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BY E-MAIL

March 2, 2015

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited
Application for Rates
Board File Number EB-2014-0116

Attached are responses prepared by Dr. Lawrence Kaufmann to Undertakings No. J3.2 to J3.9 inclusive arising from Dr. Kaufmann's testimony on Day 3 of the proceeding.

Yours truly,

Original Signed By

Martin Davies
Project Advisor, Electricity Rates & Accounting

Attachment

cc: Parties to EB-2014-0116 proceeding

ORAL HEARING UNDERTAKING RESPONSE
TO THE ONTARIO ENERGY BOARD

UNDERTAKING NO. J3.2:

Reference(s):

To provide a list of the 27 Utilities used in the PEG analysis.

RESPONSE:

Below is a list of the 27 utilities PEG used when constructing our "all urban utilities" urban core dummy variable. This list also includes the major city in each of these utilities' service territories. The econometric results when this 27 utility-urban core dummy is added to PEG's cost benchmarking model are presented in response to 1-THESL-30c).

Utility	Major City
AmerenUE	St. Louis, Missouri
Arizona Public Service	Phoenix, Arizona
Baltimore Gas & Electric	Baltimore, Maryland
Carolina Power & Light	Raleigh, North Carolina
Cincinnati Gas & Electric	Cincinnati, Ohio
Cleveland Electric Illuminating	Cleveland, Ohio
Commonwealth Edison	Chicago, Illinois
Consolidated Edison	New York City, New York
Detroit Edison	Detroit, Michigan
Duquesne Light	Pittsburgh, Pennsylvania
Entergy New Orleans	New Orleans, Louisiana
Florida Power & Light	Miami, Florida
Florida Power	St. Petersburg, Florida
Georgia Power	Atlanta, Georgia
Indianapolis Power & Light	Indianapolis, Indiana
Kansas City Power & Light	Kansas City, Missouri
Nevada Power	Las Vegas, Nevada
Niagara Mohawk Power	Buffalo, New York
Northern States Power	Minneapolis-St. Paul, Minnesota
Pacific Gas & Electric	San Francisco, California
Portland General Electric	Portland, Oregon
Potomac Electric Power	Washington, DC
Public Service of Colorado	Denver, Colorado
Puget Sound Energy	Bellevue, Washington
San Diego Gas & Electric	San Diego, California
Tampa Electric	Tampa, Florida
Wisconsin Electric Power	Milwaukee, Wisconsin

Panel: Dr. Lawrence Kaufmann

On further inspection, PEG determined that two of the utilities listed above (Carolina Power and Light and Puget Sound Energy) do not serve “urban cores”/downtown areas even though they serve extensive portions of major US metropolitan areas. However, one utility that was not originally selected does in fact serve the urban core of a major metropolitan area that includes an NFL football team (Duke Energy – Carolinas, which serves Charlotte, North Carolina). To test whether PEG’s estimate of the “urban core” dummy variable is sensitive to these differences in which “urban core utilities” are selected, we have estimated a cost model that includes a dummy variable for each of the utilities listed above, minus Carolina Power & Light and Puget Sound Energy, plus Duke Energy-Carolinas (making 26 urban core utilities in total). The results from this econometric regression/sensitivity test are presented below.

As with the results presented in response to 1-THESL-30, the estimate on the urban core dummy variable is negative but not statistically significant. This result again supports PEG’s conclusion that there is no statistically significant impact associated with a properly-measured urban core dummy variable.

Panel: Dr. Lawrence Kaufmann

Table J3.2

Econometric Cost Benchmarking Results:
Revised Data and Model

VARIABLE KEY

K= Capital Price
N= Number Retail Customers
D= Peak Demand
UD= Revised Urban Core Dummy
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*	0.7028	388.452	0.0000
N*	0.6771	22.094	0.0000
D*	0.2111	6.739	0.0000
KxK*	0.1121	18.124	0.0000
NxN*	0.6973	7.136	0.0000
DxD*	0.5982	5.686	0.0000
KxN*	0.0426	3.810	0.0001
KxD*	0.0529	4.730	0.0000
NxD*	-0.6390	-6.607	0.0000
UD	-0.0103	-1.609	0.1081
CAP	-0.0022	-0.965	0.3350
PRV*	0.0381	2.524	0.0118
PCE*	0.1302	4.332	0.0000
PDE*	0.1271	6.926	0.0000
ED*	0.0172	2.382	0.0175
PF*	0.0134	2.488	0.0130
Trend	0.0006	0.452	0.6514
Constant*	13.0432	684.169	0.0000
System Rbar-Squared	0.926		
Sample Period	2002-2012		
Number of Observations	805		

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

Panel: Dr. Lawrence Kaufmann

ORAL HEARING UNDERTAKING RESPONSE

TO ENERGY PROBE

UNDERTAKING NO. J3.3:

Reference(s):

To provide any necessary corrections to Exhibit K3.3.

