HYDRO ONE INTERROGATORIES ON THE PACIFIC ECONOMICS GROUP REPORT

M1-HON-1

Reference: Exhibit M1, Page 38

Preamble:

In docket EB-2018-0218 (the "HOSSM Case" or simply "HOSSM"), Pacific Economics Group ("PEG") corrected certain errors discovered by PSE in PEG's response to interrogatory PEG-HOSSM-6i. In an attachment labeled "Attachment PEG-HOSSM-6i(b)" to that response, PEG displayed a table showing that Hydro One's 2014-2016 average total cost score was -22.87%, and that its 2019-2022 average total cost score was -12.35%. Below is the table produced by PEG in the HOSSM Case.

Attachment PEG-HOSSM-6i(b)

Hydro One's Total Transmission Cost Performance Using PEG's Model

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-41.20%
2005	-44.20%
2006	-43.30%
2007	-38.50%
2008	-41.00%
2009	-34.70%
2010	-32.40%
2011	-31.80%
2012	-27.90%
2013	-25.30%
2014	-25.00%
2015	-21.60%
2016	-22.00%
2017	-20.50%
2018	-18.70%
2019	-16.40%
2020	-13.70%
2021	-11.00%
2022	-8.30%
Average 2004-2016	**-32.99%**
Average 2014-2016	**-22.87%**
Average 2019-2022	**-12.35%**

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

However, in the present case (the "Hydro One Networks Case"), in Table 5 on p. 38 of Exhibit M1 (the "PEG Report"), we see a substantial change in PEG's benchmarking results for Hydro One Networks. PEG's results have now changed to -2.1% for the 2014-2016 period, and +9.0% for the 2020-2022 period. This amounts to a very significant change in benchmarking results from the results PEG put forth about six months ago. This change is despite the fact that in the present case, PEG apparently: (1) reduced Hydro One's costs to make the cost definitions consistent, and (2) inserted the company's revised business plan, with lower spending levels, into the model. We would expect these two cost modifications to <u>improve</u> Hydro One's score.

Interrogatories:

a) Given this substantial change in results, Hydro One requests that PEG itemize each modification made in the current case, relative to what PEG did in the HOSSM Case. For each modification, we request that PEG provide the impact of that modification on Hydro One's 2020 to 2022 average benchmark score.

   We request the following table be filled out by PEG, although more rows should be inserted based on the methodological changes identified by PEG. PEG can begin with the model presented in Table 2 of the PEG Report and only change one modification at a time, so we can isolate the impact of each methodological change relative to their results reported in the HOSSM Case. For example, for Change #5, please start with the methodology used in the Hydro One Networks Case (the "Reported Methodology") and only perform Change #5, so we can see how the reported results would change when only Change #5 is made.

   In light of the results from the completed table, please describe what PEG thinks are the drivers of the large changes from the HOSSM results to the result in the present case.

Change #	**Methodological change from HOSSM**	**2020 – 2022 average benchmark score for HON**
0	Reported Methodology	+9.0%
1	Variable changed back to substation capacity per line mile	

2	Depreciation rates changed back to HOSSM values	
3	Cost definition on OM&A changed back to HOSSM definition	
4	Revert sample back to HOSSM sample	
5	Revert to not doing an autocorrelation correction, and use the modeling procedure used in HOSSM proceeding	
6	Revert to including capital gains in capital costs and prices the same way conducted in HOSSM proceeding	
7	Use the implicit price deflator for the Ontario utilities sector the same way used in HOSSM proceeding	
8	Please insert any other changes relative to PEG's HOSSM methodology that impact results	

b) To enable a view of how much PEG's methodology changes impacted the results from six months ago, please re-run the model used in PEG-HOSSM-6i(a) and (b), with the same exact methodology and sample as used to produce PEG-HOSSM- 6i(b), but with Hydro One's revised business plan incorporated and costs subtracted out to make the cost definitions consistent. From that model re-run, please provide tables similar to those provided in Attachment PEG-HOSSM-6i(a) and PEG-HOSSM-6i(b).

Response to HON-1: The following response was provided by PEG.

PEG acknowledges that the results of the benchmarking work changed, due to a few methodological upgrades changes made, more than one might expect. In considering this outcome, it should be remembered that the business conditions facing Hydro One are in important respects atypical of those of other sampled utilities. This increases the likelihood of prediction error.

The requested analysis cannot be addressed within a reasonable time and with reasonable effort within the current schedule for this proceeding. However, some analysis is provided below that should be helpful which is based on work undertaken during the preparation of the results presented in PEG's September report.

Change #	Methodological change from HOSSM	2020 – 2022 average benchmark score for HON
0	Reported Methodology	+9.0%
1	Do not change depreciation rates and use EOY capital stock instead of BOY	-2.4%
2	Remove correction for autocorrelation from #1	-14.1%
3	Reported SSM results after errata	-11.0%

a) The table above contains a breakout of principal reasons why the average benchmarking scores for the 2020-22 period have changed since the Hydro One SSM proceeding. Working backwards from the model presented in our September report, PEG made changes to the model to specifically reverse methodological choices that we recall affected results. The first reversal was to not change the depreciation rates and not use the beginning of year capital stock (which is the standard approach) instead of the end of year stock. This had about an 11% impact on the results. The second change was to remove the autocorrelation correction we implemented. Without this correction, results were about 12% more favorable to the Company. All other changes only affect the results by about 3% and would result in a less favorable score for HON if not done. None of these results incorporate the work done in response to HON-21 (Exhibit L1/Tab 1/Schedule 21).

The changes examined in step 1 above were some of the last we made to the work before completing the report. PEG did additional analysis at that time to find an explanation for the result. What we found was that the business conditions facing Hydro One are atypical in several respects, and that changes in the estimated values of some coefficients had a much larger impact on the predicted cost of Hydro One than other transmitters in the sample.

