will reflect the share of capital in the total cost measure. Because several O&M cost components were eliminated from US utilities' total costs while their capital costs were not modified, capital's share of cost is expected be higher in this econometric model than in previous models. A capital share of 70.1% is nevertheless reasonable and broadly consistent with PEG's econometric work elsewhere. It is also more consistent with THESL's own projected share of costs under its Custom IR plan than PSE's estimated capital cost share of approximately 56%.[13]

The coefficients on the outputs also differ somewhat. In the run correcting THESL and US data, the coefficient on customer numbers falls somewhat (from 0.758 to 0.613) while

[13] In Exhibit 1B, Tab 2, Schedule 3, p. 13, Table 5 includes Scap values for the 2016-2019 years. The average value of Scap during these years is 69.8%.

Table Two

Econometric Cost Benchmarking Results:
Corrected THESL and US Data

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
UD= Urban Core Dummy
PRV= Percent Residential Deliveries in Total Deliveries
PCE= Percent Electric Customers in Gas & Electric Customers
PDE= Percent Distribution Plant in Total Electric Plant
UG= Percent Distribution Plant Underground
ED= Elevation Standard Deviation
PF= Percent Forestation
Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.7015	389.494	0.0000
N*	0.6132	20.643	0.0000
D*	0.2552	8.357	0.0000
KxK*	0.1150	18.592	0.0000
NxN*	0.5328	5.379	0.0000
DxD*	0.4781	4.821	0.0000
KxN*	0.0502	4.506	0.0000
KxD*	0.0471	4.217	0.0000
NxD*	-0.5012	-5.320	0.0000
UD*	0.0108	3.362	0.0008
PRV*	0.0268	1.993	0.0466
PCE*	0.1141	3.574	0.0004
PDE*	0.1500	8.248	0.0000
UG	-0.0213	-1.130	0.2587
ED	0.0097	1.302	0.1933
PF	0.0098	1.758	0.0791
Trend	0.0023	1.697	0.0901
Constant*	13.0269	832.749	0.0000
System Rbar-Squared	0.923		
Sample Period	2002-2012		
Number of Observations	805		

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

the coefficient on peak demand increases (from 0.208 to 0.255). Peak demand therefore becomes a relatively more important "cost driver" in PEG's second econometric model.

PEG used the econometric estimates and updated data in Table Two to benchmark THESL's cost performance. The updated model showed that THESL's actual 2010-2012 cost was 6.3% below its predicted value. The difference was not statistically significant.

Recall that the benchmarking evaluation that corrected only the THESL data showed THESL's actual costs were 21.3% below predicted costs. The Company's efficiency score was reduced 9.8% (from -31.1% to -21.3%) when THESL's data were corrected. The current model corrects THESL data and corrects for costs that were: 1) included in the US data measure but not the THESL measure, or vice versa; or 2) potentially distorted by US utility mergers. PEG's results indicate that defining costs so that they are comparable across samples reduces THESL's efficiency score by a further 15.0% (i.e., the difference between the Company's actual and predicted cost changes from -21.3% to -6.3%).

3.2 Business Condition Variables

The third stage of PEG's review was to consider PSE's choice of business condition variables. We made only two minimal but necessary changes to PSE's business condition variables. The first was adding a variable to reflect MVa of transformer capacity for stations with primary voltage levels at or above 50 kV. The second was eliminating the urban core dummy variable.[14]

It is necessary to control for differences in distributors' high voltage transformation services. If this is not done, distributors with extensive high voltage transformation assets would be "penalized" for doing more work than distributors without such assets. PSE's current model includes the costs of high voltage transformation stations for US utilities, but it does not include a corresponding high voltage "network" or business condition variable.

[14] A "dummy" variable is a binary variable that takes a value of zero or one depending on whether certain specified criteria are satisfied. PSE's urban core dummy takes a value of one if a utility serves a city with a population of one million or more, and a value of zero if this condition is not true. A dummy variable is therefore a relatively blunt means of quantifying the impact of business conditions on a utility's operating cost because it does not measure the value of the posited business condition directly. A dummy variable also does not necessarily reflect the impact of the posited business condition, because it can capture a host of other company-specific effectes that are not explicitly included as independent variables in the model.

As explained in Section 3.1.1, controlling for differences in high voltage transformation was an important part of PEG's cost benchmarking work in Ontario. PEG eliminated all high voltage assets and OM&A costs that could feasibly be identified from our benchmark cost measures for Ontario distributors. The same should be done for US distributors, or the US utilities providing high voltage services will be unfairly disadvantaged in PSE's benchmarking analysis just as the Ontario distributors would have been in PEG's Ontario benchmarking study. Indeed, the importance of controlling for high voltage transformation appears to be at least as important in a THESL-US study as in an Ontario study. According to PEG's review, approximately 67.4% of the share of transformer stations for US utilities takes place at a primary voltage level of 50 kVA or above.

PSE did not control for differences in high voltage transformation between the US and THESL. The US FERC Form One accounts also do not provide separate data on the asset values or associated OM&A for utilities' high voltage assets. However, data are available to determine utilities' total MVa of capacity with primary voltage equal to or above 50 kV. PEG therefore included this variable in our econometric benchmarking model.

The second business condition issue concerns PSE's urban core dummy variable, which PEG believes should be eliminated from the model. Contrary to PSE's claims, PEG has never used an "urban core dummy" in our econometric benchmarking of electricity distribution. Some PEG studies have used this variable in gas distribution models, but the rationale for using such a dummy variable is much stronger for gas distribution than electricity distribution.[15] An urban core dummy is defensible for gas distribution because essentially all gas distribution assets are underground. A dummy variable is one means of distinguishing between the higher costs of installing and maintaining underground gas distribution assets in densely-populated, mature urban areas compared with "greenfield" suburban territories.

It is far less necessary to use the blunt approach of a binary dummy variable to capture these costs in electricity distribution. One important difference between electricity and gas infrastructure is that assets for the former are located both "overhead" and underground. Data on the share of lines, or plant values, that are overhead is a better and more direct measure of

[15] None of the studies Dr. Kaufmann has supervised has ever used an urban core dummy variable, for gas or electricity distribution.

the urbanization or ruralization of a service territory than a dummy variable. The share of plant *value* underground will also directly reflect the higher costs of installing and maintaining assets in a densely populated "urban core." While the OEB does not currently collect data on the value of plant underground, these data are available on the FERC Form One for US utilities, and PSE obtained the same data directly from THESL. Since PSE's model already includes a percent of plant underground variable, including an 'urban core dummy' would be redundant at best.

It should also be noted that when PEG has used urban core dummies in the past, the dummy variable was applied to most of the gas distributors in the sample. PSE, on the other hand, has applied its urban core dummy variable to only four of the 85 US utilities. Applying an urban core dummy to a larger share of the sample makes it more likely that the variable will reflect a systematic cost driver across the industry rather than idiosyncratic, utility-specific factors.

This issue is relevant to PSE's analysis because, in PEG's opinion, its urban core variable is not an accurate measure of the "urban cores" that exist throughout the US. As discussed, only four of the 85 utilities in PSE's sample are identified as having "urban cores": Consolidated Edison, which serves Manhattan and other parts of New York City; Commonwealth Edison, which serves Chicago; Arizona Public Service (APS) which serves Phoenix, AZ; and San Diego Gas and Electric (SDG&E), which serves San Diego, CA. Consolidated Edison and Commonwealth Edison clearly serve "urban cores," but the territories of SDG&E and APS can more fairly be characterized as suburban rather than densely urban. SDG&E serves a relatively normal mix of urban, suburban, and rural areas. APS's territory is overwhelmingly suburban but also contains a sizeable rural area and does not even include a significant part of Phoenix's central business district (which is served by the Salt River Project). A credible urban core dummy for the US electric utility industry would not include only these four American cities.

In addition, it must be recognized that a dummy variable can reflect a wide variety of company-specific factors, not just whether or not the selected utilities serve an urban core. One of those company-specific factors is the efficiency of company management. Using company-specific dummies is one method of estimating management efficiency.[16] It so happens that, collectively, the four utilities selected as serving urban cores tend to be average to poor cost performers. Including a dummy variable for these companies will effectively transfer some inefficiency from these utilities to the dummy variable. When this dummy variable is then used to develop econometric projections for other distributors, it effectively lowers the benchmark for the rest of the sampled firms.

There is also evidence that PSE's urban core dummy may be distorting other coefficients in PSE's cost model. Recall that the share of distribution plant underground already provides a measure of the degree of urbanization in a utility's service territory. Across a cross section of electric utilities, companies with a higher percentage of their plant underground will also tend to serve more urbanized territories. It is also well-known in the electric utility industry that it is more costly to build underground than overhead electricity distribution infrastructure. It is also not uncommon for utilities to request rate increases to recover the higher costs of undergrounding facilities. A good example is the System Modernization and Reliability Project (SMRP) proposed by Wisconsin Public Service (WPS), which specifically focused on undergrounding facilities in rural areas in an effort to improve reliability. In July 2013, WPS was allowed to increase rates by approximately 4.36% to recover the costs of the SMRP.[17]

PSE, however, finds that "undergrounding distribution capital *lowers* cost" (emphasis added) because the coefficient on the percent of distribution plant underground in its model is negative.[18] This result is contrary to the industry's experience and is not plausible.[19] Although it cannot be established definitively, this anomalous result may be due in part to the fact that the urban core dummy variable in the PSE model has a positive coefficient.

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[16] However, PEG believes this benchmarking approach is not as robust or accurate as the methodology that the Board has used to benchmark costs for Ontario electricity distributors.

[17] Public Service Commission of Wisconsin, *Final Decision: Application of Wisconsin Public Service Corporation for its Electric Distribution System Modernization and Reliability Project*, Docket 6690-CE-198. It should be noted that the rate increase represents an approximate 4.36% increase in overall, bundled power rates.

[18] PSE, *op cit*, p. 37.

[19] PEG believes the estimated negative coefficient on the undergrounding variable in the US cost model conflicts with the statement on page 36 of its report that "parameter estimates have plausible signs and magnitudes." On page 18 of the report, PSE says that "the percentage of plant that is underground can raise the capital cost of distribution delivery, but lowers maintenance (and hence OM&A) expenses." While this is true, capital accounts for a greater share of electricity costs than OM&A, which means the OM&A cost savings would have to be a multiple of the initial capital costs for undergrounding to reduce overall distribution costs. Moreover, if undergrounding actually reduced electricity distribution cost, as PSE finds, one would expect utility proposals to underground assets to be coupled with rate reflief rather than requested rate increases. Industry experience indicates the opposite is true, which means the expected sign on PSE's undergrounding variable is positive.

Finally, the Board and stakeholders should not be left with the impression that urban conditions necessarily increase electricity distribution costs. Urbanization facilitates "economies of density" that can reduce the unit cost of performing a number of electricity distribution functions. Relatively concentrated service territories also decrease the quantity of "lines and poles" needed to deliver power to end-users, which directly reduces the costs of necessary infrastructure. This is not to deny that high density levels can raise other costs, but the relationship between electricity distribution cost and urbanization is complex, and it will not be fully captured in a binary, dummy variable.

In sum, PEG believes using dummy variables is a relatively crude and imprecise means of measuring "urban core" characteristics. While this is sometimes warranted for gas distribution, more accurate and direct measures of urbanization are available in electricity distribution. PSE's specific "urban core" dummy is also not credible and is likely to reflect other company-specific factors (including management inefficiency) rather than specific aspects of an urban environment. Given these concerns, PEG eliminated the urban core dummy variable from the model used to benchmark THESL's cost.

PEG incorporated these two changes in business conditions into the dataset that includes the corrected THESL data and the corrected and/or more comparably defined cost measures for THESL and the US utilities. We then re-ran PSE's econometric model, obtained new estimates of the econometric cost function parameters, and benchmarked the Company using the new cost model. There were no other changes to the econometric estimation procedure. The third and final step of PEG's updated analysis therefore reflects corrections to the THESL and US data, as well as changes in business conditions to control for US utilities' costs of owning HV transformation assets and to eliminate the urban core dummy.

These results are presented in Table Three. The estimates on the outputs and business condition variables are all plausibly signed and statistically significant. The coefficient on the new HV transformer capacity variable has the expected positive sign, although it is not statistically significant. PEG used the econometric estimates and updated data in Table Three to benchmark THESL's cost performance. The updated and final cost model showed that THESL's actual 2010-2012 cost was 9.7% above its predicted value. The difference was not statistically significant.

Table Three

Econometric Cost Benchmarking Results:
Revised Data and Model

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
CAP= MVA of Capacity with Primary Voltage >= 50kV
PRV= Percent Residential Deliveries in Total Deliveries
PCE= Percent Electric Customers in Gas & Electric Customers
PDE= Percent Distribution Plant in Total Electric Plant
ED= Elevation Standard Deviation
PF= Percent Forestation
Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
K*	0.7024	390.050	0.0000
N*	0.6551	23.133	0.0000
D*	0.2207	7.209	0.0000
KxK*	0.1129	18.295	0.0000
NxN*	0.6856	7.053	0.0000
DxD*	0.5932	5.754	0.0000
KxN*	0.0446	4.003	0.0001
KxD*	0.0512	4.592	0.0000
NxD*	-0.6328	-6.628	0.0000
CAP	0.0009	0.451	0.6522
PRV*	0.0317	2.250	0.0247
PCE*	0.1374	4.473	0.0000
PDE*	0.1472	8.168	0.0000
ED*	0.0150	2.019	0.0438
PF*	0.0109	2.063	0.0394
Trend	0.0011	0.810	0.4180
Constant*	13.0373	740.885	0.0000
System Rbar-Squared	0.926		
Sample Period	2002-2012		
Number of Observations	805		

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

PEG also used the econometric estimates in Table Three and THESL's projected business conditions to benchmark the Company's projected costs over the term of its Custom IR plan. In the first plan year of 2015, THESL's projected cost is 30.3% above its predicted cost. The difference between THESL's projected and predicted costs increases to 31.7% in 2016, 33.3% in 2017, 33.7% in 2018, and 34.7% in 2019. All of these 2015-2019 results for the Company are statistically significant at the 10% level.

Because THESL's projected costs are above its predicted costs and the differences are statistically significant, PEG finds that THESL under the Custom IR plan is projected to be an inferior cost performer compared with PSE's sample of 85 US electric utilities. This conclusion is similar to PEG's conclusion on THESL's cost efficiency in our benchmarking study for the Ontario electricity distribution industry. THESL was also identified as an inferior cost performer in Ontario, although the magnitudes of the Company's estimated inefficiency differ somewhat depending on whether THESL is benchmarked against US or Ontario samples.

3.3 Assessment of PSE Cost Benchmarking

The three steps in PEG's analysis of PSE's benchmarking results are summarized in Table Four. The "PSE Model" column shows PSE's estimates of the Company's efficiency in 2010-2012 and in each subsequent year from 2013 through 2019. The column immediately to the right shows how THESL's 2010-2012 estimated efficiency is impacted when THESL's cost data are corrected. This correction changes the difference between the Company's actual and predicted costs from -31.1% to -21.3%. The next column to the right shows the impact of correcting the data for US utilities as well, in order to enhance the comparability of the cost measures used for THESL and the US sample. These corrections further modify the difference between the Company's actual and predicted costs from -21.3% to -6.3%. The column on the far right of Table Four shows PEG's revised model, which incorporates the corrected THESL and US data, adds a variable to control for differences in high voltage ownership, and eliminates the urban core dummy. PEG's revised model shows that the difference between THESL's actual and predicted costs is +9.7% in 2010-2012. This difference rises further to +34.7% over the term of the Company's Custom IR plan.

Table Four

Comparison THESL Benchmarking Results

Year	PSE Model	PSE Model: Corrected THESL Data	PSE Model: Corrected THESL & US Data	Revised Model and Data
2010-2012	-31.1%	-21.3%	-6.3%	9.7%
2013	-24.6%			18.9%
2014	-21.8%			21.0%
2015	-13.1%			30.3%
2016	-11.4%			31.7%
2017	-9.9%			33.3%
2018	-9.5%			33.7%
2019	-8.5%			34.7%

PEG's review therefore indicates that PSE's conclusion that THESL was historically an efficient cost performer is unfounded. Using the appropriate cost data for THESL, adjusting the data and business conditions to make THESL and US cost data more comparable, and eliminating an inappropriate urban core dummy variable leads to a more than 40% increase in the difference between the Company's actual and predicted costs (*i.e.* 9.7% - (-31.1%) = 40.8%). Most of this difference can be attributed to the fact that PSE did not use comparable cost measures for THESL and the US utility sample. After cost measures are made more comparable and the inappropriate urban core dummy variable is eliminated, PEG concludes that THESL has been, at best, an average cost performer historically and is projected to be an inferior cost performer under the Custom IR plan.[20]

[20] It should be emphasized that PEG's analysis in this proceeding focused on reviewing PSE's work, not developing an econometric model explicitly designed to benchmark US electric utiliities. As a result, the econometric cost model presented in this chapter is somewhat circumscribed by the PSE model we were asked to review. There are several data and modeling assumptions in PSE's work that PEG would not retain in US cost benchmarking (*e.g.* a 1989 benchmark year for measuring capital cost), which it was nevertheless appropriate not to modify in the current analysis.

4 Review of PSE Reliability Benchmarking

This chapter presents PEG's evaluation of PSE's reliability benchmarking work, as well as alternate reliability benchmarking studies that PEG prepared. We begin by assessing the quality of PSE's reliability database. We then present alternate SAIFI and SAIDI benchmarking models, and associated benchmarking results for THESL, using service reliability data that PEG has collected.

4.1 Data Issues

While high quality data are important in any empirical analysis, concerns about data quality are particularly acute in service reliability benchmarking. One reason is that, unlike cost data, US utilities have traditionally not reported SAIFI, SAIDI and other reliability metrics to a single regulatory agency in a standardized format.[21] Some US utilities do report reliability to their state public utility commission, but these reports differ substantially from state to state. Reliability reporting differs in terms of the metrics reported, the definition of "sustained" outages, interruptions that are included in the reported measures and those that are excluded, and in other ways. Because state reliability reports can differ so significantly, care must to be taken to document and compile service reliability data in a manner that ensures they are as comparable as possible.

Utilities can also differ in how they measure and report outages. PEG described some of the factors that impact utilities' recorded reliability metrics in a 2010 jurisdictional survey of service reliability regulation to Board Staff. In that report, PEG noted:[22]

> These service reliability metrics must generally be collected directly within the utility itself. There is considerable variation in how reliability measures such as SAIFI and SAIDI are defined and calculated across utilities. Sources of difference include…
>
> - *Step restoration* When utilities restore power after widespread outages, restoration typically proceeds in "steps," where some phases of a circuit are restored before others. Companies vary in the extent to which they

[21] However, efforts to begin more standardized reporting are underway. The US Energy Information Agency (EIA) within the US Department of Energy is expected to begin reporting SAIFI and SAIDI for US utilities soon.

[22] Kaufmann, L., *et al*, (2010), *System Reliability Regulation: A Jurisdictional Survey*, Report to the Ontario Energy Board, pp. 10-13. The elipsed portion of this quotation included an extensive discussion of which interruption events are excluded from the reliability metrics, which is not relevant in the present context since PSE and PEG have examined unadjusted reliability data.

track customer minutes of interruption in response to partial restoration of circuits. This can affect both the “start” and “stop” times of a given interruption and the total minutes of the recorded outage.

- *Degree of automation* Companies differ in the extent to which they rely on manual or automated systems (such as outage management systems, or OMSs) to record reliability data. It is quite common for companies’ measured frequency and duration of outages to rise substantially after they move to more automated recording systems. This implies that manual systems for measuring interruption data tend to miss or undercount the frequency and duration of outages.

For these and related reasons, there is often significant variation in how companies measure and record reliability indicators. In principle, reliability measurement can be standardized among electric utilities in a jurisdiction, but doing so is likely to take considerable effort. It would also lead to inconsistency between the past and standardized reliability measures for many utilities.

While it is not possible to redress many differences in how utilities measure outage events internally, this fact nevertheless underscores the sensitivity of reliability benchmarking to data quality and comparability issues. If US data are being used, analysts must compile their own reliability datasets from a variety of diverse sources. Because the quality and comparability of available US reliability data differ greatly, analysts must exercise care when compiling databases and should be as meticulous and transparent as possible in documenting the data used in the study.

PSE provided the reliability data used in its study to PEG. The data were provided subject to a confidentiality agreement, so PEG cannot discuss data points for any specific utility. However, we can report that PSE could not identify the source for 83 of the 376 observations it used for SAIFI. Similarly, PSE could not identify the source for 83 of its 376 SAIDI observations. This means PSE was not able to say where it obtained 22.1% (*i.e.* 83/376 = .221, or 22.1%) of the data used in its reliability benchmarking analyses.

PSE also provided PEG the source files used to compile PSE’s reliability databases (for the observations where PSE could identify the source). PEG compared the SAIFI and SAIDI data contained in the PSE spreadsheets/databases with the data listed in the source files. Our review found 57 of the 376 data points entered into PSE’s SAIFI data, and 66 of the 376 SAIDI data points, were erroneous and/or inconsistent with PSE’s cited sources. When combined with our findings on PSE’s data sourcing, PEG’s review indicated that

35.9% of PSE's SAIFI database and 38.3% of PSE's SAIDI database was either inaccurate or obtained from an unknown source.

In PEG's opinion, these are serious errors and omissions. Reliability benchmarking is still new in Ontario.[23] The Board must have confidence in the data that are used to estimate reliability benchmarking models. This is particularly true since SAIFI and SAIDI data will differ among sampled companies for a variety of reasons. The uncertainties and data concerns that are inherent in reliability benchmarking should be mitigated to the greatest extent possible, not amplified by a failure to document sources and data processing errors.

In light of these concerns, PEG does not believe PSE's US dataset is suitable for regulatory application. PEG believes the quality of PSE's data are not of sufficiently high quality to assure the Board that econometric results developed from these data will be accurate. We therefore recommend that the Board give no weight to PSE's reliability benchmarking.

4.2 Alternate Reliability Benchmarking Models

To develop more accurate and robust service reliability benchmarking models, PEG compiled its own SAIFI and SAIDI databases. Appendix One shows the utilities and data sources PEG used to develop this database. Appendix One also provides further references on sources from which the data were extracted.

The sample period was 2002-2011. PEG eliminated 2012 from our sample because this was the year Hurricane Sandy led to unprecedented multi-day outages along much of the US East Coast. If 2012 data were used to estimate a model benchmarking reliability performance, the benchmarks would essentially build in a 1 in 11 probability of a Hurricane Sandy type event impacting the industry's measured reliability during the period to be benchmarked.[24] This is not reasonable, because Hurricane Sandy was by any measure a severe and unusual event, and it is highly unlikely to be repeated in the near future.

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[23] In our work advising Staff on setting reliability benchmarks, PEG undertook some statistical benchmarking of Ontario's SAIFI and SAIDI performance. The initial results were unsatisfactory, for a variety of data-related reasons, and we did not pursue the matter further.

[24] That is, 2012 was one of the 11 sample years in the 2002-2012 period. Using this period to estimate forward-looking benchmarks would essentially build the 2012 experience, which was dominated by Hurricane Sandy, into the SAIFI and SAIDI benchmarks.

PEG's benchmarking models investigated the environmental business conditions in PSE's datasets. We also examined the percent of capital that is underground, since it is widely known in the electricity distribution industry that underground assets are less prone to contact and interruption than overhead lines.[25] PEG found that whenever undergrounding and customer density were both included in an econometric model, the magnitude and statistical significance of the undergrounding coefficient was greater than that for customer density, and customer density would come in with a wrong (positive) sign. In light of its larger estimated effect and greater statistical significance, PEG therefore retained the undergrounding variable but excluded customer density from our SAIFI and SAIDI econometric models.