RESPONSE:

The computations in Exhibit K3.3 appear generally correct, with one or perhaps two exceptions.

First, PEG's Billing Determinant (BD) adjustment should be -0.015. The "Comparison of THESL and PEG Custom PCI Formulas" table presents values of either -0.00125 or -0.0015 for this value (the latter value is off by one decimal point, or equal to the correct billing determinant adjustment divided by 10). If the correct BD term is applied throughout this table, the calculations in the table should be correct.

The Scenario A and Scenario B tables show a BD value of zero, and a "growth" term of -0.0003. The combination of a zero BD value and negative growth term would imply that, in the absence of price changes, total revenues – not revenues per customer - would actually decline under THESL's Custom IR plan. This appears implausible, because THESL is forecasting approximately 1.5% customer growth per year under the plan. However, if this is in fact the assumption under these scenarios, then the computations for Scenarios A and B appear to be correct. On the other hand, if the "growth" term in this scenario corresponds to declining volumes per customer and declining demand per customer, then a BD adjustment of -0.015 should also be applied throughout the Scenario A and Scenario B calculations.

ORAL HEARING UNDERTAKING RESPONSE
TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.4:

Reference(s):

To produce a cost model result table using the PEG model, and to explain any significant difference.

RESPONSE:

The table below presents the same information as Table 2 of the PSE Reply Report for PEG's econometric cost model presented in the December 2014 benchmarking report. We have also presented the t statistic and the p-value on the hypothesis that the difference between THESL's cost (actual or projected) and THESL's predicted cost (*i.e.* total cost econometric benchmark) is zero.

PEG cannot reject the hypothesis that THESL's actual cost is equal to its predicted cost in any year from 2002 through 2014. However, we can conclude that there is a statistically significant difference between THESL's actual cost and its predicted cost in each year of the 2015-2019 Custom IR period. PEG therefore concludes that THESL is an average cost performer prior to its Custom IR period but is projected to be an inferior cost performer during its Custom IR period. We have no empirical basis for concluding that THESL's 2002 – 2014 cost evaluations result from the deferral of necessary capital expenditures during this period.

PEG has also not investigated whether THESL's cost evaluation in 2002 is impacted by differences in municipal accounting (which THESL used prior to 1999) and US GAAP accounting (used by the US electric utility sample), but it is theoretically possible. If such accounting differences exist, they would impact THESL's capital costs (and therefore its total costs) in 2002 since there would be a mismatch between THESL and the US sample in the capital accounting that is used to develop measured capital stocks, and capital costs, between 1989 and 1998. THESL's capital stocks and capital costs in 2002 (and beyond) will depend on THESL's initial, measured capital stock in 1989 and all capital additions it recorded from 1989 through 2001. This, in turn, implies that the different accounting rules THESL and the US utilities used to record capital values between 1989 and 1998 can lead to persistent cost differences for THESL and the US utilities even after both adopted US GAAP accounting in 1999.

Year	Total Cost Econometric Benchmark, $M	Total Cost THESL, $M	Percent of U.S. Total Cost Econometric Benchmark	T Ratio	P Value
2002	$473	$433	-8.9%	-0.421	0.337
2003	$480	$448	-6.9%	-0.327	0.372
2004	$475	$452	-4.9%	-0.234	0.407
2005	$504	$448	-11.8%	-0.561	0.288
2006	$504	$455	-10.2%	-0.483	0.315
2007	$526	$482	-8.7%	-0.415	0.339
2008	$531	$519	-2.4%	-0.115	0.454
2009	$549	$539	-1.9%	-0.088	0.465
2010	$568	$592	4.1%	0.194	0.423
2011	$579	$643	10.4%	0.495	0.31
2012	$560	$616	9.6%	0.455	0.325
2013	$570	$677	17.3%	0.818	0.207
2014	$619	$752	19.4%	0.92	0.179
2015	$638	$850	28.7%*	1.36	0.087
2016	$677	$915	30.2%*	1.428	0.077
2017	$712	$978	31.7%*	1.501	0.067
2018	$750	$1,034	32.1%*	1.519	0.065
2019	$790	$1,100	33.1%*	1.567	0.059

ORAL HEARING UNDERTAKING RESPONSE

TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.5:

Reference(s):

To provide bad debt expenses that were excluded from THESL's model.

RESPONSE:

PEG was provided THESL's 2013-2019 projected bad debt expenses, and we subtracted these expenses from THESL's projected 2013-2019 total costs. PEG used these new, projected costs and the same econometric benchmarking model presented in December 2014 to benchmark THESL's projected total costs under its Custom IR proposal. Below we report the difference between THESL's projected and predicted cost using this revised cost measure and for the final PEG model presented in December 2014.

