ONTARIO ENERGY BOARD
File No. EB-2018-0165
Exhibit No. K10.2
Date July 15, 2019 jfs

SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS – PANEL 6

EB-2018-0165

TORONTO 2020-2024 RATES

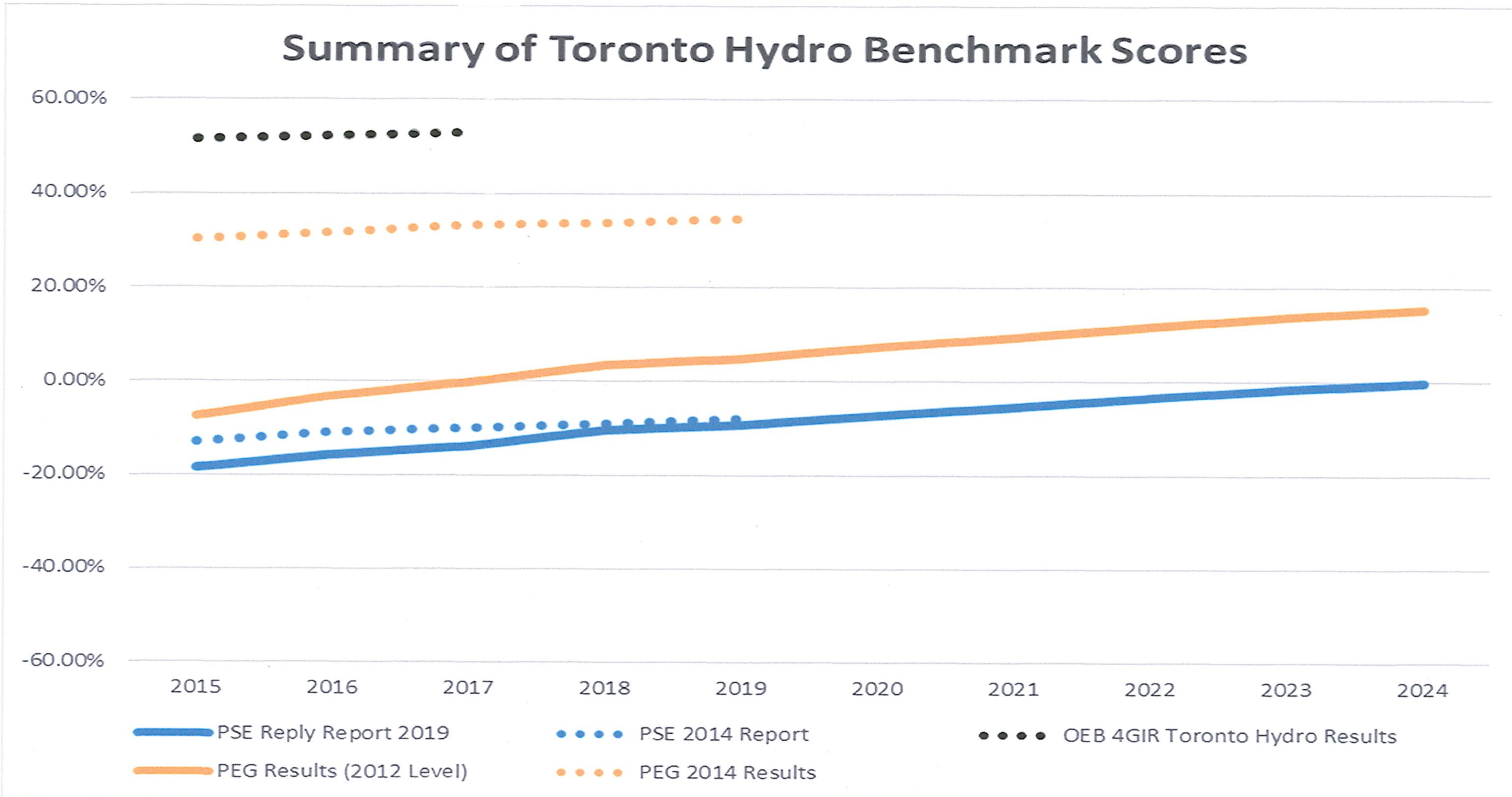

Summary of Toronto Hydro Benchmark Scores
60.00%
40.00%
20.00%
0.00%
-20.00%
-40.00%
-60.00%
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
PSE Reply Report 2019
PSE 2014 Report
OEB 4GIR Toronto Hydro Results
PEG Results (2012 Level)
PEG 2014 Results

Table 10

Year by Year Total Cost Benchmarking Results

Year	Percent Difference[1]
2005	-38.5%
2006	-37.5%
2007	-30.9%
2008	-29.1%
2009	-27.5%
2010	-20.0%
2011	-12.2%
2012	-13.9%
2013	-8.7%
2014	-6.9%
2015	-4.6%
2016	0.8%
2017	3.7%
2018	*7.5%*
2019	*8.7%*
2020	*11.4%*
2021	*13.4%*
2022	*15.9%*
2023	*17.8%*
2024	*19.5%*
Annual Averages	
2005-2017	**-17.3%**
2015-2017	**0.0%**
2020-2024	**15.6%**

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

Note: Italicized numbers are projections/proposals.