PEG also investigated other environmental variables that were not in the PSE models. These included heating degree days (HDD), cooling degree days (CDD), and precipitation. HDD and CDD are proxies for the severity of winter and summer weather, respectively. Severe winter weather can increase the frequency and duration of outages because of factors such as ice on lines, strong winds during winter storms, and conditions that increase the time it takes to respond to interruptions and restore power. Severe summer weather can cause conductors to sag and become more prone to contact, as well as increase the thermal loading of transformers and other assets. Precipitation is correlated with vegetation and wildlife, both of which are common causes of interruptions. For all three of these variables, the expected sign on the SAIDI and SAIFI coefficients are expected to be positive, because higher values for HDD, CDD, and precipitation are all expected to be associated with higher SAIDI and SAIFI values.

PEG's estimated econometric reliability model for SAIFI is presented in Table Five. Our estimated econometric model for SAIDI is presented in Table Six. Each table provides coefficient estimates and the t statistic on the hypothesis that the parameter value is equal to zero.

For SAIFI, PEG's econometric model finds:

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[25] PSE has argued that it did not include undergrounding as an independent variable because it reflects management actions and is therefore not independent. While there is some merit to this claim, many undergrounding decisions also occur because of municipal regulations that mandate undergrounding of assets. Undergrounding is also so strongly correlated with observed SAIFI and SAIDI experience that if it was not included in an econometric model, there is a high probabiltity that the coefficients on the variables that were included would be characterized by ommited variable bias.

Table Five

SAIFI Benchmarking: PEG US Data

VARIABLE KEY

UG= Percent of Line Plant Underground
L= Lightning
E= Standard Deviation of Elevation
CDD= Cooling Degree Days
PCP= Precipitation

Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
UG*	-0.3131	-10.209	0.0000
L*	0.0910	7.148	0.0000
E*	0.1348	6.089	0.0000
CDD*	0.1346	4.697	0.0000
PCP*	0.2202	5.723	0.0000
Trend	0.0044	0.782	0.4349
Constant	0.0854	1.866	0.0629
R-Squared	0.273		
Sample Period	2002-2011		
Number of Observations	369		

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

Table Six

SAIDI Benchmarking: PEG US Data

VARIABLE KEY

UG= Percent of Line Plant Underground
L= Lightning
E= Standard Deviation of Elevation
HDD= Heating Degree Days
CDD= Cooling Degree Days
PCP= Precipitation

Trend= Time Trend

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	P-VALUE
UG*	-0.4867	-7.522	0.0000
L*	0.1417	5.262	0.0000
E*	0.3115	5.378	0.0000
HDD*	0.1505	2.155	0.0318
CDD*	0.2951	3.548	0.0004
PCP*	0.4467	5.014	0.0000
Trend*	0.0380	3.195	0.0015
Constant*	-0.4527	-4.291	0.0000
R-Squared	0.248		
Sample Period	2002-2011		
Number of Observations	375		

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

- Greater undergrounding is associated with fewer outages
- More lighting strikes are associated with more outages
- Greater variance in elevation is associated with more outages
- Higher values of CDD are associated with more outages
- Higher values of precipitation are associated with more outages

All estimates were statistically significant at the 1% level. For SAIDI, PEG's econometric model found:

- Greater undergrounding is associated with fewer minutes of outages
- More lighting strikes are associated with more minutes of outages
- Greater variance in elevation is associated with more minutes of outages
- Higher values of CDD are associated with more minutes of outages
- Higher values of HDD are associated with more minutes of outages
- Higher values of precipitation are associated with more minutes of outages
- A positive time trend, meaning a trend increase in minutes of outages that is unrelated to any of the business condition variables

All estimates were statistically significant at the 1% level, except HDD, which was statistically significant at the 5% level.

PEG used these models to benchmark THESL's SAIFI and SAIDI performance. For the 2009-2011 period, PEG found that THESL's actual SAIFI was 78.7% greater than its expected SAIFI. This means THESL customers were experiencing about 79% more outages than would be expected for a distributor operating under the Company's business conditions. This difference was statistically significant at the 1% level. For SAIDI, PEG found that THESL's actual SAIDI was 20.6% above its expected SAIDI. This difference was not statistically significant.

Although PEG recommends that no weight be placed on PSE's reliability benchmarking, it is interesting to note that PEG and PSE both find THESL's SAIFI performance is far below what is expected. However, our findings are somewhat different with respect to SAIDI. PSE estimates that THESL's SAIDI is well below expected levels. PEG finds THESL's SAIDI is not statistically different from expected levels.

5 Simultaneous Cost and Reliability Benchmarking

PSE has undertaken separate benchmarking analyses of THESL's cost and reliability performance. These analyses are entirely independent, yet PSE has used evidence from its cost benchmarking models to draw "suggestive" implications on THESL's SAIFI performance. As explained in Chapter Two of this report, these conclusions are unfounded, and PSE's cost benchmarking provides no empirical basis for assessing THESL's SAIFI or SAIDI performance or the need for capital investment to address reliability problems.

Indeed, PSE's benchmarking studies are tangential to the issue of how electricity distribution cost and reliability intersect. PSE relates these two dimensions of performance only rhetorically, by appealing to what might be called a general understanding of the electricity distribution industry. For example, PSE writes that, in its "opinion, it is certainly possible that the poor SAIFI performance (of THESL) is a symptom of the condition of the distribution network....poor SAIFI performance tends to be an indicator of old and failing infrastructure."[26] Since "old and failing infrastructure" can be remedied by purchasing and installing new infrastructure, PSE posits a relationship between changes in THESL costs (especially the investment costs associated with installing new capital) and future changes in its SAIFI.

PEG does not dispute this common-sense linkage, but we note that this understanding predates PSE's benchmarking studies, and these studies do nothing to illuminate or enhance parties' understanding of this relationship. For example, PSE's studies provide no evidence on the tradeoffs between cost and enhanced reliability, or how those tradeoffs may be related to the business conditions distributors face. PSE's studies for THESL also provide no evidence on the magnitudes of SAIFI or SAIDI improvements it is reasonable to expect THESL to achieve given its additional capital spending.

We believe these issues raise two points that are noteworthy and relevant to our review. First, the relationship between cost and reliability is central to THESL's Custom IR application, and this relationship may be amenable to statistical examination. Second, PSE

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[26] PSE, *op cit*, p. 10.

has provided other evidence in this proceeding that explores the relationship between cost and reliability.

On the first point, the intersection between cost and reliability is clearly integral to THESL's Custom IR plan. THESL plans to increase its capital spending significantly under its Custom IR plan, and this spending is intended (in part) to maintain and/or improve service reliability. PSE's summary conclusion also assesses cost and reliability simultaneously (*e.g.* as represented in Figure 6 of its report) although, as discussed in Chapter Two, the benchmarking tools it employed were not designed or appropriate for this purpose.

However, statistical analysis can be used to explore the relationship between electricity distributors' cost and reliability, instead of treating each as a stand-alone benchmarking exercise. Statistical tools can also quantify how this relationship is impacted by differences in business condition variables such as scale of outputs, customer density, and asset undergrounding. These are inherently empirical issues and therefore potentially amenable to statistical quantification and testing. US utilities also operate under a wide variety of business conditions, and this diversity in operating environments facilitates robust statistical estimation and inference.

Of course, benchmarking cost and reliability simultaneously does pose a number of challenges. One involves the quality of the service reliability data. As discussed, the quality of these data vary, and care should be exercised when developing a service reliability sample. Second, while cost and reliability are inter-related, they are also both "endogenous" variables (and not "exogenous" or independent variables) that depend on management choices. This means that if cost and reliability are benchmarked simultaneously, cost will be a function of reliability, and reliability will also be a function of cost. Modeling these types of relationships can be complex, but simultaneous estimation approaches are available to address these complexities. Finally, there may be significant lags between changes in cost and associated changes in reliability. Quantifying these lag structures may also be challenging, but these difficulties become less pronounced with relatively long time series samples, such as those that exist for US electric utilities.

In sum, while the simultaneous benchmarking of cost and reliability does create some technical challenges, it is in essence similar to the cost benchmarking analyses that the Board employed in 4thGenIR. Statistical methods and data sources are available to address the challenges involved with simultaneous cost and reliability benchmarking. If the Board is asked in the future to assess the statistical relationship between cost and reliability in regulatory applications, effort should be directed towards developing appropriate simultaneous benchmarking models rather than relying on statistical tools that are not fit for this purpose.

In that regard, it should be noted that PSE has in fact presented other evidence in this proceeding that addresses the cost-reliability relationship more directly. This evidence was provided in response to Board Staff Interrogatory 11. That response included April 2013 testimony submitted on behalf of Wisconsin Public Service which referenced what PSE called a "SAIDI impact benchmark model." This model was designed to "address and evaluate the cost-effectiveness of reliability projects."[27] This is done through "a SAIDI benchmark model (that) examines the impact of utilities' capital cost levels on SAIDI values after controlling for the effects of other factors that influence SAIDI."[28] In response to the question "What did the models find relative to the *interaction* between SAIDI improvement and capital spending?" (emphasis added), the answer in the testimony is the following:

> The capital cost elasticity of SAIDI is -0.285, such that a one percent increase in the capital score (increased capital spending of one percent) results in a 0.285 percent reduction in SAIDI. In other words, when a utility increases its capital spending by one percent, it is expected to see a SAIDI improvement equal to approximately 0.285%. This finding is quite logical and is statistically significant at a 90 percent confidence level.[29]

Board Staff requested a copy of the dataset and computer program used to develop the SAIDI impact benchmark model. PSE responded that it "signed a confidentiality agreement that does not permit us to share these items with outside parties."[30] However, the PSE testimony states clearly and explicitly that "when a utility increases its capital spending by one percent, it is expected to see a SAIDI improvement equal to approximately 0.285%." This result can be used to "address and evaluate the cost effectiveness of reliability projects"

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[27] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, Appendix A, p. 3 lines 5-6.

[28] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, Appendix A, p. 3 lines 12-14.

[29] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, Appendix A, p. 4 lines 12-19.

[30] Toronto Hydro-Electric System Limited, EB-2014-0116 Interrogatory Responses, 1B-OEBStaff-11, p.2, lines 14-16.

contained in the Custom IR application, by examining the changes in capital spending and SAIDI projected by THESL under the plan and comparing them to the SAIDI changes expected from this capital spending according to PSE's SAIDI impact benchmark model.

At Exhibit 1A, Tab 2, Schedule 1 page 15, THESL presents a summary of its historical and projected capital expenditures. This page indicates the Company's capital expenditures averaged $441 million per annum in 2012-2014. Projected capital expenditures under custom IR are $540 million in 2015; $504 million in 2016; $467 million in 2017; $470 million in 2018; and $502 million in 2019. Average capital expenditures over the custom IR plan accordingly average $496.6 million per annum.

PEG calculated the growth rate in THESL capital expenditures as the change in its average capital spending per annum over the Custom IR plan compared with the Company's average capital spending per annum over the 2012-2014 period just preceding the proposed Custom IR. These figures are $496.6 million per annum and $441 million per annum respectively. THESL's capital spending is therefore projected to increase by 12.61% per annum (*i.e.* 496.6/441 = 1.1261) over the term of the Custom IR.

PSE has written that, according to its SAIDI impact benchmark model, a one percent change in capital spending is expected to lead to a 0.285% improvement in SAIDI (*i.e.* a reduction in SAIDI of 0.285%). THESL projects capital spending in each year of its Custom IR plan to increase by an average of 12.61%. Given the estimated capital cost elasticity of -0.285, this implies that THESL's SAIDI should be expected to decline by 3.59% per annum in each year of its plan (*i.e.* 12.61% * -0.285 = -3.59%).

In Tables 15 and 16 of its report, PSE presents THESL's projected SAIDI value for 2014 as well as the Company's projected SAIDI in each year from 2015-2019. THESL expects its SAIDI in 2014 to equal 71.4. Taking this initial value as given, it is straightforward to compute the "SAIDI Impact" projection of THESL using the SAIDI impact benchmark model. This is done by decreasing THESL's 2014 SAIDI value of 71.4 minutes by 3.59% per annum in each of the five years of the Custom IR plan. These SAIDI Impact projections can then be compared with THESL's own projection of SAIDI over the Custom IR, as reported in PSE's report. These alternate projections for THESL's SAIDI under Custom IR, and the difference between them, are presented in Table Seven.

Table Seven

SAIDI Impact Benchmarking Projections

Year	THESL Actual SAIDI	THESL Projection SAIDI	"SAIDI Impact" Projection	Difference
2014	71.4			
2015		73.8	68.8	5.0
2016		70.2	66.4	3.8
2017		67.2	64.0	3.2
2018		64.8	61.7	3.1
2019		61.2	59.5	1.7

According to the SAIDI impact benchmark model, THESL's increase in capital spending is expected to lead to declines in SAIDI from 71.4 minutes in 2014 to 68.8 minutes in 2015, 66.4 minutes in 2016, 64 minutes in 2017, 61.7 minutes in 2018, and 59.5 minutes in 2019. These are the "benchmark" levels of SAIDI expected for an average utility investing the same amount of money as THESL is planning to invest.

Compared to these benchmarks, THESL projects smaller declines in SAIDI in each of these years. In 2015, THESL projects SAIDI of 73.8 minutes, falling to 70.2, 67.2, 64.8, and 61.2 minutes, respectively, in each of the four remaining years of the Custom IR plan. PSE's SAIDI impact model therefore implies that THESL's capital plan is delivering less SAIDI improvement than would be expected for an average utility investing the same amount of money.

PEG realizes this is a rough measure, and given our profound concerns with PSE's benchmarking work for THESL we certainly do not endorse its SAIDI impact benchmark model. Nevertheless, the model is interesting because it shows the type of work that could pursued in order to understand the interaction between distributors' cost and reliability performance. Work that simultaneously benchmarks cost and service reliability is feasible, and there may be merit in further research on this topic if the interaction between cost and reliability performance is expected to remain an important regulatory issue in Ontario.

6 Toronto Hydro's Stretch Factor and C Factor

This Chapter briefly addresses THESL's proposed stretch factor and custom capital factor, or C factor. The stretch factor is a component of the Company's proposed price cap index that will adjust rates in 2016 through 2019. The C factor is a component of the price cap index designed to recover capital-related costs that exceed the funding for capital expenditures implicitly provided by the plan's "I – X" rate adjustment mechanism.

6.1 Stretch Factor

THESL and PSE both recommend a 0.3% stretch factor in the Custom IR rate adjustment formula. This represents a reduction from the 0.6% stretch factor THESL would be assigned if it elected the Price Cap IR option in the RRFE.[31] PSE explicitly bases this recommendation on the findings of its econometric research, since the difference between the Company's projected and expected costs under the Custom IR plan is within the +/- 10% band the Board established for the cohort of distributors assigned a 0.3% stretch factor. PSE writes "total costs (of THESL) are projected to be well within the 0.3% stretch factor range of plus/minus 10% set in the November 2013 Board Report…based on these findings, reducing the stretch factor from 0.6% to 0.3% seems to be in line with the Board's intention of assigning a 0.3% stretch factor to utilities with "normal" total cost benchmark evaluations."[32]

PEG's review finds this conclusion is unwarranted. A more accurate appraisal indicates that, in a US-only benchmarking study, THESL's costs are projected to be 34.7% above its expected costs under the Custom IR plan. A 34.7% difference between projected and benchmark costs would put THESL in the cohort of distributors assigned a 0.6% stretch factor in Price Cap IR. This finding supports PEG's conclusion regarding THESL's cost performance in our Ontario cost benchmarking study.

It should also be noted that the Company exhibits generally poor reliability performance. PSE and PEG agree that THESL's SAIFI is far greater than what is expected

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[31] A stretch factor is not a necessary component of a Custom IR plan, although Custom IR plans can certainly contain stretch factors. PSE and THESL have elected to include a stretch factor in their proposal, and the PSE report and THESL application both link the magnitude of the proposed stretch factor to THESL's projected cost performance under the Custom IR plan, as measured by PSE's benchmarking analysis that includes data on US electric utilities.

[32] PSE, *op cit*, p. 11.

for a utility operating under its business conditions. PEG's analysis also indicates that THESL is an average SAIDI performer.

Since THESL displays poor cost performance and average to poor reliability performance, PEG believes a stretch factor in excess of 0.6% is defensible for THESL. While the Board has previously linked stretch factors to past cost performance, rather than past reliability performance, the latter may arguably be appropriate for at least two reasons.[33] One is to hold management accountable and establish consequences for sub-par reliability. A second is to compensate customers for the poor reliability they have been experiencing. Customers experience outage costs and/or lost value when their demands for continuous power deliveries are "unserved" because of power outages. Raising the stretch factor to reflect poor reliability performance would reduce the rate of price escalation customers experience and thereby partially compensate them for this lost value.

There are precedents for 1% stretch factors in North American incentive regulation. Based on the results from our cost and reliability benchmarking, PEG therefore recommends that the stretch factor in THESL's Custom IR price cap index be set no lower than 0.6% and no higher than 1%. A stretch factor at the upper end of this range would be more appropriate if the Board wishes to consider demand-side and value of service factors in addition to the cost efficiency considerations it has previously used as the basis for assigning stretch factors.

PEG also recommends that the stretch factor be applied to capital as well as non-capital costs. THESL has acknowledged that the formula for the price cap index (PCI) in the Company's Custom IR plan is equivalent to the following:[34]

$$PCI = (1 - S_{cap}) * (I – X) + C_n$$

In this formula, "PCI" refers to the growth in the price cap index for THESL; "S_{cap}" is the share of capital in the Company's total costs; "I" is the growth in the inflation factor; "X" is the value of the stretch factor (since the productivity factor component of the X factor is

[33] The stretch factor is typically chosen to reflect the potential for incremental productivity gains (relative to the industry productivity trend) under IR. Because relatively inefficient utilities have more potential to achieve incremental productivity gains, all else equal, it is reasonable for the magnitude of assigned stretch factors to be inversely related to a utility's measured relative cost performance.

[34] EB-2014-0116, Interrogatory Responses, 1B-OEBStaff-6, page 2, response to part a).

zero); and "C_n" is the value of the C-factor, which recovers capital cost that is not otherwise recovered via the PCI.

The formula above shows that the stretch factor is applied only to non-capital costs. Because of this, the effective stretch factor in THESL's PCI is not the nominally proposed value of 0.3%. The formula shows that the stretch factor is actually equal to $(1\text{-}S_{cap}) * X$. The C_n factor stands outside of this product and provides dollar-for-dollar recovery of the Company's proposed capital costs, which do not embed an explicit stretch factor. Since the S_{cap} value for Toronto Hydro is about 0.7, the effective stretch factor in THESL's Custom IR is therefore actually 0.09% (*i.e.* (1-0.7) * 0.3% = 0.09%) rather than 0.3%.

PEG believes stretch factors should apply to both capital and non-capital costs. This is the norm in North American, index-based incentive regulation, and it is also how the Board has applied stretch factors in previous IR plans for electricity distributors. Moreover, PEG believes THESL's proposal is not compatible with the Board's Renewed Regulatory Framework for Electricity. In the RRFE Report, the Board writes that it "continues to support a comprehensive approach to rate-setting, recognizing the inter-relationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an outcome-based framework."[35] PEG does not believe the Company's PCI is consistent with the Board's support for a comprehensive approach to rate-setting that recognizes the inter-relationship between capital expenditures and OM&A expenditures. A comprehensive ratesetting approach would not exempt capital expenditures from stretch factor goals, nor would it separate capital from non-capital costs when implementing the plan's main benefit-sharing provision (*i.e.* the stretch factor). THESL has not addressed the important issue of how its Custom IR plan recognizes the inter-relationship between capital and OM&A expenditures. Indeed, its plan appears to specify distinct and independent ratemaking treatment for capital and non-capital costs.

PEG therefore recommends that the stretch factor be applied to all of THESL's costs, rather than non-capital costs as in the Company's proposal. Since THESL's effective stretch

[35] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 9.

factor is (1 – S_{cap}) * (proposed stretch factor), this can be accomplished by subtracting a term from Toronto Hydro's PCI equal to S_{cap} multiplied by the Board's selected factor.

6.2 Custom Capital Factor

The C factor is designed to recover capital-related costs that exceed the funding for capital expenditures implicitly provided by the plan's "I – X" rate adjustment mechanism. THESL's C factor subtracts Scap * (1-X) from the percentage change in the capital costs to be recovered. This is a sound method for ensuring that the C factor reflects only incremental capital spending (*i.e.* capital spending in excess of that implicitly provided under the inflation minus X adjustment formula).

However, while THESL's proposed C factor does collect only incremental capital needs, it does not appropriately translate those cost changes into price changes. The C_n factor converts the percentage change in incremental capital costs into an equivalent percentage change in base rates. This approach will lead to revenue adjustments that exceed what is necessary to recover the change in capital cost because it does not take account of revenue growth from changes in billing determinants.

In cost of service proceedings, setting updated prices clearly considers changes in billing determinants as well as changes in costs.[36] The same principle applies when specific cost components are tracked and recovered in an incentive regulation plan. This principle is also reflected in the "indexing logic" that is used to set the terms of I – X, indexing plans. The following equations display this logic for a price adjustment specifically focused on recovering a change in capital costs.

The rate of growth in revenue (R) can be decomposed into the growth in a price index (P) and a revenue-weighted output index (Y^R) (a dot over a variable indicates the annual growth rate in that variable).

$$\dot{R} = \dot{P} + \dot{Y}^{R} \qquad [1]$$

Let C^N refer to the price changes specifically designed to recover incremental capital costs.

[36] More precisely, determining rate changes considers changes in cost and changes in billing determinatnts between the costs and billing determinants reflected in current, cost-based rates and the costs and billing determinants in the test year (or years) that is (are) used to set upated rates.

$$\dot{P} = C^N \qquad [2]$$

Assume the total revenue to be generated by the C_n charge just recovers the change in the utility's capital-related costs C_k.

$$\dot{R} = \dot{C}_k \qquad [3]$$

If we substitute [2] and [3] into [1] and rearrange terms, the following formula shows the price change that is just sufficient to recover the utility's change in capital costs:

$$C^N = \dot{C}_k - \dot{Y}^R \qquad [4]$$

It can be seen that, in general, the appropriate price change should be equal to the change in capital costs minus the change in a revenue-weighted output index.[37] For THESL, the latter term is equivalent to a revenue-share weighted average of annual growth in the Company's billing determinants. The formula in [4] subtracts the annual change in a revenue-share weighed average of billing determinants from the annual percentage change in capital costs to be recovered in that year. An adjustment for changes in billing determinants will prevent THESL's proposed C factor from over-recovering changes in the Company's incremental capital costs.[38]

The formula in equation [4] can be easily implemented using THESL billing data. This can be done using either projected billing determinants for the coming year (and truing-up those projections to actual billing determinants in the following year) or using the most recently observed rate of change in billing determinants for the adjustment. It is not problematic if THESL has not already provided forecasts of all billing determinants, as observed historical data already exist and forecasting billing determinants for the following year should not be unduly burdensome.

Although the impact of this adjustment depends on how billing determinants evolve in future years, THESL has provided some forecasts that can be used to approximate the impact of the billing determinant adjustment. The Company has projected that its customer numbers

[37] When prices are also adjusted by an I-X mechanism, the price change should also net off the implicit funds for capital investment provided by the indexing mechanism, as THESL's proposal does.