	Revised	December 2014 PEG Results
2015	+ 27.0%	+ 28.7%
2016	+ 28.5%	+ 30.2%
2017	+ 30.2%	+ 31.7%
2018	+ 30.6%	+ 32.1%
2019	+ 31.7%	+ 33.1%

Panel: Dr. Lawrence Kaufmann

ORAL HEARING UNDERTAKING RESPONSE
TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.6:

Reference(s):

If the model generated for Undertaking J3.4 shows a difference, to identify why it is taking place, and to review data on the PSE model and attempt to determine and quantify reasons for the difference in the model.

RESPONSE:

This undertaking has several dimensions. PEG was asked to: 1) quantify the factors that caused the econometric benchmark in the PSE cost model to grow more rapidly on a prospective basis (over the projected 2015-2019 Custom IR period) than it did on a historical (2002-2014) basis; 2) quantify the factors that caused the econometric benchmark in the PEG cost model to grow more rapidly on a prospective basis (over the projected 2015-2019 Custom IR period) than it did on a historical (2002-2014) basis; and 3) identify any factors that are leading to differences in the growth rates between the PSE and PEG econometric benchmark costs on either a prospective or historical basis.

The data below present the annual growth rates in benchmark econometric costs in the PSE and PEG models for the 2002-2014 and 2015-2019 periods (the latter period corresponds to all five years in the Custom IR period; it is therefore calculated as the average growth in benchmark costs from 2014 to 2019). All growth rates in this response will be expressed in logarithmic rather than arithmetic terms; logarithmic growth rates are more convenient and natural in the current context because the cost models are also in logarithmic form. “Prospective” will also refer to the 2015-2019 period, since this undertaking specifically contrasted the 2002-2014 and 2015-2019 growth rates in econometric benchmarks (notwithstanding the fact that PSE forecast 2013 and 2014 benchmarks as well). The “PSE” growth rates below reflect the econometric benchmarks presented in their Reply Report; the “PEG” growth rates reflect the econometric benchmarks presented in our amended econometric work, after correcting minor errors in some utilities’ high voltage transformer capacity data.

Average Annual Growth in Econometric Cost Benchmark (% per annum)

	PSE Cost Model	PEG Cost Model
2002-2014	2.69%	2.24%
2015-2019	4.97%	4.87%

Panel: Dr. Lawrence Kaufmann

PEG's approach for quantifying the factors in observed cost growth was designed to be as transparent and intuitive as possible. We considered and investigated an alternate approach that directly uses each independent variable's contribution to econometric benchmark cost. While this alternate approach would generate similar conclusions, it is also more complicated and less clear than the comparable analysis PEG presents in this response. However, to illustrate the contributions that each independent variable makes to econometric cost predictions, Exhibit K3.6 provides a table with these values on a prospective basis for the PSE model.

Our approach begins by recognizing that the change (expressed with a '^' over the variable) in an observed and measured cost (C) index can be decomposed into a change in an input price index (W) and an input quantity index (X).

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \Delta\hat{X}^{Observed} \quad [1]$$

The change in a TFP index can be expressed as the growth in an elasticity-weighted output quantity index (Y) minus the growth in an input quantity index.

$$\Delta T\hat{F}P^{Observed} = \Delta\hat{Y}^{Observed} - \Delta\hat{X}^{Observed} \quad [2]$$

Equation [2] can be re-expressed as

$$\Delta\hat{X}^{Observed} = \Delta\hat{Y}^{Observed} - \Delta T\hat{F}P^{Observed} \quad [3]$$

Substituting [3] into [1] yields

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \Delta\hat{Y}^{Observed} - \Delta T\hat{F}P^{Observed} \quad [4]$$

Appendix One of the Concept Paper that PEG wrote at the outset of 4th Generation Incentive regulation showed that TFP growth can be decomposed into six different components: 1) a scale economy effect; 2) a Z variable effect; 3) a trend or technological change effect; 4) a cost share effect; 5) a non-marginal cost pricing effect; and 6) an inefficiency effect. The decomposition of TFP growth presented in that Concept Paper is replicated in equation [5] below, although for simplicity (and because they cannot be separately identified in the PSE study, given available data) the final three effects discussed above are aggregated together and termed a "residual" effect.

$$\Delta T\hat{F}P^{Observed} = \left(1 - \sum_i \varepsilon_i\right)\Delta\hat{Y}^{Observed} - \sum_n \varepsilon_Z \dot{Z}_n - trend + residual \quad [5]$$