Pacific Economics Group Research, LLC

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

1.2. Summary

X Factor

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

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

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

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

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

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

We applaud the Company's willingness to present reliability benchmarking results and suggest some upgrades to their models. These models show that Toronto Hydro has substandard outage frequency but superior outage duration. PEG developed an alternative total cost benchmarking model using a longer sample period that includes 2017, more accurate capital cost data, and a better model specification. Using this model we found that Toronto Hydro's total cost was about equal to the benchmark on average from 2015 to 2017. However, the Company's total cost performance has deteriorated steadily under the current Custom IRM and is forecasted to continue to deteriorate under the proposed new plan. The projected/proposed total cost is about 15.6% above our model's prediction on average in the five years from 2020 to 2024.

PEG also developed experimental models to evaluate Toronto Hydro's projected/ proposed operation, maintenance, and administrative ("OM&A") expenses, capital cost, and capital expenditures ("capex"). These models are sensible and generate results that should be informative to regulators and the Company alike. During the term of the proposed plan, the Company's projected/proposed OM&A expenses would be about 12.1% *below* the model's predictions whereas the Company's capital cost would be about 35.7% *above* the predictions and capex would be about 14.9% above predictions. The results of these studies are summarized in Figures 1 and 2.

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

Figure 1

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

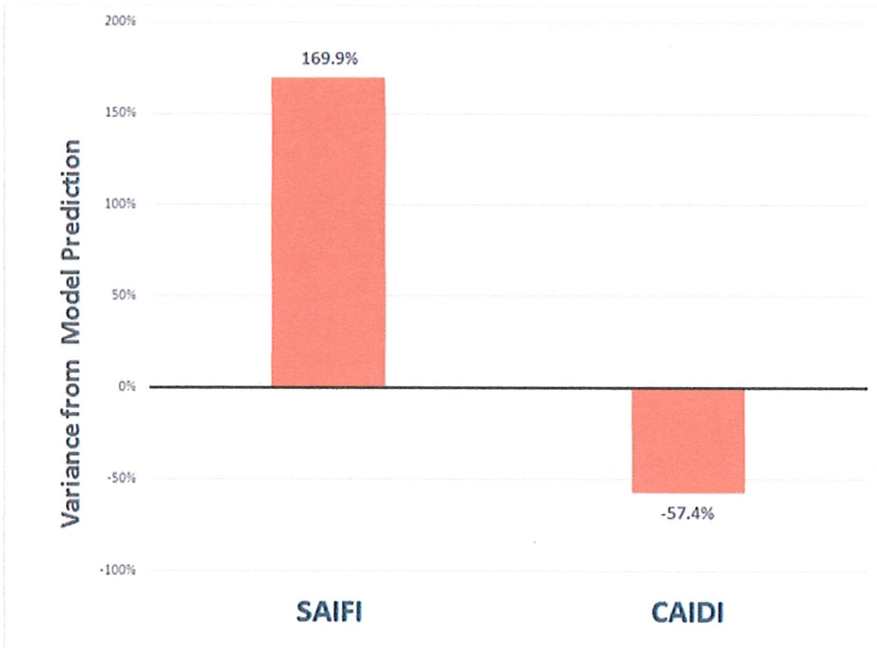
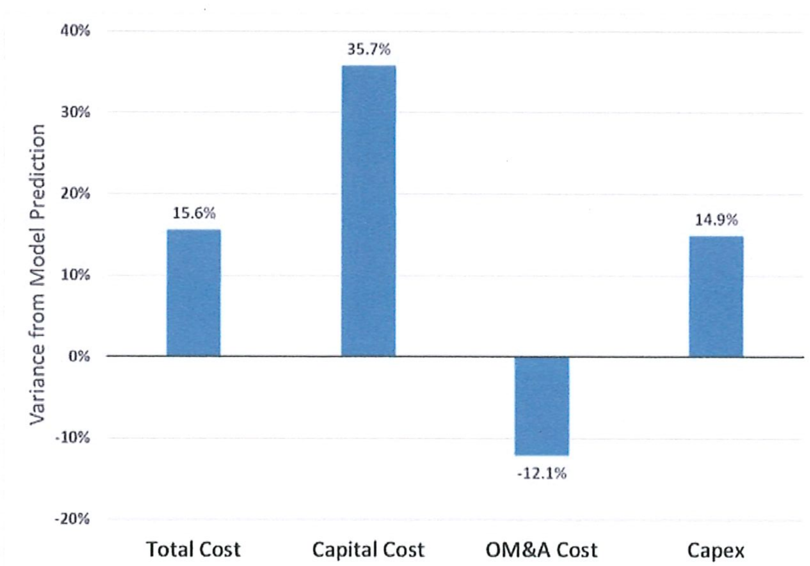


Figure 2

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



L1.INTERROGATORY SEC-13

Reference: Exhibit M1 [p. 66]

Please provide an example of how a materiality threshold and dead zone for capital could be added to Toronto Hydro's proposal, and what the impact would be of doing so.

Response to SEC-13: The following response was provided by PEG.

Toronto Hydro proposes to receive, through a C factor term in its price cap index ("PCI"), supplemental revenue for the shortfall between its proposed capital revenue requirement and the growth in revenue which would otherwise result from growth in the PCI and billing determinants. Assuming a 0.45% stretch factor, the capital revenue requirement in index year 1 would, for example, effectively be

$$RK_1 = CK_0 \times [1 + (I - X - g) + g] + [CK_1 - CK_0 \times (1 + I)] \quad [1a]$$

$$= CK_0 \times (1 + I - X) + [CK_1 - CK_0 \times (1 + I)] \quad [1b]$$

$$= CK_1 - 0.0045 \times CK_0. \quad [1c]$$

Here

RK = Allowed capital revenue

CK = Capital revenue requirement

I = growth in the PCI inflation measure

X = productivity factor (including stretch)

g = growth in billing determinants (assumed for simplicity to equal forecasted growth)

The cost saving from any cumulative net capex underspend would be returned to customers in full. The depreciated cost of any capex overspends would potentially be eligible for recovery in future rebasings. The OEB granted Hydro One Networks Inc. Distribution this ratemaking treatment of capex overspends in EB-2017-0049.