[38] An exception to this rule is if the C factor explicitly sets prices by allocating future costs to projections of future billing determinants, but PEG has seen no indication from the Custom IR application that the C factor will be implemented in this manner. In fact, the entire demonstration of how the C factor would be implemented in Exhibit 1B, Tab 2, Schedule 3, pp. 8 -13 makes no reference to changes in billing determinants or to billing determinants at all.

will grow at an average annual rate of 1.53% in the 2016-2019 period.[39] If kWh per customer and kW per customer remain constant for all customer classes over 2016-2019, then a revenue-weighted index of billing determinants will grow at approximately the same rate as customer growth, or by 1.53% per annum. If kWh per customer and kW per customer grow over the 2016-2019 period, then a revenue-weighted index of billing determinants will grow more rapidly than 1.53% per annum over this period. Conversely, if kWh per customer and kW per customer decline over the 2016-2019 period, then a revenue-weighted index of billing determinants will grow less rapidly than 1.53% per annum over this period.

Given the ongoing emphasis on energy conservation in the Province, PEG believes it is reasonable to expect modest declines in kWh per customer and kW per customer over the Custom IR period. However, provided these declines in consumption and demand are modest, and the forecasts in customer growth are accurate, the change in revenue-weighted billing determinants will still be close to1.5% per annum. PEG therefore estimates that the revenue-weighted change in the Company's billing determinants will grow by about 1.5% per annum during the term of the Custom IR plan. All else equal, this adjustment to THESL's C Factor will therefore reduce price growth by approximately 1.5% per year in 2016 – 2019.

[39] This growth rate is computed using data on the "Customers by Class" table presented in Exhbit 3, Tab 1, Schedule 1, Appendix C-1, page 1.

7. Concluding Remarks and Ratemaking Recommendations

PEG's review indicates that PSE's conclusions regarding Toronto Hydro's cost and reliability performance are largely, but not entirely, unfounded. Based on an econometric analysis of THESL and 85 US utilities, PSE's analysis indicated that THESL's 2010-2012 costs were 31.1% below the costs expected for an average electric utility operating under the Company's business conditions. PEG's review identified a number of areas in which the costs of THESL and the US were not comparably defined or measured. After correcting and/or controlling for these differences, and eliminating an unwarranted "urban core dummy" variable from PSE's econometric cost model, PEG found THESL's costs were 9.7% above its expected costs. The Company's total costs are projected to be 34.7% above its expected costs in 2019, the final year of its Custom IR plan.

PEG's review partly confirmed PSE's reliability benchmarking conclusions. Based on an econometric analysis of THESL and 46 US utilities, PSE found the Company's SAIFI performance was 73% above its expected value but found THESL's SAIDI was 50% below its expected SAIDI. PEG believes the data PSE used for its reliability benchmarking are not suitable for regulatory application, so we compiled an alternative SAIFI and SAIDI dataset and used it to estimate alternate SAIFI and SAIDI benchmarking models. Using these data and models, PEG confirms PSE's finding that THESL's SAIFI is far above its expected level, but we find the Company's SAIDI is not statistically different from its expected level.

Overall, PEG finds THESL has been a sub-par performer with respect to cost and reliability. Given these findings, and a broader review of the Company's Custom IR application and the record in this proceeding, PEG recommends the following changes to Toronto Hydro's Custom IR proposal:

1. Adopt a stretch factor of between 0.6% and 1% rather than THESL and PSE's recommended 0.3%
2. Apply the stretch factor to both OM&A and capital costs under the Custom IR plan
3. Apply an adjustment to the C_n factor in each year to net off the annual growth in billing determinants
4. Spread the Company's proposed capital expenditures over the eight year, 2015-2022 period rather than the proposed five year, 2015-2019 period

Recommendations 1, 2 and 3 were presented and explained in Chapter 6. Below we explain PEG's fourth recommendation.

Spread the Company's proposed capital expenditures over eight years rather than five years

PEG believes there may be value to ratepayers in extending the period of THESL's capital spending program. Doing so is consistent with the RRFE principles of pacing and prioritization of capital spending, while at the same time managing the pace of rate increases for customers. PEG therefore recommends that the capital expenditures in THESL's Custom IR plan be spread out over eight years (2015-2022) rather than concentrated in five years (2015-2019).

Table Eight shows the projected increase in THESL's Custom PCI in 2016 – 2019 under the Company's original proposal, as well as the increase in THESL's Custom PCI with PEG's proposed adjustments to the plan. The inflation and S_{cap} components of the adjustment are identical for THESL and PEG. The Company's stretch factor is equal to 0.3%, and this scenario for the PEG alternative selects a 0.6% stretch factor, which is the lower end of our suggested stretch factor range. PEG's alternative also includes the Stretch factor * S_{cap} and Billing Determinant adjustments previously described, while the THESL plan does not. For simplicity, PEG has also multiplied THESL's C_n value in each year by (5/8), to reflect our recommendation that the Company's capital program be implemented over an eight-year rather than five-year time horizon. We recognize that this is a rough approximation of the impact of spreading capital expenditures over eight years, and other patterns of smoothing capital expenditures can certainly be contemplated.

It can be seen that PEG's recommendations reduce the 2016-2019 growth in the Company's prices from 6.26% per annum to 2.07% per annum. PEG's recommendations therefore reduce the change in THESL prices by 4.19% per annum in each year from 2016 to 2019 (*i.e.* 6.26% - 2.07% = 4.19%). Over the 2016-2019 period, THESL proposes to increase prices by a cumulative 27.4%. With PEG's recommended changes to the Company's Custom IR plan, THESL prices would rise by a cumulative 8.5% over the 2016-2019 period or 18.9% less than under the Company's proposal.

Table Eight

Comparison of Custom PCI Values between Toronto Hydro and PEG for Custom IR Period

	Toronto Hydro				PEG			
Year	2016	2017	2018	2019	2016	2017	2018	2019
Inflation	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
X = Stretch Factor	-0.3%	-0.3%	-0.3%	-0.3%	-0.6%	-0.6%	-0.6%	-0.6%
Cn	4.10%	7.56%	6.67%	5.01%	2.56%	4.73%	4.17%	3.13%
Stretch Factor * Scap	N/A	N/A	N/A	N/A	-0.40%	-0.41%	-0.42%	-0.43%
Billing Determinant Adjustment	N/A	N/A	N/A	N/A	-1.50%	-1.50%	-1.50%	-1.50%
Scap	67.10%	69.20%	70.80%	71.90%	66.90%	68.50%	70.22%	71.35%
Change in Custom PCI	4.56%	7.99%	7.08%	5.40%	1.03%	3.16%	2.58%	1.52%
Average Annual PCI Growth				**6.26%**				**2.07%**

Source of Toronto Hydro data: Toronto Hydro Updated Application Exhibit 1B, Tab 2, Schedule 3.

About 40% of this downward adjustment (*i.e.* 1.5% of the overall 4.19% annual reduction) results from the Billing Determinant adjustment, which is necessary to prevent the C_n factor from over-recovering capital cost. Approximately 10% of the downward adjustment (*i.e.* about 0.41% of the overall 4.19% annual reduction) is due to applying the stretch factor to capital as well as non-capital costs. Approximately 50% of the price reduction is primarily due to spreading the capital spending program over eight years rather than five years. This recommendation will likely defer rather than eliminate these rate changes for THESL, subject to Board review and approval of the Company's deferred, 2020-2022 capital expenditures.

Appendix One: Sources for Reliability Data

PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
8	2008	Document 8.2008	pdf page 4	pdf page 2
8	2009	Document 8.2009	pdf page 4	pdf page 2
8	2010	Document 8.2010	pdf page 4	pdf page 2
8	2011	Document 8.2011	pdf page 5	pdf page 3
12	2002	Document 12.2003	pdf page 8, chart 1.3 (estimate based on graphical representation)	pdf page 7, chart 1.1 (estimate based on graphical representation
12	2003	Document 12.2003	pdf page 8, chart 1.3 and pdf page 6, Major Event Day Table	pdf page 7, chart 1.1 (estimate based on graphical representation
12	2004	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2005	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2006	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2007	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2008	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2009	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2010	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
12	2011	Document 12.2013	pdf page 1, table 1	pdf page 2, table 1
13	2002	Document 13.2002	doc page 1, section (1)(a)	doc page 1, section (1)(a)
13	2003	Document 13.2003	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2004	Document 13.2004	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2005	Document 13.2005	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2006	Document 13.2006	pdf page 2, section (1)(a)	pdf page 2, section (1)(a)
13	2007	Document 13.2007	pdf page 1, section (1)(a)	pdf page 1, section (1)(a)
13	2008	Document 13.2008 and Document 13.2010DR	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11
13	2009	Document 13.2009 and Document 13.2010DR	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11	pdf page 1, section (1)(a), and pdf page 15, table in response to OPCDR2-11
13	2010	Document 13.2012	pdf page 4, table titled "All interruption data"	pdf page 4, table titled "All interruption data"
13	2011	Document 13.2013	pdf page 3, row 2 of table	pdf page 3, row 1 of table
21	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
21	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
21	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
21	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
21	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
21	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
21	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
23	2002	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2003	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2004	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2005	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2006	Document 23.2006	pdf page 11, Exclusion Criteria "None" column for SAIDI in table titled "System Performance Index Comparison"	pdf page 11, Exclusion Criteria "None" column for SAIFI in table titled "System Performance Index Comparison"
23	2007	Document From Files, Email from Ann L. Thierault, CMP Pricing and Analysis, dated 04/02/2009		
23	2008	Document From Files, Email from Ann L. Thierault, CMP Pricing and Analysis, dated 04/02/2009		
23	2009	Document 23.2009	pdf page 97, (27 of 74)	pdf page 97, (27 of 74)
23	2010	Email From Commission		
23	2011	Email From Commission		
27	2003	Attachment to Email from PUCO dated July 16, 2009		
27	2004	Attachment to Email from PUCO dated July 16, 2009		
27	2005	Attachment to Email from PUCO dated July 16, 2009		
27	2006	Attachment to Email from PUCO dated July 16, 2009		
27	2007	Attachment to Email from PUCO dated July 16, 2009		
27	2008	Attachment to Email from PUCO dated July 16, 2009		
27	2009	Document 27.2009	pdf page 2, table 2	pdf page 2, table 3
27	2010	Document 27.2010	pdf page 2, product of tables 1 and 2 values before exclusions	pdf page 2, table 2
27	2011	Document 27.2011	pdf page 3, product of tables 1 and 2 values before exclusions	pdf page 3, table 2

PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
30	2003	Attachment to Email from PUCO dated July 16, 2009		
30	2004	Attachment to Email from PUCO dated July 16, 2009		
30	2005	Attachment to Email from PUCO dated July 16, 2009		
30	2006	Attachment to Email from PUCO dated July 16, 2009		
30	2007	Attachment to Email from PUCO dated July 16, 2009		
30	2008	Attachment to Email from PUCO dated July 16, 2009		
30	2009	Document FE.2009	pdf page 2, table 2	pdf page 2, table 3
32	2002	Document 32.2002	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2003	Document 32.2003	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2004	Document 32.2004	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2005	Document 32.2005	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2006	Document 32.2006	doc page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	doc page 2, table 18a, value for system (rightmost column)
32	2007	Document 32.2007	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2008	Document 32.2008	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2009	Document 32.2009	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2010	Document 32.2010	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
32	2011	Document 32.2011	pdf page 2, table 18a, product of CAIDI and SAIFI values for system (rightmost column)	pdf page 2, table 18a, value for system (rightmost column)
36	2002	Document 36.2006	pdf page 7, table below chart 2	pdf page 8, table below chart 3
36	2003	Document 36.2007	pdf page 7, table below chart 2	pdf page 8, table below chart 3
36	2004	Document 36.2008rev	doc page 8, table attached to chart 2	doc page 8, table attached to chart 3
36	2005	Document 36.2009	pdf page 8, table attached to chart 2	pdf page 8, table attached to chart 3
36	2006	Document 36.2010	pdf page 8, table attached to chart 2	pdf page 8, table attached to chart 3
36	2007	Document 36.2011	pdf page 8, table attached to chart 2	pdf page 8, table attached to chart 3
36	2008	Document 36.2012	pdf page 8, table attached to chart 2	pdf page 9, table attached to chart 3
36	2009	Documents 36.2012 and 36.2013	pdf page 8, table attached to chart 2 and doc page 7, table attached to chart 2	pdf page 9, table attached to chart 3 and doc page 9, table attached to chart 3
36	2010	Documents 36.2012 and 36.2013	pdf page 8, table attached to chart 2 and doc page 7, table attached to chart 2	pdf page 9, table attached to chart 3 and doc page 9, table attached to chart 3
36	2011	Documents 36.2012 and 36.2013	pdf page 8, table attached to chart 2 and doc page 7, table attached to chart 2	pdf page 9, table attached to chart 3 and doc page 9, table attached to chart 3
40	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
40	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
40	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
40	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
40	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
40	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
40	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
43	2002	Document 43.2011	pdf page 3	pdf page 3
43	2003	Document 43.2012	pdf page 3	pdf page 3
43	2004	Document 43.2013	pdf page 3	pdf page 3
43	2005	Document 43.2013	pdf page 3	pdf page 3
43	2006	Document 43.2013	pdf page 3	pdf page 3
43	2007	Document 43.2013	pdf page 3	pdf page 3
43	2008	Document 43.2013	pdf page 3	pdf page 3
43	2009	Document 43.2013	pdf page 3	pdf page 3
43	2010	Document 43.2013	pdf page 3	pdf page 3
43	2011	Document 43.2013	pdf page 3	pdf page 3
44	2005	Attachment to Email from PUCO dated July 16, 2009		
44	2006	Attachment to Email from PUCO dated July 16, 2009		
44	2007	Attachment to Email from PUCO dated July 16, 2009		
44	2008	Attachment to Email from PUCO dated July 16, 2009		
44	2009	Document 44.2009	pdf page 2, table 2	pdf page 2, table 3
46	2002	Document 46.2013	pdf page 4	pdf page 4
46	2003	Document 46.2013	pdf page 4	pdf page 4
46	2004	Document 46.2013	pdf page 4	pdf page 4

PSEID	Year	Source	SAIDI Page(s) and Table Name(s) or Number(s), if Given	SAIFI Page(s) and Table Name(s) or Number(s), if Given
46	2005	Document 46.2013	pdf page 4	pdf page 4
46	2006	Document 46.2013	pdf page 4	pdf page 4
46	2007	Document 46.2013	pdf page 4	pdf page 4
46	2008	Document 46.2013	pdf page 4	pdf page 4
46	2009	Document 46.2013	pdf page 4	pdf page 4
46	2010	Document 46.2013	pdf page 4	pdf page 4
46	2011	Document 46.2013	pdf page 4	pdf page 4
62	2005	Document FL.2005	pdf pages 17, 19, and 20	pdf pages 17, 19, and 20
62	2006	Document FL.2006review	pdf pages 29, table 2-1, and 67, table A-1	pdf pages 29, table 2-1, and 67, table A-1
62	2007	Document FL.2007review	pdf pages 30, table 2-1, and 72, table A-1	pdf pages 30, table 2-1, and 72, table A-1
62	2008	Document FL.2008review	pdf pages 26, table 2-1, and 68, table A-1	pdf pages 26, table 2-1, and 68, table A-1
62	2009	Document FL.2009review	pdf pages 30, table 2-1, and 82, table A-1	pdf pages 30, table 2-1, and 82, table A-1
62	2010	Document FL.2010review	pdf pages 33, table 2-1, and 84, table A-1	pdf pages 33, table 2-1, and 84, table A-1
62	2011	Document FL.2011review	pdf pages 32, table 2-1, and 84, table A-1	pdf pages 32, table 2-1, and 84, table A-1
63	2005	Document FL.2005	pdf pages 22, 23. and 24	pdf pages 22, 23. and 24
63	2006	Document FL.2006review	pdf pages 30, table 2-3 and 69, table A.5	pdf pages 30, table 2-3 and 69, table A.5
63	2007	Document FL.2007review	pdf pages 31, table 2-2 and 76, table A.5	pdf pages 31, table 2-2 and 76, table A.5
63	2008	Document FL.2008review	pdf pages 27, table 2-2 and 71, table A.5	pdf pages 27, table 2-2 and 71, table A.5
63	2009	Document FL.2009review	pdf pages 31, table 2-2 and 85, table A.5	pdf pages 31, table 2-2 and 85, table A.5
63	2010	Document FL.2010review	pdf pages 34, table 2-2, and 88, table A-5	pdf pages 34, table 2-2, and 88, table A-5
63	2011	Document FL.2011review	pdf pages 33, table 2-2, and 88, table A-5	pdf pages 33, table 2-2, and 88, table A-5
68	2005	Document FL.2005	pdf pages 28 and 30	pdf pages 28 and 30
68	2006	Document FL.2006review	pdf pages 32, table 2-7, and 62, table A-13	pdf pages 32, table 2-7, and 62, table A-13
68	2007	Document FL.2007review	pdf pages 33, table 2-4, and 80, table A-13	pdf pages 33, table 2-4, and 80, table A-13
68	2008	Document FL.2008review	pdf pages 29, table 2-4, and 74, table A-13	pdf pages 29, table 2-4, and 74, table A-13
68	2009	Document FL.2009review	pdf pages 33, table 2-4, and 88, table A-13	pdf pages 33, table 2-4, and 88, table A-13
68	2010	Document FL.2010review	pdf pages 36, table 2-4, and 96, table A-13	pdf pages 36, table 2-4, and 96, table A-13
68	2011	Document FL.2011review	pdf pages 35, table 2-4, and 96, table A-13	pdf pages 35, table 2-4, and 96, table A-13
78	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
78	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
89	2002	Document 89.2006	pdf page 3, table/section D	pdf page 3, table/section D
89	2003	Document 89.2007	pdf page 3, table/section D	pdf page 3, table/section D
89	2004	Document 89.2009	pdf page 3, table/section E	pdf page 3, table/section E
89	2005	Document 89.2010	pdf page 4, table 1	pdf page 4, table 1
89	2006	Document 89.2010	pdf page 4, table 1	pdf page 4, table 1
89	2007	Document 89.2010	pdf page 4, table 1	pdf page 4, table 1
89	2008	Document 89.2011	pdf page 8, table 7	pdf page 8, table 7
89	2009	Document 89.2012	pdf page 7, table 7	pdf page 7, table 7
89	2010	Document 89.2013	pdf page 6, table 7	pdf page 6, table 7
89	2011	Document 89.2013	pdf page 6, table 7	pdf page 6, table 7
91	2008	Document 91.2008	pdf page 4, section 4, values under "Including MED"	pdf page 4, section 4, values under "Including MED"
91	2009	Document 91.2009	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
91	2010	Document 91.2010	pdf page 3, section 4, values under "Including MED"	pdf page 3, section 4, values under "Including MED"
91	2011	Document 91.2011	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2008	Document 98.2008	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2009	Document 98.2009	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2010	Document 98.2010	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
98	2011	Document 98.2011	pdf page 2, section 4, values under "Including MED"	pdf page 2, section 4, values under "Including MED"
99	2002	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2003	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2004	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2005	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"

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99	2006	Document WI.2007	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 4, chart titled "MGE SAIFI, CAIDI, and SAIDI Reliability Indexes"
99	2007	Document 99.2008	pdf page 2, table titled "Total Annual Statistics"	pdf page 2, table titled "Total Annual Statistics"
99	2008	Document 99.2009	pdf page 2, table titled "Total Annual Statistics"	pdf page 2, table titled "Total Annual Statistics"
99	2009	Document 99.2010	pdf page 2	pdf page 2
99	2010	Document 99.2011	pdf page 2	pdf page 2
99	2011	Document 99.2012	pdf page 2	pdf page 2
124	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
124	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
124	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
124	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
124	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
124	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
124	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
126	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
126	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
126	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
126	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
126	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
126	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
130	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
130	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
135	2003	Attachment to Email from PUCO dated July 16, 2009		
135	2004	Attachment to Email from PUCO dated July 16, 2009		
135	2005	Attachment to Email from PUCO dated July 16, 2009		
135	2006	Attachment to Email from PUCO dated July 16, 2009		
135	2007	Attachment to Email from PUCO dated July 16, 2009		
135	2008	Attachment to Email from PUCO dated July 16, 2009		
135	2009	Document FE.2009	pdf page 2, table 2	pdf page 2, table 3
136	2003	Attachment to Email from PUCO dated July 16, 2009		
136	2004	Attachment to Email from PUCO dated July 16, 2009		
136	2005	Attachment to Email from PUCO dated July 16, 2009		
136	2006	Attachment to Email from PUCO dated July 16, 2009		
136	2007	Attachment to Email from PUCO dated July 16, 2009		
136	2008	Attachment to Email from PUCO dated July 16, 2009		
136	2009	Document AEP.2009	pdf page 2, table 2	pdf page 2, table 3
140	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
140	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
140	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
140	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33

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140	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
140	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
140	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
142	2002	Document 142.2011	pdf page 3, Table 1	pdf page 3, Table 1
142	2003	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2004	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2005	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2006	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2007	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2008	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2009	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2010	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
142	2011	Document 142.2012	pdf page 4, Table 1	pdf page 4, Table 1
148	2002	Document OR.2008	pdf page 10	pdf page 8
148	2003	Document OR.2008	pdf page 10	pdf page 8
148	2004	Document OR.2008	pdf page 10	pdf page 8
148	2005	Document OR.2008	pdf page 10	pdf page 8
148	2006	Document OR.2008	pdf page 10	pdf page 8
148	2007	Document OR.2013	pdf page 7	pdf page 9
148	2008	Document OR.2013	pdf page 7	pdf page 9
148	2009	Document OR.2013	pdf page 7	pdf page 9
148	2010	Document OR.2013	pdf page 7	pdf page 9
148	2011	Document OR.2013	pdf page 7	pdf page 9
150	2002	Document 150.2007	pdf page 132, table 2.3-D	pdf page 132, table 2.3-D
150	2003	Document 150.2008	pdf page 140, table 2.3-C	pdf page 140, table 2.3-C
150	2004	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2005	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2006	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2007	Document 150.2011	pdf page 223, table 2.4-E	pdf page 223, table 2.4-E
150	2008	Document 150.2012	pdf page 343, table 2.4-E	pdf page 343, table 2.4-E
150	2009	Document 150.2013	pdf page 280, table 2.4-E	pdf page 280, table 2.4-E
150	2010	Document 150.2013	pdf page 280, table 2.4-E	pdf page 280, table 2.4-E
150	2011	Document 150.2013	pdf page 280, table 2.4-E	pdf page 280, table 2.4-E
152	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
152	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
159	2002	Document NY.2006	pdf page 4, product of duration and frequency times 60	pdf page 4
159	2003	Document NY.2007	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2004	Document NY.2008	pdf page 33, product of duration and frequency times 60	pdf page 33
159	2005	Document NY.2009	pdf page 29, product of duration and frequency times 60	pdf page 29
159	2006	Document NY.2010	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2007	Document NY.2011	pdf page 33, product of duration and frequency times 60	pdf page 33
159	2008	Document NY.2012	pdf page 39, product of duration and frequency times 60	pdf page 39
159	2009	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2010	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
159	2011	Document NY.2013	pdf page 32, product of duration and frequency times 60	pdf page 32
163	2002	Document 163.2011	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2003	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2004	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2005	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"