Substituting [5] into [4] yields

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \Delta\hat{Y}^{Observed} - \left[\left(1 - \sum_i \varepsilon_i\right)\Delta\hat{Y}^{Observed} - \sum_n \varepsilon_Z \dot{Z}_n - trend + residual\right] \quad [6]$$

Equation [6] can be simplified to the following:

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \sum_i \varepsilon_i \Delta\hat{Y}^{Observed} + \sum_n \varepsilon_Z \dot{Z}_n + trend - residual \qquad [7]$$

It can be seen that historical cost growth can be decomposed into five components: 1) changes in input prices; 2) an elasticity-weighted change in output (*i.e.* multiply the growth in each output by its cost elasticity and sum across all outputs); 3) a Z variable effect (*i.e.* multiply changes in all Z variables by their cost function coefficients and sum across all Z variables); 4) the estimated trend coefficient; and 5) a residual term.

The same logic detailed in equations [1] – [7] also applies to prospective cost changes. In PSE's model, $\dot{Z}_n$=0 for every Z variable since the only independent variables that PSE projects will change over the 2015-2019 period are input prices and outputs. Because the Z variables are not changing, the Z variable term drops out of the equation PEG used to decompose prospective cost growth. The four remaining components for decomposing prospective cost growth are presented in equation [8] below.

$$\Delta\hat{C}^{E} = \Delta\hat{W}^{E} + \sum_i \varepsilon_i \Delta\hat{Y}^{E} + trend - residual \qquad [8]$$

Accounting for the *differences* between projected and observed cost growth can be done straightforwardly by subtracting equation [7] from equation [8]; doing so and simplifying yields the following:

$$\Delta\hat{C}^{E} - \Delta\hat{C}^{Observed} = \Delta\hat{W}^{E} - \Delta\hat{W}^{Observed} + \sum_i \varepsilon_i \left(\Delta\hat{Y}^{E} - \Delta\hat{Y}^{Observed}\right) - \sum_n \varepsilon_Z \dot{Z}_n + residual^{E} - residual^{Observed} \qquad [9]$$

PEG applied equations [7], [8], and [9] to the PSE and PEG models. We then used these decompositions to examine and quantify which factors were most important for explaining the acceleration of benchmark econometric costs between the historical and projected periods, and for understanding differences between the PSE and PEG models.

The results of this analysis for the PSE model are presented in Table J.3.6.1. The most notable element in this table is that PSE projects a quite rapid acceleration in the capital service price in 2015-2019 compared with 2002-2014. Over the 2002-14 period, capital service prices grew by 1.14% per annum. Over the Custom IR period, capital service prices are projected to grow by 4.55% per annum.

The relatively slow growth in capital service prices over the 2002-14 period is partly due to the decline in interest rates. However, PSE projects interest rates and the cost of capital will remain constant over the Custom IR period. The cost of capital is therefore not contributing to PSE's projection of more rapidly growing capital service prices.

The projected acceleration in capital service prices is due to PSE forecasting that THESL's capital asset prices will grow at the average annual 40-year growth rate in the electric utility construction price index (the EUCPI; p. 29 of the July 2014 PSE Benchmarking Report). Between 1973 and 2013, the EUCPI grew at an average rate of 4.55%, which is identical to the projected, annual growth in capital service prices. However, recent inflation in the EUCPI has been much more modest. Below we present the 10-year average growth rates in the EUCPI over the entire 40-year period PSE used for its capital asset price forecasts.

1973-83	9.6% per annum
1983-93	3.2% per annum
1993-2003	2.4% per annum
2003-2013	2.0% per annum

PSE's forecast of capital asset prices is therefore greatly impacted by the inflation in capital asset prices during the high-inflation 1970s. This distant inflationary experience is built into PSE's forecast of capital asset prices. This forecast is, in turn, greatly impacting the growth rate of PSE's estimated econometric benchmarks for THESL relative to observed history.

In fact, Table J3.6.1 shows that PEG estimates 72.3% of the acceleration in PSE's econometric benchmark cost results from the assumed acceleration in capital asset prices (which accounts entirely for the acceleration in capital service prices since the cost of capital and depreciation rates are each assumed to remain constant). An additional 32.6% of the acceleration in PSE's econometric benchmark costs results from the more rapid assumed inflation in OM&A input prices. Output growth is also expected to accelerate over the Custom IR period, and the cost impact of more rapid output growth is projected to contribute 21.9% towards the acceleration of econometric benchmark costs.