The following table shows how values of the business condition variables in PEG's model compared to those for the U.S. sample mean in 2016. A few observations are pertinent. The first is that Hydro One has a much larger operating scale than the typical U.S. transmitter.

Comparison of Hydro One Network's Business Conditions in 2016 to Full Sample Norms

Business Condition	Name from Table 1	Parameter Value	Hydro One Networks, 2016 [A]	Sample Mean, 2016 [B]	2016 HONI Values / 2016 Sample Mean [A/B]
Kilometers of transmission line	**YL**	0.492	20,949	3,472	603%
Kilometers of transmission line - Squared	**YL * YL**	0.402	438,853,072	12,056,296	3640%
Kilometers of transmission line x Ratcheted Peak Demand	**YL * D**	-0.207	565,722,892	22,483,035	2516%
Ratched maximum peak demand	**D**	0.571	27,005	6,475	417%
Ratched maximum peak demand - Squared	**D * D**	0.243	729,270,025	41,927,211	1739%
Substation capacity per substation	**MVA**	0.044	419.8	320.4	131%
Average voltage of transmission line	**VOLT**	0.063	222	179.71	123%
Construction standards index	**CS**	0.238	0.87	0.67	129%
Percent of transmission plant that is overhead	**PCTPOH**	-0.395	97%	89%	109%
Percent of transmission plant in total plant	**PCTPTX**	0.140	100%	21%	486%

The length of its transmission lines is especially large. This means that the density of its system is unusually low. The model includes a squared term for each scale variable as well as scale variable interaction term km x peak. The dispersion of Hydro One's values for these so-called "second order" terms is even larger.

The other salient difference is that Hydro One is the only company in the sample that only performs transmission service. The metric used to capture the scope of operations is the percent of plant that is transmission. This is 100% for Hydro One and any scope economies with Hydro One's distribution services have been ignored for this analysis. This compares to only 21% for the U.S. sample, making Hydro One an outlier in this regard.

The impact on the predicted value for Hydro One from a change in model parameters will be related due to the magnitude of the change and how different Hydro One is from average. From the above table, we can see that the scale, substation capacity, and scope variable are the most atypical. Therefore, changes in these parameters will have an outsized impact for Hydro One.

Below is a table with the parameters for the final model (change #0) and the model prior to the most impactful methodological changes (change #2). The quadratic and interaction scale variables and the scope variable are candidates to explain why the results changed and are in bold.

Parameter Values (excluding HON) used in Predicted Cost Calculation

	Final Model	**No Autocorrelation**		
	(A)	(B)	(A) - (B)	(A) / (B)
Intercept	12.1824	12.2394	-0.0571	99.5%
YL	0.4911	0.4916	-0.0005	99.9%
YL * YL	0.4017	0.3447	0.0570	**116.6%**
D	0.5793	0.5798	-0.0005	99.9%
D * D	0.2470	0.1510	0.0960	**163.6%**
YL * D	-0.2035	-0.1580	-0.0455	**128.8%**
MVA	0.0420	0.0298	0.0122	140.8%
VOLT	0.0656	0.1006	-0.0349	65.3%
CS	0.2492	0.2694	-0.0202	92.5%
PCTPOH	-0.3911	-0.5086	0.1175	76.9%
PCTPTX	0.1510	0.3015	-0.1505	**50.1%**
Trend	-0.0070	-0.0070	0.0000	99.4%

When taken together the positive impact on predicted cost from the increased values for the quadratic terms is mitigated by the more negative value of the interaction (YL * D) term. The principal driver of the changed result is that the cost impact attributed to scope considerations is considerably lower than before.

b) PEG believes that the response to part a) adequately explains the source of the performance difference. Please see the response to HON-21 (Exhibit L1/Tab 1/Schedule 21) for additional discussion of the impact from the revised business plan data.

M1-HON-3

Reference: Exhibit M1, page 28

Preamble: PEG states it excluded Hydro One's cost categories for transmission by others (account 565), load dispatching (accounts 561-561.8), maintenance of miscellaneous regional transmission plant (account 566).

Interrogatories:

a) Please provide the amounts subtracted for Hydro One in each category for each year, including the forecasted years.

b) Please discuss the methodology used in determining those subtracted amounts for Hydro One for each year.

c) Please discuss why the new category of costs (account 569.4) are now being excluded, but were not in PEG's HOSSM research.

Response to HON-3: The following response was provided by PEG.

a) Please see the response to HON-21 (Exhibit L1/Tab 1/Schedule 21).

b) Please see the response to HON-21 (Exhibit L1/Tab 1/Schedule 21).

c) Account 569.4 is miscellaneous regional transmission plant and was excluded from the HOSSM work. The 569.1-569.4 accounts are relatively new and PEG did not have variable names assigned. It calculated transmission O&M cost by adding up the accounts from its database and added the values for 569.1-569.3 from the PSE working papers. Account 569.4 was excluded by its intentional omission. It is a very small account, but clearly associated with regional transmission operations and it was treated the same as dispatching. Accounts 569.1-569.3 are larger and PEG did not believe that the regional part of these accounts could be removed without also removing cost that should be part of transmission O&M. Therefore, these accounts were left in.

M1-HON-10

Reference: Exhibit M1, page 33

Preamble: PEG produced an econometric model that has one variable difference from PEG's HOSSM work, and that has one fewer variables relative to PSE's research.