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163	2006	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2007	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2008	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2009	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2010	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
163	2011	Document 163.2012	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"	pdf page 8, table titled "HISTORICAL SYSTEM RELIABILITY DATA (USING IEEE 1366 EXCLUSION CRITERIA)"
169	2002	Document 169.2011	pdf page 3, table titled "Historical System Reliability (IEEE Std 1366-2003)"	
169	2003	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2004	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2005	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2006	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2007	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2008	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2009	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2010	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
169	2011	Document 169.2012	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"	pdf page 4, table titled "Historical System Reliability (IEEE Std 1366-2003)"
171	2002	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2003	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2004	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2005	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2006	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2007	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2008	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2009	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2010	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
171	2011	Document IN.2012	pdf page 2, table titled "Electric Reliability: Including Major Events*"	pdf page 2, table titled "Electric Reliability: Including Major Events*"
178	2005	Document FL.2005	pdf pages 25, 26, and 27	pdf pages 25, 26, and 27
178	2006	Document FL.2006review	pdf pages 31, table 2-5, and 70, table A-9	pdf pages 31, table 2-5, and 70, table A-9
178	2007	Document FL.2007review	pdf pages 32, table 2-3, and 78, table A-9	pdf pages 32, table 2-3, and 78, table A-9
178	2008	Document FL.2008review	pdf pages 28, table 2-3, and 72, table A-9	pdf pages 28, table 2-3, and 72, table A-9
178	2009	Document FL.2009review	pdf pages 32, table 2-3, and 86, table A-9	pdf pages 32, table 2-3, and 86, table A-9
178	2010	Document FL.2010review	pdf pages 35, table 2-3, and 92, table A-9	pdf pages 35, table 2-3, and 92, table A-9
178	2011	Document FL.2011review	pdf pages 34, table 2-3, and 92, table A-9	pdf pages 34, table 2-3, and 92, table A-9
186	2002	Document 186.2006	pdf page 10, chart IV-1.1	pdf page 11, chart IV-1.2
186	2003	Document 186.2007	pdf page 9, chart IV-1.1	pdf page 10, chart IV-1.2
186	2004	Document 186.2008	pdf page 9, chart IV-1.1	pdf page 10, chart IV-1.2
186	2005	Document 186.2009	word doc page 9, chart IV-1.1	word doc page 10, chart IV-1.2
186	2006	Document 186.2010	word doc page 14, chart IV-4.1	word doc page 15, chart IV-4.2
186	2007	Document 186.2011	word doc page 11, chart IV-4.1	word doc page 12, chart IV-4.2
186	2008	Document 186.2012	word doc page 8, chart IV-4.1	word doc page 9, chart IV-4.2
186	2009	Document 186.2013	word doc page 10, chart IV-4.1	word doc page 11, chart IV-4.2
186	2010	Document 186.2013	word doc page 10, chart IV-4.1	word doc page 11, chart IV-4.2
186	2011	Document 186.2013	word doc page 10, chart IV-4.1	word doc page 11, chart IV-4.2

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195	2002	Document VA 2010	Row for DVP	Row for DVP
195	2003	Document VA 2010	Row for DVP	Row for DVP
195	2004	Document VA 2010	Row for DVP	Row for DVP
195	2005	Document VA 2010	Row for DVP	Row for DVP
195	2006	Document VA 2010	Row for DVP	Row for DVP
195	2007	Document VA 2010	Row for DVP	Row for DVP
195	2008	Document VA 2010	Row for DVP	Row for DVP
195	2009	Document VA 2010	Row for DVP	Row for DVP
195	2010	Document VA 2010	Row for DVP	Row for DVP
195	2011	Document 195.2012	pdf page 12	pdf page 14
198	2002	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2003	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2004	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2005	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2006	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2007	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2008	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2009	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2010	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
198	2011	Document 198.2012	Worksheet labeled PEG - ALL YEARS	Worksheet labeled PEG - ALL YEARS
201	2002	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2003	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2004	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2005	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2006	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2007	Document WI.2007	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 5, chart titled "WEPCO SAIFI, CAIDI, and SAIDI Reliability Indexes"
201	2008	Document 201.2008	pdf page 5, table titled "We Energies RELIABILITY INDICES"	pdf page 5, table titled "We Energies RELIABILITY INDICES"
201	2009	Document 201.2009	pdf page 5, table titled "We Energies RELIABILITY INDICES"	pdf page 5, table titled "We Energies RELIABILITY INDICES"
201	2010	Document 201.2010	pdf page 6, table titled "We Energies RELIABILITY INDICES"	pdf page 6, table titled "We Energies RELIABILITY INDICES"
201	2011	Document 201.2011	pdf page 5, table titled "We Energies RELIABILITY INDICES"	pdf page 5, table titled "We Energies RELIABILITY INDICES"
202	2009	Document 202.2013	pdf page 4, table titled "Historical Comparison"	pdf page 4, table titled "Historical Comparison"
202	2010	Document 202.2013	pdf page 4, table titled "Historical Comparison"	pdf page 4, table titled "Historical Comparison"
202	2011	Document 202.2013	pdf page 4, table titled "Historical Comparison"	pdf page 4, table titled "Historical Comparison"
203	2002	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2003	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2004	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2005	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2006	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2007	Document WI.2007	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"	pdf page 6, chart titled "WPS SAIFI, CAIDI, and SAIDI Reliability Indexes"
203	2008	Document 203.2008	pdf page 7, table titled "2008 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2008 Electric Distribution Customer Interruptions"
203	2009	Document 203.2009	pdf page 7, table titled "2009 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2009 Electric Distribution Customer Interruptions"
203	2010	Document 203.2010	pdf page 7, table titled "2010 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2010 Electric Distribution Customer Interruptions"
203	2011	Document 203.2011	pdf page 7, table titled "2011 Electric Distribution Customer Interruptions"	pdf page 7, table titled "2011 Electric Distribution Customer Interruptions"

Appendix Two: Econometric Research

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog.[40] This very flexible function is the most frequently used in econometric cost research, and by some account the most reliable of several available alternatives.[41] The general form of the translog cost function is:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A.2.2 Estimation Procedure

We estimated this system of equations using a procedure first proposed by Zellner (1962).[42] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve even a better estimator, PEG iterates this procedure to convergence.[43] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[44]

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[45] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

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

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

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

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

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Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2014-0116

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Application for electricity distribution rates effective from May 1, 2015 and for each following year effective January 1 through to December 31, 2019

BEFORE: **Christine Long**
Presiding Member

Ken Quesnelle
Vice Chair and Member

Cathy Spoel
Member

December 29, 2015

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1 INTRODUCTION AND SUMMARY

This is a Decision of the Ontario Energy Board (OEB) in response to an Application by Toronto Hydro-Electric System Limited (Toronto Hydro) for permission to charge certain distribution rates to its customers.

Toronto Hydro is an electricity distributor licensed by the OEB which provides electricity to the City of Toronto and serves approximately 730,000 customer accounts. Toronto Hydro's distribution system consists of distribution lines, poles and equipment, distributing approximately 18 percent of the electricity consumed in the province of Ontario. Toronto Hydro is a wholly-owned subsidiary of Toronto Hydro Corporation (THC), whose sole shareholder is the City of Toronto.

Toronto Hydro has applied for distribution rates for the years 2015 to 2019. The OEB allows distributors to propose a "custom" application which addresses the unique circumstances that their utility will face over the next five years (Custom IR).

Toronto Hydro has filed a Custom IR on the basis that it is required to spend a large amount on capital replacement and upgrades. In order to be able to minimize the amount of the annual bill impact on customers and to be able to complete the sheer volume of work required, Toronto Hydro has proposed a paced strategy which spreads the capital work over an extended period of time.

Intervenor groups participating in the Application process generally oppose the levels of spending proposed by Toronto Hydro for both capital and operating expenses. These groups argue that Toronto Hydro could be more efficient and does not need to undertake the volume of capital projects it proposes within the timeframe contemplated. Projects that the intervenors concede are necessary could be completed for a lower cost.

The OEB's job is to determine distribution rates that are just and reasonable. In doing so, the OEB must balance the needs of customers and the utility.

The OEB is approving capital spending which will allow Toronto Hydro to proceed with some of the proposed upgrades to its capital infrastructure. While the OEB understands the position taken by the utility, the OEB is not granting Toronto Hydro the entire amount it seeks to spend on capital. The OEB is of the view that efficiencies could be realized which would reduce the amount necessary to complete capital projects. The OEB also is of the view that reductions could be made to Toronto Hydro's proposed operations and maintenance budgets.

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. It is on the basis of outcomes that the OEB has reviewed the Application and come to its Decision.

Key Decision Points are listed below.

- Toronto Hydro's rates will be set on a 5 year Custom IR basis.
- Toronto Hydro's rate framework is structured in such a way as to support the achievement of RRFE objectives
- - The 2015 base OM&A increase should be 2.1%, approximately the rate of inflation over the 2014 actual spending, providing a base OM&A of $246 million.
- Toronto Hydro's proposed capital budget will be reduced by 10% annually
- The C-factor mechanism for capital recovery in the 2016 to 2019 period is accepted subject to certain modifications
- An earnings sharing mechanism (ESM) as proposed by Toronto Hydro is accepted. The ESM will be symmetrical and incorporate a 100 basis point dead band. Earnings in excess of the 100 basis point dead band are to be split on a 50:50 basis with ratepayers.
- The proposal regarding the transfer of street lighting assets and Toronto Hydro's load forecast are approved

The OEB will allow Toronto Hydro to implement rate and fiscal year synchronization effective January 1, 2016. Rates will be effective May 1, 2015.

While Toronto Hydro will provide more accurate bill impacts with its draft rate order filing, the OEB approximates that this Decision will increase the distribution portion of the bill by 5%.

2 ORGANIZATION OF THE DECISION

As summarized above, the OEB has determined that it will approve rates for the 2015 to 2019 period using the Custom IR framework proposed by Toronto Hydro with the modifications outlined in this Decision.

The OEB has organized this Decision into chapters, reflecting the issues that the OEB has considered in making its findings. Each chapter covers the OEB's reasons for approving or denying certain aspects of the Application in the form requested and its determinations on what level of spending is allowed in the calculation of Toronto Hydro's rates using the Custom IR methodology.

The initial chapter provides the OEB's views as to the extent to which Toronto Hydro's Application conforms to the RRFE policy and why the OEB believes this to be the case.

Subsequent chapters deal with the proposed work plans of Toronto Hydro in terms of operations and maintenance spending as well as its capital spending and how it developed its capital spending plan as well as its proposal for a C-factor capital recovery mechanism.

Matters dealing with the development of the rates themselves are covered in chapters dealing with revenue requirement (which incorporates the results of the budgets for capital and operations and maintenance, cost of capital, depreciation, etc.) load forecast, cost allocation and rate design

3 DECISION ON ISSUES

3.1 The OEB's Renewed Regulatory Framework for Electricity (RRFE) (Issue 2.1)

The OEB must consider whether Toronto Hydro's proposed Custom IR approach provides an appropriate framework for rate-setting in light of Toronto Hydro's capital needs and operating circumstances and the OEB's policies as set out in the RRFE.

The OEB assesses rate applications within the context of the RRFE, a new policy framework it adopted in 2012. Toronto Hydro has applied for a Custom IR for 2015-2019, one of the options available to it under the RRFE.

Throughout this Decision the OEB makes findings and observations on the objectives and implementation of the RRFE in the context of Toronto Hydro's Application. These are summarized here in order to assist all interested parties to understand the OEB's approach to the RRFE.

The OEB intends to provide guidance to distributors who have yet to file applications, which will provide an opportunity for the OEB to articulate its views as the industry evolves in response to the RRFE, as regulatory predictability is a necessary component of an effective regulatory framework.

This section of the Decision addresses the extent to which Toronto Hydro's Application conforms to the RRFE and is likely to achieve its objectives.

The OEB does not decide whether the option chosen by the applicant is the most appropriate. The OEB decides rather whether the proposal contains features that can be relied on to achieve the RRFE objectives. The Custom IR is described in the 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.

At the heart of the RRFE policy objectives are customer-focused outcomes and continuous performance improvement by distributors. The policy reflects the OEB's view that these outcomes are most likely to be achieved when the service interests of customers and the business interests of distributors are aligned.

This alignment will only be achieved through an ongoing effort by distributors to engage customers in a way that provides useful input into the development of their business plans. The process should educate customers and distributors of each other's issues and priorities. Distributors should develop plans that respond to customer service needs.

This alignment also requires that distributors be financially rewarded for successful performance. This shifts the focus of regulatory review from strictly an examination of the reasonableness of costs to measuring and monitoring performance indicators as they relate to the value of services received by customers.

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.[1]

In this proceeding, a variety of views were advanced as to whether Toronto Hydro's Application adequately meets the expectations of the RRFE. Some parties agreed with Toronto Hydro that its proposal complies with the RRFE and all related OEB guidance, while others urged the OEB to deny Toronto Hydro's 5 year Custom IR and set rates on a two year cost of service basis.

Particular concerns were raised about benchmarking and customer engagement.

[1] The OEB recently provided a decision on a Hydro One Custom rate application. The OEB determined that Hydro One's proposal was not likely to achieve the RRFE policy objectives. Instead, the OEB approved rates on a three year cost of service framework basis. It did so to allow for necessary program spending and to allow the time necessary for Hydro One to develop features intended to achieve the RRFE policy objectives.

Findings

Toronto Hydro's rate framework proposal incorporates features that are aligned with the RRFE's objectives. Toronto Hydro will be incented to achieve improved performance over the life of the plan. Its "C factor" method of funding its capital plan is intended to correspond to its capital program execution over the life of the plan and is a customized solution to its business needs. The OEB has determined that Toronto Hydro's rates will be set on a 5 year Custom IR basis. The OEB accepts that Toronto Hydro's rate framework is structured so as to support the achievement of RRFE objectives but, as discussed later in the Decision, finds that Toronto Hydro's evidence does not fully support its proposed spending levels.

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, as discussed in the section of the Decision dealing with reporting requirements.

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.

Toronto Hydro does not monitor whether or not it has optimized the manner in which it tenders the work but instead relies heavily on the fact that it goes to market to perform over 80%[2] of its work. It has no comparisons of a holistic project RFP approach versus

[2] Argument In Chief Compendium Tab 1 Table of Contents, p.1 and discussed in Transcript, Volume 4, p. 87 L23 to p.88 L17,

its unit of work approach. There are no tangible performance enhancement programs with its service providers.

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. The effect of these determinations is provided in subsequent sections.

3.2 Customer Engagement and Outcomes (Issues 2.1 and 2.3)

Background

Toronto Hydro's Application stated that it had undertaken two levels of customer engagement:

i. ordinary course, day-to-day engagement with its residential, non-residential and very large customers, and

ii. customer engagement activities undertaken specifically in connection with the Application.

Many intervenors argued that Toronto Hydro's customer engagement efforts were inadequate in producing acceptable outcomes for existing and future customers. They argued that the activities undertaken were inadequate to meet the OEB's requirements for two reasons: (i) customers had not been provided with enough information to understand the impact of proposed levels of work on their rates and (ii) Toronto Hydro did not adequately demonstrate how what was heard from its customers was reflected in the Application. Several intervenors questioned Toronto Hydro's conclusion from its customer engagement activities that a majority of its customers accept the need for the proposed rate increases and expressed concerns about the process used to reach this conclusion. These concerns included the reliability of the survey, the lack of context in the way spending proposals were put to customers, and the fact the results were too late to have any meaningful influence on the capital and operating plans.

Toronto Hydro argued that their plans are consistent with customers' views expressed during its customer engagement exercises.

Findings

The OEB finds that Toronto Hydro's customer engagement efforts undertaken as part of the Application are reasonable as the first such effort in the context of the RRFE.

However, there are some deficiencies which the OEB will expect Toronto Hydro to address by the time it files its next full cost of service or Custom IR rate application.

The OEB agrees with intervenors and OEB staff that Toronto Hydro did not provide its customers with sufficient information on the context of the proposed Application such as its existing benchmarking ranking and its relative levels of productivity and efficiency.

Toronto Hydro did not develop its plan in conjunction with its customer engagement activities. It sought input to confirm the plan it had already prepared rather than engaging its customers to ascertain their preferred options in the context of Toronto Hydro's current cost and reliability situations.

Achievement of RRFE outcomes relies on an ongoing effort by the distributor to engage customers in a process designed to inform its plans. Without this, it is unlikely that a distributor will be able to align customer needs with its business needs. This engagement process is intended to educate customers and distributors of each other's issues and priorities. The OEB expects distributors to develop plans based on its customers' informed input on the service that distributors provide.

3.3 OM&A Programs and Expenditures (Issue 3.1)

Background

Toronto Hydro's proposed OM&A expenses are summarized below:

Toronto Hydro - 2015 Test Year Increase versus Prior Years
$M

	2011 A	2012 A	2012 R	2013 A	2014 B	2014 A	2015 T
OM&A	238.6	243.5	215.8	246.4	246.6	241.2	269.5

A=Actual
R=With restructuring costs removed
B=Bridge
T=Test

Findings

Toronto Hydro requested an OM&A budget of $269.5 million for 2015, with indexed adjustments over the 5 years of the plan.

The 2015 request is an increase of 11.7% over the 2014 actual expenditures of $241.2 million.

The OM&A expenses since the last rebasing in 2011 have been fairly flat as can be seen in the above table.

The breakdown of spending on program areas was not available for 2014 actuals at the time of the hearing, so comparisons are with the 2013 actual expenses.

The main drivers of the requested increase are preventative and predictive maintenance (57% over 2013), corrective maintenance (31% over 2013), customer care (16% over 2013), information technology and facilities management. The only significant decrease is in emergency response which was anomalously high in 2013 due to the ice storm in December of that year.

The intervenors and OEB staff raised the following main issues about the OM&A budget:

1. The increase in the 2015 base is excessive given historical levels of spending and does not adequately reflect customers' ability to pay
2. The OM&A budget does not reflect reductions in maintenance that would be expected with increased capital spending on system renewal
3. Toronto Hydro did not prepare 5 years of OM&A budgets
4. Should Toronto Hydro be required to give ratepayers the IRM benefit of restructuring in 2012?

As well, the proposed treatment of certain specific budget items was questioned:

1. Regulatory costs
2. Sharing of savings due to ERP in later years of the plan
3. Accounting methodology for OPEBs (Other Post-Employment Benefits)

3.3.1 The Base Level of OM&A

Toronto Hydro described its budgeting process as "top down/bottom up". In oral evidence, the Toronto Hydro witness explained the process:

> The instructions were provided by the executive that the departments should come forward with their 2015 needs, as those needs would persist for five years, and exercise some constraint before requesting increases, but where increases were requested over current levels …be prepared to justify those increases.[3]

[3] Transcript, Vol. 9, p.20 L16-22

No specific target was given, except that it would be preferable to keep the OM&A envelope from 2015 onwards at inflation.

The witness further went on to say:

> …the top-down instruction was to put forward what the expert in those areas believe is required and to exercise some constraint in doing so, and there was that iterative exercise with those requests coming in and reviewing those requests as a whole, and considering factors such as functional requirements, customer service and rate impacts,…and balancing, again, those customer needs against things like customer impacts such as rate impacts …[4]

From 2011 to 2014 the actual spending by Toronto Hydro on OM&A was essentially flat. While the test year budget for 2014 was $246.6 million, the actual spend was $241.2 million. Notably, several of the program areas for which large increases have been requested for 2015 were actually underspent in 2014. For example, preventive and predictive maintenance ($14.9 million actual whereas $16.1 million was budgeted), corrective maintenance ($17.6 million actual whereas $19 million was budgeted) and customer care ($40.6 million actual whereas $42.2 million was budgeted).

In the absence of compelling evidence as to the reasons for the spending levels in 2014, the inference drawn by the OEB is that this is the level of spending reasonably required by Toronto Hydro to maintain and operate its system.

The OEB expects that the benefits of Toronto Hydro's IRM from 2011 to 2014 will persist for ratepayers into the next rate cycle. Toronto Hydro's request for an OM&A budget for 2015 of $269.5 million is an 11.7% increase over its actual spending in 2014. Given Toronto Hydro's evident ability to operate for the last 4 years with very modest increases, the OEB finds that a 2015 base OM&A increase should be 2.1%, approximately the rate of inflation over the 2014 actual spending. This provides a base OM&A spending level of $246 million.

[4] Transcript, Vol. 9, p. 21 L8 -17.

3.3.2 Relationship between OM&A and Capital Spending

Toronto Hydro argued that OM&A does not decrease with increased spending on capital system renewal, hence the large requested increases in the maintenance program areas.

While the OEB recognizes that the relationship between capital spending and OM&A is complex, the OEB finds that it is reasonable to expect that there will be some reductions in OM&A costs, particularly those related to maintenance, from the large capital expenditures, over many years, on system renewal, general plant, and system service. New assets should require less maintenance than old assets (at least in the corrective maintenance category) and underground assets should require less maintenance than overhead assets as there is no need for vegetation management, and no issue of animal interference.

Toronto Hydro`s own evidence suggests that given the historical record, there should be less maintenance required with newer assets. The Toronto Hydro witness said in oral evidence:

> …when I started at the Hydro, we used to have our crews organized in a group called construction and maintenance, and the reason we did that is their normal job would be to do capital construction, and they would be called away periodically if there was a reactive requirement, if something failed and it needed to be replaced, and then they would go back to their capital work.
>
> Today, we have two departments and 13 full-time crews that do nothing but replacement of failing assets, and that`s because of this age-related problem.[5]

The OEB finds that as aging assets are replaced the extent to which the system requires reactive maintenance should be reduced. Most of Toronto Hydro's capital spending is on system upgrades and renewal rather than expansion of the system, so new assets are replacing old ones that require corrective maintenance in addition to routine inspections and preventive maintenance. The OEB agrees with Toronto Hydro that the need for inspections and routine maintenance will continue with new assets, but the expensive corrective maintenance and the unplanned reactive maintenance should reduce over time if the system is well managed. None of these relative costs are reflected in Toronto Hydro's OM&A budget. However, the OEB will not reduce the OM&A budget from that spent over the last few years as it recognizes that some of the

[5] Transcript, Vol. 6, p. 67, L12-L22.

assets not replaced will continue to require extensive maintenance, and that system renewal is a gradual process.

3.3.3 Are 5 years of OM&A forecast required?

The OEB agrees with Toronto Hydro and some of the intervenors that Toronto Hydro is not required to prepare a forecast of five years of OM&A budgets to comply with the RRFE for a Custom IR application. This would essentially result in a five year cost of service application, rather than an incentive ratemaking scheme. The OEB will expect Toronto Hydro to manage within the OM&A envelope adjusted annually by the incentive factor for the five year period of the plan addressed later in this Decision..

3.3.4 Sharing Benefits of IRM restructuring

The OEB does not agree with intervenors that the restructuring savings incurred by Toronto Hydro during the IRM period should be shared beyond their persistence in a lower base OM&A. This would be counter to the principles of an IRM regime. The OEB recognizes that Toronto Hydro has restructured, which undoubtedly contributed to its ability to manage with essentially flat OM&A spending from 2011 to 2014. Toronto Hydro did incur real costs to restructure, from which the ratepayers will benefit going forward.

3.3.5 Regulatory Costs

There are several issues related to the recovery of regulatory costs. Toronto Hydro seeks recovery of the full costs of preparing the Application, spread out over the 5 years of the Custom IR period. Some of these costs were incurred and paid by Toronto Hydro in prior years, so the first issue is whether these can and should be recovered in 2015 and going forward. Some of the intervenors also argue that the costs are excessive and some portion should be disallowed. Finally, Toronto Hydro has also requested recovery of its costs related to the wireless forbearance application as it is for the benefit of ratepayers. These costs were also substantially incurred in prior years.

The OEB agrees with Toronto Hydro that the regulatory costs of the Application can and should be recovered over the 5 year Custom IR period. This is consistent with the OEB's usual practice, and is the reasonable way for Toronto Hydro to recover those costs. Preparation of an application often spans more than one rate year.