Other factors are estimated to lead to a *deceleration* in econometric benchmark costs, which means they tend to offset the input price and output effects above. Between 2002 and 2014, PSE data show that there was a dramatic increase in the percent of load delivered to THESL's residential customers (from 19% of total deliveries in 2002 to 46.6% in 2014). Because PSE's model found that residential customers are more expensive to serve, this trend contributed to an increase in THESL's econometric cost benchmark of 0.28% per annum. Going forward, however, PSE assumes that the share of deliveries to residential customers will remain constant. The historically estimated 0.28% annual increase in econometric benchmark costs resulting from a more residential load profile is therefore projected to vanish under the Custom IR period, and this projected change contributes a 12.1% decline in econometric benchmark costs. The trend and residual effects contribute an additional 14.7% deceleration in the econometric benchmark cost.

In sum, PEG finds that the main factor contributing to more rapid growth in PSE's econometric benchmark costs for THESL under its Custom IR plan is that PSE projects THESL's capital asset prices will grow by 4.55% per annum over the Custom IR period. This factor accounts for more than 72% of the acceleration in THESL's econometric cost benchmark under Custom IR. The second most important factor contributing to more rapid growth in econometric benchmark costs is PSE's assumed growth in OM&A prices. The third most important contributing factor is the assumed growth in output.

The results of this analysis for the PEG model are presented in Table J3.6.2. The results are broadly similar, because PEG did not adjust any of PSE's assumptions for the future when developing projected benchmark costs for THESL. Hence the same 4.55% annual increase in capital service prices are also built into the PEG econometric cost projections.

In fact, PEG's model shows somewhat more rapid acceleration relative to history than PSE's model, because PEG historically projected slower growth in THESL's benchmark costs than PSE (2.24% per annum for PEG vs. 2.69% per annum in the PSE model). PEG continues to project slower growth in THESL's benchmark costs under Custom IR, but the differences between the PEG (4.87% per annum) and PSE (4.97% per annum) projections are smaller on a prospective basis than on an observed, historical basis.

PEG estimates that 58.4% of the acceleration in our benchmark costs for THESL result from PSE's forecast of accelerating capital service prices. This is the most important factor contributing to more rapid growth in PEG's econometric benchmark costs for THESL under its Custom IR plan. The second most important contributing factor to this acceleration is the more rapid forecast in OM&A input prices (contributes 29.1%). The third most important contributing factor is the projected growth in output (contributes 17.2%). As with the PSE model, the growth in PEG's econometric benchmark costs declined due to the assumption that THESL would no longer continue to serve an increasingly residential load, as it did over the 2002-2014 period; this factor contributes -8.5% to the change in PEG's econometric benchmark costs. Trend and residual factors contribute 3.8% to the acceleration of PEG's benchmark costs.

Exhibit K3.6

Variable	Estimated Coefficient	Toronto Hydro Data (Transformed) 2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CONST	20.101	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WK	0.554	0.272	0.254	0.227	0.205	0.178	0.167	0.162	0.171	0.156	0.137	0.069	0.058	0.139	0.162	0.184	0.206	0.228	0.250
Y1	0.723	-0.329	-0.323	-0.317	-0.312	-0.309	-0.307	-0.301	-0.292	-0.277	-0.264	-0.251	-0.245	-0.227	-0.210	-0.193	-0.178	-0.164	-0.149
Y2	0.229	-0.100	-0.090	-0.154	-0.052	-0.050	-0.096	-0.144	-0.135	-0.097	-0.069	-0.088	-0.069	-0.069	-0.131	-0.099	-0.086	-0.074	-0.064
WKWK	0.063	0.037	0.032	0.026	0.021	0.016	0.014	0.013	0.015	0.012	0.009	0.002	0.002	0.010	0.013	0.017	0.021	0.026	0.031
Y1Y1	0.288	0.054	0.052	0.050	0.049	0.048	0.047	0.045	0.043	0.038	0.035	0.032	0.030	0.026	0.022	0.019	0.016	0.013	0.011
Y2Y2	0.171	0.005	0.004	0.012	0.001	0.001	0.005	0.010	0.009	0.005	0.002	0.004	0.002	0.002	0.009	0.005	0.004	0.003	0.002
WKY1	-0.004	-0.090	-0.082	-0.072	-0.064	-0.055	-0.051	-0.049	-0.050	-0.043	-0.036	-0.017	-0.014	-0.032	-0.034	-0.035	-0.037	-0.037	-0.037
WKY2	0.007	-0.027	-0.023	-0.035	-0.011	-0.009	-0.016	-0.023	-0.023	-0.015	-0.010	-0.006	-0.004	-0.010	-0.021	-0.018	-0.018	-0.017	-0.016
Y1Y2	-0.199	0.033	0.029	0.049	0.016	0.015	0.030	0.043	0.039	0.027	0.018	0.022	0.017	0.016	0.028	0.019	0.015	0.012	0.009
Z1	0.020	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306
Z2	0.037	-0.651	-0.714	-0.749	-0.647	-0.706	0.292	0.258	0.767	0.383	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244
Z3	0.141	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124
Z4	0.122	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710
Z5	-0.032	0.866	0.866	0.866	0.866	0.872	0.857	0.864	0.868	0.872	0.881	0.887	0.898	0.898	0.898	0.898	0.898	0.898	0.898
Z6	0.015	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995
Z7	0.020	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176
TREND	0.002	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
WOM	N/A	1.000	1.024	1.054	1.086	1.108	1.148	1.181	1.186	1.228	1.253	1.269	1.288	1.310	1.340	1.371	1.404	1.438	1.472
Econometric Estimate:		20.299	20.294	20.267	20.292	20.278	20.300	20.289	20.323	20.322	20.324	20.291	20.296	20.355	20.366	20.401	20.428	20.456	20.483
EXP()		654,137,431	651,240,323	633,401,817	649,446,174	640,605,623	654,687,497	647,705,848	670,083,825	669,504,481	670,872,723	649,119,836	652,338,956	692,183,682	699,579,057	724,432,899	744,580,684	765,318,312	786,631,218
* WOM		654,130,889	666,570,521	667,326,818	705,597,290	709,515,570	751,555,059	764,992,423	794,504,990	822,010,907	840,308,338	823,661,668	840,160,388	906,636,031	937,303,017	993,501,766	1,045,532,750	1,100,328,749	1,157,991,949
THESL Actual Cost:		435,010,368	450,339,136	454,122,880	449,667,584	457,014,912	484,482,944	518,147,392	535,624,544	586,112,768	637,697,472	598,313,344	657,159,296	729,767,040	824,746,240	887,888,000	949,368,896	1,003,643,904	1,067,738,240
Difference (ln):		-0.408	-0.392	-0.385	-0.451	-0.440	-0.439	-0.390	-0.394	-0.338	-0.276	-0.320	-0.246	-0.217	-0.128	-0.112	-0.096	-0.092	-0.081