PEG has criticized Toronto Hydro's proposed C Factor approach on various grounds. We believe that it would weaken capex containment incentives since (a) there would be dollar for dollar recovery of any approved capital cost that exceeds $CK_0 \times (1 + I)$, (b) the cost savings from capex underspends would be returned, (c) some portion of overspends might be recoverable and (d) incentives to contain OM&A expenses are stronger. Regulatory cost would be higher, and exaggerated capex requirements and strategic "bunching" of capex to bolster supplemental revenue would be encouraged. Customers would be denied the benefits of industry productivity growth, even in the long run and even if it is achievable. PEG has also expressed concern that a more favorable ratemaking treatment of capex in Custom IR than in 4GIRM can encourage utilities to embrace Custom IR, with its many disadvantages.

The EB-2017-0049 decision also included a reform of the C factor mechanism that merits consideration for Toronto Hydro's new plan. The total capital cost eligible for supplemental revenue was reduced by a further stretch factor that we denote by "S". The value of S was set at 0.15%. Assuming once again a 0.45% stretch factor, the capital revenue requirement in index year 1 would effectively then be

$$RK_1 = CK_0 \times (1 + I - X - g + g) + [CK_1 - CK_1 \times (1 + I + S)] \quad [2a]$$

$$= CK_1 - (X+S) \times CK_0 \quad [2b]$$

$$= CK_1 - 0.0060 \times CK_0. \quad [2c]$$

PEG acknowledges that the $0.0060 \times CK_0$ term in [2c] (and the $0.0045 \times CK_0$ term in [1c]) both provide a materiality threshold and dead zone for capital revenue. Our concern is that the threshold and dead zone are not ideal.

- We believe that 0.0060 does not establish parity with the materiality threshold for supplemental capital revenue in 4GIRM. One problem is that the effective capital revenue markdown depends on the base productivity trend, which is 0. In contrast, the 10% deadband factor for the ACM/ICM in 4GIRM is not linked to the base productivity trend. Our preliminary research on this issue, which is more complicated than it first appears,[1] suggests that an S factor of around **0.6%** would achieve rough parity between the Custom IR and ACM/ICM markdowns.[2] A substantially more exact estimate of a parity value for S is beyond the scope of this project, as is PEG's assessment of the ideal materiality threshold and dead zone for supplemental capital funding.
- A straightforward way to sidestep this calculation is to abandon the current C factor mechanism and to instead use the current ACM/ICM mechanism to determine the capex that is eligible for supplemental revenue. Alternatively, the ACM/ICM mechanism might be used to determine incremental capex eligible for supplemental revenue, which would then be used to determine the C-factor for the rate adjustment in each year. This might require some adjustments to the C-factor formula to maintain parity with the ACM/ICM.
- Even if parity was established between Custom IR and 4GIRM markdowns, the

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[1] The complexity arises as one is trying to balance considerations of performance incentives, regulatory cost, and fairness to customers with the legitimate need of some utilities for capital spending surges.

[2] Our analysis identified the value of the supplemental stretch factor "S" that would cause the C-factor to yield a similar outcome to the ACM/ICM materiality threshold given some mathematical simplifications and the capital cost data that Toronto Hydro has used in its C-factor proposal.

markdowns would likely not be enough to address all of our concerns (noted above) about supplemental capital revenue. Determination of a more optimal markdown is also beyond the scope of this project.

- Neither the C factor nor the 4GIRM approach strengthen incentives to contain *incremental* capex once the materiality threshold is exceeded. The following alternative approach to calculating the C factor has better incentive properties than [2a-c].

$RK_1 = CK_0 \times (1 + I - X - g + g) - [CK_1 \times (1\text{-}S)] - CK_0 \times (1 + I)\}$ [3a]

$= CK_1 x\ (1\text{-}S) - CK_0 \times X$ [3b]

Another way to incentivize containment of incremental capex is to permit the Company to keep a share (say 10%) of any cumulative CRRRVA balance at the end of the next plan. An analogous share of capital cost overruns could, similarly, be ineligible for supplemental revenue at the end of the plan. The OEB took a step in the direction of sharing variances with the approval of Hydro One Networks' Capital In-Service Additions Variance Account, which only requires refunds when capital spending is 98% or less of the OEB's approved amount. Actual additions are compared to the amounts approved by the OEB in each year, and the account will be cleared at the end of the Custom IR plan.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 22:

Reference(s): **Exhibit 1B, Tab 4, Schedule 2, p. 6**

SEC is interested in understanding the impact of the %CU variable and the %UG*%CU variable on the results in Table 1. Please re-specify and rerun the PSE model without those variables, and provide the results in the same form as Table 1.