Interrogatories:

a) Please verify that the only variable change from PEG's HOSSM model to PEG's current model was that rather than substation capacity per line mile, the variable has been modified to substation capacity per substation.

b) Why was the variable modified from substation capacity per line mile to substation capacity per substation?

c) Does PEG believe the number of transmission substations is a relevant cost driver for a transmission utility, particularly in light of the fact that PSE found the number of transmission substations to be a statistically significant cost driver with a large t-stat of 7.300?

d) Is PEG concerned that a transmission utility with a relatively large number of smaller substations that serve more remote areas may be disadvantaged in PEG's model? For example, if Hydro One added 1,000 smaller substations on its system, PEG's substation capacity per substation variable would be lowered for the company, implying lower substation costs, yet obviously the company's costs would increase substantially.

e) Substation capacity can be thought of as the number of transmission substations multiplied by the average capacity of those substations. PEG only has one of those measures in its model and omits the other component, whereas PSE controls for both components. Does PEG believe that substation capacity is an important cost driver of transmission costs?

f) Given that this is the only major variable difference between PSE and PEG's models and the variable change PEG made from their HOSSM research, please re-run PEG's model leaving all other methodologies intact, but adding the number of Tx substations per KM of line variable to PEG's model. Please revise Table 2 and Table 5 of the PEG Report accordingly.

g) How did PEG determine the value for Hydro One for its percent of transmission plant that is overhead? Why did PEG not use the physical percentage of overhead lines, similar to what PSE used for their undergrounding variable?

h) Please describe the autocorrelation and heteroskedasticity procedure implemented by PEG. In the description please discuss how PEG determined any weighting necessary for the correction.

Response to HON-10: The following response was provided by PEG.

a) That is correct.

b) The capacity per substation variable in the new model has a higher elasticity estimate and t stat than the capacity per line km variable in the old model. We tried capacity per line mile in the new model but it did not have a statistically significant parameter estimate.

c) PEG acknowledges that the number of transmission substations is a potentially relevant driver of power transmission cost. Its cost impact is an empirical issue. We tried a substations per line mile variable in the new research but it did not have a statistically significant parameter estimate.

d) Please see the response to part c) of this question.

e) PEG acknowledges that substation capacity is a potentially important driver of power transmission cost. However, in our revised econometric cost model in the Hydro One SSM proceeding, the substation capacity per line km variable had only marginal statistical significance, with a t statistic of 1.371. Moreover, this run did not include any autocorrelation correction.

f) PEG believes that this request cannot be addressed within a reasonable time and with reasonable effort within the current schedule of this proceeding. However, PEG believes that PSE can perform this run.

g) PEG used plant value data for this calculation, as we did in its calculation for the sampled U.S. utilities. Plant value data reflect a wider range of transmission assets than line mile data. For example, they reflect the prevalence of underground substations.

h) PEG's model was estimated using the panel AR function (contained within the panel AR package) of the statistical software R. This function PEG corrects for AR(1)-type autocorrelation via a two-step Prais-Winsten feasible generalized least squares ("FGLS") procedure, in which a common autocorrelation coefficient is estimated using the sample correlation coefficient estimator. Then a panel-weighted least squares procedure is used to correct for heteroskedasticity. In the heteroskedasticity correction, the weights are at the panel level because, due to differences between companies, costs typically vary more for some firms over time than for others.

M1-HON-12

Reference: Exhibit M1, pages 48 and 49

Preamble: PEG discusses sources of productivity growth. PEG states on p. 48: "System age can drive productivity growth in the short and medium term." On p. 49 PEG states that a utility with unusually slow output growth and unusually high number of assets needing replacement might have unusually slow productivity growth.

Interrogatories:

a) Does PEG believe that the industry's overall system age is possibly contributing to the productivity growth rates below -1.00% in recent years?

b) Does PEG believe the industry will resolve the aging infrastructure issue prior to 2021, and that as a result productivity trends will increase from their recent strongly negative trends?

c) Does PEG believe it is a possibility that Hydro One will have unusually slow output growth in 2021 and 2022, with an unusually high number of assets needing replacement?

d) If we assume that Hydro One has unusually slow output growth and an unusually high number of assets needing replacement, please explain how it is compensatory to the utility to place a total stretch factor of 0.72% on the utility's capital, requiring it to exceed the capital productivity of the industry by an extraordinary amount.

Response to HON-12: The following response was provided by PEG.

a) Yes. PEG believes that system age has contributed to the negative productivity growth of U.S. power transmitters in recent years. However, PEG's review of the drivers of negative productivity growth suggested that other cost drivers were also quite important. These drivers included investments to reduce transmission congestion, access renewable resources, and increase system resiliency. PSE had the opportunity to present evidence on the importance of system age in U.S. transmission productivity growth in both Hydro One transmission proceedings but did not do so.

b) PEG does not believe that the challenge of aging industry infrastructure is likely to be rectified prior to 2021.

c) PEG has no reason to doubt Hydro One's forecast of slow output growth. There may also be a need for unusually high asset replacement, but PEG was not asked to appraise the merit of Hydro One's evidence on this matter. PEG did find that Hydro One's proposed rate-setting plan would weaken the Company's incentive to contain capex.

d) PEG notes that the S factor commensurate with X = 0 is actually 0.31%, as discussed in our response to HON-13 (Exhibit L1/Tab 1/Schedule 13). PEG has proposed an X factor of 0.05% with a commensurate S factor of 0.26%. Thus, the sum of the stretch factors would be 0.30 + 0.26 = 0.56. This would be applied to the Company's projected/proposed capital cost, which entails substantially negative capital productivity growth. The Company's capital revenue would grow by far more than Inflation - 0.56%.

   The rationale for the 0.30 stretch factor is the same as in other IR plans and requires no explanation. The rationale for adding the S factor is to raise the markdown to the rather modest level that would occur under an ACM. The OEB's rationale for a dead band in the materiality threshold for the ACM is to discourage marginal applications and protect customers from overcompensation. Additional rationales include stronger capex containment incentives. These rationales could easily justify a higher S factor.