Table J3.6.1

Decomposition of THESL Predicted Cost: PSE Model[1]

	THESL		Average	THESL		Average	Acceleration	
	2002	2014	Growth	2014	2019	Growth	Amount	Percent Explained
Predicted Cost	$ 591,000,000	$ 816,000,000	2.69%	$ 816,000,000	$ 1,046,000,000	4.97%	2.28%	
Input Price Effects								
Capital Price	11.65	13.36	1.14%	13.36	16.77	4.55%	3.42%	72.3%
OM&A Price	1.00	1.31	2.25%	1.31	1.47	2.34%	0.09%	32.6%
Capital Weight	69.9%	66.2%		66.2%	73.2%			
OM&A Weight	30.1%	33.8%		33.8%	26.8%			
Input Price Index			**1.49%**			**3.88%**	**2.39%**	**104.9%**
Output Quantity Effects								
Customers	665,043	736,076	0.85%	736,076	795,967	1.56%	0.72%	
Demand	4,771	4,921	0.26%	4,921	4,948	0.11%	-0.15%	
Customer Weight	78.0%	78.0%		78.0%	78.0%			
Demand Weight	22.0%	22.0%		22.0%	22.0%			
Output Quantity Index			0.72%			1.24%		
Customer Coefficient			0.738			0.738		
Demand Coefficient			0.208			0.208		
Cost Impact of Output Growth			94.6%			94.6%		
Output Effect			**0.68%**			**1.18%**	**0.50%**	**21.9%**
Other Effects								
Percent Residential	19.04%	46.60%	7.46%					
Percent Residential Coefficient			0.037					
Percent Residential Effect			**0.28%**				**-0.28%**	**-12.1%**
Trend + Residual			0.24%			-0.09%	-0.33%	-14.7%

[1] **The Customer, Demand and Percent Residential coefficients are based on the sample averages, because the THESL-specific coefficients were not provided with the PSE Reply Report.**

