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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Table of Contents

The views expressed in this report are those of Dr. Lawrence Kaufmann and Pacific Economics Group Research, LLC, and do not necessarily represent the views of, and should not be attributed to, the Ontario Energy Board, any individual Board Member, or Ontario Energy Board staff.

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

[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*

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[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.

4[th]GenIR 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 4[th] 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

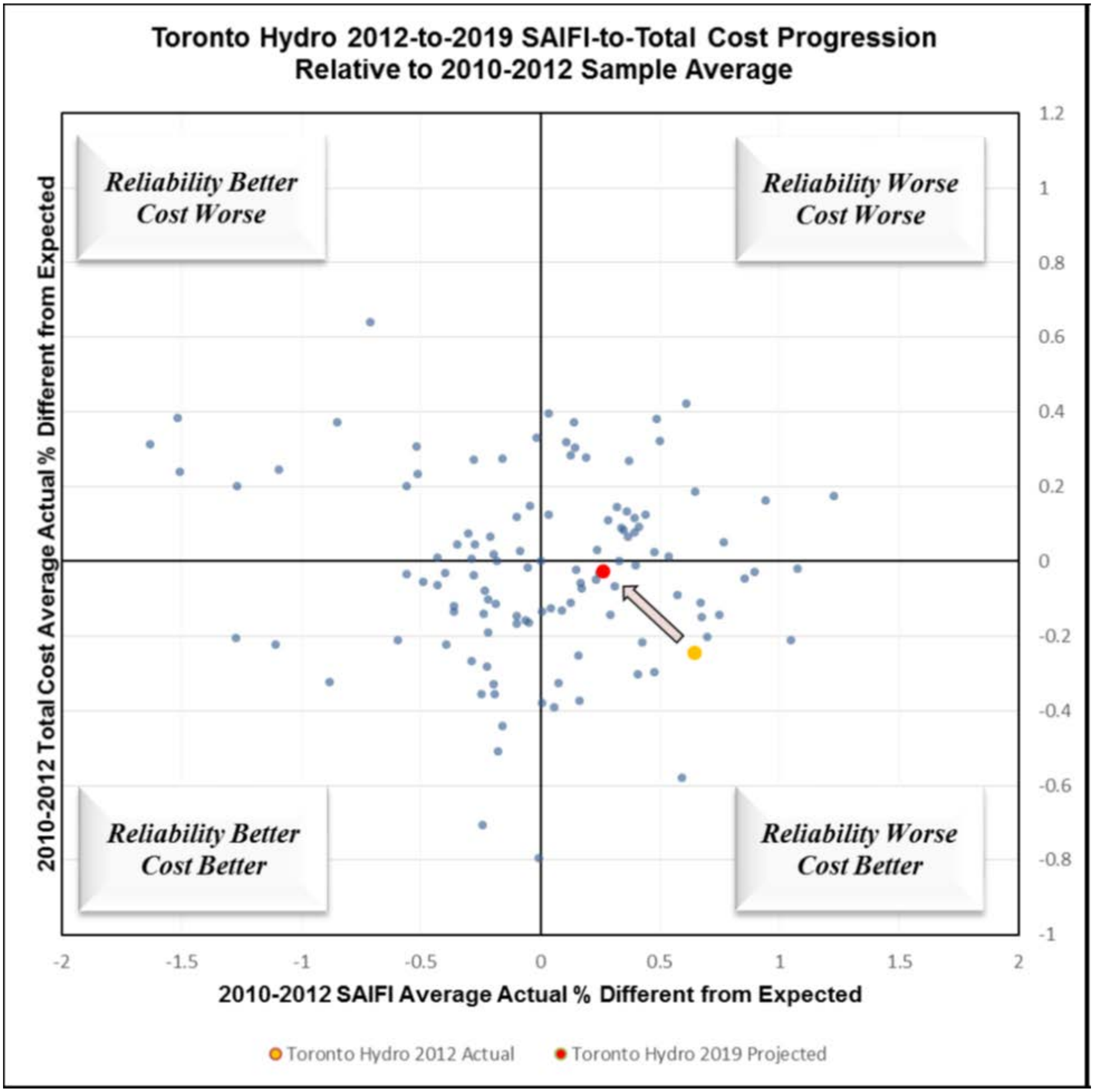
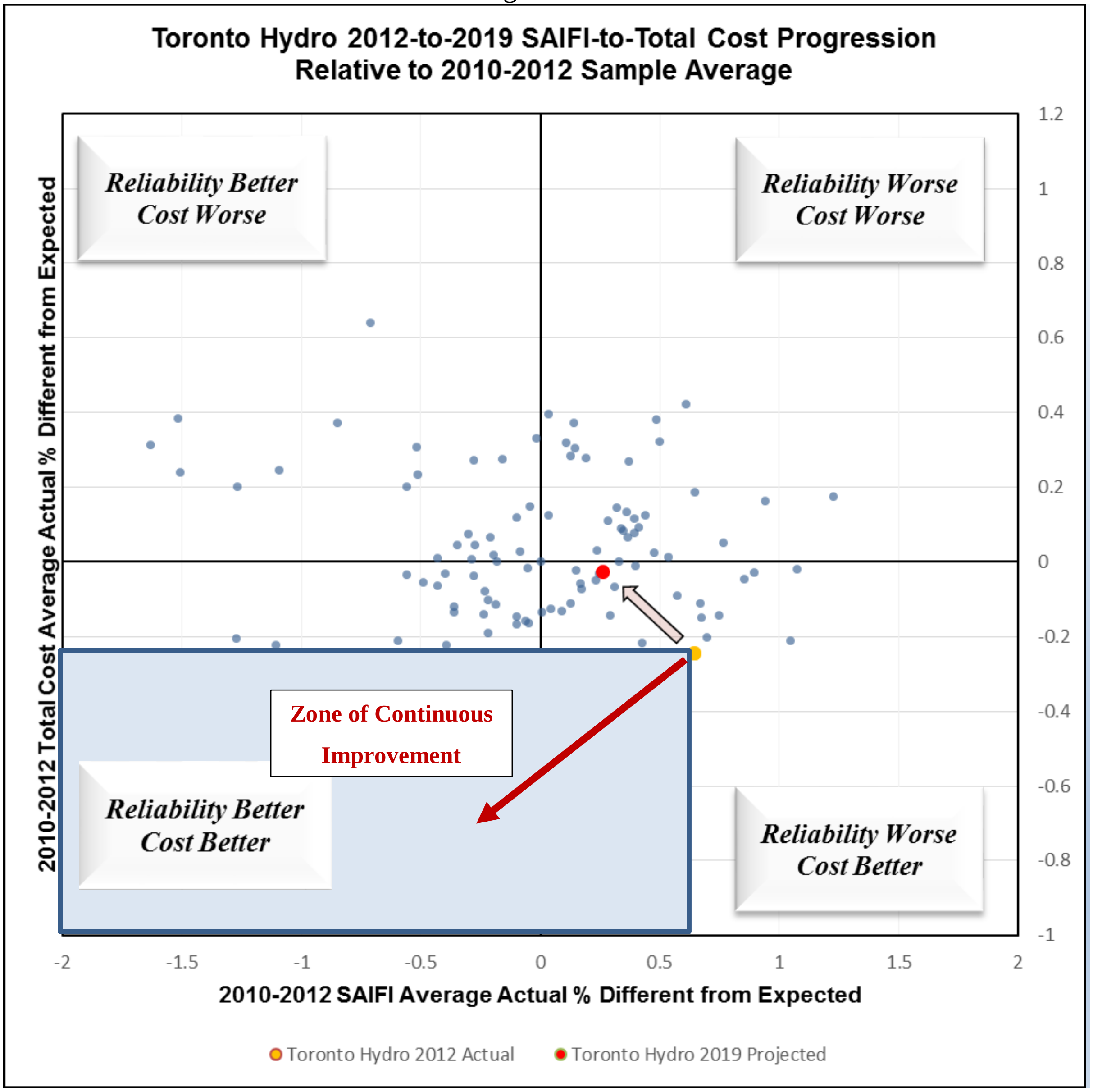

Toronto Hydro 2012-to-2019 SAIFI-to-Total Cost Progression
Relative to 2010-2012 Sample Average
Reliability Better
Cost Worse
Reliability Worse
Cost Worse
Reliability Better
Cost Better
Reliability Worse
Cost Better
2010-2012 Total Cost Average Actual % Different from Expected
2010-2012 SAIFI Average Actual % Different from Expected
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
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.

[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

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[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.

[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

[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

[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

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[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-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

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[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.

<u>Spread the Company's proposed capital expenditures over eight years rather than five years</u>

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"

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
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

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
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)"

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
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

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
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:

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

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:

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[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.

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[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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