RESPONSE (PREPARED BY PSE):

This request is to create and run a different model that is not PSE's model, and is a fundamentally different approach. Excluding these variables, and creating a model without them, is not a proper or robust approach and would produce misleading results in portraying Toronto Hydro's cost performance. Serving a congested urban core and constructing underground power lines in congested urban areas significantly increases a distributor's total costs. This fact has been confirmed both empirically and through engineering analysis. Excluding these variables from the model would be ignoring important and statistically significant cost drivers that are significant at a 99.9% confidence level. Excluding variables that have both strong engineering and statistical support will produce misleading results that suffer from omitted variable bias. See also the responses to 1B-SEC-28 and 1B-Staff-32 (b) in respect of the importance of these variables.

year typically being the lower value. The table below shows the logarithmic percentage differences.

PSE Expanded Table 1 (Logarithmic)

Toronto Hydro Actual and Benchmark Cost Increases				
Using PSE Model				
Year	*Actual*	*Increase*	*Benchmark*	*Increase*
2005	$436,128		$641,275	
2006	$450,686	3.3%	$681,212	6.0%
2007	$502,433	10.9%	$744,486	8.9%
2008	$556,429	10.2%	$813,528	8.9%
2009	$595,932	6.9%	$852,775	4.7%
2010	$647,456	8.3%	$882,130	3.4%
2011	$710,544	9.3%	$912,729	3.4%
2012	$691,388	-2.7%	$910,814	-0.2%
2013	$727,152	5.0%	$925,488	1.6%
2014	$777,414	6.7%	$976,095	5.3%
2015	$826,886	6.2%	$1,024,030	4.8%
2016	$861,394	4.1%	$1,034,492	1.0%
2017	$904,560	4.9%	$1,061,642	2.6%
2018	$964,885	6.5%	$1,095,430	3.1%
2019	$999,492	3.5%	$1,122,407	2.4%
2020	$1,044,567	4.4%	$1,148,601	2.3%
2021	$1,085,324	3.8%	$1,174,549	2.2%
2022	$1,134,689	4.4%	$1,201,662	2.3%
2023	$1,180,820	4.0%	$1,229,463	2.3%
2024	$1,225,282	3.7%	$1,257,907	2.3%
Total 19 Year Increase		103.3%		67.4%
CAGR - 19 years		5.44%		3.55%
Increase from 2017		30.35%		16.96%
CAGR - 7 years		4.34%		2.42%

b) The table below provides Toronto Hydro's outputs, which are the number of customers and maximum peak demand. The percentage increase is calculated arithmetically, to match the calculations found in the table in the question. However,

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 27:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 18, 21

With respect to input prices:

a) Please explain why the expert did not use the same measure of input prices that the OEB uses to calculate inflation.

b) Please provide tables for each of the seven Ontario distributors showing the changes in OM&A inputs assumed by PSE, and a breakdown of each such assumption.

c) Please reconcile the resulting changes in assumed input prices with the assumed 1.2% inflation factor used by Toronto Hydro in the Application (e.g. Table 5).

RESPONSE (PREPARED BY PSE):

a) Important measures of input prices for a benchmarking study are the input price levelizations used to adjust for the fact that items like wages and construction costs vary from city to city and region to region. For example, salaries and wages will tend to be significantly higher in New York City than in Madison, Wisconsin. These differences need to be properly adjusted to create a level playing field for the entire sample within the benchmarking study.

A key difference in the PSE Study versus the OEB Study is that the PSE adjusts for the construction cost differences between the utilities using RSMeans construction cost indexes by city. A city like Toronto is likely to have higher construction costs than a city like London, ON. The OEB Study assumes all the Ontario distributors have equal capital prices. This will tend to unfairly harm the benchmarking scores of utilities serving higher cost regions, such as Toronto Hydro. PSE has corrected for this omission in our study.

PSE also updated our labour levelizations using 2010 Canadian census data and U.S. Bureau of Labor Statistics (BLS) data. We are unsure of how the OEB Study specifically adjusted for labour input prices but we use the updated Canadian Census on over 100 job occupations to create a composite wage level that matches the composition of an electric utility. We used Bureau of Labor Statistic (BLS) data to match those same occupations for the U.S. sample.

After the levelizations are set, growth rates (inflation) are applied to move the levelized input prices from year to year. PSE used Handy-Whitman indexes for electric distribution in constructing the capital input price. The OEB Study methodology uses the Canadian Electric Utility Construction Price Index (EUCPI). However, the EUCPI has been discontinued as of 2014. Further, PSE is of the opinion that it is more appropriate to use a construction cost inflation index that is specific to the electric distribution industry, rather than other possibilities that are generalized to either the electric utility industry or just the utility industry at large. For the Ontario distributors, we did translate the Handy-Whitman electric distribution indexes into Canadian currency using the purchasing power parity indexes (PPPs) for Canada. Similarly, PSE used U.S. employment cost indexes and a GDP price index to inflate OM&A related costs, but adjusted these inflation measures using the Canadian PPP for the Ontario distributors.

b) The table below illustrates the input price levels and trends for the Ontario distributors including in the PSE sample. As can be seen by the fact the growth rates are all the same, we used identical input price inflation assumptions for all seven distributors. The differences show up in the levelizations of labour and capital. Toronto Hydro and Enersouce have the same input prices in all years because we mapped each one to the city of Toronto to determine the levels of salaries and wages and capital construction prices. The other utilities were mapped to their respective headquarter cities.