The OEB also does not agree that any part of the costs of the Application should be disallowed. Toronto Hydro is larger and has more complex issues than most if not all distributors in Ontario, and the Application involves billions of dollars of spending. The RRFE requires distributors to prepare and support their applications, particularly Custom IRs, in a very thorough way. The OEB finds that the level of background work undertaken by Toronto Hydro prior to preparing its Application was reasonable and appropriate given its circumstances. The fact that some of this work may not ultimately be filed in support of the Application does not mean that it was not useful in helping Toronto Hydro to refine its plans. .

While Toronto Hydro is correct that the Wireless Forbearance Application does benefit ratepayers, to the extent that funds were spent in 2014, the OEB will not allow them to be recovered in 2015. The appropriate way to recover these costs in a subsequent year would have been to request a deferral account in the year the costs were incurred. The OEB does not consider these costs to be part of this Application.

3.3.6 Enterprise Resource Planning (ERP) Savings

The ERP will be implemented in 2016 and savings are expected from the efficiencies that will result starting in 2017 or 2018. Some intervenors requested that the OEB deviate from its usual approach and require Toronto Hydro to adjust its OM&A budget to account for these savings in later years of the Custom IR.

Toronto Hydro proposed an 11.7% increase in OM&A spending over its 2014 actual spending level. The OEB has approved a 2.1% increase recognizing the historic spending levels. The OEB notes that Toronto Hydro will have to find efficiencies to accomplish the required OM&A and will therefore not require further reductions specifically to account for any savings resulting from the introduction of the ERP.

3.3.7 Other Post-Employment Benefits (OPEBs)

OEB staff and some intervenors requested that the OEB require Toronto Hydro to account for OPEBs on a cash rather than accrual basis as the OEB did for Ontario Power Generation.[6]

The OEB will require Toronto Hydro to account for OPEBs on a cash rather than an accrual basis for ratemaking purposes. The OEB has initiated a generic consultation to deal with this issue. Given that the difference between the two accounting methods will be material for Toronto Hydro, the OEB is of the view that the most appropriate way to deal with this issue is to set rates on the cash basis for now and to establish a variance account which will track the difference between the forecast cash and forecast accrual methods pending the outcome of the generic consultation.. Toronto Hydro shall file a draft accounting order as part of its draft rate order filing and shall use a separate sub-account of account 1508.

[6] EB-2013-0321, Ontario Power Generation, *Decision with Reasons,* November 20, 2014, p.88.

3.4 The Custom Framework Proposed by Toronto Hydro (Issue 2.2)

Background

The OEB must decide whether the proposed Custom formula proposed by Toronto Hydro is appropriate. Toronto Hydro has proposed that distribution rates in Years 2 through 5 be adjusted annually by using a custom Price Cap Index (PCI):

PCI = I – X + C

Where,

- "**I**" is the OEB's inflation factor, determined annually
- "**X**" is the sum of:
  - The OEB's productivity factor
  - Toronto Hydro's custom stretch factor
- "**C**" provides incremental funds that are necessary to fund capital needs

Toronto Hydro has proposed two changes to the price cap mechanism that the OEB normally uses.

First, based on the benchmarking it has filed to support this Application, Toronto Hydro is proposing a stretch factor of 0.3%, rather than the 0.6% that would otherwise be applied by the OEB to Toronto Hydro. Second, Toronto Hydro has proposed the use of a custom capital "C" factor

3.4.1 The Custom Stretch Factor

a) The Appropriate Stretch Factor

The OEB undertakes annual benchmarking for all Ontario distributors and based on those benchmarking results assigns each distributor a stretch factor. One of five possible stretch factors is assigned based on whether the distributor's costs are above or below the benchmark. The "middle" stretch factor is 0.3% which represents an "average" performer. The stretch factor is part of the formula that is used to adjust a distributor's rates. Based on the OEB's current methodology, Toronto Hydro's stretch factor is 0.6%. Toronto Hydro submitted benchmarking evidence in the form of Power System Engineering's Econometric Benchmarking Report (the PSE Report). On the basis of this report, Toronto Hydro argues that it should be assigned a "better" stretch factor in the proposed Custom PCI framework of 0.3%. Toronto Hydro argued that

PSE's total cost benchmarking evidence demonstrates the reasonableness of its past and projected cost levels by demonstrating that Toronto Hydro is within +/- 10% of the benchmark which supports the assignment of the middle (0.3%) stretch factor.

OEB staff engaged Dr. Lawrence Kaufmann of the Pacific Economic Group (PEG) to analyze Toronto Hydro's proposed stretch factor and custom capital factor, to advise on Toronto Hydro's Application generally, and to assess the design of the Custom IR plan. PEG was also asked to evaluate the technical work of PSE and, where relevant, to provide alternate cost and reliability benchmarking evidence.

As a result of the annual benchmarking the OEB undertakes for all Ontario distributors, the OEB has detailed benchmarking evidence involving both costs and reliability for Toronto Hydro. Based on this benchmarking data, Toronto Hydro is classified as a high cost performer with a stretch factor of 0.6%. Parties argued that it would not be unreasonable for the OEB to continue to apply a stretch factor of 0.6%, and argued that Toronto Hydro has not justified why its current stretch factor of 0.6% is inappropriate.

Some parties argued for an even higher stretch factor. They proposed a stretch factor of 1.0%. OEB staff, based on Dr. Kaufman's evidence, took the position that the OEB should consider a higher stretch factor to, in effect adjust for the fact that Toronto Hydro was a relatively poor performer in prior years. OEB staff argued that one way to implement this would be to set a stretch factor for the term of this Custom IR plan that is higher than 0.6%. Most parties argued that a stretch factor between 0.6% and 1% would be appropriate. They also submitted that the benchmarking analysis demonstrates that Toronto Hydro's costs are significantly higher than other Ontario utilities and its US peers. They also argued that the 0.3% stretch factor proposed by Toronto Hydro does not incent productivity.

Toronto Hydro argued that adopting any stretch factor greater than 0.6% would be contrary to OEB policy and arbitrary.

Findings

The appropriate stretch factor for Toronto Hydro is 0.6%. The OEB finds that the evidence as a whole is not sufficiently persuasive to support the change sought by Toronto Hydro.

The experts' evidence on benchmarking differs in three key areas;

1. The Urban core variable
2. Approach to CDM costs
3. Asset price inflation costs (capital cost escalation rate)

The Board will address its conclusions in each of the three areas.

3.4.2 The Urban Core Variable

The primary difference between the two experts was whether an “urban core” variable exists and should be included in the statistical formula used for benchmarking. This formula incorporates a number of variables to account for differences in operating conditions from one utility to another. Toronto Hydro argued that the OEB is benchmarking Toronto Hydro against the wrong set of comparators. Toronto Hydro says that it is dissimilar to other Ontario utilities because these utilities do not have to operate in the dense urban core like Toronto Hydro must. Toronto Hydro retained PSE to undertake a benchmarking study which included comparisons to US utilities that operate in areas where there are dense urban cores. Toronto Hydro, supported by PSE’s study, argued that it is more costly to undertake distribution activities in an area where there is a dense urban core. PSE conducted benchmarking on this basis and determined that the results showed that Toronto Hydro’s costs were in line with the US utilities, which operated in a dense urban core.

While Toronto Hydro argued that the cost challenges of operating in an urban core are highly statistically significant, and need to be factored into the benchmarking model, Dr. Kaufman’s evidence substituted a dummy variable for the urban core and determined that the urban core variable was not statistically significant.

One of the difficulties the OEB has in assessing the expert evidence is the differences in the data used by PSE and PEG. PSE’s sample size was very small as they were only able to identify 4 utilities that served urban cores similar to Toronto’s and whose data is publicly available. PEG, on the other hand, had a much larger sample of 27 US cities. However, PEG’s sample included a number of cities such as Buffalo which do not seem to have the population or urban density that Toronto has. While the OEB agrees that the premise of an urban core variable warrants further investigation, it cannot determine that the evidence demonstrates that it exists. As well as the issues with sample size, it is not clear to the OEB how much of Toronto Hydro service area is part of the urban core, or what percentage of the capital projects proposed by Toronto Hydro will be undertaken within that area.

3.4.3 Cost Benchmarking

PSE’s analysis indicated that Toronto Hydro’s costs were 31.1% *below* the costs expected for an average electric utility operating under similar circumstances. On this basis, Toronto Hydro says that its costs are within +or- 10% of the benchmark and therefore it qualifies for a stretch factor of .03%. PEG concluded that Toronto Hydro’s costs were 9.7% *above* its expected costs and predicted the company’s costs to be

34.7% *above* its expected costs in 2019, the final year of the Custom IR plan. PEG characterizes Toronto Hydro as a sub-par performer[7] and recommends a stretch factor of between 0.6 and 1.0%.

The OEB is faced with conflicting expert evidence.

PEG takes issue with a number of measures used by PSE in the cost benchmarking. These include the following:

- PSE use of a more limited cost measure – (relying on Total Factor Productivity based cost measure)
- PSE use of a standardized treatment of certain costs in order to compare to US utilities
- PEG disagreed with PSE's use of business condition variables. PEG added a variable to control for high voltage assets owned by US utilities, and eliminated the urban core variable arguing that it was redundant, inappropriate in electricity distribution benchmarking and appears to distort the estimated impact of other business condition variables – especially undergrounding.

3.4.4 CDM expenses

The two experts took different approaches to account for CDM expenses. The issue arose as CDM expenses are reflected in the costs of the U.S. utility sample but not those of Toronto Hydro. PEG's approach was to eliminate customer service and information (CSI) expenses from the U.S. utility sample as CDM expenses account for the largest share of CSI costs. PSE's approach was to add CSI costs back to its U.S. cost measure, while also adding in Toronto Hydro's actual and projected CDM expenses.

3.4.5 Asset Price Inflation Factor

The PEG and PSE assessments also differed in their approaches to asset price inflation with PSE projecting a rate of 4.55%, while PEG considered a 2% annual growth rate to be more reasonable.

Several parties argued that PSE's asset price inflation factor is distorted by the anomalously high capital asset price inflation from 1973-1983 that was included in the calculation.

[7] PEG Report, December 2014, p.55

The OEB considers the asset price inflation value used by PEG to be more appropriate. The 2.0% annual growth rate is more closely aligned to the value used by the OEB as the annual inflation factor.

Similarities between the Experts

There were also areas where the experts agreed. While they disagreed on the rate of increase, both experts did agree that Toronto Hydro's costs are increasing at a faster pace than the US comparators'.

b) Application of the Stretch Factor to Capital

Some parties argued that a stretch factor should be applied to capital as well as OM&A costs. They pointed out that the OEB has always applied stretch factors to total costs rather than just OM&A costs. Others did not favour this approach, and submitted that the capital budget should be reduced or it should be linked to performance metrics instead.

Toronto Hydro argued that the stretch factor should not be applied to capital (the C factor) as productivity is sufficiently embedded in Toronto Hydro's capital plan and the rate framework.

Findings

The OEB has consistently applied stretch factors to total costs in order to incent productivity in both the areas of capital expenditure and OM&A. The OEB finds no compelling reason to depart from this approach. While the Application put forward by Toronto Hydro may be a custom application, one of the key aspects of the OEB's RRFE is the requirement to continue to make productivity improvements. As discussed later in this Decision, the OEB is concerned that the Application does not contain enough productivity incentives. Application of the stretch factor to the C factor is one way to remedy this deficiency.

The Use of Benchmarking

SEC argued that custom benchmarking is a critical aspect of a Custom IR application and that any distributor seeking greater increases in revenue requirement or rate than the norm should be in a position to file benchmarking evidence consistent with those greater levels. If they cannot, their additional spending requirements cannot be supported.

The OEB has emphasized in the RRFE[8] and in previous cases[9] the importance of benchmarking. It is an important input to the OEB's assessment of an application, but it is not the sole determining factor in setting rates. In the context of a Custom IR, the OEB will use benchmarking as a tool to inform its decisions, but will not use it as the method by which to determine rates.

Findings

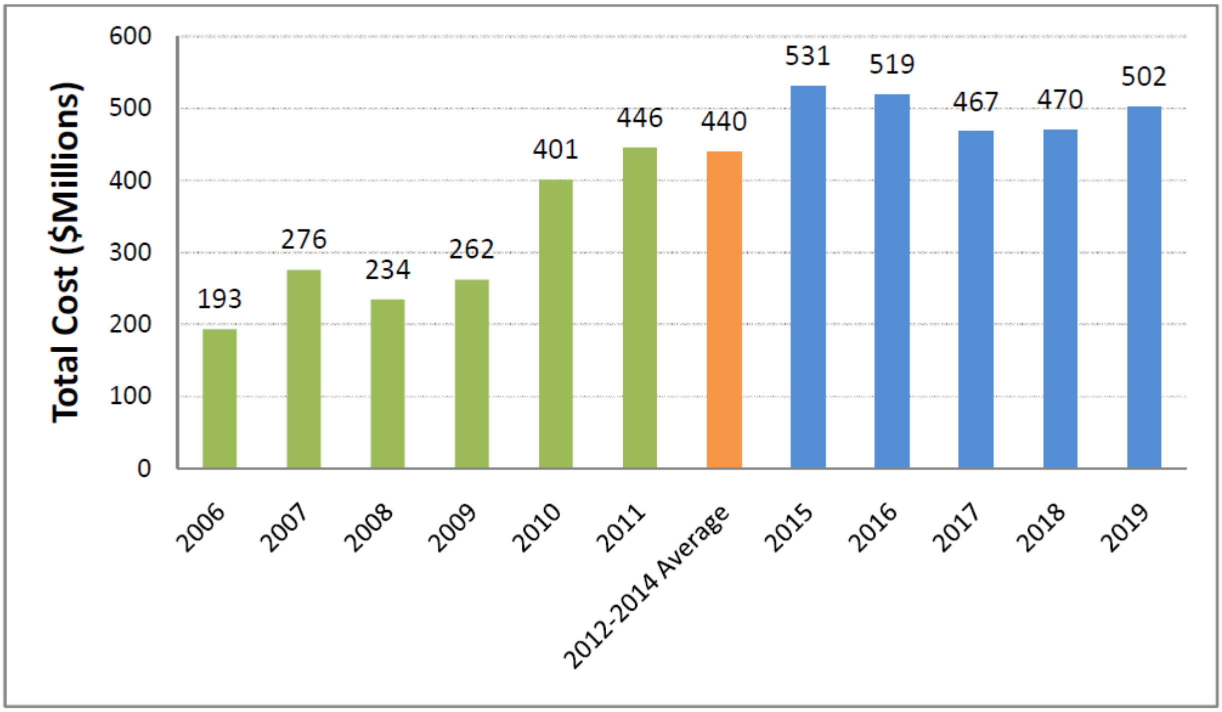
The OEB finds that a 0.6% stretch factor is appropriate. The stretch factor will apply to the C-factor, which will be discussed later in the Decision. The OEB is not convinced, based on the evidence provided, that there is any reason to deviate from the stretch factor applied to Toronto Hydro, as a result of the OEB's annual benchmarking.

3.5 The Distribution System Plan (DSP): Capital Programs and expenditures for the 2015-2019 period (Issue 3.2)

Background

Toronto Hydro has stated that this custom Application is driven by a significant capital program. Toronto Hydro's historic and forecast capital spending in the 2006 to 2019 period is summarized in the figure below which is reproduced from its evidence[10]:

[8] Ontario Energy Board *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, pp. 59-60
[9] EB-2013-0416/EB-2014-0247, p. 15.
[10] EB-2014-0116 Application E 1B/T2/S4/p. 6 Filed 2014 Jul 31 Corrected 2015 Feb 6



These expenditures total just under $2.5 billion for the five-year period of the DSP.

Toronto Hydro stated that it was confident that it can execute the proposed capital plan arguing that its successful delivery of the 2012-2014 ICM program is the best evidence of its ability to deliver a capital program of the size and complexity contained in the Application. It stated that it is proposing four specific measures to track and evaluate cost efficiency of executing its DSP: (a) Engineering, Design and Support Costs, (b) Materials Handling on-Cost, (c) Contractor Cost Efficiency and (d) Asset Assemblies Framework.

Productivity outcomes will be shared with customers throughout the duration of the plan in the form of more cost-effective assets being placed into service and reinvestment into the system.

Toronto Hydro stated that it considers age, condition, customer impacts and other asset-specific information in its capital planning.

Intervenors and OEB staff generally argued that Toronto Hydro had not adequately supported a $2.5 billion capital plan.

Their objections included:

- Inadequate evidence of the need and prioritization of the proposed programs

- Reliability and outage trends do not support the capital investment levels proposed in the Application, as Toronto Hydro's evidence showed an improvement in reliability during a period in which Toronto Hydro was spending considerably less than proposed for the next five years.
- Rate impacts on customers
- Assets proposed for replacement are not aligned with the recent results of Toronto Hydro's asset condition assessments.

Intervenors also submitted that the OEB should require Toronto Hydro to undertake various studies and/or filings related to the implementation of the DSP during the Custom IR period.

Toronto Hydro took the position that the objections of the intervenors were not supported by the evidence and were based on the mistaken assumptions that Toronto Hydro has moved from condition based to age based planning and that using asset age in planning leads to premature replacements.

There was no consensus amongst OEB staff and intervenors as to an appropriate level of spending. Suggested levels ranged from $400 million to about $480 or $490 million per annum. Some intervenors argued that there should be much reduced spending on system renewal. SEC argued that, the OEB should significantly reduce Toronto Hydro's proposed capital plan and apply a productivity formula to the capital budget.

Toronto Hydro argued that due to the integrated nature of the DSP, it is not practical from a project management or work execution perspective to arbitrarily reduce spending in various categories or programs and an overall reduction in approved capital expenditures would require a re-evaluation of the capital plan.

Toronto Hydro also submitted that there is no simple correlation between system-wide reliability and total expenditures and the relationship is much more complex and nuanced.

Findings

The OEB will not accept the capital budget as requested by Toronto Hydro. An annual reduction of 10% to the proposed capital spending is required.

Toronto Hydro presented three possible approaches to its DSP capital spending.

1. The Economically Optimal Approach – Capital spend of $2.560B in the first year
2. The Accelerated 5 year Pacing – Capital spend of $840M for two years, $830M for the next three
3. The Paced Approach – the Application filed with the OEB.

Toronto Hydro's evidence did not include a full slate of reasonable funding requests as set out in the Economically Optimal Approach. Instead it chose the "Paced Approach" in order to balance operational and customer needs with consideration of rate impacts. The proposed Paced Approach contemplates capital spend of an average of $498M per year over the plan period. Toronto Hydro states that this is the "minimal level of investment that is appropriate given the magnitude of the asset backlog and other critical system issues and operational needs that the utility faces."[11] The OEB disagrees.

As a general principle, the OEB accepts that the DSP represents a comprehensive approach to capital planning by Toronto Hydro over the next five years. Generally, the OEB does not take issue with the content of the DSP. The OEB's concerns in respect of the approach proposed by Toronto Hydro fall into two categories;

1. Asset Replacement Rate
2. Productivity Improvements

Asset Replacement Rate

Toronto Hydro's proposal is largely supported by an asset condition analysis as opposed to a reliability impact assessment. Choices about spending are driven by assets, rather than based on services. Toronto Hydro considers the reliability impact to be an outfall of its asset replacement program.[12] The optimization tool, while very useful in providing the economic analysis of when to change out a particular asset does not give a clear indication of how the overall spend is directly correlated to the customer experience.

Toronto Hydro states that its response to manage the renewal of the backlog of end-of-life useful assets is guided by a lifecycle cost reduction policy. Toronto Hydro says that it can minimize costs, including customer interruption costs by replacing assets at the economic end of life.[13] Toronto Hydro defines an asset's economic end-of-life as being when the total life cycle cost, defined as the sum of the annualized risk cost and the annualized capital cost, is at its lowest. This is considered to be the optimal intervention time. The annualized risk cost which increases as the asset ages, represents the quantifiable costs of asset failure (including customer interruption costs) multiplied by the probability of failure. The annualized capital cost, which decreases as the asset ages, represents the capital cost of replacement, annualized over the asset's life.

[11] EB-2014-0116 Toronto Hydro-Electric System Limited *Argument in Chief Compendium,* p. 19.
[12] Transcript, Vol. 9, p. 189, L 4-7.
[13] EB-2014-0116 Toronto Hydro-Electric System Limited *Custom Incentive Rate-setting Application for 2015-2019 Electricity Distribution Rates and Charges,* July 31, 2014, E 2B, S D3.

Several parties raised the concern that assets were being replaced too soon and that asset age was driving system renewal. Currently 26% of Toronto Hydro assets are beyond their useful lives. Despite a push on asset renewal since 2011, 26% is an increase from 22% beyond useful lives in 2011. Toronto Hydro explained that 33% of its assets will be beyond their useful lives by the end of the 5 year plan if the utility does not take a proactive approach and allows the assets run to failure. Toronto Hydro's objective is to reduce the backlog so that it can achieve a "steady state" where the percentage of assets beyond useful lives does not increase.

Toronto Hydro's evidence shows the following:

Year	% Assets not at end of life	% Assets past end of life	% Assets to reach end of life by 2020
2011	71	22	7 (between 2011-2016)
2015	67	26	7

Toronto Hydro argues that the useful life of an asset is the mid-point between the Kinetrics Minimum Useful Life and Maximum Useful Life for a specific asset type. By

definition, assets that are approaching or have surpassed this mid-point have reached an age when a majority of those assets typically fail and when the statistical probability of failure increases exponentially every year .[14] This leads to a higher cost to repair and replace than asset renewal. Toronto Hydro states that the Asset Condition Assessment Audit carried out by Kinectrics in 2014 shows a significant decline in the health of the system. Intervenors questioned whether this additional cost of later replacement was borne out by the evidence.

The OEB shares the concerns of the parties that the age of the assets may be too heavily weighted in the determination of end of useful life. Toronto Hydro concedes that age of the asset is the primary driver with respect to asset replacement. Toronto Hydro also states that asset condition does factor into the decisions they make in respect of asset replacement.

SEC drew the OEB's attention to Toronto Hydro's single largest program its Underground Circuit Renewal Program (E6.1). This program seeks to replace underground switches, transformers and cable at a cost of $459.3 over the five year term. Toronto Hydro plans to replace 1,667 underground transformers over the 5 years.

[14] Kinectrics report, p.9 of 29 of AIC

348 are scheduled to be replaced in 2015 alone. However the Asset Condition Assessment conducted by Kinectrics shows that in 2014 only 33 underground transformers are in poor or very poor condition, as show in the table below.[15] This is only one example, but it demonstrates the OEB's concern that there is too heavy an emphasis placed on asset age, rather than asset condition.