Table J3.6.2

Decomposition of THESL Predicted Cost: PEG Model

	THESL		Average	THESL		Average	Acceleration	
	2002	2014	Growth	2014	2019	Growth	Amount	Percent Explained
Predicted Cost	$ 473,149,648	$ 619,183,584	2.24%	$ 619,183,584	$ 789,746,473	4.87%	2.62%	
Input Price Effects								
Capital Price	11.65	13.36	1.14%	13.36	16.77	4.55%	3.42%	58.4%
OM&A Price	1.00	1.31	2.25%	1.31	1.47	2.34%	0.09%	29.1%
Capital Weight	69.8%	65.7%		65.7%	65.7%			
OM&A Weight	30.2%	34.3%		34.3%	34.3%			
Input Price Index			**1.50%**			**3.79%**	**2.30%**	**87.5%**
Output Quantity Effects								
Customers	665,043	736,076	0.85%	736,076	795,967	1.56%	0.72%	
Demand	4,771	4,921	0.26%	4,921	4,948	0.11%	-0.15%	
Customer Weight	76.3%	76.3%		76.3%	76.3%			
Demand Weight	23.7%	23.7%		23.7%	23.7%			
Output Quantity Index			0.71%			1.22%		
Customer Coefficient			0.674			0.674		
Demand Coefficient			0.210			0.210		
Cost Impact of Output Growth			88.4%			88.4%		
Output Effect			**0.62%**			**1.08%**	**0.45%**	**17.2%**
Other Effects								
Percent Residential	19.04%	46.60%	7.46%					
Percent Residential Coefficient			0.030					
Percent Residential Effect			**0.22%**				**-0.22%**	**-8.5%**
Trend + Residual			-0.10%			0.00%	0.10%	3.8%

ORAL HEARING UNDERTAKING RESPONSE
TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.7:

Reference(s):

To identify factors behind any significant differences in the rate of change of costs in the benchmark and THESL numbers.

RESPONSE:

Our response to Undertaking J3.6 provided a detailed analysis of the factors giving rise to differences in the growth rates of econometric benchmark costs over the observed and prospective, Custom IR periods. PEG's original analysis did not focus on this issue, because we concentrated on ensuring comparability of PSE and PEG cost measures and technical, econometric issues. However, we do not believe that it is reasonable to project 4.55% annual growth in THESL's capital service prices under its custom IR period. The EUCPI data show that inflation rates of that magnitude have not been observed on a sustained, multi-year basis for more than 30 years.

PEG believes a more reasonable forecast in capital service prices is the 10-year historical growth in the EUPCI. As discussed in the response to Undertaking J3.6, the EUCPI has grown by 2.0% per annum over the 2003-2013 period. A more reasonable capital asset price forecast could potentially lead to a significant difference in the relationship between THESL's benchmark and projected costs over the Custom IR period.

To explore this issue, PEG amended our econometric benchmark model presented in response to J3.5 so that it projected 2% annual growth in capital service prices over the 2013-2019 period rather than the 4.55% assumed by PSE (with the possible exception of 2013, in which actual EUCPI data were available at the time of PSE's study). Recall that the response to J3.5 subtracted THESL's projected bad debt expenses from its total costs in 2013-2019 and therefore incorporated "Adjustment #1" recommended in the PSE Reply Report.

PEG presents the results of this amended econometric model in Table J3.7.1 below. The amendments do not impact the 2002-2012 data used to estimate the model or PEG's 2002-2012 benchmarking results for THESL. Compared with the Table presented in response to Undertaking J3.4, this table reflects only the impact of changing the asset price forecast for THESL over the 2013-2019 period. PEG's results below therefore differ from the results presented in PSE's Reply Report in three ways: 1) PEG has not accepted PSE's proposed adjustment for CDM expenses (because it adds historical and projected expenses to THESL's cost measure that are not part of this application); 2) PEG does not include an urban core dummy variable because our statistical work rejects the hypothesis that this is a significant driver of electricity distribution costs, after other independent variables are controlled for; and 3) PEG projects 2% annual asset price growth rather than the 4.55% PSE projection for the Custom IR period.

One result of this change is the growth in THESL's econometric benchmark costs slows markedly over the Custom IR period. Recall from the response to Undertaking J3.6 that PEG's previous work projected annual growth in benchmark costs for THESL of 4.87% per annum during the Custom IR years. After the projected growth in capital asset prices over these years is reduced to 2% per annum from 4.55% per annum, PEG's econometric benchmark grows by only 3.0% per annum. This growth rate is more compatible with historical changes in econometric benchmark costs.

It can also be seen that THESL is now a worse cost performer. THESL's costs are projected to 33.1% above their benchmark levels in 2015. This projected difference rises to 45.2% by 2019. All these differences are statistically significant.

The increasingly worse THESL performance is expected, because slower projected input price inflation will have a cumulative effect on the cost benchmarks. By continually leading to less escalation in cost benchmarks compared with PEG's earlier econometric model, the gap between THESL's actual and projected costs will continue to widen over time.

PEG believes the refinements of our cost projections in this undertaking lead to more accurate inferences on THESL's projected cost performance. They also strengthen our conclusion that THESL is projected to be an inferior cost performer under its Custom IR plan.