Distributor	2016 Labour OM&A Input Price	2005-2016 Annual % Growth Rate	2016 Non-Labour OM&A Input Price 2016	2005-2016 Annual % Growth Rate	2016 Capital Input Price	2005-2016 Annual % Growth Rate
Toronto Hydro	90,563	3.0%	1.40	2.0%	13.38	4.0%
Enersource	90,563	3.0%	1.40	2.0%	13.38	4.0%
Horizon Utilities	85,546	3.0%	1.40	2.0%	13.04	4.0%
London Hydro	81,346	3.0%	1.40	2.0%	12.85	4.0%
Kitchner-Wilmont	85,236	3.0%	1.40	2.0%	12.32	4.0%
Hydro Ottawa	91,495	3.0%	1.40	2.0%	12.95	4.0%
EnWin	87,251	3.0%	1.40	2.0%	12.20	4.0%

c) The input price inflation assumed by PSE is looking at the historic industry inflation for each year, whereas the 1.2% is the recent escalation factor. Further, the industry inflation has been higher than the inflation factor, primarily due to the 4.0% growth in capital prices and the 3.0% growth in utility employment cost indexes. We would expect the industry-specific inflation to be different from the more general indexes used in the inflation factor. In a benchmarking study, all utilities receive the same or similar treatment regarding inflation assumptions, and this assumption will likely have a small impact on the relative scores or rankings of the individual utilities being benchmarked. The inflation assumptions are important when benchmarking projected data. PSE believes we have used estimates that are conservative in those projections. For example, rather than continuing the 4.0% capital inflation rate, we instead used a capital inflation assumption of 2.18% for 2020 to 2024. PSE stayed on the lower bound of what we would consider reasonable estimates for asset price inflation in order to help address one of the three Board concerns cited in the Board's 2015 Decision.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 28:

Reference(s): **Exhibit 1B, Tab 4, Schedule 2, p. 20**

Please explain why the %CU variable and the %UG*%CU variable do not measure similar or related effects.

RESPONSE (PREPARED BY PSE):

The congested urban variable (%CU) measures the cost impact of serving a highly congested urban service territory. This has been shown both empirically and through engineering analysis to be a significant driver of a distributor's total costs.

The underground variable (%UG*%CU) measures the important cost differences between undergrounding power lines in congested urban areas relative to non-congested urban areas. It will tend to be far less costly to underground lines in suburban and/or rural areas. In fact, in many areas, utilities are able to direct bury power lines, and overall costs can be reduced relative to constructing overhead power lines (see the negative coefficient value on the %UG variable). By including the %UG*%CU variable, the model can disaggregate the vast cost differences between undergrounding in rural/suburban areas versus undergrounding lines in congested urban areas.

The added flexibility of distinguishing between the differences this variable provides is important to accurately evaluating Toronto Hydro's total cost performance, given their high percent undergrounding and high percentage of congested urban service territory. If this variable were excluded, undergrounding costs in the model would combine the lowcost rural/suburban undergrounding with the much higher cost urban undergrounding making the model less precise and accurate.

PSE stated the importance of disaggregating the underground costs on p. 20 of the PSE report:

> The **percent underground multiplied by congested urban variable** provides the interaction between the percent underground variable and the congested urban variable. Constructing underground lines in urban settings is far more costly than in more rural settings. For example, underground lines in rural settings can be "direct buried" without the need for concrete-enclosed banks and other capital infrastructure. We would expect a positive coefficient on the variable.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 29:

Reference(s): Exhibit 1B, Tab 4, Schedule 2, p. 22

SEC is seeking to understand how the change in the maximum peak demand variable impacts the model results.

a) Please provide a table showing the maximum peak demand of Toronto Hydro for each year from 2002 onwards using the 2015 methodology and using the current methodology, and explain each year that there is a difference.

b) Please confirm that the new methodology assumes that, even if demand declines, that never, over time, reduces the costs of an electricity distributor. If not confirmed, please explain.

RESPONSE (PREPARED BY PSE):

a) The maximum demand variable is defined the same as the capacity variable included in the 4th Generation OEB benchmarking model. The difference in the annual peak demand and maximum peak demand is due to the maximum peak demand variable measuring the highest peak demand variable from either the current year, or from all past years since 2002, whereas the annual peak demand measures only the current year.

Table 1: Annual and Maximum Peak Demand for Toronto Hydro

Year	Annual Peak Demand	Maximum Peak Demand
2002	4,771	4,771
2003	4,821	4,821
2004	4,521	4,821
2005	5,005	5,005
2006	5,018	5,018
2007	4,788	5,018
2008	4,564	5,018
2009	4,607	5,018
2010	4,786	5,018
2011	4,919	5,018
2012	4,830	5,018
2013	4,915	5,018
2014	4,274	5,018
2015	4,404	5,018
2016	4,592	5,018
2017	4,260	5,018
2018	4,217	5,018
2019	4,195	5,018
2020	4,165	5,018
2021	4,119	5,018
2022	4,069	5,018
2023	4,038	5,018
2024	4,052	5,018

b) A distributor's actual total costs can still increase or decrease based on the actual cost levels incurred. It is true that the definition of the variable prevents the maximum peak demand variable from decreasing over time. This is because the distribution system is required to be built to meet maximum peak demands over a multi-year period and not just the annual peak demand in each year.

if you can find a natural break.

MR. SHEPHERD: I am happy to do that. It is up to you.

MS. ANDERSON: Thank you.

CROSS-EXAMINATION BY MR. SHEPHERD:

MR. SHEPHERD: By the way, I am hopeful that I will not take my full hour. I am not making promises, I am just expressing desires.

We have a compendium, and I wonder if I could have that added as an exhibit. I think you have copies, and --

MR. MILLAR: K9.5.

EXHIBIT NO. K9.5: SEC COMPENDIUM FOR PANEL 5.

MR. SHEPHERD: An electronic version has been provided.

Before I get to my compendium, Mr. Fenrick and I know each other well. We have talked sitting in exactly these same seats numerous times, right?

MR. FENRICK: We have.

MR. SHEPHERD: I wanted to follow up on something you talked about with Mr. Millar earlier today. It isn't in my compendium, because I didn't think I was going to ask about it.

You specified different models for Toronto Hydro and for Hydro One, right?

MR. FENRICK: Yes, there was a different sample and different -- a different model.

MR. SHEPHERD: And if you produced benchmarking results for Toronto Hydro using the Hydro One model, those results would be materially different from what you are testifying to in this proceeding, right?

MR. FENRICK: Right. Likely. Possibly. I would also say they would be less accurate, just given the data set that we use for the Hydro One to include 300 rural cooperatives which would detract from the model accurately projecting for Toronto Hydro.

MR. SHEPHERD: And conversely, if you compared Hydro One using -- to a benchmark and you used the Toronto Hydro model to benchmark them, again it would be materially different, right?

MR. FENRICK: Likely would be different, a different result.

MR. SHEPHERD: Now, so I am trying to understand this because -- and I think this is what Mr. Millar was trying to get to. I thought the idea of a cost model was to identify all the material cost drivers and figure out how they relate to each other in a formula. Right?

MR. FENRICK: No, not entirely. The objective is to develop a cost model that most precisely estimates the cost drivers of the studied utility and how those impact costs, which is why you see for the Hydro One, we included 300-some rural utilities because the closer you can get the studied utility to what the sample is and the sample means, the more precise that estimate is going to be.

So that is why we added those rural utilities. That would actually detract from the Toronto Hydro estimate because including those rural, extremely rural cooperatives in the U.S. data set would move the variable values actually away from Toronto Hydro and away from the mean. It would make that result far less precise for Toronto Hydro.

And so the objective when we're doing this is to develop the best possible model that provides the best possible benchmark for the studied utility.

MR. SHEPHERD: So the OEB has a model that it uses, right? And that's a model that -- the same model applies to everybody. Everybody is measured against the same benchmarks. Right? Against the same modelled benchmarks.

MR. FENRICK: Right. The Ontario model that uses the Ontario distributors, the model -- it's essentially the same model. There is actually -- each utility is actually pulled out. So it's -- for all intents and purposes, it is the same model.

MR. SHEPHERD: Well, no. It is exactly the same model, isn't it?.

You specified differently for each utility, but the actual variables, which ones are used and how they're used, is exactly the same, right?

MR. FENRICK: No, not exactly.

MR. SHEPHERD: Tell us how that is not true.

MR. FENRICK: For instance, if you are benchmarking a utility, say you are looking at Hydro One. When PEG does that model, they will pull out Hydro One and rerun the model and get the coefficients for the sample, absent Hydro One. So it is an external benchmark.

And then if they're going and doing Toronto Hydro, they will pull out Toronto Hydro, recalculate the model. So the co-efficients are slightly different. That is just why I don't want to say yes to your answer, because it is not exactly the same model and co-efficients.

It is the same variables. It is the same structure, if you will. The co-efficients are just tweaked because you are pulling out the -- the utility that it applies to is pulled out of the sample to make it a fully external benchmark.

MR. SHEPHERD: And other than that, the same rules are applied to everybody, right?

MR. FENRICK: The same model and specification and variables are used.

MR. SHEPHERD: So here's what I am trying to understand is why would it be appropriate then for you to say, well, no, Toronto's different than Hydro One, so we need a different model for them. We need a different peer group. We need a different set of variables -- quite a different set of variables.

Why would you want to do that? Shouldn't you be looking at all of the cost drivers and if they have a small impact, well, so what?

MR. FENRICK: Well, I think, Mr. Shepherd I explained that given -- I mean, Hydro One and Toronto Hydro are vastly different utilities. I think we would agree. Hydro One is much more rural. Toronto Hydro is much more congested urban.

As I mentioned, you know, we adjusted the sample first of all to try to properly calibrate the ruralness of Hydro One by adding those rural utilities.

Further, we improved and advanced the model for Toronto Hydro in calculating the congested urban variable, and improved the model based on that.

And we also did not include the rural cooperatives in the Toronto Hydro model, but we did include the Ontario distributors that are most like Toronto Hydro that serve congested urban to get a sample that is the most appropriate one possible to, as precisely as possible, calculate those coefficients as they apply to the studied utility.

MR. SHEPHERD: So I understand that. And yet you were very clear that, for example, Commonwealth Edison is not like Toronto Hydro because Commonwealth Edison has all of this rural and you don't include a rural variable. Right?

MR. FENRICK: There's differences between all of the utilities in the sample. Some are more rural. Some are less rural.

But we included all of the U.S. investor-owned utilities because that data set is the appropriate.

I might also add --

MR. SHEPHERD: Sorry, can I just stop you there? It's the most appropriate why? That sounds like begging the question to me.

MR. FENRICK: For Toronto Hydro, because I mean Toronto Hydro is an outlier when it comes to the Ontario data set, given their size and their congested urban characteristics.

MR. SHEPHERD: They're an outlier in the U.S. data set, too. You have admitted that.

MR. FENRICK: They're far less of an outlier when it comes to size and also the congested urban. We have Consolidated Edison, which is beyond Toronto Hydro's congested urban variable value.

MR. SHEPHERD: I just have one more question and then it will be a good time to break.

You had a back and forth with Mr. Millar about why you put in the congested urban variable. I am going to come back to that variable later.

But do I understand correctly that you added that variable in because it appeared to you that it was a cost driver that was important for a utility like Toronto, and then you quantified it using the U.S. data -- the full peer group?

MR. FENRICK: Our engineering team identified that as a very important cost driver of utility costs, serving a congested urban service territories.

So that's why it was included and we quantified it, you know, if response to the Board decision from the last application. You know, they weren't comfortable with the blunt instrument that we used last round, so we put forth the effort to create a continuous variable so we could adjust for that characteristic.

MR. SHEPHERD: My question was, you tailored the model

MR. FENRICK: We look at that, yes.
MR. SHEPHERD: You wouldn't include a variable that doesn't appear to have some reason for being there, would you?
MR. FENRICK: Right. That's the first selection criteria is the variable needs to have engineering or theoretical basis to be included.
MR. SHEPHERD: All right. So the question I am asking is -- you've said, well, but a U.S. model will better reflect numbers of customers.
But it would appear to me -- and tell me whether this is right -- that that implies that smaller companies, smaller utilities have a lower cost per customer than Toronto Hydro. Why would that be?
MR. FENRICK: I don't see how you can get that implication. There's also -- also there's -- and you alluded to this, and I neglected to mention it. We're also estimating the economies of scale in the translog cost function, and smaller utilities are likely to have more economies of scale than a larger utility as well.
MR. SHEPHERD: So help me with that. So I actually asked about diseconomies of scale, because economies of scale are as you get bigger, your unit cost is cheaper, right?
MR. FENRICK: Yes.
MR. SHEPHERD: So you just said smaller utilities will have more economies of scale than bigger utilities. That sounds like the opposite. Help me understand.

MR. FENRICK: So to the extent that smaller utilities have more availability for economies of scale, I mean the model -- and this gets into the quadratic variables -- the model will estimate that and come up with an estimate of the economies of scale, the available economies of scale at the sample mean.

To the extent that the model is saying, okay, a typical utility in this data set has this level and this availability of economies of scale, given that Toronto Hydro is an outlier in the Ontario data set, the model is going to project that estimate on to the utility, Toronto Hydro.

So if it's saying there are strong availability of economies of scale as you get bigger, it's going to apply that to Toronto Hydro, even though Toronto Hydro's 30 times bigger than the mean, and I think that Toronto Hydro has those same availability of economies of scale, which likely isn't the fact. At some point, those are diminished.

So I guess it's a long way of saying you want a sample that can encompass your studied utility, because these issues rise, you are measuring the impact of number of customers, maximum demand, you're looking at economies of scale all in this model.

You don't want the model to have extrapolate out. You want the model to encompass the studied utility, which is why the U.S. sample, when estimating these co-efficients, is a far superior compared to the Ontario only.

MR. SHEPHERD: So your explanation sounds like it is an explanation with respect to total factor productivity, where you are calculating the delta from year to year.

But you don't do that in benchmarking, do you? In benchmarking you are looking at the costs at a point in time. You are estimating what the costs at a point of time should be, isn't that right? It's different.

MR. FENRICK: That's right. You are estimating the impacts of the cost drivers and what the cost impacts would likely be on to that. It's not a trend analysis.

MR. SHEPHERD: So doesn't that mean that if you are estimating -- if you look at the costs of Toronto Hydro, that includes all of the economies of scale they have been able to get in growing bigger and bigger, whereas a smaller utility has had less opportunity to do that, so its unit cost should be higher, its cost per customer should be higher, isn't that right?

MR. FENRICK: That point is right. My point is at some point economies of scale are exhausted and, you know, it's an empirical issue. I don't know when that is. But economies of scale at some point are exhausted.

Given the Ontario data set and how small the distributors are, it is unlikely they have been exhausted for the vast majority of those distributors.

So the model is going to contain or incorporate that, and then it is required to extrapolate that on to Ontario Toronto Hydro, so that is my point. I know it is a very technical point I am trying to make here, but...

MR. SHEPHERD: Can we go to page 22 of our materials, right now, so they would not say that, believe me.

MR. FENRICK: If I could go back. Toronto Hydro does much better in the PSE model compared to the OEB model, not because they're my client, but because we have properly adjusted for the cost challenges of the congested urban variable.

I would like to add if you looked at PEG's results, there would also be a vast difference in the results between the OEB model and PEG's results, again for the reasons we have cited, the congested urban variable being the primary reason for that.

MR. SHEPHERD: We will cross-examine them on Monday about that.

MR. FENRICK: Okay. I will be listening. I mean, the Kitchener Wilmot, I don't know what's primarily driving that result and that difference.

MR. SHEPHERD: So doesn't it concern you that your model would produce such markedly different results? I mean, these are not -- you know, a 33 percent difference in 2014, for example, or 32 in 2016, that doesn't sound like it is trivial. That is a lot of money.

MR. FENRICK: You have to look at the differences in the approaches between the Ontario model and sample and then the PSE and PEG approach in benchmarking Toronto Hydro.

Two entirely different -- well, mostly entirely, PSE does include six Ontario distributors. But primarily a different data set, a different set of variables that best estimate Toronto Hydro's benchmarks.

You would expect some deviation, I would say for a number of these utilities, they are close. You even said that yourself. You would expect some deviations as you have an entirely different model, sample model, different variables, improved variables from the model that was developed back in 2013.

It would be my expectation there would be differences.

MR. SHEPHERD: Okay. So the OEB should stop using that model, then. It is clearly like very far wrong. Right?

MR. FENRICK: In relation to for custom IR on a case-by-case basis, when determining Toronto Hydro's stretch factor and the appropriate stretch factor, yes, I believe that the PSE model is the best and most accurate depiction of the company's performance.

MR. SHEPHERD: But it wouldn't be a good model for Kitchener-Wilmot.

MR. FENRICK: I would say the Ontario model would be more appropriate for Kitchener-Wilmot. I would have to give that more thought, which one would be best.

We have designed the sample and -- to best reflect Toronto Hydro. You know, Kitchener-Wilmot is, what, 90,000-some customers. So there would likely be differences there.

I would say the Ontario data set is more appropriate for Kitchener-Wilmot than it is for Toronto Hydro.

MR. SHEPHERD: So right at the beginning of this cross-examination I asked you whether your model would be specified differently for a different client for a different target utility, and why they would have different cost drivers than everybody else.

You said, no, no, no, no, the only reason why my Hydro One model is different than this one is because we've evolved. So now you are saying, no, Kitchener-Wilmot would not -- it would not be appropriate to use your model for Kitchener-Wilmot? Is that what you are saying?

MR. FENRICK: I think if you go back to my response, another reason was the sample differences. So for Hydro One we included 300 rural electric cooperatives in that sample to better reflect Hydro One's circumstances.

If we were doing a benchmarking study for Kitchener-Wilmot, we would likely want to include more of the Ontario sample, just given the size, you know, the smaller size of Kitchener-Wilmot, including more of the Ontario sample when doing a benchmark study for Kitchener-Wilmot would be the more appropriate approach.

MR. SHEPHERD: See, it sounds a lot to me, Mr. Fenrick, like what you're saying is we should measure Toronto Hydro against a different standard than everybody else. Isn't that what you're saying?

MR. FENRICK: You should measure it against the best standard you can possibly do.

MR. SHEPHERD: But the best standard is different for them than for somebody else, Kitchener-Wilmot, for example.

MR. FENRICK: Yes. Doing -- developing the best possible benchmark for Toronto Hydro is going to be a different exercise than for Hydro One, given the different circumstances that the utilities face, the samples should be different.

You see PEG themselves, the Board Staff's consultant, evidently agrees with that point. They have a U.S.-only sample for Toronto Hydro, and then they do an Ontario sample for the other distributors.

They did the same thing for Hydro One where they used a U.S. sample. That's the best -- you want to do the best benchmark possible for the studied utility.

MR. SHEPHERD: Can we go to page 37 of your report. So which of these cost drivers would you exclude if you were doing a model for Kitchener-Wilmot?

MR. FENRICK: As I stated, if I was doing a model for Kitchener-Wilmot I would likely add to the sample a number of the smaller Ontario distributors to get the sample more appropriate for Kitchener-Wilmot.

MR. SHEPHERD: Because they have different cost drivers?

MR. FENRICK: Because they're a different size. They have different variable values.

MR. SHEPHERD: All right. Just while we're on this, let me ask you a couple of questions about this.

All of these various variables and the quadratics that are associated with them, they're all used in your model, right? It is not just the highlighted ones that are used in your model. They're all used in your model, right?

MR. SHEPHERD: They would increase it, though, the quadratic would increase it, and so would the undergrounding increase it, right, the impact?

MR. FENRICK: No. The quadratic actually decreases. There's a negative value there. So as you have more congested urban, the cost impact is actually -- it goes down.

MR. SHEPHERD: It's curved.

MR. FENRICK: So we're getting that curvature. Since it is negative, you know, there appears to be some sort of economies of scale as you are serving more congested urban service territory, yes, your costs are increasing, but they will increase at a lower rate.

MR. SHEPHERD: You get better at it.

MR. FENRICK: You get better at it, yes, exactly.

MR. SHEPHERD: You see, here is what I am concerned with. You have these 83 utilities with only one that is anywhere close to Toronto in congested urban.

And they have this very tiny percentage of congested urban, and you're somehow teasing out a cost that you are then saying let's multiply that by 20 and apply it to Toronto Hydro.

That sounds like there's a tremendous opportunity for error. Isn't that right?

MR. FENRICK: It is true that Toronto Hydro is certainly an outlier when it comes to the congested urban variable.

And that's one of the reasons why we put the quadratic in, to get that curvature in since Toronto Hydro is an outlier.

If in a perfect world, if we could add a bunch of Consolidated Edisons and New York Cities into the data set, we would.

Unfortunately, given the reality in the data that we have, this is the best possible estimate. We did the best possible job we could given the data.

Another reason why we added the Ontario six distributors is because, you know, they had values around .4 percent congested urban.

And so given the reality of what we have, this is the best possible estimate. You know, PEG did the same exact approach, except for the Ontario distributors, but they included this variable as well.

Is it less precise than if we had a whole bunch of New York Cities? Yes, absolutely. But this is the best estimate of the cost performance for Toronto Hydro that is available.

MR. SHEPHERD: Can you go to page 5 of our materials?

MS. ANDERSON: Time check; we do have another person and panel questions, so I am not sure...

MR. SHEPHERD: Another person?

MS. ANDERSON: Mr. Hann still needs to go.

MR. SHEPHERD: I'm sorry, I had an hour.

MS. ANDERSON: Yes.

MR. SHEPHERD: So I have 10 minutes?

MS. ANDERSON: Yes. But you started at 3:00.