	Asset	% very poor	% poor	% fair	% good	% very good	% very poor & poor	# very poor	# poor	# fair	# good	# very good	# very poor & poor
1	Station Power	1.24%	13.64%	49.59%	23.14%	12.40%	14.88%	3	37	133	62	33	40
2	Station Switchgear	4.84%	36.69%	33.47%	9.27%	15.73%	41.53%	14	102	93	26	44	116
3	Air Blast Circuit	0.00%	3.89%	87.78%	2.78%	5.56%	3.89%	0	11	255	8	16	11
4	Air Magnetic Circuit	0.21%	4.72%	74.25%	18.88%	1.93%	4.93%	1	30	466	118	12	31
5	Oil Circuit Breakers	0.64%	10.19%	82.80%	6.37%	0.00%	10.83%	2	34	275	21	0	36
6	Oil KSO Breakers	0.00%	4.55%	81.82%	13.64%	0.00%	4.55%	0	3	48	8	0	3
7	SF6 Circuit Breaker	0.00%	0.00%	7.69%	46.15%	46.15%	0.00%	0	0	15	93	93	0
8	Vacuum Circuit	0.00%	0.21%	3.14%	10.25%	86.40%	0.21%	0	1	21	69	583	1
9	Submersible	0.00%	0.02%	6.68%	34.93%	58.36%	0.02%	0	2	638	3337	5576	2
10	Vault Transformers	0.00%	0.23%	23.48%	39.80%	36.50%	0.23%	0	30	3060	5188	4757	30
11	Padmounted	0.00%	0.02%	10.09%	43.51%	46.38%	0.02%	0	1	722	3115	3321	1
12	Padmounted Switches	0.00%	0.39%	7.20%	36.12%	56.30%	0.39%	0	3	58	290	452	3
13	3 Phase O/H Gang	0.00%	0.39%	3.01%	63.84%	33.15%	0.39%	0	4	33	707	367	4
14	3 Phase O/H Gang	0.00%	0.00%	15.38%	76.92%	7.69%	0.00%	0	0	2	12	1	0
15	SCADAMATE Switches	0.13%	0.00%	1.14%	57.34%	41.39%	0.13%	1	0	11	531	383	1
16	Wood Poles	2.34%	7.64%	44.13%	7.28%	38.61%	9.98%	2885	9419	54403	8975	47598	12303
17	Automatic Transfer	0.00%	16.98%	32.08%	30.19%	20.75%	16.98%	0	10	19	18	12	10
18	Network Transformers	0.00%	0.00%	16.40%	41.45%	42.14%	0.00%	0	0	310	784	797	0
19	Network Protectors	0.00%	0.00%	3.75%	32.25%	64.00%	0.00%	0	0	61	521	1034	0
20	Network Vaults	1.70%	8.80%	72.37%	16.08%	1.04%	10.50%	18	93	769	171	11	112
21	Cable Cambers	0.26%	1.60%	10.77%	50.17%	37.20%	1.86%	28	174	1174	5470	4056	203

Exhibit 2B Section D2 Appendix A: 2014 Audit Results By Asset Class[16]

Toronto Hydro stated in its evidence that the asset condition or health index of an asset would only be used to accelerate the replacement of an asset but the inverse was not true. The better than expected condition of an asset does not factor into the model to delay the replacement of the asset[17]. The OEB is of the view that actual asset condition rather than calculated "end of life" should be the primary determining factor when an asset should be replaced.

Toronto Hydro states that capital replacement is the cornerstone of the Application. Therefore the OEB finds that Toronto Hydro's approach should include more emphasis

[15] School Energy Coalition Toronto Hydro Rates 2015-2019 EB-2014-0116 *Final Argument, p.34.*
[16] SEC Final Argument, p. 37,April 3, 2015
[17] EB-2014-0116 Transcript, Vol. 4, p.140, L 60- 61

on asset condition in the assessment of when a steady state of asset renewal should be achieved. This will require some changes to the proposed capital plan.

Productivity Improvements

The OEB has consistently been clear that distributors need to strive to increase productivity. The OEB has specifically stated that custom applications require that applicants demonstrate productivity improvements. The OEB is not satisfied that Toronto Hydro has incorporated adequate productivity improvements within the Application.

In its evidence, Toronto Hydro relies upon the fact that 81% of capital project jobs are sourced externally and cites this alone as the mechanism which drives efficiency and productivity gains. Toronto Hydro explained that it relies upon a competitive process to cost projects. It provided the example of 6400 units of work being bid with 81% of the costs associated with the capital work program being determined through a competitive process. Four elements make up the type of work bid; materials, civil engineering, electrical design and construction work. The procurement is based on qualified bidders offering individual fixed prices for various units of work. Toronto Hydro explained their rationale as follows:

> "once contractors are selected on the basis of their qualifications and overall pricing, they are not guaranteed any particular amount of work. Instead contractors are assigned to individual projects based on their cost to complete each project so that the lowest priced contractor for a particular project gets the work"[18]

Toronto Hydro advanced that the process leads to the best value, while satisfying the operational needs of the utility.

The OEB is concerned that this method of costing may not in fact lead to efficiencies. Competitive bidding for unit cost contracting is not in itself a sufficient demonstration of productivity improvements. For example, Toronto Hydro does not seem to benefit from any of the efficiencies gained by contractors as they undertake similar projects over the period of the plan..

The OEB is not satisfied that bidding 81% of work to a competitive market is sufficient to ensure continuous productivity improvement. While Toronto Hydro provided some evidence on cost containment in respect of negotiated labour rates and performance tracking of its internal staff, it relies heavily on external contractors to achieve productivity improvements. Many parties argued that that Toronto Hydro was lagging in

[18] Transcript, Vol. 6, pp. 98-108.

productivity, especially when benchmarked against other utilities. Based on the benchmarking results, the OEB does not accept that there are no further productivity gains that can be made over the next five years. The OEB finds that Toronto Hydro must place more emphasis on productivity gains and that Toronto Hydro must find efficiencies over the five years of the capital plan.

Length of the Planning Horizon

The OEB has approached the planning horizon in this Custom IR application by considering the five year horizon as is contemplated in the RRFE. The evidence provided does not convince the OEB that any changes need to be made and the OEB accepts the five years planning horizon that is proposed by Toronto Hydro. The OEB will not require Toronto Hydro to come back to the OEB after two years as was suggested by an intervenor. The OEB has determined that Toronto Hydro has met the RRFE criteria for a custom application, one of which is a requirement for a 5 year plan supported by a DSP. It is in the context of this 5 year plan that the OEB has made its determinations in this case. The OEB also disagrees with Dr. Kaufman that the capital projects should be extended over an 8 year period. Dr. Kaufman was not qualified as an expert in distribution system planning, and the OEB is satisfied that Toronto Hydro has a plan to be able to complete projects within the five years and that it will ensure that it is physically equipped to undertake the work as it has successfully managed large capital programs over the last few years. The OEB is generally satisfied with Toronto Hydro's DSP and rejects the notion that Toronto Hydro's DSP requires oversight by an independent engineer.

Reliability

Benchmarking

PEG suggested that the reliability benchmarking provided by Toronto Hydro should not be accepted by the OEB. PEG disagreed with the information sources which form the basis of the benchmarking.

While the experts used different information in coming to their conclusions, the OEB notes that both PEG and PSE agree that SAIFI (the frequency of outage measure) performance is below what is expected. The experts disagree on the SAIDI measure (the outage duration measure). PSE states that Toronto Hydro's measure is well below expected measures, while PEG finds that SAIDI is not statistically different from expected levels.

While the OEB does consider the relationship between a distributor's costs and its reliability performance to be important from a regulatory standpoint, at this point, the

OEB is of the view that statistical methods of comparing distributors costs and service reliability are not sufficiently advanced to be persuasive.

It is the OEB's expectation that one of the outcomes of the capital plan will be better system-wide reliability. While Toronto Hydro submits that there is no direct co-relation between total expenditures and reliability and that the relationship is complex and nuanced, the OEB is of the view that system-wide reliability should improve as a result of the approved capital plan. The OEB expects that improvements in reliability will be demonstrated in Toronto Hydro's reliability statistics which are tracked by the OEB. The OEB encourages Toronto Hydro to pursue this type of analysis and be in a position to provide evidence regarding this relationship at its next full cost of service or Custom IR application.

Capital Reduction

For the reasons stated above, the OEB has chosen to reduce the amount of requested capital spend by 10% annually. Quantifying the amount of capital reduction is not an exact science. The 10% reduction allows an increase over the current budget, but does not allow the significant increase which Toronto Hydro seeks. The amount of the reduction is material. However, the OEB is of the view that there are significant opportunities for Toronto Hydro to improve upon its productivity. This productivity improvement should allow the utility to complete capital projects for a lower cost. By reducing the capital budget by 10%, the OEB has also balanced the capital needs of the distributor with the rate impacts with customers.

Business Plans

Toronto Hydro has proposed 46 specific investment programs. The OEB will not opine on each program. The OEB will not reduce spending in individual programs. It will require Toronto Hydro to work within the approved capital budget and plan accordingly.

The Custom C Factor

Background

The second custom aspect of Toronto Hydro's Application is a custom capital factor. It is described as a scaling adjustment that will annually incorporate the cost recovery for THESL's capital program from 2016-2019. It is calculated by dividing the difference between the year over year capital requirement by the total revenue requirement. That percentage amount is then added to base rates. The C-factor is the only means of capital recovery proposed for 2016-2019 (after rebasing).

Toronto Hydro proposes the following C-factors listed below:

- 2016 – 4.47%
- 2017 – 8.25%
- 2018 – 6.69%
- 2019 – 5.01 %

Toronto Hydro stated that the premise of the inclusion of a C-factor is to allow it to address the RRFE's statement that the Custom IR framework is suitable for utilities with significant multi-year capital investment requirements, as it is clear that the standard 4th Generation IR framework is not. Toronto Hydro further stated the proposed C-factor is designed as a rate adjustment mechanism that is directly proportional to the degree of capital investment required by Toronto Hydro. It is comprised of two sub-components which are designed to: (i) reconcile Toronto Hydro's capital investment needs in a price cap framework, and (ii) return to ratepayers the funding already provided for capital through the standard "I-X" increase.

PEG reviewed the C-factor and stated that it should include an adjustment for the growth in Toronto Hydro billing determinants to prevent the C-factor from over-recovering capital cost. PEG concluded that its recommended C-factor adjustment would eliminate over-recovery of capital costs and reduce Toronto Hydro's price growth by an estimated 1.5% per annum in 2016 through 2019.

Most parties supported the use of the C-factor, though some issues were raised and modifications proposed. Most parties also supported the PEG proposal for some form of billing determinant adjustment. OEB staff submitted that Toronto Hydro's failure to provide five full years of cost forecasts in support of the C-factor calculations resulted in approximations and that more thorough calculations should be provided.

Findings

The OEB is not opposed to the C-factor mechanism as proposed, but the quantum will change as it relates to revenue requirement to reflect the reduction in capital spending approved by the OEB. Under the Application proposed by Toronto Hydro, the C-factor is the mechanism by which increases in capital spending are funded.

C-factor growth determinant

Background

PEG's evidence suggested that the C-factor should include an adjustment for the growth in Toronto Hydro's billing determinants in order to prevent the C factor from over-recovering capital costs. PEG stated that to ensure the C factor recovers only the change in incremental capital spending, it should be modified to reduce the change in prices by the annual change in a revenue share weighted average of Toronto Hydro's billing determinants. PEG recommended an adjustment estimated at 1.5% per annum in 2016 through 2019. Toronto Hydro did not object to including such a growth factor, but disagreed with the magnitude of the adjustment proposed by PEG and the other parties. Toronto Hydro argued that a more appropriate growth factor adjustment would be closer to 0.3% rather than PEG's proposed 1.5%.

Findings

The OEB is of the view that a growth factor is reasonable in order to prevent an over-recovery of costs. Toronto Hydro is in the best position to anticipate what its growth factor will be over the term of the rate plan. The 0.3% suggested by Toronto Hydro appears to be reasonable as it is based on Toronto Hydro's detailed forecast of its load and customers by class for the 2015 to 2019 period[19] which has been accepted later in the Decision.

The ICM Application

The 2012-2014 Incremental Capital Module (ICM[20]) was the source of some discussion in the Application. Parties argued that approximately 86% of proposed capital spending in the five year DSP is similar in nature to the ICM work. Therefore the results of the ICM true up were of interest to many of the parties. Toronto Hydro advised that the ICM true-up was to be completed in 2015 Q2 after 2014 financial close and the full reconciliation by segment of work completed during the ICM period. Toronto Hydro did advise that expenditures for the 2012-2014 ICM program are forecasted to be within 5% of overall OEB-accepted forecast amounts on a three year basis. The OEB observes that projects under the previous ICM application appear to be advancing as scheduled and reasonably within the forecast costs. However, given the limited information that the panel had before it in this proceeding, it did not form the basis of any findings.

Revenue Requirement

3.6 Rate Base (Issue 5.1)

Background

The OEB must determine whether the rate base component of the revenue requirement for 2015 is appropriate.

[19] Reply Argument, p. 193
[20] Ref IR 2B-SIA-15; Ex 1B-T2-S4

The table below, which is reproduced from Toronto Hydro's evidence[21] summarizes its proposed rate base:

	2011 OEB Approved	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2015 Test MIFRS
Opening PP&E NBV	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,436.6
ICM	-	-	-	-	-	372.6
Street Lighting	-	-	-	-	-	39.8
Opening PP&E NBV Adjusted	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,849.0
Closing PP&E NBV	2,105.1	2,183.5	2,251.9	2,356.0	2,456.3[1]	3,161.0
Average PP&E NBV	2,001.5	2,039.7	2,217.7	2,304.0	2,406.1	3,005.0
Working Capital Allowance	296.7	318.1	316.6	354.4	369.5	241.5
Rate Base	2,298.2	2,357.7	2,534.3	2,658.4	2,775.6	3,246.5

There are two aspects of rate base that the OEB must address: a new working capital allowance rate, and whether Toronto Hydro has correctly applied the "used or useful" principle when adding assets to rate base.

3.6.1 Working Capital Allowance

Toronto Hydro has proposed a reduction in its Working Capital Allowance (WCA) from 12.88% of controllable expenses plus cost of power to 8.00% for the 2015 Test year. In support of this reduction, Toronto Hydro filed an updated Lead-Lag Study performed by Navigant Consulting Inc. entitled "Working Capital Requirements of Toronto Hydro Electric System Limited's Distribution Business" dated June 27, 2014. Parties were supportive of Toronto Hydro's updated WCA.

The OEB accepts Toronto Hydro's proposed working capital allowance as reasonable as it was based on an updated lead-lag study.

3.6.2 Used or Useful Principle

Some intervenors questioned whether or not Toronto Hydro had correctly applied the "used or useful" principle. SEC argued that Toronto Hydro should revise its in-service forecasts to remove civil work brought into service earlier than the completion of the actual project which includes all in-service additions for Copeland before 2016, unless it meets the actual criteria set out in the OEB's Phase 1 ICM decision. BOMA submitted

[21] EB-2014-0116 Application E2A/T1/S1/p.1 Filed: 2014 Jul 31 Corrected 2015 Feb 6.

that the OEB should not allow assets to be placed in service prematurely, that is not until energized.

Toronto Hydro argued it had correctly applied the “used or useful” principle and noted that SEC and BOMA had objected in general to the addition of assets to rate base unless they are “energized” or conveying electricity to ratepayers. Toronto Hydro submitted that both had materially misinterpreted the OEB’s decision in EB-2012-0064 and were attempting to advance the same incorrect, restrictive definitions of the term “used or useful” that had been expressly rejected by the OEB.

CCC argued that the amount of $17.3 million associated with the 715 Milner Ave. property should not be included in 2015 opening rate base. CCC submitted that this was an imprudent purchase since two property assessments undertaken showed lower market values. Furthermore, it is not yet used or useful as Toronto Hydro still has an active lease and staff working at the 601 Milner Avenue property which it is planned to replace. VECC expressed general agreement with CCC, but argued that rather than excluding the property entirely from rate base as proposed by CCC, half the property value could be included, based on the assumption that property becomes useful mid-way in the rate plan.

Toronto Hydro argued that the purchase was prudent and no evidence to the contrary had been provided. Toronto Hydro submitted that the purchase price of the property was actually $15.6 million. Toronto Hydro argued that the purchase price fell between the two valuations which demonstrated the reasonableness of the price.

Findings

The OEB notes that in its 2013 Toronto Hydro *Partial Decision and Order*[22] the in-service approach had been adopted:

> The Board agrees with THESL that the traditional and long established test in Ontario has been the “used or useful” rule. Therefore, the “in-service” approach should more properly be described as the “used or useful” approach. The Board does not anticipate that there will be any material difference for most of the projects, as they are likely to come into service at the same time as they become “useful”. However, in some cases, it may be that THESL’s work has been completed on a project but it is not yet “in service” as work which is the responsibility of other parties has not

[22] EB-2012-0064 Toronto Hydro-Electric System Limited *Partial Decision and Order,* pp. 13-14.

> been completed. In these circumstances, the Board finds that THESL may consider the work to be completed and hence "useful", even if it is not yet being "used".

The OEB is satisfied based on the evidence presented by Toronto Hydro that it has correctly applied the "used or useful" principle in the Application. Specifically, the OEB has reviewed the evidence related to the Copeland transformer project and is satisfied that Toronto Hydro has properly applied the "used or useful" principle. The OEB will not require that the asset be energized before additions are made to rate base.

In respect of the specific asset, 715 Milner, the OEB accepts the reply submission of Toronto Hydro in which it clarified the purchase price and confirmed the expected occupancy of the building to be in 2016. The OEB is prepared to accept that some amount of time is required to transition into a new building. Taking a reasonable amount of time to move in to new premises does not disqualify the asset from being used or useful.

3.6.3 Renewable Enabling Improvement (REI) Investments

Background

Toronto Hydro stated that it expects to connect approximately 972 renewable energy generation (REG) facilities during the 2015 to 2019 rate period, with a corresponding capacity of 148.9 MW.

Toronto Hydro proposed to undertake a number of REI investments as part of its DSP. The OEB has addressed matters related to the DSP in its discussion of Issue 3.2 above.

Toronto Hydro noted that the Ontario Power Authority (OPA) had reviewed its plans for REG investments and found that: 1) the utility's plans were reasonably consistent with the OPA's information regarding REG, and 2) that the investments support and enable the connection of additional REG.

Toronto Hydro stated that in accordance with the OEB's Filing Requirements, it had applied the six percent direct benefit assumption provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts provided in its evidence.

Findings

The OEB notes that subject to any concerns that may have been expressed related to any of these investments in DSP submissions, no parties raised any concerns with respect to Toronto Hydro's evidence regarding the proposed cost recovery breakdown related to renewable enabling improvement investments. The OEB accepts Toronto Hydro's proposal, subject to its findings on the DSP in the Decision.

3.7 Street lighting Assets (Issue 5.2)

Background

Toronto Hydro is proposing to transfer former street lighting assets into its rate base effective January 1, 2015 at a transfer price of $39.8 million. Toronto Hydro stated that this value represents the opening net book value of the assets in 2015, which is the actual cost incurred by Toronto Hydro to acquire the 2012 transferred assets from TH Energy, the additional assets that were put into service in the intervening 2012 to 2014 period as well as depreciation on all assets. The OEB had, in its Decision and Order dated August 3, 2011, approved a value of $28.9 million for the assets that were found eligible to be transferred.

Toronto Hydro submitted that the revised transfer value of the street lighting assets has no effect on its revenue requirement for all rate classes other than the Street Lighting and Unmetered Scattered Load (USL) rate classes because the costs associated with the street lighting assets are directly allocated to the street lighting (95%) and the USL (5%) rate classes.

Toronto Hydro stated that for the street lighting class, these costs are offset by revenues from a Service Agreement with the City of Toronto and that for the USL class the effects are minimal.

Toronto Hydro further noted that for the purpose of the present Application, the effects of the proposed transfer have been fully integrated into its capital and operating expenses as well as its cost allocation model.

Toronto Hydro stated that the revenue requirement consequences of its proposal are a base revenue requirement impact of zero.

Parties did not oppose Toronto Hydro's proposal while expressing some concerns. OEB staff noted two implications of the proposed approach:

1. The OEB's Valuation decision of August 3, 2011 had determined that while the use of historic costs was preferable, the DRC valuation technique should be used and as such Toronto Hydro's approach, which uses historic costs, is not strictly in accordance with OEB's Valuation decision. OEB staff however considered that Toronto Hydro has provided adequate justification for its proposed departure from that valuation method.

2. The justification for Toronto Hydro's approach of zeroing out the revenue requirement impact of the transfer of the street lighting assets into Toronto Hydro's rate base is not clear.

OEB staff therefore submitted that there may not be an adequate basis given the evidence on the record to make a determination as to whether or not the proposed arrangements result in a cross-subsidy going from Toronto Hydro to TH Energy or vice-versa.

SIA argued that Toronto Hydro is asking for a second opportunity to present valuation data, essentially revising the original Valuation decision which while undoubtedly more accurate could undermine the finality of the OEB's decision-making process.

SIA argued that Toronto Hydro's justifications as to why an accurate study was not undertaken in 2010 are unclear and unconvincing and suggested the OEB needed to consider whether the merits of improved data accuracy outweigh what appears to be a direct attempt at overturning a prior OEB decision with relatively limited justification.

Toronto Hydro addressed the concern expressed by OEB staff about cross-subsidization between Toronto Hydro and TH Energy. Toronto Hydro submitted that the risk of cross-subsidization between the two entities (if any) is very small because the utility has evaluated the costs of serving the transferred assets and proposes to offset the costs with a corresponding portion of revenue from the City of Toronto contract.

Toronto Hydro stated that the concerns expressed about departing from the OEB's 2011 Decision are unjustified and in any event do not outweigh the merits of approving the transfer on the basis of the most accurate information available.

Findings

The OEB accepts Toronto Hydro's proposal to transfer former street lighting assets into its rate base at a transfer price of $39.8 million.

This particular transaction has been the subject of considerable regulatory scrutiny over the past several years. The manner in which records were kept and the fact that the assets were previously owned by the several different entities that predated the merged entity Toronto Hydro creates significant complications in assessing the historic value of the assets.

The OEB is satisfied that the current valuation adequately reflects the historic costs. The pursuit of additional precision is unlikely to yield any benefit.

The OEB accepts that the current valuation was derived with new information that came to light after the OEB had approved a value of $28.9 million for the assets. The OEB considers the updating of the valuation to be justified because it results in a more accurate representation of costs expended. However the OEB also considers that Toronto Hydro's proposal should have been more reflective of the fact that its proposal was a direct departure from a previous OEB ruling. That ruling was based on a record of financial valuation presented by Toronto Hydro as the most accurate that it could formalize. The OEB accepts that Toronto Hydro believed that to be true but given that it proved not to be the case, Toronto Hydro should have framed its current proposal accordingly from the outset, prior to the discovery phase of this proceeding.

3.8 Capital Structure and Cost of Capital (Issue 5.3)

Background

Toronto Hydro has proposed using the OEB's deemed capital structure and cost of equity, but proposed its own long and short term debt rates. The proposed rates are shown in the table below:

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.0%		$1,855,547,537	4.31%	$79,974,099
2	Short-term Debt	4.0%	(1)	$132,539,110	1.38%	$1,829,040
3	**Total Debt**	60.0%		$1,988,086,646	4.11%	$81,803,139
	Equity					
4	Common Equity	40.0%		$1,325,391,098	9.30%	$123,261,372
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$1,325,391,098	9.30%	$123,261,372
7	**Total**	100.0%		$3,313,477,744	6.19%	$205,064,511

OEB staff, supported by SEC and VECC, expressed two concerns with the cost of long-term debt proposed by Toronto Hydro. The first was that the overall cost rate of 4.31% was not consistent with the more detailed information filed by Toronto Hydro. Toronto Hydro identified and corrected a calculation error in their reply argument.

The second concern related to the $45 million promissory note due to THC which is due on demand. During cross-examination by OEB counsel,[23] Toronto Hydro was asked to explain why Toronto Hydro would pay its parent company a 6.16 percent coupon rate on a promissory note which is due on demand. Toronto Hydro's response was that this

[23] EB-2014-0116 Transcript, Vol. 7, p.140, L 26 - p. 144, L22

note "was part of an earlier instrument -2003 Series 1 Note – held by the parent company at the time the note was issued. As a result, the $45 million promissory note was issued at the same rate as the original instrument." [24]

OEB staff submitted as it appears that this issue is no longer outstanding at the THC level, it no longer meets the criteria of being written on the same terms as THC debt. OEB staff further noted that the coupon rate of 6.16% is more than 50 basis points higher than any of the other outstanding promissory note issues of Toronto Hydro.