Table J3.7.1

Year	Total Cost Econometric Benchmark, $M	Total Cost THESL, $M	Percent of U.S. Total Cost Econometric Benchmark	T Ratio	P Value
2002	$473	$433	-8.9%	-0.421	0.337
2003	$480	$448	-6.9%	-0.327	0.372
2004	$475	$452	-4.9%	-0.234	0.407
2005	$504	$448	-11.8%	-0.561	0.288
2006	$504	$455	-10.2%	-0.483	0.315
2007	$526	$482	-8.7%	-0.415	0.339
2008	$531	$519	-2.4%	-0.115	0.454
2009	$549	$539	-1.9%	-0.088	0.465
2010	$568	$592	4.1%	0.194	0.423
2011	$579	$643	10.4%	0.495	0.310
2012	$560	$616	9.6%	0.455	0.325
2013	$576	$663	14.1%	0.667	0.253
2014	$593	$738	21.9%	1.039	0.150
2015	$600	$835	33.1%*	1.567	0.059
2016	$625	$900	36.5%*	1.727	0.042
2017	$646	$963	39.9%*	1.889	0.030
2018	$668	$1,019	42.2%*	1.997	0.023
2019	$690	$1,085	45.2%*	2.136	0.016

ORAL HEARING UNDERTAKING RESPONSE
TO TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

UNDERTAKING NO. J3.8:

Reference(s):

To verify whether PSE included high-voltage costs for THESL.

RESPONSE:

In its original report, PSE used the "TFP-based" cost measure for THESL, which included the costs of high-voltage transformation. However, as discussed in PEG's December 2014 report, PEG's TFP-based cost measure was not used to benchmark THESL's cost performance in 4th Generation Incentive Ratemaking. It is also not appropriate to use the TFP-based cost measure to benchmark THESL's cost performance in the Company's Custom IR application.

The empirical analysis in PEG's December 2014 report therefore began with THESL's "benchmark-based" cost measure, which *excluded* the costs of high-voltage transformation. In its Reply Report, PSE has endeavored to make its cost measure compatible with the cost measure used in PEG's analysis, with the exception of the first two "adjustments" described in the Reply Report. Neither adjustment #1 (for bad debt expenses) nor adjustment #2 (for CDM expenses) pertain to the costs of high-voltage transformation. Including THESL's high-voltage costs would have involved an additional "adjustment #4" to PEG's cost measure, which was not detailed in PSE's Reply Report. Therefore, it is PEG's understanding that the cost measure presented in PSE's most recent cost analysis does not include high-voltage transformation costs for THESL.

Panel: Dr. Lawrence Kaufmann

ORAL HEARING UNDERTAKING RESPONSE
TO TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

UNDERTAKING NO. J3.9:

Reference(s):

To review Figures 1 and 2 of the PSE reply report for accuracy of results.

RESPONSE:

THESL asked whether Figures 1 and 2 of the PSE Reply Report "accurately sets out the results of your own (*i.e.* PEG's) reliability benchmarking" (Tr3, p. 159 at 3-4). The answer is no; Figures 1 and 2 of the PSE Reply Report do not accurately set out the results of PEG's own reliability benchmarking.

As explained in the responses to 1-THESL-4 b) and 1-THESL-66, PEG did not benchmark THESL's projected SAIDI or SAIFI performance. PEG only benchmarked THESL's observed SAIFI and SAIDI performance between 2002 and 2011, for reasons that are detailed in those responses (PEG excluded observed 2012 reliability data because of the distorting impact of Hurricane Sandy on many utilities' recorded reliability in that year). Figures 1 and 2 show PEG benchmarks for SAIFI and SAIDI in the 2012 - 2019 period that never appeared in PEG's December 2014 report. Accordingly, these Figures do not accurately set out the results of the reliability benchmarking that PEG undertook.

PEG also believes the scales used in Figures 1 and 2 do not facilitate meaningful comparisons between PEG's and PSE's reliability benchmarking results. For example, Figure 1 includes THESL's 2013 value for SAIDI, which is more than 500% above the SAIDI values that THESL either experienced or projects over every other year in the 2002-2019 period. Including this large, outlier value greatly expands the range of values displayed on the graph's vertical axis. This, in turn, reduces the available vertical space within which PEG and PSE SAIDI benchmarks are plotted. Plotting the PEG and PSE SAIDI benchmarks in a narrow vertical space makes it more difficult to discern differences between these benchmarks visually.

Over the 2002-2011 period, PSE found that THESL's actual SAIDI was about 50% below its econometric benchmark and the difference was statistically significant. Over the same period, PEG found THESL's actual SAIDI was about 20% below our econometric benchmark and the difference was not statistically significant. PEG believes our SAIDI benchmarking results differ substantively from PSE's, but it is difficult to grasp the 30% average gap between PEG's and PSE's benchmarks on Figure 1 since the graph includes an observation that exceeds the PEG and PSE benchmarks by more than 500%.

Panel: Dr. Lawrence Kaufmann