M1-HON-13

Reference: Exhibit M1, pages 60-69

Preamble: PEG discusses their calculations of the supplemental stretch factor.

Interrogatories:

a) PEG recommends a supplemental stretch factor of 0.42% applied to the capital portion of the revenue requirement. Please verify that this 0.42% assumes an X-Factor of 0.0%.

b) If the X-Factor was set at the PEG recommendation of 0.05%, would PEG's recommended S-Factor be lowered to 0.37%?

c) If the X-Factor was, instead, set at the HOSSM value of 0.3%, would this lower the PEG recommendation of the S-Factor to 0.12%?

d) Did PEG consider the company's progressive productivity proposal in its plan when setting the S-Factor?

e) If the progressive productivity proposal amounts to a 0.15% stretch factor in 2021 and a 0.3% stretch factor in 2022, and the Board determines a 0.3% X-Factor, would PEG then recommend a negative S-Factor?

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

a) PEG acknowledges that the 0.42% S factor calculation that it proffered in its September report was based on the assumption of a zero X factor. However, a review of its calculations revealed a small error. The corrected value of the ACM-equivalent S factor which is consistent with a zero X factor is 0.31%. Table HON-13 provides S factor, C factor, and revenue cap escalator results under three X factor assumptions (0, 0.05%, and 0.3%) and compares the results to Hydro One's proposal.

b) Were the X factor set at 0.05% per PEG's recommendation, PEG believes that the ACM-equivalent S factor would be 0.26%.

Table HON-13

Impact of X Factor and S Factor Changes on HON C Factor and RCI Growth

	Index Year			Difference from HON Proposal
	2021	**2022**	**Averages**	
Variable				
Cn	5.18	4.68	4.93	
Sck	78.42	79.16	78.79	
I	1.4	1.4	1.4	
X = 0 (PSE)	0	0	0	
X = 0.0005 (PEG)	0.0005	0.0005	0.0005	0.0005
X = 0.3	0.0030	0.0030	0.003	0.0030
S=0, X=0 (PSE)	0	0	0	
S (X=0)	0.0031	0.0031	0.0031	0.0031
S (X=0.0005) (PEG)	0.0026	0.0026	0.0026	0.0026
S (X=0.30)	0.0001	0.0001	0.0001	0.0001
C (X=0) PSE	4.09	3.58	3.83	
C (X=0)	3.84	3.33	3.59	-0.24
C (X=0.0005) (PEG)	3.88	3.37	3.63	-0.20
C (X=0.30)	4.08	3.57	3.82	-0.01
RCI (X=0) PSE	5.49	4.98	5.23	
RCI (X=0)	5.24	4.73	4.99	-0.24
RCI (X=0.0005) (PEG)	5.23	4.72	4.98	-0.25
RCI (X=0.30)	5.18	4.67	4.92	-0.31

*Values for the C Factor and RCI under Hydro One's proposal may differ from those in Exhibit A, Tab 4, Schedule 1, pages 7-8 due to rounding.

c) Were the X factor set at 0.3%, PEG calculates that the ACM equivalent S factor would be 0.01%. However, the OEB may wish to place a lower bound on the S factor at the 0.15% that it chose for Hydro One’s distribution services.

d) No.

e) No.

M1-HON-15

Reference: Exhibit M1, pages 29 and 30

Preamble: PEG discusses the treatment of input prices in their research.

Interrogatories:

a) Given that PEG uses different input price indexes that measure different items and different treatments of capital in their research, and evidently uses different capital treatments and depreciation rates between Hydro One and the US sample, does PEG believe the Hydro One MFP (Table 4 in PEG Report) and industry MFP results (Table 3 in PEG Report) are comparable?

b) Please calculate the 2004 to 2016 average growth rates for the total input price and the components of labour, non-labour, and the capital price for both Hydro One and the average for the US sample. Please insert the results into the following table.

Input Price Component	Hydro One 2004 to 2016 Growth Rate	US Sample Average 2004 to 2016 Growth Rate
Total Input Price		
Labour Component Input Price		
Non-Labour Component Input Price		
Capital Component Input Price		

Response to HON-15: The following response was provided by PEG.

a) PEG believes that the transmission input price and productivity trends of Hydro One and the sampled U.S. electric utilities should be measured as accurately as possible. Concern about differences in the capital asset price indexes employed is less than in the recent Toronto Hydro IR proceeding because: 1) PEG used the more rapidly-growing implicit capital stock deflator for the utility industry of Canada rather than that for Ontario; 2) the Handy Whitman index ("HWI") for North Atlantic power transmission construction costs did not grow as rapidly in recent years as the HWI for North Atlantic distribution construction costs; 3) transmission construction costs are not particularly sensitive to fluctuations in copper prices; 4) PEG used a building construction cost HWI to deflate general plant additions; and 5) the capital price index was levelized in 2012, after the recent period of brisk transmission construction cost inflation. PEG's response to Schools Energy Coalition's interrogatory SEC-4 (Exhibit L1/Tab 4/Schedule 4) also discusses the asset price deflator issue.

b) PEG believes that this request cannot be addressed within a reasonable time and with reasonable effort within the current schedule of this proceeding. However, PSE can calculate these values from the "working papers" provided earlier.

M1-HON-16

Reference: Exhibit M1, page 69, table B4

Interrogatories:

a) In Table B4, PEG shows its calculations for the proposed "S-factor". Please reconcile the capital cost shown in the CK line of the identified table with Hydro One's capital costs, as shown in Exhibit B, Tab 1, Schedule 3.

b) Please explain how PEG has calculated the CK^{NEW} variable in the table.

Response to HON-16: The following response was provided by PEG.

a) Exhibit B, Tab 1, Schedule 3 outlines Hydro One's recent and proposed *capex*, not the annual capital cost that results from it. We did not use these data in our calculations. Rather, PEG used the capital-related revenue requirement data from line 8 of Table 2 in Exhibit A, Tab 4, Schedule 1 as updated on June 19, 2019. PEG relied on gross plant additions from Exhibit C, Tab 2, Schedule 1, p. 2 as updated on June 19, 2019.

b) PEG developed an estimate of CK^{NEW} for each of 2021 and 2022 based on data provided by Hydro One in its application and responses to data requests. In addition to the sources noted in response to part a, we relied on the depreciation expenses on 2020 to 2022 plant additions from Exhibit I, Tab 1, Schedule 179. Assumptions about the capital structure, rate of return on debt, and rate of return on equity were provided in Exhibit G, Tab 1, Schedule 3. PEG assumed that the rate of return on debt and equity will not change between 2020 and 2022. PILs/Taxes were assumed to be 11.5% for provincial income tax and 15% for Canadian income tax. PEG also followed the half year rule to better reflect Ontario ratemaking policy. The full calculations supporting PEG's estimates of CK^{NEW} were provided in the working papers, which are available to any party who has signed a confidentiality agreement.

M1-HON-17

Reference: Exhibit M1, page 68

Preamble: Hydro One notes utilities are allowed cost recovery for assets once they are placed in service, as opposed to when capital costs are actually incurred. As indicated in Exhibit C, Tab 2, Schedule 1, there are differences in the timing of capital costs and when assets are put in-service due to the multi-year nature of large transmission projects.

Interrogatories:

a) Given this fact, please explain why it is appropriate for PEG to assume that equations [B23] and [B33] should be equal.

b) Please explain how PEG is considering the timing difference between capital spending and in-service additions in calculating the RK parameter.

Response to HON-17: The following response was provided by PEG.

a) PEG notes that this is an approximation of the real-world phenomena. Similar approximations and assumptions are also used in the OEB's approved ICM/ACM materiality threshold formula. Econometric, productivity, and other kinds of statistical cost research used in ratemaking also involve approximations to reality.

b) PEG did not consider the timing difference between capital spending and in-service additions in calculating RK.

M1-HON-20

Reference: Exhibit M1, page 45

Preamble: On pages 44 and 45 PEG lists various alternatives for the OEB's consideration. On page 45 PEG states that "The proposed capex budget could be reduced by a material amount, as in the OEB's decisions in the last Toronto Hydro proceeding and the Hydro One distribution IR proceeding." PEG then states that after considering the pros and cons of each option that it recommends that the OEB add a supplemental stretch factor calibrated "so that it produces a markdown on plant additions that is similar to what would be produced by an ACM."

Interrogatories:

a) Please confirm that PEG's recommendation of the calibration the S-factor is based on the assumption that no other reductions are made to Hydro One's proposed capital envelope.

b) Please provide a reference in OEB materials that indicates or implies that the OEB intends the ACM/ICM materiality threshold to serve as a "markdown" on capital expenditures.

c) Please explain why the OEB's ACM/ICM mechanism is relevant when the OEB made clear as follows at p. 14 of the *Report of the Board, New Policy Options for the Funding of Capital Investments: the Advanced Capital Module* (emphasis added):

> *…there must be a clear distinction between a cost of service application under the Price Cap IR option (with ACM proposals beyond the test year), and the Custom IR method. The use of an ACM is most appropriate for a distributor that:*
>
> *• does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;*
>
> *• is not seeking funding for a series of projects that are More related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects); or*
>
> *• is not proposing to use the entire eligible incremental capital envelope available for a particular year.*

Response to HON-20: The following response was provided by PEG.

a) PEG believes that the final S factor should reflect the OEB's decision on Hydro One's transmission capital envelope. Disallowances would reduce but would not necessarily eliminate the need for an S factor. The Board disallowed a sizable part of Hydro One's forecasted/proposed capex in the recent distribution IR proceeding and still levied a 0.15% S factor.

b) PEG understands that the OEB prefers the term "dead band" to the term "markdown" when discussing the funding provided by its capital modules. However, the OEB has clearly intended for the materiality thresholds for these modules to include a dead band that effectively marks down eligible capex. For example, in their 2013 decision on Toronto Hydro's proposed Incremental Capital Module application the OEB stated that:

> The Board finds that the wording of the Supplemental Report is clear – that only eligible expenditures in excess of the materiality threshold are eligible for ICM4, and that the purpose of the deadband is to reduce the amount of funding available by a further 20%. The Board finds that the 20% threshold adjustment continues to be appropriate[1]

The Board stated on pages 18-19 of the same decision that

> While the Board will not adopt the suggestion of some parties that each project put forward by THESL should meet the overall materiality threshold, the Board does not expect that projects that are minor expenditures in comparison to the overall budget should be considered eligible for ICM treatment. A certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget.[2]

c) The relevance of the ACM/ICM markdown provision is that the OEB deemed a material markdown of forecasted/proposed capex to be warranted, regardless of its chosen X factor, for multiple reasons. For example, the Board stated in EB-2014-0219 that a dead band of 10% balances "the need for appropriately funding necessary incremental capital investments while avoiding numerous marginal applications and providing some protection that amounts are not already funded through rates."[3] These reasons also apply to Custom IR, and PEG has advanced

[1] Decision, EB-2012-0064, May 9, 2013, pp. 15-16.

[2] *Ibid*., pp. 18-19.

[3] EB-2014-0219, p. 18.

other valid reasons for markdowns. The need for a markdown is heightened in this case by the fact that Hydro One's proposed X factor is zero.

HYDRO ONE INTERROGATORIES ON THE WORKING PAPERS OF PACIFIC ECONOMICS GROUP

M1-HON-21

Reference: Exhibit M1, Working Papers

Preamble:
In examining the PEG working papers and on p. 28 of the PEG Report, we understand that PEG subtracted certain cost categories from Hydro One's OM&A expenses to make a more consistent cost definition with the sample. These categories include miscellaneous transmission expenses, load dispatching, maintenance of miscellaneous regional transmission plant, and transmission by others. However, in examining the working papers it only appears that PEG subtracted these costs from Hydro One's OM&A expenses for the years 2008 to 2017 and that when PEG subtracted the expenses for Hydro One the costs were in different units than the rest of the costs. When Hydro One provided these cost breakouts to PEG in updated response to I-01-OEB-12 the company stated that the broken out cost data was only available for the years 2008 to 2017 but that the accounts averaged around 13% of OM&A expenses. The response also mentioned the provided data is in millions of dollars.

Interrogatories:

a) Please confirm that PEG did not subtract these cost categories for the forecasted years of 2018 to 2022 and for years prior to 2007. If confirmed, please explain why PEG did not subtract an estimated portion in these years to make the cost definition consistent with the US sample in years other than 2008 through 2017.

b) Please confirm that in the years of 2008 to 2017, when PEG did subtract these costs, the effect was to only subtract 1/1,000th of the costs that should have been subtracted from Hydro One. For example, in 2017 Hydro One reported $42.7 million in miscellaneous transmission expenses but PEG only subtracted $42.7 thousand for these miscellaneous transmission expenses. Please confirm that our understanding of PEG's methodology in this regard is correct.

Response to HON-21: The following response was provided by PEG.

PEG used the Hydro One data as provided but did not make the adjustments mentioned above. PEG has subsequently fixed the units issue and imputed the 2017-2020 OM&A values using the 2016 ratio of unadjusted OM&A expenses to adjusted OM&A expenses for future years and the 2008 ratio for previous years. The values after 2021 were extended from 2020 using the normal procedure in the code.

Revised benchmarking results are provided in Tables HON 21-A and HON 21-B. The change in results is minor and does not alter PEG's main conclusion that a 0.30% stretch factor is appropriate for Hydro One's transmission services. It can be seen that the revised average cost performance score for the 2020-2022 period is 6.8% rather than 9.0%. Neither the new nor the old benchmarking scores are statistically different from zero. One reason that the change in the score is small is that OM&A is a very small part of total cost in the forecast period. The MFP trend of the Company over the full 2005-2016 historical sample period is -1.18% rather than -1.17% if these costs are excluded. The new MFP results are presented in Table HON 21-C.

The reason to exclude these costs was to provide better comparability with the US MFP results, which does not apply to a stand-alone analysis of HON TFP. PEG believes that the MFP trend with no exclusions could be seen as more reliable because it does not require the imputations needed due to missing data. The MFP trend with no exclusions is presented in Table HON 21-D.

Please note also that the output parameters yielded the same output weights as before (46.3% weight on line length) and no change to the US MFP results was required.

a) Confirmed

b) Confirmed

Table HON 21-A

PEG's Alternative Econometric Model of Total Transmission Cost

VARIABLE KEY

YM = Kilometers of transmission line
P = Ratched maximum peak demand
MVA = Substation capacity per substation
VOLT = Average voltage of transmission line
CS = Construction standards index
PCTPOH= Percent of transmission plant that is overhead
PCTPTX = Percent of transmission plant in total plant
Trend = Time trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YM	0.491	26.098	0.000
YM * YM	0.401	14.459	0.000
P	0.569	30.508	0.000
P * P	0.241	7.257	0.000
YM * P	-0.207	-8.478	0.000
MVA	0.044	2.347	0.019
VOLT	0.062	2.045	0.041
CS	0.234	5.165	0.000
PCTPOH	-0.397	-8.390	0.000
PCTPTX	0.138	10.300	0.000
Trend	-0.006	-7.295	0.000
Constant	12.173	695.355	0.000

Adjusted R^2	0.948
Sample Period	1995-2016
Number of Observations	1,127

Table HON 21-B

Hydro One's Total Transmission Cost Performance

[Actual - Predicted Cost (%)][1]

Year	Cost Benchmark Score
2004	-23.4%
2005	-26.0%
2006	-25.4%
2007	-22.6%
2008	-23.8%
2009	-21.5%
2010	-18.9%
2011	-15.9%
2012	-13.9%
2013	-7.5%
2014	-7.2%
2015	-4.2%
2016	-3.7%
2017	-0.8%
2018	-0.1%
2019	1.3%
2020	4.0%
2021	6.5%
2022	9.9%
Average 2004-2016	**-16.5%**
Average 2014-2016	**-5.0%**
Average 2020-2022	**6.8%**

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

Table HON 21-C

Hydro One's Transmission Productivity Annual Growth Rates - Revised

(Growth Rates)[1]

Year	Output Quantity Index	Input Quantities			Productivity		
		OM&A	Capital	Multifactor	OM&A	Capital	Multifactor
2004							
2005	1.43%	-9.42%	0.32%	-1.59%	10.85%	1.11%	3.02%
2006	1.88%	10.14%	-0.22%	1.83%	-8.26%	2.10%	0.05%
2007	0.00%	10.51%	1.46%	3.40%	-10.51%	-1.46%	-3.41%
2008	0.08%	-13.40%	0.32%	-2.56%	13.48%	-0.24%	2.64%
2009	-0.01%	7.56%	2.49%	3.50%	-7.57%	-2.50%	-3.51%
2010	0.04%	-0.11%	3.87%	3.08%	0.15%	-3.83%	-3.04%
2011	0.04%	-4.51%	3.01%	1.57%	4.55%	-2.97%	-1.53%
2012	0.44%	-2.32%	5.68%	4.22%	2.76%	-5.24%	-3.78%
2013	0.03%	5.69%	1.52%	2.27%	-5.66%	-1.50%	-2.24%
2014	-0.05%	-9.84%	2.77%	0.61%	9.80%	-2.82%	-0.66%
2015	0.15%	1.26%	0.71%	0.80%	-1.12%	-0.57%	-0.66%
2016	0.00%	-4.78%	2.14%	1.06%	4.78%	-2.14%	-1.06%
2017	-0.58%	-3.06%	1.77%	1.05%	2.49%	-2.35%	-1.62%
2018	0.61%	-4.49%	3.25%	2.14%	5.11%	-2.64%	-1.53%
2019	0.00%	-16.81%	1.78%	-0.61%	16.81%	-1.77%	0.62%
2020	0.00%	4.06%	2.03%	2.27%	-4.06%	-2.03%	-2.27%
2021	0.01%	-0.10%	3.13%	2.75%	0.10%	-3.12%	-2.74%
2022	0.01%	-0.10%	2.77%	2.44%	0.11%	-2.76%	-2.43%
Average Annual Growth Rates							
2005-2016	**0.34%**	**-0.77%**	**2.01%**	**1.52%**	**1.10%**	**-1.67%**	**-1.18%**
2012-2016	**0.11%**	**-2.00%**	**2.57%**	**1.79%**	**2.11%**	**-2.45%**	**-1.68%**
2021-2022	**0.01%**	**-0.10%**	**2.95%**	**2.59%**	**0.11%**	**-2.94%**	**-2.58%**

[1]All growth rates are calculated logarithmically.

Table HON 21-D

Hydro One's Transmission Productivity Annual Growth Rates with No Exclusions

(Growth Rates)[1]

Year	Output Quantity Index	Input Quantities OM&A	Input Quantities Capital	Input Quantities Multifactor	Productivity OM&A	Productivity Capital	Productivity Multifactor
2004							
2005	1.43%	-9.42%	0.32%	-1.80%	10.85%	1.11%	3.23%
2006	1.88%	10.14%	-0.22%	2.06%	-8.26%	2.10%	-0.18%
2007	0.00%	10.51%	1.46%	3.62%	-10.51%	-1.46%	-3.62%
2008	0.08%	-15.00%	0.32%	-3.23%	15.08%	-0.24%	3.32%
2009	-0.01%	11.84%	2.49%	4.56%	-11.85%	-2.50%	-4.57%
2010	0.04%	-1.38%	3.87%	2.69%	1.42%	-3.83%	-2.65%
2011	0.04%	-4.07%	3.01%	1.48%	4.11%	-2.97%	-1.44%
2012	0.44%	0.19%	5.68%	4.54%	0.24%	-5.24%	-4.10%
2013	0.03%	2.30%	1.52%	1.68%	-2.27%	-1.50%	-1.65%
2014	-0.05%	-11.22%	2.77%	0.09%	11.17%	-2.82%	-0.14%
2015	0.15%	9.93%	0.71%	2.43%	-9.78%	-0.57%	-2.29%
2016	0.00%	-9.69%	2.14%	-0.03%	9.69%	-2.14%	0.03%
2017	-0.58%	-5.26%	1.77%	0.57%	4.68%	-2.35%	-1.15%
2018	0.61%	-1.98%	3.25%	2.40%	2.59%	-2.64%	-1.78%
2019	0.00%	-16.81%	1.78%	-0.99%	16.82%	-1.77%	1.00%
2020	0.00%	4.06%	2.03%	2.31%	-4.06%	-2.03%	-2.31%
2021	0.01%	-0.10%	3.13%	2.69%	0.10%	-3.12%	-2.68%
2022	0.01%	-0.10%	2.77%	2.38%	0.11%	-2.76%	-2.37%
Average Annual Growth Rates							
2005-2016	**0.34%**	**-0.49%**	**2.01%**	**1.51%**	**0.83%**	**-1.67%**	**-1.17%**
2012-2016	**0.11%**	**-1.70%**	**2.57%**	**1.74%**	**1.81%**	**-2.45%**	**-1.63%**
2021-2022	**0.01%**	**-0.10%**	**2.95%**	**2.53%**	**0.11%**	**-2.94%**	**-2.53%**

[1]All growth rates are calculated logarithmically.

M1-HON-22

Reference: Exhibit M1, Working Papers

Preamble: It is the standard approach in benchmarking work to report the econometric model that includes the entire sample. PEG has done this both in the PEG Report and in the working papers. It is also the standard approach to estimate the model excluding the studied utility and calculate the benchmarks from that model.

Interrogatories:

a) Please confirm that the econometric total cost model used to calculate Hydro One's total cost benchmarks excluded Hydro One from the model run.

b) Please provide the estimated econometric total cost model parameter values that excluded Hydro One's observations and was used to calculate the Hydro One benchmarks.

Response to HON-22: The following response was provided by PEG.

a) This statement is confirmed.

b) The requested information is provided in the table below.

EXPLANATORY VARIABLE	PARAMETER ESTIMATE		EXPLANATORY VARIABLE	PARAMETER ESTIMATE
YL	0.491		VOLT	0.066
YL * YL	0.402		CS	0.249
YL * D	-0.203		PCTPOH	-0.391
D	0.579		PCTPTX	0.151
D * D	0.247		Trend	-0.007
MVA	0.042		Constant	12.182

M1-HON-23

Reference: Exhibit M1, Working Papers

Preamble: In the output file titled "pegTCOutput.txt" in PEG's working papers, it is PSE's understanding that PEG calculated the average total cost score for each utility in the sample for the most recently available three-year period. This is labeled as the "diff" column. It is PSE's understanding that for most of the utilities in the sample, other than Hydro One, this would be the average total cost benchmarking score for 2014 to 2016.

Interrogatories:

a) Please provide the PEG benchmark scores for each utility in the sample in the individual years of 2014, 2015, and 2016. PEG may use the "pegid" identifier only and not include the company name to shield the identity of the observation's benchmark score.

b) Please provide the PEG benchmark scores for each utility in the sample in the individual years of 2014, 2015, and 2016 for the PEG model that adds a quadratic trend variable with all other PEG variables and methodologies the same. This should be the same model as requested in Hydro One's interrogatory #6 part (h) to PEG. PEG may to use the "pegid" identifier only and not include the company name to shield the identity of the observation's benchmark score.

c) Please provide the PEG benchmark scores for each utility in the sample in the individual years of 2014, 2015, 2016, 2017, and 2018 for the PEG model that adds 2017 and 2018 US sample data to PEG's benchmarking sample with all other PEG variables and methodologies the same. This should be the same model as requested in Hydro One's interrogatory #6 part (c) to PEG. PEG may to use the "pegid" identifier only and not include the company name to shield the identity of the observation's benchmark score.

Response to HON-23: The following response was provided by PEG.

a) The requested information is provided in Sheet 1 of Attachment_M1-HON-23A&B.xlsx. Please note that the benchmarking scores are calculated for the latest three years of data available for each utility, which are not always the period 2014-2016.

b) PEG believes that this request cannot be addressed within a reasonable time and with reasonable effort within the current schedule for this proceeding. However, PEG believes that Mr. Fenrick has the required data and expertise to do this in both the PEG models and his own.

c) PEG was not commissioned to update its study to include 2017 or 2018 data. Moreover, PEG has relied upon PSE's business condition variables in its research which have not, to the best of PEG's knowledge, been updated to 2017 or 2018. PEG believes that this request, which would require collection and analysis of significant data for the sample of utilities, cannot be addressed within a reasonable time and with reasonable effort given the current schedule for this proceeding.

M1-HON-24

Reference: Exhibit M1, Working Papers

Preamble: On p. 59 of the PEG Report, PEG mentions its econometric model estimation procedure now corrects for autocorrelation, whereas in the HOSSM proceeding it did not. Normally, a small change in results would be expected due to making such a methodological change. Yet, PSE notices a large difference in results from PEG's HOSSM proceeding and a large difference in PEG's results relative to a model estimated using Pooled Ordinary Least Squares (OLS) that PSE was able to estimate from PEG's working papers.

Interrogatories:

a) Would PEG normally expect a large change in results based on the autocorrelation methodological change made by PEG relative to either an OLS model or PEG's Generalized Least Squares model reported in the HOSSM case?

b) Given the PEG approach in HOSSM was a valid approach and an OLS modelling approach still produces unbiased parameter estimates even in the presence of autocorrelation and heteroskedacity, is PEG concerned about the large change in results stemming from its modeling procedure now used in this application?

c) Please list the applications in PEG's prior cost benchmarking research in Ontario where PEG's econometric modeling procedures included this same autocorrelation correction. The list of possible applications should include 3rd Generation IR model, 4th Generation IR model, two Toronto Hydro Custom IR applications, Hydro One Distribution Custom IR, and the Hydro One SSM application.

d) Please list the applications in PEG's prior cost benchmarking research in Ontario where PEG's econometric modeling procedures did not include this same autocorrelation correction. The list of possible applications should include 3rd Generation IR model, 4th Generation IR model, two Toronto Hydro Custom IR applications, Hydro One Distribution Custom IR, and the Hydro One SSM application.

Response to HON-24: The following response was provided by PEG.

a) Please see the response to part (b).

b) In our work for Board Staff in the HOSSM proceeding, PEG did not make the autocorrelation correction that we normally do. Thus, while the estimation procedure for the new model was valid, that for our model in the HOSSM proceeding was not. It is true that OLS is unbiased even in the presence of autocorrelation and heteroskedasticity. However, being unbiased only means that parameter estimates do not deviate *systematically* from their true values. It does not mean that any *particular* estimate will be close to the true value. Thus, an estimator that is unbiased is not necessarily a good estimator. For example, if the true value of a parameter is zero, an estimator that yields 100 and -100 with equal frequency is unbiased. In the presence of autocorrelation and heteroskedasticity, the efficiency (i.e., precision) of the OLS approach declines—so while its estimates generally remain unbiased, any particular estimate may differ substantially from those produced by a more efficient approach (such as the FLGS procedure used by PEG). Thus, it is plausible that PEG's new econometric estimates and resulting benchmarks could differ materially from analogous OLS results or from our HOSSM results.

c) and d) PEG has not always specified in our reports the exact autocorrelation correction specification used in the development of our econometric cost models. To answer these questions, we would accordingly need to review our working papers for various projects dating back at least 10 years. PEG believes that this request cannot be addressed within a reasonable time and with reasonable effort within the current schedule for this proceeding. However, PEG has used its best efforts to provide information below as to whether an autocorrelation correction was undertaken in our Ontario research.

PEG corrected for autocorrelation in our econometric research for IRM4, the Hydro One distribution IR proceeding, and the two Toronto Hydro IR proceedings. We believe that a feasible GLS method was used in all cases. In several additional reports, notably for the 3rdGIRM proceeding and in EB-2014-0116, PEG relied on an FGLS approach to model estimation but did not report whether an autocorrelation correction was made. PEG did not correct for autocorrelation in our work in the 2007 IR proceedings for Enbridge Gas and Union Gas in Cases EB-2007-0606/0615 or in the Hydro One Sault Ste. Marie IR proceeding. PEG did not specify whether an autocorrelation correction was made in our 2006-2008 benchmarking reports (EB-2006-0268).

PEG understands that PSE did not correct for autocorrelation in the recent Toronto Hydro IR proceeding.