OEB staff submitted that in the absence of an adequate explanation by Toronto Hydro, the OEB should either apply the OEB's deemed long-term debt rate of 4.77%, or given that Toronto Hydro has recently issued long-term debt in the 4 to 4.15% range deem a lower rate in this range for rate-setting purposes on this debt.

Energy Probe suggested that the OEB should consider whether under this type of Custom IR plan there should be annual adjustments (over a materiality Threshold) made to the cost of debt based on actual debt issues.

Toronto Hydro submitted that it has calculated its debt costs in accordance with the OEB cost of capital methodology and the OEB should accept the evidence as filed and updated. With respect to the $45 million promissory note due to THC, Toronto Hydro stated that since the 6.16% rate is reflective of market rates at that time it is appropriate to reflect this amount for this particular component of Toronto Hydro's debt.

No concerns were raised with respect to the short-term debt rate used by Toronto Hydro.

Findings

The OEB finds that with respect to the long-term debt rate that Toronto Hydro's correction of the calculation error discussed above addresses this matter.

The OEB finds that the interest rate on the $45 million promissory note to THC that is to be applied for rate-setting purposes will be the OEB's 2014 deemed long-term debt rate of 4.77%. The OEB notes that this debt is callable on demand and OEB policy establishes the deemed long-term debt rate as a ceiling on the allowed rate for such debt.

The OEB will not require that annual adjustments be made to the cost of debt based on actual debt issues. The OEB notes that Toronto Hydro is not proposing annual capital cost adjustments and considers such an approach as overly complex and not in

[24] EB-2014-0116 Oral Hearing Schedule J7.10 Filed: March 2, 2015

alignment with the desirability of minimizing annual adjustments under the Custom IR approach.

3.9 Depreciation (Issue 5.4)

Background

Toronto Hydro stated that it depreciates its assets in accordance with the Accounting Procedures Handbook (APH) and that it had not made any significant material changes to its estimated useful lives since its last rebasing application (EB-2010-0142) except for amortizing a software application Customer Care and Billing over 10 years rather than the previous four or five years.

No party took issue with Toronto Hydro's depreciation policy.

Findings

The OEB finds that Toronto Hydro's depreciation policy is appropriate.

The OEB notes that the depreciation component of the revenue requirement is dependent on the approved level of capital expenditures.

Subject to the impacts of the adjustments to capital expenditures outlined in section 3.5, the OEB finds that the depreciation component of the revenue requirement is appropriate.

3.10 Taxes/PILs (Issue 5.5)

Background

Toronto Hydro's rate Application was prepared using USGAAP for the historical and bridge years, and MIFRS for the test year, while the PILS calculation was prepared using MIFRS for both the bridge and test years. Toronto Hydro indicated that this was done to be able to reconcile 2015 MIFRS amounts in the PILS model.

Findings

The OEB notes that no parties commented on Toronto Hydro's proposed taxes/PILs component of the 2015 revenue requirement.

The OEB approves the taxes/PILs component of the 2015 revenue requirement, subject to any necessary adjustments for the OEB's findings in other sections of the Decision which impact the taxes/PILs component.

3.11 Revenue Offsets (Issue 5.6)

Toronto Hydro's revenue offsets, as updated in the Wireline Pole Attachment Rate Settlement Proposal is summarized below[25]:

Description	Actual Year 2011	Actual Year 2012	Actual Year 2013	Bridge Year 2014	Test Year 2015
Specific Service Charges Excluding Pole Attachment (4235)	$5.7	$6.3	$6.4	$6.4	$9.8
Late Payment Charge (4225)	$4.2	$4.0	$3.8	$4.0	$4.0
Other Distribution Revenue Excluding Duct Rental (4082,4084,4090,4210,4215,4220)	$3.9	$3.7	$3.7	$3.4	$11.5
Other Income & Deductions Including Pole Attachments (4210, 4235, 4324, 4325,4330,4335,4355,4375,4398,4405)	$18.8	$5.3	$11.5	$12.0	$15.9
Total Revenue Offset	**$32.6**	**$19.4**	**$25.4**	**$25.7**	**$41.3**

The OEB notes that the wireline attachment pole rate has been dealt with through the settlement proposal of June 11, 2015 which the OEB accepted.

Revenue offsets are also impacted by specific service charge amounts which are dealt with separately in Issue 6.6.

Findings

The OEB finds that the revenue offset component of the revenue requirement is appropriate, subject to its findings under issue 6.6 related to specific service charges.

Load Forecast, Cost Allocation and Rate Design

3.12 Load Forecast (Issue 6.1)

Background

Toronto Hydro prepared load forecasts for each year from 2015 to 2019. The load forecast was prepared according to the OEB's filing requirements using a multivariate regression load model that has been employed by Toronto Hydro since 2006. It includes an explicit forecast of CDM savings.

Toronto Hydro's total load, customer and distribution revenue forecast is summarized in Table 1: Total Loads, Revenues and Customers of its evidence which is reproduced below.[26] Toronto Hydro stated that the revenue forecast is calculated based on

[25] EB-2014-0116, Wireline Pole Attachment Rate Settlement Proposal, p.5: 2015 Jun 11
[26] EB-2014-0116 Application E3/T1/S1, p.1 Filed: 2014 Jul 31 Corrected: 2015 Feb 6

proposed distribution rates, excluding commodity, rate riders, and all other non-distribution rates.

YEAR		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($M)	Total Customers
2009	Actual	25,572.8	42,754.7	$475.2	689,399
2010	Actual	25,607.2	43,273.3	$519.3	696,729
2011	Actual	25,419.0	43,020.2	$522.2	705,756
2012	Actual	25,639.2	43,544.5	$527.9	713,093
2013	Actual	25,213.2	42,658.7	$529.5	724,144
2014	Bridge	25,018.5	42,712.7	$539.4	736,974
2015	Test	24,993.3	42,697.2	$655.1	749,679
2016	Test	25,027.4	42,806.2	$692.8	763,091
2017	Test	24,841.6	42,631.3	$754.4	773,850
2018	Test	24,696.9	42,584.4	$810.5	785,107
2019	Test	24,611.4	42,529.2	$857.8	796,865

Notes:

1. Total Normalized GWh are purchased GWh (before losses), and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer allowance.
4. Total Customers are as of mid-year and exclude street lighting devices and unmetered load connections.

OEB staff argued that as this table shows that Toronto Hydro’s load forecast projects a 2.4% decline in Total Normalized GWh from 2013 to 2019, while at the same time total customers are projected to increase by 10%. The results are anomalous and the load forecast should not be accepted by the OEB. OEB staff urged the OEB to use the 2013 actual results instead.

VECC questioned whether gross or net CDM results should be incorporated into the load forecast.

Findings

The OEB accepts Toronto Hydro’s load forecast as filed.

The OEB notes that Toronto Hydro’s total customer count has been increasing steadily from 2009 to 2014, while Total Normalized GWh has been decreasing, so the forecast going forward appears to continue this trend. Toronto Hydro’s evidence was that the forecasts and actual results have tracked within 1% over the historic period.

Toronto Hydro also pointed out that many factors contribute to energy consumption beyond customer numbers. Demographics, type of customer and housing unit, and energy conservation all play a part.

The OEB observes that some increase in customer count can also be attributed to the fact that some multi-unit residential buildings which historically were billed as one customer have been converted into Competitive Sector Multi- Unit Residential customers where each unit is billed separately. This increases the overall customer count without changing any other parameter such as occupancy or consumption.

The OEB also agrees with Toronto Hydro that the use of gross CDM to model and forecast loads is more accurate because it represents the real impact of CDM activity. While net CDM, excluding free-riders and “natural conservators”, is important for other purposes such as the calculation of LRAM, for the purpose of a load forecast, it is actual consumption that matters. The reasons for conservation are irrelevant for this purpose.

3.13 Rate Classes (Issue 6.2)

Toronto Hydro did not propose any changes to its existing rate classes, nor did any other party request such changes. The OEB approves the continued use of the rate classes and definitions in Toronto Hydro’s tariff sheet.

3.14 Cost Allocation Model Inputs (Issue 6.3)

Background

Toronto Hydro has reviewed and updated all of the inputs to the cost allocation model. The load profiles for each class have been updated to reflect the most recent full year of data available (2012) and the profiles use metered data for each rate class, weather normalized to 2015 heating and cooling degree days.

As required by the EB-2010-0142 decision with respect to the new CSMUR class, Toronto Hydro has reviewed each of the assumptions underlying that application. Toronto Hydro’s evidence is that it has not found any need for revisions, and that the assumptions used for allocations to the CSMUR class remain unchanged.

The EB-2010-0142 decision also directed Toronto Hydro to establish a tracking account to record amounts related to the allocation of costs and revenues between the CSMUR class and the GS >50 classes depending on whether the CSMUR customers are to be considered bulk customers or customers in the CSMUR class.

Toronto Hydro stated it considered that a tracking account is unnecessary as this is a cost allocation issue, and effectively there are no real costs to track. Toronto Hydro advised the OEB that the issue is best addressed through scenarios using the Cost Allocation Model as that better demonstrates the potential effect of the CSMUR class on the costs and revenues allocated to the GS >50 class. Toronto Hydro ran models using these scenarios and concluded that in the absence of the CSMUR class, the GS 50-999 class rates would increase slightly.

Issues raised by the parties concerned:

1. the cost allocation used for street lighting,
2. updates to the model
3. revenue to cost ratios

Street lighting

Toronto Hydro noted that it had incorporated approved street lighting assets and operating expenses into its 2015 revenue requirement. For the purposes of cost allocation, it had directly allocated all assets and expenses 95% to the Street lighting class, and 5% to the Unmetered Scattered Load class.

Toronto Hydro stated that this allocation reflected the fact that these assets are serving only these two classes currently and ensured no other rate classes are allocated these costs. In addition, Toronto Hydro noted that for the Street lighting class 100% of the additional revenue requirement is offset through a direct allocation of the revenues received through the existing street lighting contract to Revenue Offsets for the Street lighting class. The effect is that for these assets and costs, the revenue-to-cost ratio is 1.0.

SIA submitted that the OEB should direct Toronto Hydro to perform its cost allocation to the Street lighting rate class on the same basis as all other classes. SIA did not accept Toronto Hydro’s claim that it was keeping street lighting rates constant at 2014 rates on the basis that the OEB is still looking into one of the important components of the cost allocation model when it comes to street lighting.

Updates to the model

VECC argued that the next time Toronto Hydro updates its cost allocation model it should be directed to undertake a new minimum system study that would reflect its circumstances if it proposes to depart from the OEB’s default values.

Toronto Hydro suggested this be done by the OEB so all LDCs can benefit.

VECC also suggested that the OEB should correct issues regarding the determination of the cost allocation model’s composite allocators prior to its release to distributors filing their 2016 cost of service based rate applications.

Findings

The OEB will not require Toronto Hydro to undertake a new minimum system study as proposed by VECC pending a generic determination by the OEB as to its approach to cost allocation model updates and issues.

3.15 Revenue-to-cost Ratios (Issue 6.4)

Toronto Hydro's proposed revenue-to-cost ratios are within the OEB target ranges as is shown in the Table below:[27]:

Rate Class	2011 OEB Approved	2015		OEB's Guideline Ranges
		Model	Proposed	
Residential	89	94	94	85-115
Competitive Sector Multi-Unit Residential		110	100	
General Service <50kW	97	90	92	80-120
General Service 50-999kW	118	119	119	80-120
Intermediate 1000-4999kW	124	102	102	80-120
Large Use	116	95	96	85-115
Streetlighting	71	92	82	70-120
Unmetered Scattered Load	82	87	89	80-120

Findings

Some intervenors argued that despite falling within the OEB's Guideline ranges adjustments should be made to Toronto Hydro's proposed ratios. Toronto Hydro's proposal is that the Guideline is clear that if the ratios fall within the range, the OEB will not require changes.

SEC submitted that the OEB should order Toronto Hydro to file a plan to bring all classes within the 90%-110% range recently approved by the OEB in EB-2013-0416 for Hydro One.

The OEB observes that the context was quite different for Hydro One. Hydro One itself had proposed moving all customer classes to ranges of 98%-102%. The 90% - 110% range was imposed by the OEB as a mitigation measure as many of Hydro One's customer classes were outside the range and the OEB was not persuaded that the data

[27] EB-2014-0116 Application E7/T1/S1/p. 7 Filed 2014 Jul 30 Corrected 2015 Feb 6

supported a move to the narrow range proposed by Hydro One. The OEB does not view the Hydro One decision as a precedent for requiring LDCs that are already within the approved range to make further changes.

Street lighting

SIA and VECC submitted that Toronto Hydro should be required to perform its cost allocation to the Street lighting class on the same basis as all other classes. SIA does not believe that there is any reason to limit the application of current policy and freeze rates for one class on the basis of speculative expectations about future changes to an applicable policy. SIA argued that this approach had been rejected by the OEB when a similar argument had been brought before it as part of a motion by the City of Hamilton requesting that Hydro One’s street lighting rates be declared interim.

The OEB agrees with Toronto Hydro that that since the revenue to cost ratio determined in this hearing will apply for the next five years and since the proposed rates result in a revenue to cost ratio for this class that is significantly more than when last approved while still well within the OEB’s guidelines, its proposal is appropriate.

3.16 Fixed and Variable Charges (Issue 6.5)

Toronto Hydro is proposing fixed and variable rates for all rate classes based on the current split of revenue generated through these components. Toronto Hydro noted that the OEB has initiated a process to review rate design for the Residential and GS<50 kW rate classes, but that it has not incorporated any of the rate designs as outlined in the Draft Report of the Board. Toronto Hydro plans to incorporate any changes required by the OEB once the review is completed.

Toronto Hydro provided its proposed monthly fixed charges for each customer class in the table below:[28]

[28] EB-2014-0116 Application E8/T1/S1/p. 6 Filed: 2014 Jul 31 Corrected: 2015 Feb 6

	Residential	CSMUR	GS<50 kW	GS 50-999 kW	GS 1000-4999 kW	Large Use	Streetlighting	USL
CA Model Floor	4.24	3.40	13.78	43.31	82.72	-35.83	0.23	9.53
CA Model Ceiling	19.34	9.32	31.66	86.22	244.36	210.01	10.53	19.32
Current (2014)	18.63	17.35	24.80	36.29	700.68	3,071.47	1.32	4.94
Proposed (2015)	22.72	18.90	30.43	43.63	831.65	3,668.99	1.32	6.12

Toronto Hydro noted that the OEB's Cost Allocation model produces estimates of the floor and ceiling monthly fixed rates for each rate class based on data from the model. Toronto Hydro stated that the proposed fixed rate for the Residential, CSMUR, GS 1000-4999 kW, and Large Use classes is above the ceiling calculated by the model. Toronto Hydro explained that for the Residential and CSMUR classes, this results from changes in inputs to the Cost Allocation model as well as maintaining the fixed variable split at current levels. Toronto Hydro noted that the new OEB policy will require all distributors to structure residential rates that are 100% fixed by 2019 and that the proposed fixed rates for the Residential and CSMUR classes generally conform with this policy.

For the GS 1000-4999 kW and Large Use classes, Toronto Hydro noted that the fixed charge has been above the ceiling rate since information from the Cost Allocation model has been provided in 2006. Toronto Hydro further noted that the proportion of total revenue recovered through the fixed rate for the GS 1000-4999 kW and Large Use classes is less than 10%.

While most aspects of the fixed variable split were accepted by intervenors and OEB staff, VECC and Energy Probe argued that for the Residential Class, the monthly fixed charge should not exceed the ceiling value calculated by the Cost Allocation Model. This would be consistent with OEB policy, and would also reduce the bill impacts to be experienced by Residential customers.

Residential Rate Design

Currently, all residential distribution rates include a fixed monthly charge and a variable usage charge. The OEB's April 2, 2015 policy on electricity distribution rate design set out that distribution rates for residential customers will transition to a fully fixed rate structure from the current combination of fixed and variable charges over four years. Starting in 2016, the fixed rate will increase gradually, and the usage rate will decline.

The OEB is requiring distributors to calculate and report on the rate impacts of the change so that strategies may be employed to smooth the transition for the customers most impacted, such as those that consume less electricity, if mitigation is required. In support of this, the OEB requires distributors to calculate the impact of this change to residential customers in general; it also requires applicants to calculate the combined impact of the fixed rate increase and any other changes in the cost of distribution service for those customers who are at the 10^{th} percentile of overall consumption. Any increase of 10% or greater to these low-consumption customers' bills arising from changes made in this Decision, or an increase to the monthly fixed charge of greater than $4 prior to incentive rate-setting adjustments, may result in the requirement for a longer transition period than four years specified in the OEB policy. Distributors may also propose other strategies to smooth out these increases as appropriate.

Findings

The OEB accepts the fixed variable splits proposed by Toronto Hydro. The OEB recognizes that the Residential Class fixed charge is slightly higher than the current ceiling but anticipates that the new policy will soon require a higher fixed charge in any event.

The OEB expects that Toronto Hydro will implement the transition to fully fixed residential rates in 2017.

3.17 Charges for Specific and Miscellaneous Services Charges (Issue 6.6)

Toronto Hydro proposes to continue using previously approved standard charges, but is applying to update specific service charges to reflect the actual cost of providing the services.

Findings

The Wireline attachment charge has already been approved by the OEB.

Issues were raised about the general concept of utility-specific charges, increases proposed for the reconnection charge, and the proposal to charge customers for missed appointments.

The OEB finds that Toronto Hydro's proposals to reflect actual costs comply with the requirements of the Distribution Rate Handbook. The OEB does not approve charges to customers for missed appointments. While Toronto Hydro is correct that it has standards to meet regarding missed appointments, it does not require 100%

compliance, and more importantly, does not compensate the affected customer when it misses an appointment.

3.18 Line Losses (Issue 6.7)

In the Settlement Agreement approved by the OEB in Phase II of Toronto Hydro's ICM application (EB-2012-0064), Toronto Hydro agreed to evaluate options to measure or estimate actual line losses and the impacts on Account 1588 balances. Subsequently, the OEB conducted an audit of Toronto Hydro's Group 1 and Group 2 Deferral and Variance accounts (the OEB Audit), which made a finding related to Toronto Hydro's approach of recording variance amounts in account 1588 RSVA Power. As a result, Toronto Hydro, in consultation with OEB audit staff, has undertaken a significant amount of work to accurately estimate the correct balances in the RSVA accounts. This included analyzing and estimating the actual loss factors from 2009 to 2013.

These efforts are ongoing, so Toronto Hydro proposes that the current OEB-Approved loss factors be continued until the OEB Audit concludes. Once the OEB Audit is completed, if changes to the approved loss factor are warranted, Toronto Hydro intends to apply to incorporate the revised loss factor into distribution rates.

Findings

The OEB agrees with OEB staff that Toronto Hydro's update on line losses should take all relevant factors into account, and not be limited to a variance analysis of actual versus deemed losses, but also notes that the implications for loss factors of the work proposed by Toronto Hydro are complex. Toronto Hydro's current loss factors are among the lowest in the province.

The OEB expects Toronto Hydro to incorporate the result of the OEB audit into its distribution rates as well as to update its loss factors at its next full cost of service or Custom IR rate application.

3.19 Monitoring and Reporting Proposals (Issue 2.4)

Background

Toronto Hydro's annual reporting section of the Application made monitoring and reporting proposals: (a) Annual Reporting, consisting of meeting the OEB's Scorecard Approach for Performance Measurement, reporting on the proposed performance measures framework as detailed in the DSP and filing a rate schedule for the following year upon the OEB's update of its inflation factor. (b) ICM True-up – Deferral proposal for which Toronto Hydro stated its accounting process is not expected to have a final report of actual in-service additions (ISAs) for 2014 until the second quarter of 2015.

Toronto Hydro proposed to defer the ICM true-up and bring forward a separate application in 2015, once the actual ICM amounts are known.

Intervenors and OEB staff generally took the view that Toronto Hydro's monitoring and reporting proposals were inadequate and suggested various ways to address these concerns including the establishment of specific performance targets for the proposed measures and additional measures that would provide a stronger focus on benchmarking and productivity. A number of parties argued that more specific information should be provided that would allow for approved capital expenditures by asset class to be assessed against resulting performance and reliability improvements and OM&A savings.

Some parties suggested additional review measures to occur during the Custom IR period. These included suggestions for annual program reviews, or that Toronto Hydro be directed to work with OEB staff and intervenors to develop appropriate annual reporting requirements, meaningful metrics and associated targets.

Toronto Hydro stated that it did see merit in receiving the input of stakeholders and discussing the outputs of its metrics mid-way through the Custom IR plan, and submitted that it would be of assistance to conduct a workshop on these measures with interested parties in 2018.

Findings

The OEB will accept Toronto Hydro's proposals for monitoring and reporting contained in the Application. The OEB, however, will expect Toronto Hydro to develop better performance metrics as part of its ongoing customer engagement efforts with the objective of achieving greater conformity with the general intent of the RRFE.

The OEB will not require Toronto Hydro to hold a stakeholder session in 2018. It is Toronto Hydro's responsibility to develop these measures and to undertake such activities as it sees appropriate to do so.

The OEB is of the view that the key reason for the requests for additional reporting requirements is a desire to expose cost savings. The OEB considers that rather than directing Toronto Hydro to implement additional monitoring and reporting at the present time, this matter is best addressed after Toronto Hydro has had time to consider the OEB's findings in this Decision and developed new measures.

The OEB will for the present address the concerns about cost savings by ordering the implementation of the earnings sharing mechanism proposed by Toronto Hydro in its reply argument. The OEB will outline this finding in further detail in the next section of the Decision.

3.20 Off-ramps and Annual Adjustments (Issue 2.5)

Background

Toronto Hydro noted that the RRFE indicates that each rate-setting method includes a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review may be initiated. Toronto Hydro proposed to apply the OEB's existing policy with respect to off-ramps.

Toronto Hydro stated that it proposed to incorporate within its rate framework the availability of Z-factor relief, which Toronto Hydro understood is available to Custom IR filers as part of the RRFE framework. Toronto Hydro requested guidance from the OEB with respect to certain proposed Z-factor criteria.

Parties were generally opposed to Toronto Hydro's request that the OEB provide it with additional guidance with respect to certain proposed Z-factor criteria, agreeing with the views of OEB staff that the OEB has established the criteria for Z-factor applications on a generic basis and should Toronto Hydro wish to make a Z-factor application during the term of the approved Custom IR plan that it should be on the basis of these criteria.

BOMA argued that the OEB should direct Toronto Hydro to enter into an earnings sharing proposal similar to the one the OEB directed should be included in the Enbridge Gas Distribution Custom IR plan[29]. BOMA suggested that such a plan would incorporate a 50 point dead band for the utility with 50-50 sharing of excess earnings over 50 basis points. CCC also supported the inclusion of an earnings sharing mechanism.

Toronto Hydro submitted that requests for an earnings sharing mechanism should be rejected, but if such a mechanism was to be approved it should be symmetrical and incorporate a 100 basis point dead band. Toronto Hydro argued that this was appropriate having regard to the explicit benefit sharing mechanism (the stretch factor) already embedded in the rate framework. Toronto Hydro further submitted that earnings in excess of the 100 basis point dead band but below the 300 basis point off-ramp should be split on a 50/50 basis with customers. Furthermore, any approved ESM should necessarily only track the variance between the non-capital related revenue requirement embedded in rates and the actual non capital related revenue requirement.

Findings

The OEB will not provide the additional guidance requested by Toronto Hydro with respect to certain Z-factor criteria which it had proposed. The OEB has already established the criteria for Z-factor applications on a generic basis and it is open to

[29] Enbridge Gas Distribution EB-2012-0459, August 22, 2014

Toronto Hydro to make Z-factor applications on the basis of these criteria should it wish to do so.

The OEB has decided to adopt the earnings sharing mechanism (ESM) proposed by Toronto Hydro. The OEB finds that the ESM will be symmetrical and incorporate a 100 basis point dead band. Earnings in excess of the 100 basis point are to be split on a 50:50 basis with ratepayers.

As the OEB will also be approving the proposed Capital Related Revenue Requirement Variance Account (CRRRVA), the ESM will only track the variance between the non-capital related revenue requirement embedded in rates and the actual non capital related revenue requirement. Toronto Hydro should include a detailed explanation as to how it believes the ESM would operate as part of its Draft Rate Order supporting material.

The OEB is of the view that the establishment of the ESM will allow Toronto Hydro's customers to benefit from efficiency gains achieved during the course of the Custom IR Plan and thereby alleviate the need for additional reporting requirements to track savings achieved during the term of the plan.

Deferral and Variance Accounts and Rate Riders

3.21 Existing Deferral and Variance Accounts (Issue 4.1)

Toronto Hydro did not propose that any of its existing deferral accounts be terminated with the exception of Account 1508 – Transit City. No party objected to this proposal.

Findings

The OEB accepts Toronto Hydro's proposal.

3.22 New Deferral and Variance Accounts (Issue 4.2)

In addition to the new variance account for OPEBs established in Section 3.3.7, Toronto Hydro has requested approval for seven new deferral and variance accounts:

1. Variance Account for Externally Driven Capital,
2. Variance Account for Derecognition,
3. Renewable Enabling Investments Provincial Rate Protection Recovery,
4. Deferral Account for the Mandatory Transition to Monthly Billing
5. Variance Account for Gains on Sale of Properties related to the Company's Operating Centers Consolidation Program;

6. Variance account for 2015 opening rate base to capture prudence-based ICM disallowances; and
7. Variance account for Capital Related Revenue Requirement to capture the revenue requirement implications of shortfalls in capital spending over the 2015-2019 period relative to amounts approved in this Application

Variance Account for Externally Driven Capital

In this account Toronto Hydro proposes to capture the difference between the amounts included in rates related to capital spending on third party initiated relocation and expansion projects and the amounts actually spent from 2015 to 2019. Toronto Hydro's evidence is that it has no discretion in making these investments. Toronto Hydro's reasons for establishing this account are to manage the uncertainty and volatility surrounding this type of project, and to protect ratepayers from potential over recovery.

None of the parties objected to the creation of the account; however some argued that the amount included in rates for this work at $4 million annually is too low, which could result in large balances to be recovered later from ratepayers. Toronto Hydro did not object to including a higher amount in rates, but did point out that the work is uncertain and may not materialize.

Findings

The OEB approves this account as requested. As these projects are completely outside Toronto Hydro's control as to both need and timing, they are appropriate for a variance account. Given the size of Toronto Hydro's overall budget, the OEB is not inclined to require Toronto Hydro to include a larger portion of these expenditures in its budget. The OEB recognizes the risk of this approach is there may be a significant recovery from ratepayers when the account is cleared, but is of the view that is preferable to the risk of ratepayers paying now for work that may not materialize. The issues of prudence and recovery periods will be dealt with as usual when Toronto Hydro applies to clear the balance of this account.

The OEB does not agree with Energy Probe's suggestion that there be a materiality threshold for each project before it can be added to the account. This is needlessly complicated and inconsistent with the operation of other variance accounts.

Variance Account for Derecognition,

The purpose of this account is to record costs associated with derecognition of assets as a result of accounting treatment under IFRS. None of the parties objected to the need for this account, however SEC noted that the amounts could be significant and suggested that the OEB establish a policy review of the accounting treatment of derecognition losses.

Findings

The OEB finds that this account is appropriate. This impact of derecognition expenses was considered by the OEB in its IFRS Report Addendum[30] and Toronto Hydro's approach is consistent with it. While further review may be warranted, this is not a reason not to establish this account at this time.

Renewable Enabling Investments Provincial Rate Protection Recovery

Toronto Hydro requested approval for the establishment of a new variance account for the purpose of tracking the variance between Toronto Hydro's revenue requirement required to support the portion of the investments that are eligible for the provincial rate protection, and the actual Provincial Rate Protection amounts collected from the IESO.

Toronto Hydro stated that the proposed variance account is being requested in accordance with the OEB's guidance in the Filing Requirements and supporting appendices.

The OEB approves Toronto Hydro's request.

Deferral Account for the Mandatory Transition to Monthly Billing

The purpose of this account is to capture the costs and benefits of a transition to monthly billing. Toronto Hydro anticipates that based on the OEB's notice of proposal to change the distribution system code to require all distributors to implement monthly billing it will be required to do so during the term of this Custom IR.

Some intervenors objected to the establishment of this account.

VECC objected on the basis that if the OEB orders Toronto Hydro to implement monthly billing adjustments should be made to the capital and operating budgets and revenues to account for it.

CCC argues that it is premature at this time to establish a deferral account to capture costs associated with monthly billing as there has not been evidence presented that the costs will outweigh the benefits and it is unclear whether the incremental costs would meet Toronto Hydro's materiality threshold. CCC suggested a Z-factor could be used, but the OEB agrees with Toronto Hydro that these costs are unlikely to meet the test for a Z-factor as the event is not unexpected.

[30] EB-2008-0408, June 13, 2011 p. 23

Findings

The OEB approves the account as requested by Toronto Hydro.

The timing and costs of the transition are as yet unknown which makes a deferral account appropriate. No amount has been included in Toronto Hydro's Application for this purpose.

Variance Account for Gains on Sale of Properties related to the Company's Operating Centers Consolidation Program

Toronto Hydro has forecast proceeds from the sale of two properties. The purpose of this account is to track the difference between the forecast sale price which is already being credited to ratepayers through a rate rider and the actual proceeds of sale.

The OEB agrees with Toronto Hydro that this is the appropriate approach rather than the alternative suggested by SEC - a deferral account for property sales to which the difference between sale price and net book value is credited as SEC's approach is overly complex.

Variance account for 2015 opening rate base to capture prudence-based ICM disallowances

The ICM true up process is a revenue reconciliation exercise between the 2012-2014 capital related revenue requirement approved by the OEB in the ICM proceeding (EB-2012-0064) and the actual ICM-eligible work completed by Toronto Hydro over this period. This process has not been completed, and if the OEB finds any of the ICM work to be imprudent, there will be an impact on the opening rate base for 2015.

The purpose of this variance account is to capture any differences between amounts to be included in 2015 rate base related to ICM work undertaken in 2012-2014, and any disallowance based on prudence that may result from the ICM true-up process.

There were no objections to the creation of the account, and the OEB finds that it is appropriate.

As the ICM amounts will be dealt with in a future proceeding the OEB need not decide on the manner in which amounts will be recorded to the account at this time.

Variance account for Capital Related Revenue Requirement (CRRRVA)

In order to protect ratepayers, SEC recommended the establishment of a variance account to track the revenue requirement associated with approved in-service capital additions and actuals, if they were less that approved. AMPCO supported this recommendation. The creation of such an account would allow Toronto Hydro to catch up in subsequent years as long as it did not go over the cumulative total and would ensure that if Toronto Hydro is behind on its capital program in any given year, ratepayers are to be held whole.

Toronto Hydro submitted that although concerns of some parties about the potential for over-recovery if actual in-service amounts are less than forecast in a given year are unfounded, it nevertheless proposes a capital related revenue requirement variance account to address any concerns relating to the company's ability to place capital in-service over the Custom IR term. However, it is critical to Toronto Hydro that the CRRRVA operate on a cumulative basis rather than annually as it is only if it operates on a cumulative basis that Toronto Hydro can maintain the required flexibility to plan and execute its capital investment strategy in response to the various factors that may require the shifting of projects and project spending earlier or later in the Custom IR term.

The OEB approves the creation of the CRRRVA account.

3.23 Accounts, Balances and the proposed Disposition of Deferral and Variance Accounts (Issue 4.3)

In general, none of the parties objected to the balances in the existing deferral accounts, the proposed allocation methodology, or the resulting rate riders.

Toronto Hydro had originally proposed to dispose of all Retail Settlement Variance Accounts (RSVAs) including Account 1550 LV Variance. However work is still ongoing to address some outstanding issues identified during an OEB audit of these accounts. As a result, Toronto Hydro proposes to defer the disposition of the RSVAs (except Account 1550 as this account was not impacted by the audit finding) and to continue to book monthly amounts to the accounts in the ordinary course. Toronto Hydro stated that it expected to update the balances in the accounts and request disposition as part of its update to 2016 distribution rates.

The OEB approves Toronto Hydro's proposed disposition of accounts and its request to defer the disposition of the RSVA accounts. Upon conclusion of the OEB audit, the OEB expects Toronto Hydro to request disposition of all the RSVA balances in its next rate application.

Accounts 1518 and 1548

Background

Since Toronto Hydro's Regulatory Assets Phase 2 decision (RP-2004-0117) in 2004, Toronto Hydro has included the costs and revenues associated with providing retail services in the determination of its revenue requirement and has not recorded amounts in Account 1518 RCVA Retail and Account 1548 RCVA Service Transaction Request. Toronto Hydro interpreted the Regulatory Assets Phase 2 decision to mean that the tracking of amounts in the accounts was no longer necessary. The OEB staff audit finding indicates that these amounts should be recorded, although Toronto Hydro's failure to report any amounts in these accounts since 2004 seems not to have been of concern to OEB staff.

Toronto Hydro indicated that from 2011 to 2013, had variances been recorded in Accounts 1518 and 1548, they would amount to approximate credits of $272k and $19k in total respectively.[31] As Toronto Hydro believes the amounts continue to be immaterial, Toronto Hydro is requesting relief from having to track and record costs and revenues in Accounts 1518 and 1548 and will include these amounts as a part of its requested revenue requirement in the current and future applications.

Findings

While these accounts may technically be required, the amounts involved are not material. As observed by OEB staff, ratepayers will not be harmed as the associated revenues and costs have been incorporated into Toronto Hydro's revenue requirement, although OEB staff argued that for the sake of consistency with other distributors, Toronto Hydro should be required to use them.

The OEB agrees with Toronto Hydro that there is no benefit in recording and reporting the amounts in these accounts and will not require it to do so.

Account 1592

Background

Toronto Hydro proposed to clear a credit of $1.2 million in Account 1592 PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs). The balance pertains to the period of July 1, 2010 to December 31, 2010. In its Application, Toronto Hydro provided the calculation of the amount it has recorded in the sub-account of Account 1592. Toronto Hydro used the 2009 actual PST paid for

[31] EB-2014-0116 Application E 9/T1/S1, p. 20

operating and capital expenses as the basis for the calculation. Toronto Hydro is proposing to return 100% of the estimated savings.

OEB staff pointed out that 50% rather than 100% of the savings are supposed to be returned to ratepayers, but suggested the OEB approve Toronto Hydro's proposal as it is in the ratepayer's favour.

As the amount involved does not meet Toronto Hydro's materiality threshold, the OEB will approve Toronto Hydro's proposal. However, the OEB notes that OEB policies should be followed when material amounts are involved, regardless of whether shareholders or ratepayers benefit,

Account 1575

Toronto Hydro proposed to dispose of a debit of $30.5 million (composed of an account balance of $25.8 million and $4.7 million return) in Account 1575 IFRS-CGAAP Transitional PP&E Amounts over a four year period. Of this amount, approximately $25.7 million is due to derecognition losses.

Findings

The OEB approves the disposition of the balances in this account. The only objections raised by OEB staff concerned the accounting treatment of items below the materiality threshold.

Other Post Employment Benefits (OPEB)

Account 1508 – USGAAP Deferral Account.

OEB staff noted that the OEB approved Account 1508-USGAAP Deferral Account in an accounting order application (EB-2012-0079) to capture the post-employment benefit difference arising from Toronto Hydro's transition from CGAAP to USGAAP. As at December 31, 2013, the account had a balance of $38.8 million.

Toronto Hydro has indicated that as a result of its transition to IFRS, there is a transitional difference from USGAAP to IFRS and the estimated balance in the account as at December 31, 2014 is expected to be $36 million.

Toronto Hydro requested approval to continue to use this deferral account to capture ongoing differences in OPEBs as a result of its transition from USGAAP to IFRS. In this application, Toronto Hydro is not seeking recovery for the account. Toronto Hydro indicated that it projects interest rates are more likely to increase over the Custom IR period, which would reduce the amount recorded in the account.

Toronto Hydro's view is that there is a reasonable probability that the current balance in the account will be substantially reduced without the necessity of funding from ratepayers and hence, it is not requesting disposition of the account at this time.[32]

There were no objections to Toronto Hydro's request not to dispose of this account at this time.

The OEB accepts Toronto Hydro's request.

LRAMVA

Background

The total amount claimed by Toronto Hydro for CDM activities in 2011, 2012 and 2013 is $3,452,615, plus carrying charges of $99,759 for which recovery was requested through a 12-month rate rider. Toronto Hydro stated that an application for the 2014 LRAMVA amount would be submitted at a later date.

Toronto Hydro confirmed that it would not be submitting an application to recover LRAM amounts related to 2008, 2009 and 2010 consistent with the OEB's CDM Guidelines.

Toronto Hydro noted that its load forecast for 2011 did not include an explicit amount for CDM savings as CDM was accounted for through the trend variables in the customer class regression. Therefore, in order to determine the amount of CDM implicitly embedded in the trend variables used in the 2011 load forecast, which is the basis for the LRAMVA calculations, Toronto Hydro estimated a relationship between the actual historical CDM savings and the trend variables used in the forecast models for each rate class.

With respect to the actual CDM savings for 2011, 2012 and 2013, Toronto Hydro relied on the most recent evaluation report from the Ontario Power Authority (OPA) – the 2013 OPA draft verified results report - in support of its LRAMVA calculations.

OEB staff commented that Toronto Hydro's approach to its LRAMVA calculations is a more precise approach than the standard one but is not inconsistent with it, so the results should be accepted.

The OEB agrees and will approve Toronto Hydro's proposal.

[32] EB-2014-0116 IRR 9-OEBStaff-86

3.24 Rate Riders (Issue 4.4)

Toronto Hydro's proposed rate riders were generally accepted by parties, with the exception of the rate rider to allow for the recovery of lost revenue associated with the IRM framework in the 2012 to 2014 period, which OEB staff and most intervenors opposed as a form of retroactive rate-making.

The OEB denies Toronto Hydro's request for the lost 2012 to 2014 revenue recovery rate rider.

The OEB agrees with OEB staff that Toronto Hydro's request for the recovery of this amount would be a form of retroactive rate-making. The OEB made a finding in EB-2012-0064 that it would not approve a departure from the usual policy with respect to averaging of rate base and the use of the half-year rule for depreciation, and that rate base is not adjusted during the term of the IRM. This was consistent with the OEB's policy not to allow for recovery of forgone amounts related to the implementation of the half year rule when a utility rebases. The full amount of depreciation expense for the related assets is only included in base rates going forward.

Had the OEB intended that Toronto Hydro would be permitted to request recovery of this amount in a future cost of service application, the OEB would have established a deferral account to record these amounts. It did not do so.

The OEB approves Toronto Hydro's other proposed rate riders.

Rate Implementation

3.25 Toronto Hydro's proposal to implement Rate and Fiscal Year Synchronization (Issue 7.1)

Background

Toronto Hydro is seeking approval to align its Rate Year with its Fiscal Year effective January 1, 2016. Rates for 2015, its rebasing year, are proposed to be effective May 1, 2015. Rates for the first year under the proposed Price Cap would be effective January 1, 2016. Toronto Hydro confirmed that it was not requesting any special treatment for the calculation of 2015 rates (i.e., it is not calculating rates based on recovering the full year of revenue requirement over an eight-month May to December period). Toronto Hydro submitted that neither its customers nor the utility are harmed by this proposed change in rate year.

Findings

The OEB accepts Toronto Hydro's proposal for rate synchronization effective January 1, 2016.

The OEB notes that the RRFE contemplates a five year Custom IR plan period and that there were some concerns expressed by intervenors that with alignment to the January 1 rate year, the application falls short of five years as it only covers the period from May 1, 2015 to December 31, 2019, which is four years and eight months

The OEB agrees that this is technically true, but considers that Toronto Hydro's application meets the critical elements of a Custom IR application. In addition, the four month shortfall is not substantially short of the five year requirement and is justified by the one-time transition to the January 1, 2016 rate year.

The OEB accordingly approves the requested rate year realignment.

Effective Date

The OEB has determined that rates will be effective May1, 2015 in keeping with Toronto Hydro's proposal. Intervenors were largely supportive of this request. The OEB has determined 2015 rates on the basis of the revenue requirement necessary for 2015 and therefore will not reduce this amount by ordering a different effective date than the one contemplated in the Application.

3.26 Previous Board Directives (Issue 1.1)

Background

Toronto Hydro identified[33] in its evidence previous OEB directives and undertakings and how these were being addressed in the application. These directives included the following:

1. File a cost allocation model that will disaggregate meter reading costs appropriately into Account 5310.
2. Review each of the assumptions set out in the decision and order when its cost allocation study is refreshed for its next cost of service application.
3. Provide external evidence related to productivity and capital planning in the next cost of service application.
4. Provide seminar on Feeder Investment Model (FIM) to Intervenors before filing 2015 application.

[33] EB-2014-0116 Application E 1A/T3/S1/p. 5.

5. Use best efforts to track any assets taken out of service before the end of their useful lives associated with the completion of ICM work segments approved in Phase 2 of this proceeding.
6. Evaluate options to measure or estimate actual line losses and the impacts on Account 1588 balances in accordance with the Accounting Procedures Handbook. File the results in its application for 2015 rates.

Findings

The OEB is satisfied that Toronto Hydro has responded to all relevant OEB directions. This issue was not contested by the parties.

3.27 Do any of Toronto Hydro's proposed rates require rate smoothing?

Background

The OEB's Filing Requirements[34] state that "A distributor must file a mitigation plan if total bill increases for any customer class exceed 10%."

Toronto Hydro has not proposed a mitigation plan for the rate classes exceeding the 10% threshold in 2016.

Findings

Subject to the OEB's comments on the foregone revenue rate rider below, the OEB will not require rate smoothing. The OEB recognizes that any increase in rates has an impact on customers and is mindful of the concerns expressed by some intervenors that the magnitude of the proposed increases would justify rate smoothing.

However, the OEB has established a threshold at which point the applicant must undertake rate smoothing. Toronto Hydro's proposed rates do not meet that threshold. The OEB has also not approved the entire rate increase applied for by Toronto Hydro. This will consequently lead to lower rate impacts.

In this Decision, the OEB is approving foregone revenue rate riders for the May 1, 2015 to February 29, 2016 period. Toronto Hydro shall assess any additional impacts from the application of these riders and shall propose a mitigation plan if required.

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[34] Ontario Energy Board *Filing Requirements for Electricity Distribution Rate Applications -2014 Edition for 2015 Rate Applications,* Ch 2/pp. 58-59.

4 IMPLEMENTATION

New rates for 2015 are to be effective May 1, 2015 and implemented on March 1, 2016. New rates for 2016 are to be effective January 1, 2016 and implemented on March 1, 2016. Toronto Hydro must calculate a rate rider to be applied to 2016 rates that recovers the revenue that Toronto would have recovered in rates from May1, 2015 to December 31, 2015 (consistent with the findings in this Decision). Toronto Hydro shall file a schedule showing the calculation of the rate rider and its consistency with the 2015 draft rate order. In addition, Toronto Hydro must calculate a rate rider to be applied to 2016 rates that recovers the revenue that Toronto Hydro would have recovered in rates from January 1, 2016 to February 29, 2016 consistent with the findings in this Decision. Toronto Hydro shall file a schedule showing the calculation of the rate rider and its consistency with the 2016 draft rate order.

As indicated in rate design section of this Decision, the OEB expects that the draft rate orders submitted by Toronto Hydro for 2017, 2018 and 2019 will contain a proposal for the transition to fully fixed residential rates. If applicable, Toronto Hydro must show how it has considered mitigation for low volume customers consistent with approach outlined in section 2.8.13 of Chapter 2 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications (2015 Edition)*.

The rates for 2017, 2018 and 2019 are approved on an interim basis, and the rate order and tariff sheets for those years must indicate this status in the title of the document.

In addition to its findings on the proposed Settlement Agreement, the OEB is making provision for the following three matters to be incorporated into Toronto Hydro's Tariff of Rates and Charges.

Rural or Remote Electricity Rate Protection Charge

The Rural or Remote Electricity Rate Protection (RRRP) program is designed to provide financial assistance to eligible customers located in rural or remote areas where the costs of providing electricity service to these customers greatly exceeds the costs of providing electricity to customers located elsewhere in the province of Ontario. The RRRP program cost is recovered from all electricity customers in the province through a charge that is reviewed annually and approved by the OEB.

Wholesale Market Service Rate

Wholesale market service (WMS) charges recover the cost of the services provided by the Independent Electricity System Operator (IESO) to operate the electricity system and administer the wholesale market. These charges may include costs associated with: operating reserve, system congestion and imports, and losses on the IESO-controlled grid. Individual electricity distributors recover the WMS charges from their customers through the WMS rate.

Ontario Electricity Support Program

The Ontario Electricity Support Program (OESP) is a new rate assistance program for low-income electricity customers. Starting January 1, 2016, eligible low-income customers will receive a monthly credit on their bills. At the same time, all electricity customers in the province will begin paying a charge to fund the program, which will be referred to as the OESP charge.

These regulatory charges are established annually by the OEB through a separate order.

The OEB issued its Decision and Rate Order for the RRRP, WMS and OESP charges on November 19, 2015. The Tariff of Rates and Charges flowing from this Decision and Order should reflect these new charges.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. Toronto Hydro-Electric System shall file with the OEB, and shall also forward to the Intervenors, a draft rate order attaching a proposed Tariff of Rates and Charges for 2015-2019, reflecting the OEB's findings in this Decision and the Wireless Settlement decision and order and draft accounting orders for the eight approved deferral and variance accounts, by **January 22, 2016**. The draft rate orders shall also include:

    - For each year, customer rate impacts resulting from the implementation of this Decision and supporting information showing the calculation of the rates
    - For each year, a completed version of the Revenue Requirement Work Form excel spreadsheet, which can be found on the OEB's website
    - For 2015, the calculation of the rate rider to be applied during 2016 to recover revenue that would have been recovered in rates from May 1, 2015 to December 31, 2015
    - For 2016, the calculation of the rate rider to be applied during 2016 to recover revenue that would have been recovered in rates from January 1, 2016 to February 29, 2016
    - For 2017, 2018 and 2019, a proposal for the first three years of the transition to fully fixed residential rates, with a schedule for each of these years showing the year-over-year change to the monthly fixed charge and the combined bill impact of the transition to fixed rates and other changes resulting from this Decision, for a low-volume customer as discussed in section 2.8.13 of Chapter 2 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications (2015 Edition)*.

2. OEB staff and Intervenors shall file any comments on the draft rate order with the OEB, and forward the comments to Toronto Hydro on or before **February 5, 2016.**

3. Toronto Hydro shall file with the OEB and forward to the intervenors responses to any comments on its draft rate order on or before **February 12, 2016.**

All filings to the OEB must quote the file number, EB-2014-0116, be made in searchable / unrestricted PDF format electronically through the OEB's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. Two paper copies must also be filed at the OEB's address provided below. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Martin Davies at Martin.Davies@ontarioenergyboard.ca and OEB Counsel, at Maureen.Helt@ontarioenergyboard.ca.

ADDRESS

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DATED at Toronto, **December 29, 2015**

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary