HYDRO ONE NETWORKS IR #1

1. Reference: Exhibit M1, page 37, 38; Exhibit A, Tab 4, Schedule 1

The evidence states that, under the C-Factor, "capital revenue is chiefly determined on a cost of service basis" and that "British distributors operating under several generations of IR based on cost forecasts have repeatedly spent less on capex than they forecasted." Please confirm that, unlike cost of service, Hydro One's proposed C-Factor:

a. contains an in-service variance account that returns underspending to customers; and

b. Is made subject to a "productivity factor" so that the recovery is less than forecasted amounts.

c. PEG states that "another problem with the proposal is that customers must fully compensate Hydro One for expected capital revenue shortfalls." Please explain how this statement is true given that Hydro One's Custom IR proposal includes a capital in-service variance account as described in Exhibit A, Tab 4, Schedule 1 of the Application.

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

a. Dr. Lowry confirms this statement and acknowledges that this would reduce but not eliminate Hydro One's incentive to exaggerate its capex requirements.

b. Dr. Lowry confirms that the productivity factor ensures that capital revenue will be less than proposed capital cost.

c. Dr. Lowry notes that he was talking about the Company's expectation of the capital revenue shortfalls resulting from its proposed capex. Under the Company's proposal it will recover its annual capital cost so long as it is less than or equal to its projection.

HYDRO ONE NETWORKS IR #2

2. Reference: Exhibit M1, page 37

The evidence speculates that Hydro One may be timing the construction of its Integrated System Operating Centre in a way to increase its revenue.

a. Please advise of the facts upon which this statement is made and whether PEG made any attempt to investigate any facts in this regard.

b. Please explain how the impact on the C factor would be much less if the center was finished in 2019.

Response to HONI-2: The following response was provided by PEG.

a. Under the Company's proposed IRM, capital revenue is sensitive to the timing of capital expenditures. The proposed integrated system operating center would require less supplemental revenue if completed in 2018, 2021, or 2022. PEG has reviewed the Company's evidence in support of the centre and concludes that it is not clear why it is optimal for the centre to be completed in the middle of the IRM when the claim to supplemental revenue would be high.

b. Dr. Lowry intended to say on page 37 of his report that "The impact of the C factor would be much less if the center were finished in *2018* or 2022."

HYDRO ONE NETWORKS IR #3

3. Reference: Exhibit M1, page 9

The evidence notes that the C-Factor "is similar to that which the Board approved for Toronto Hydro." Please confirm that PEG provided evidence on the Toronto Hydro C-Factor proposal and did not raise concerns with the incentives that it claims are inherent in a C-Factor that it is raising here.

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

PEG's evidence in the Toronto Hydro proceeding was provided by Senior Advisor Lawrence Kaufmann without input from Dr. Lowry. Dr. Lowry has testified in several proceedings on the ratemaking treatment of capital, including three incentive ratemaking proceedings in Alberta, and has developed his own views on this issue after seeing how attempts to obtain supplemental capital revenue are chronic amongst larger Canadian utilities subject to indexed IRMs.

HYDRO ONE NETWORKS IR #4

4. Reference: Exhibit M1 Page 9

In the Toronto Hydro proceeding, PEG's pre-filed evidence stated:

"THESL's C factor employs a sound method for ensuring that the C factor reflects only incremental capital spending, but the proposed C factor does not appropriately translate those cost changes into price changes. THESL's C factor will lead to revenue adjustments that exceed the change in capital costs because it does not account for the revenue growth resulting from changes in billing determinants.

Please confirm that the concern raised by PEG with respect to changes in billing determinants does not apply to Hydro One's proposal given that it is proposing a revenue cap, and not a rate cap.

Response to HONI-4: The following response was provided by PEG.

Dr. Lowry confirms this statement. Hydro One proposes a revenue cap and the C factor would influence the growth of the revenue requirement. The further step of converting the revenue requirement to rates would consider the growth in billing determinants.

HYDRO ONE NETWORKS IR #5

5. Reference: Exhibit M1, page 41

Also with respect to the Toronto Hydro decision, the evidence refers to regulatory incentives that are postulated as capable of reducing capital costs and refers to the fact that the OEB disallowed 10% of Toronto Hydro's proposed capex in that decision. Although the footnote and the context suggest that this disallowance was for the purposes of adjusting the C factor, please confirm that the disallowance was made on its merits in a different part of the decision and not as a formulaic adjustment to the C factor.

Response to HONI-5: The following response was provided by PEG.

Dr. Lowry noted on pp. 37-41 of his testimony several problems that arise when utilities operating under rate or revenue cap indexes seek supplemental revenue to fund capex.

a) It is difficult for a regulator and intervenors to identify required capex.
b) Regulatory cost rises, and this problem is especially vexing when the amount of additional revenue needed is small relative to regulatory costs.
c) The incentive to contain capex is weakened.
d) Forecasted capex requirements may not reflect achievable productivity gains.
e) Utilities may be incentivized to bunch capex in ways that bolster supplemental capital revenue.
f) Distributors may be fully compensated when required capex surges slow productivity growth, but need not commensurately compensate consumers in future plans when productivity growth is naturally brisk. Extra revenue is requested for capex that is routinely incurred by companies in the productivity studies used to set X. As a consequence, over multiple plans consumers do not , on average, receive the benefit of industry productivity growth even when it is achievable.

The OEB has rationalized 10% materiality thresholds and deadbands for incremental and advanced capital modules in 4th Generation IRMs just to address problem b). However, such thresholds can also address the other listed problems.

Several of the problems on the above list were discussed in the OEB's Toronto Hydro decision and order (EB-2014-0116). The Board stated that:

> … the OEB is not granting Toronto Hydro the entire amount it seeks to spend on capital. The OEB

is of the view that efficiencies could be realized which would reduce the amount necessary to complete capital projects. (p. 1)

It is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity (RRFE) which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application. (p.2)

Intervenors and OEB staff generally argued that Toronto Hydro had not adequately supported a $2.5 billion capital plan. (p. 20)

… the OEB does not accept that there are no further productivity gains that can be made over the next five years. The OEB finds that Toronto Hydro must place more emphasis on productivity gains and that Toronto Hydro must find efficiencies over the five years of the capital plan. (p. 26)

The OEB is not opposed to the C-factor mechanism as proposed, but the quantum will change as it relates to revenue requirement to reflect the reduction in capital spending approved by the OEB. (p. 28)

Thus, multiple arguments supported the 10% disallowance, and the C factor was clearly affected.

HYDRO ONE NETWORKS IR #6

6. Reference: Exhibit M1, page 38

The evidence asserts that "customers must fully compensate Hydro One for expected capital revenue shortfalls when capex is high". Please confirm your understanding that Hydro One will not be compensated for capex above what is forecasted.

Response to HONI-6: The following response was provided by PEG.

Dr. Lowry again confirms that Hydro One will not be compensated for costs of capex that exceed its proposed levels.

HYDRO ONE NETWORKS IR #7

7. Reference: Exhibit M1, page 38

The evidence states that customers "are not offered timely revenue reductions for expected cost reduction opportunities such as the acquisition of other utilities." Please confirm your understanding that the allocation of utility acquisition costs and revenues are addressed through a different OEB policy than IRM, i.e., in its policy respecting mergers, acquisitions, amalgamations and divestitures.

Response to HONI-7: The following response was provided by PEG.

Dr. Lowry confirms that the ratemaking treatment of acquisitions is addressed by different OEB policies such as the OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* and the *Handbook for Utility Rate Applications*. However, to the extent that Hydro One has been active in the acquisitions area, this makes the Company's proposed C factor more unfair to customers.

HYDRO ONE NETWORKS IR #8

8. Reference: Exhibit M1, page 39

The evidence notes the author's disappointment with the ability of regulators such as Ofgem, the OEB and the AUC to address capital costs and proposes a new policy of addressing capital. The evidence also refers to "a future 5th GIRM proceeding" (e.g., at p. 20). Please confirm that there is also value in the OEB providing consistency and predictability in its regulatory treatment under the current IR regime before changing it in the middle of a proceeding without notice.

Response to HONI-8: The following response was provided by PEG.

Dr. Lowry acknowledges that there are benefits from consistency and predictability in rate regulation but notes that the OEB has some flexibility in approving the terms of Custom IR plans. The OEB stated in its RRFE report that:

> In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.[1]

and that:

> The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence.

The OEB stated in the Toronto Hydro decision that:

> The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests.[2]

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[1] OEB Report of the Board*, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach,* October 18, 2012, pp 18-19.

[2] OEB, *Decision and Order*, EB2014-0116, Toronto Hydro-Electric System Limited, December 29, 2015, p. 4.

This policy presumably does not preclude the consideration and adoption of innovative proposals made by intervenors or OEB witnesses. Dr. Lowry is not proposing to change the provisions of any IRM or Custom IR plan mid-term.

HYDRO ONE NETWORKS IR #9

9. Reference: Exhibit M1

Please provide all working papers associated with the Pacific Economics Group ("PEG") study titled "IRM Design for Hydro One Networks, Inc." ("PEG Report"). These working papers should include the following:

i. All data in Excel Format.
ii. Calculations in Excel format or program code to show the derivation of the results from publicly available data.
iii. Identification of variable names and company ID numbers.
iv. Any other information needed for an experienced consultant to be able to replicate the work.

Response to HONI-9: The following response was provided by PEG.

The requested working papers are provided in Attachment HONI-9. Due to the size of the files, these will be made available on the OEB's website for this proceeding. Certain of these papers contain variations on the confidential working papers provided to PEG by PSE and are being treated as confidential for the reasons set out in the cover letter to these interrogatory responses. The remainder of the material being provided in response to this interrogatory is non-confidential supplemental material, and therefore it is being made available publicly.

HYDRO ONE NETWORKS IR #10

10. Reference: Exhibit M1, page 4

Please confirm that (1) the cited PSE TFP trend for Hydro One of -1.4% is the reported unadjusted TFP trend put forth by PSE, and (2) that the PSE-reported adjusted TFP trend for 2003-2015 for Hydro One is -0.9%.

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

Dr. Lowry confirms this statement.

HYDRO ONE NETWORKS IR #11

11. Reference: Exhibit M1

PSE put forth two TFP indexes to measure Hydro One's productivity, labelled "unadjusted" and "adjusted." In PEG's opinion, which TFP index is a more comprehensive measure of Hydro One's performance trend?

Response to HONI-11: The following response was provided by PEG.

Dr. Lowry believes that PSE's adjusted TFP index is a more comprehensive performance measure. However, he is not sure that the treatments of reliability and safety are satisfactory. Furthermore, he is not sure that safety should be addressed by such an index since:

- workers and the general public can obtain some compensation from the Company for injuries and damages that its operations cause; and
- costs Hydro One incurs for injuries and damages are included in a more conventional TFP index.

Appraising these innovations was not a high priority given the limited time PEG had to answer numerous interrogatories since these innovations influence neither the stretch factor nor the base TFP trend.

HYDRO ONE NETWORKS IR #12

12. Reference: Exhibit M1

Does PEG believe that negative stretch factors should be considered in certain circumstances? If so, please describe the circumstances that would warrant a negative stretch factor.

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

Dr. Lowry does believe that negative stretch factors should be considered if a utility's performance is demonstrably superior.

HYDRO ONE NETWORKS IR #13

13. Reference: Exhibit M1

Does PEG believe that a negative productivity factor should be considered in certain circumstances? If so, please describe the circumstances that would warrant a negative productivity factor.

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

Dr. Lowry does believe that negative productivity factors should be considered under certain circumstances. Here are some circumstances where such consideration is reasonable.

- The IRM has a price cap index and the utility has high residential and commercial usage charges and is experiencing a materially downward trend in R&C average use.
- The IRM has a revenue cap index and the X factor must be calibrated on the basis of the medium-term TFP trend of an industry experiencing declining cost efficiency.

HYDRO ONE NETWORKS IR #14

14. Reference: Exhibit M1, page 18

Please describe the "Utility Sector Capital Stock Deflator" for the Canadian utility sector mentioned in Table 1 on page 15 of the report, including any sources used. (This Stock Deflator is also referred to as the "implicit capital stock deflator" in other parts of the PEG report.) Is the sole source Statistics Canada? Please provide the calculations and specific indexes used by PEG using the Statistics Canada data or other data to arrive at this Stock Deflator.

Response to HONI-14: The following response was provided by PEG.

PSE's use of a Handy Whitman Index ("HWI") to measure the TFP trend of Hydro One and Statistics Canada's decision to suspend calculation of its Electric Utility Construction Price Index ("EUCPI") have prompted PEG to investigate alternative asset price deflators in our work for OEB staff in this proceeding. Attachment HONI.14 provides a detailed discussion of this research.

HYDRO ONE NETWORKS IR #15

15. Reference: Exhibit M1, page 13

What other asset price inflation measures did PEG consider? Please provide a list of the asset price inflators or deflators, along with any data gathered by PEG, and the reasons the alternatives were not preferred to the Utility Sector Capital Stock Deflator for the Canadian utility sector.

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

Please see our response to HONI-14.

HYDRO ONE NETWORKS IR #16

16. Reference: Exhibit M1, page 19

Is the data for the Canadian utility sector from Statistics Canada mentioned on p. 19 of the exhibit inclusive of utility functions other than electric distribution (i.e. power production and transmission)? Please list the possible utility functions included in the measure of the utility capital stock.

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

As discussed further in Attachment HONI-14, the Canadian utility sector comprises utilities that provide power generation, transmission, and distribution; gas distribution; and water and sewer services. The utility sector designation does not include gas pipeline utilities.

HYDRO ONE NETWORKS IR #17

17. Reference: Exhibit M1, page 18

For the PEG preferred implicit Utility Sector Capital Stock Deflator, is PEG aware of how each utility function (e.g., distribution, transmission, production) is weighted within the measure?

a. If so, please provide the weights.
b. If PEG is not aware of the weights used in the implicit Utility Sector Capital Stock Deflator, what percentage of the Canadian utility capital stock does PEG reasonably expect would be associated with electric distribution functions, as opposed to non-distribution functions (i.e. power production and transmission)?

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

Please see our response to HONI-14.

HYDRO ONE NETWORKS IR #18

18. Reference: Exhibit M1, page 18

Does PEG believe that one weakness to the Utility Sector Capital Stock Deflator used by PEG for the Canadian utility sector is that it is not specific to the electric distribution industry? If PEG does not believe this is a weakness, please explain the reasoning for this conclusion.

Response to HONI-18: The following response was provided by PEG.

Dr. Lowry agrees that this is a disadvantage of his preferred asset price deflator. However, the trend in this deflator was similar to the trend in the EUCPI for many years, as PEG discusses further in Attachment HONI-14.

HYDRO ONE NETWORKS IR #19

19. Reference: Exhibit M1

The table below provides the North Atlantic American Handy Whitman indexes for total steam production plant, total nuclear production plant, total hydraulic production plant, total transmission plant, and total distribution plant from 2002 to 2015.

Note: the table below uses the reported Handy-Whitman in July of each year to simplify.

Year	Total Steam Production	Total Nuclear Production	Total Hydraulic Production	Total Transmission	**Total Distribution**
2002	438	403	364	416	**368**
2003	441	407	365	416	**373**
2004	465	427	384	455	**398**
2005	493	457	405	486	**428**
2006	515	479	418	523	**473**
2007	546	501	451	564	**521**
2008	596	545	486	629	**576**
2009	578	531	480	610	**591**
2010	604	556	497	638	**617**
2011	631	581	513	669	**649**
2012	645	595	519	682	**679**
2013	653	603	523	695	**701**
2014	672	620	534	712	**720**
2015	700	654	550	724	**735**
[redacted]					
2002-2015	3.6%	3.7%	3.2%	4.3%	**5.3%**

a. According to the North Atlantic Handy Whitman indexes, have total distribution construction costs increased more rapidly than any of the major power production or total transmission construction costs from 2002 to 2015?

b. Please calculate and provide a revised TFP estimate for Hydro One, found in Table 2, using the Utility Sector Capital Stock Deflator for the Canadian utility sector, and adjusting PEG's index by adding the difference in annual growth rates of the North Atlantic Handy Whitman index for total electric distribution to total steam production plant.

c. Please calculate and provide a revised TFP estimate for Hydro One, found in Table 2, using the Utility Sector Capital Stock Deflator for the Canadian utility sector, and adjusting PEG's index by adding the difference in annual growth rates of the North Atlantic Handy Whitman index for total electric distribution to total nuclear production plant.

d. Please calculate and provide a revised TFP estimate for Hydro One, found in Table 2, using the Utility Sector Capital Stock Deflator for the Canadian utility sector, and adjusting PEG's index by adding the difference in annual growth rates of the North Atlantic Handy Whitman index for total electric distribution to total hydraulic production plant.

e. Please calculate and provide a revised TFP estimate for Hydro One, found in Table 2, using the Utility Sector Capital Stock Deflator for the Canadian utility sector, and adjusting PEG's index by adding the difference in annual growth rates of the North Atlantic Handy Whitman index for total electric distribution to total transmission plant.

Response to HONI-19: The following response was provided by PEG.

a. No. The table excludes other power generation, which was an important area of capital spending during the sample period and experienced similarly-brisk (if slightly slower) construction cost growth.

b. This request is unreasonable since it focusses unconstructively on a single alternative HWI and PEG has struggled to answer the numerous interrogatories in the time available. PEG provides more helpful evidence on the accuracy of a comprehensive electric sector HWI in Attachment HONI-14. Hydro One can make the requested calculations if desired. A response was therefore not prepared.

c. Please see our response to HONI-19b.

d. Please see our response to HONI-19b.

e. Please see our response to HONI-19b.

HYDRO ONE NETWORKS IR #20

20. Reference: Exhibit M1, page 21

In a separate table (or in a new column in Table 2), please add PSE's reliability and safety adjustments to Table 2 for both the PEG-calculated TFP and the PSE-calculated TFP for Hydro One. How does including PSE's reliability and safety adjustments affect Hydro One's productivity results?

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

Please see Tables HONI-20a and 20b below for the requested calculations.

Table HONI-20a

Input and Output Indexes

	Input Quantity (PEG Upgrade)			Output	Output
Year	**Summary**	**OM&A**	**Capital**	**Quantity[fn]**	**Quantity w/ Safety**
2002					
2003	1.5%	-1.2%	3.2%	1.6%	1.6%
2004	-0.8%	-6.3%	2.4%	0.7%	0.7%
2005	3.4%	5.8%	2.0%	1.2%	1.2%
2006	6.1%	10.2%	3.6%	0.3%	0.3%
2007	9.9%	16.2%	5.6%	1.0%	1.2%
2008	0.6%	-4.6%	4.2%	0.6%	0.5%
2009	5.0%	5.6%	4.6%	0.0%	0.0%
2010	4.0%	4.2%	3.8%	0.4%	1.1%
2011	1.4%	-1.2%	3.2%	0.5%	1.2%
2012	0.2%	-4.0%	2.9%	0.5%	2.2%
2013	6.3%	8.4%	4.8%	0.2%	0.3%
2014	3.2%	3.7%	2.9%	0.0%	1.6%
2015	-2.9%	-14.6%	4.0%	0.7%	1.3%
2003-2015	**2.9%**	**1.7%**	**3.6%**	**0.6%**	**1.0%**
2003-2010	**3.7%**	**3.7%**	**3.7%**	**0.7%**	**0.8%**
2011-2015	**1.6%**	**-1.6%**	**3.6%**	**0.4%**	**1.3%**

fn The output measure for these calculations was the multidimensional elasticity-weighted output index developed by PEG for the OEB in 4th GIRM.

Table HONI-20b

Alternative Productivity Results for Hydro One

Productivity

	PEG Upgrade			PSE Methodology		
Year	**TFP**	**OM&A**	**Capital**	**TFP**	**OM&A**	**Capital**
2002						
2003	0.1%	2.8%	-1.6%	0.4%	2.7%	-1.0%
2004	1.5%	7.0%	-1.6%	1.9%	7.2%	-0.9%
2005	-2.2%	-4.6%	-0.8%	-1.5%	-4.3%	0.0%
2006	-5.8%	-9.9%	-3.2%	-4.8%	-10.4%	-1.8%
2007	-9.0%	-15.3%	-4.6%	-7.2%	-15.3%	-2.4%
2008	0.0%	5.2%	-3.6%	0.7%	4.6%	-1.6%
2009	-5.0%	-5.6%	-4.6%	-4.1%	-6.7%	-2.8%
2010	-3.5%	-3.7%	-3.4%	-2.3%	-3.8%	-1.6%
2011	-1.0%	1.7%	-2.7%	-0.1%	1.5%	-1.0%
2012	0.3%	4.5%	-2.4%	1.1%	4.5%	-0.7%
2013	-6.1%	-8.2%	-4.6%	-4.6%	-8.1%	-2.7%
2014	-3.2%	-3.7%	-2.9%	-2.1%	-3.5%	-1.4%
2015	3.6%	15.4%	-3.3%	3.9%	15.3%	-1.6%
2003-2015	**-2.31%**	**-1.11%**	**-3.03%**	**-1.45%**	**-1.25%**	**-1.49%**
2003-2010	**-2.97%**	**-3.00%**	**-2.93%**	**-2.12%**	**-3.25%**	**-1.51%**
2011-2015	**-1.26%**	**1.93%**	**-3.20%**	**-0.36%**	**1.95%**	**-1.47%**

Productivity with PSE Safety Adjustments

	PEG Upgrade + Safety			PSE Methodology		
Year	**TFP**	**OM&A**	**Capital**	**TFP**	**OM&A**	**Capital**
2002						
2003	0.1%	2.8%	-1.6%	0.4%	2.7%	-1.0%
2004	1.5%	7.0%	-1.6%	1.9%	7.2%	-0.9%
2005	-2.2%	-4.6%	-0.8%	-1.5%	-4.3%	0.0%
2006	-5.8%	-9.9%	-3.2%	-4.8%	-10.4%	-1.8%
2007	-8.7%	-15.1%	-4.4%	-7.0%	-15.1%	-2.2%
2008	-0.1%	5.0%	-3.7%	0.6%	4.5%	-1.7%
2009	-5.0%	-5.6%	-4.6%	-4.2%	-6.7%	-2.8%
2010	-2.9%	-3.1%	-2.8%	-1.7%	-3.1%	-1.0%
2011	-0.3%	2.4%	-2.0%	0.6%	2.2%	-0.2%
2012	2.0%	6.2%	-0.8%	2.8%	6.2%	1.0%
2013	-6.0%	-8.1%	-4.5%	-4.5%	-8.0%	-2.6%
2014	-1.5%	-2.0%	-1.2%	-0.4%	-1.8%	0.3%
2015	4.2%	16.0%	-2.7%	4.5%	15.9%	-1.0%
2003-2015	**-1.89%**	**-0.69%**	**-2.61%**	**-1.03%**	**-0.83%**	**-1.08%**
2003-2010	**-2.88%**	**-2.92%**	**-2.84%**	**-2.04%**	**-3.16%**	**-1.43%**
2011-2015	**-0.31%**	**2.88%**	**-2.25%**	**0.59%**	**2.90%**	**-0.52%**

Productivity with PSE Reliability Adjustments

	PEG Upgrade + Reliability			PSE Methodology		
Year	**TFP**	**OM&A**	**Capital**	**TFP**	**OM&A**	**Capital**
2002						
2003	0.1%	2.8%	-1.6%	0.4%	2.7%	-1.0%
2004	1.5%	7.0%	-1.6%	1.9%	7.2%	-0.9%
2005	-0.8%	-3.2%	0.6%	-0.1%	-2.9%	1.4%
2006	-4.1%	-8.3%	-1.6%	-3.2%	-8.7%	-0.2%
2007	-10.3%	-16.6%	-5.9%	-8.5%	-16.7%	-3.8%
2008	0.3%	5.4%	-3.3%	1.0%	4.9%	-1.3%
2009	-5.2%	-5.8%	-4.8%	-4.4%	-6.9%	-3.0%
2010	-3.5%	-3.7%	-3.3%	-2.3%	-3.7%	-1.5%
2011	-0.4%	2.3%	-2.2%	0.5%	2.1%	-0.4%
2012	0.2%	4.4%	-2.5%	1.0%	4.4%	-0.8%
2013	-5.9%	-8.0%	-4.4%	-4.4%	-7.9%	-2.5%
2014	-3.7%	-4.2%	-3.4%	-2.6%	-4.0%	-1.9%
2015	2.8%	14.5%	-4.1%	3.1%	14.5%	-2.4%
2003-2015	**-2.22%**	**-1.02%**	**-2.94%**	**-1.36%**	**-1.16%**	**-1.41%**
2003-2010	**-2.74%**	**-2.78%**	**-2.70%**	**-1.90%**	**-3.02%**	**-1.29%**
2011-2015	**-1.39%**	**1.80%**	**-3.33%**	**-0.49%**	**1.83%**	**-1.59%**

Productivity with PSE Safety and Reliability Adjustments

	PEG Upgrade + Safety and			PSE Methodology		
Year	**TFP**	**OM&A**	**Capital**	**TFP**	**OM&A**	**Capital**
2002						
2003	0.1%	2.8%	-1.6%	0.4%	2.7%	-1.0%
2004	1.5%	7.0%	-1.6%	1.9%	7.2%	-0.9%
2005	-0.8%	-3.2%	0.6%	-0.1%	-2.9%	1.4%
2006	-4.1%	-8.3%	-1.6%	-3.2%	-8.7%	-0.2%
2007	-10.1%	-16.4%	-5.7%	-8.3%	-16.5%	-3.6%
2008	0.2%	5.3%	-3.4%	0.9%	4.8%	-1.4%
2009	-5.2%	-5.8%	-4.8%	-4.4%	-6.9%	-3.0%
2010	-2.9%	-3.1%	-2.7%	-1.7%	-3.1%	-0.9%
2011	0.3%	3.0%	-1.4%	1.2%	2.8%	0.4%
2012	1.9%	6.1%	-0.8%	2.7%	6.1%	0.9%
2013	-5.8%	-8.0%	-4.4%	-4.3%	-7.8%	-2.5%
2014	-2.0%	-2.5%	-1.7%	-0.9%	-2.3%	-0.2%
2015	3.4%	15.1%	-3.5%	3.7%	15.1%	-1.8%
2003-2015	**-1.81%**	**-0.60%**	**-2.52%**	**-0.94%**	**-0.74%**	**-0.99%**
2003-2010	**-2.66%**	**-2.70%**	**-2.62%**	**-1.82%**	**-2.94%**	**-1.20%**
2011-2015	**-0.44%**	**2.75%**	**-2.38%**	**0.46%**	**2.77%**	**-0.64%**

HYDRO ONE NETWORKS IR #21

21. Reference: Exhibit M1, page 21

In a separate table (or in a new column in Table 2), please add the PEG-calculated customer-only output index adjustment in Table 1 to the PEG-calculated TFP and PSE-calculated TFP for Hydro One found in Table 2. How does adding the customer-only index impact Hydro One's productivity results?

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

Please see Table HONI-21 below for the requested calculations.

Table HONI-21

Alternative Productivity Results for Hydro One: Output = Customers

	Input Quantity (PEG Upgrade)			Output	Productivity					
					PEG Upgrade			PSE Methodology		
Year	Summary	OM&A	Capital	Quantity[fn]	TFP	OM&A	Capital	TFP	OM&A	Capital
2003	1.5%	-1.2%	3.2%	1.4%	-0.1%	2.6%	-1.8%	0.1%	2.4%	-1.2%
2004	-0.8%	-6.3%	2.4%	1.0%	1.8%	7.3%	-1.3%	2.2%	7.5%	-0.6%
2005	3.4%	5.8%	2.0%	1.1%	-2.3%	-4.7%	-0.9%	-1.6%	-4.4%	-0.1%
2006	6.1%	10.2%	3.6%	1.0%	-5.1%	-9.2%	-2.5%	-4.1%	-9.7%	-1.1%
2007	9.9%	16.2%	5.6%	0.8%	-9.1%	-15.4%	-4.7%	-7.4%	-15.5%	-2.6%
2008	0.6%	-4.6%	4.2%	1.2%	0.6%	5.7%	-3.0%	1.3%	5.2%	-1.0%
2009	5.0%	5.6%	4.6%	0.5%	-4.4%	-5.0%	-4.0%	-3.6%	-6.2%	-2.3%
2010	4.0%	4.2%	3.8%	0.8%	-3.2%	-3.4%	-3.0%	-2.0%	-3.4%	-1.3%
2011	1.4%	-1.2%	3.2%	0.6%	-0.8%	1.9%	-2.6%	0.1%	1.7%	-0.8%
2012	0.2%	-4.0%	2.9%	0.8%	0.6%	4.8%	-2.1%	1.4%	4.9%	-0.3%
2013	6.3%	8.4%	4.8%	-0.1%	-6.3%	-8.5%	-4.9%	-4.8%	-8.4%	-3.0%
2014	3.2%	3.7%	2.9%	0.0%	-3.2%	-3.7%	-2.9%	-2.1%	-3.5%	-1.4%
2015	-2.9%	-14.6%	4.0%	1.5%	4.4%	16.1%	-2.6%	4.6%	16.1%	-0.9%
2003-2015	**2.9%**	**1.7%**	**3.6%**	**0.8%**	**-2.09%**	**-0.88%**	**-2.81%**	**-1.22%**	**-1.02%**	**-1.27%**
2003-2010	**3.7%**	**3.7%**	**3.7%**	**1.0%**	**-2.72%**	**-2.76%**	**-2.68%**	**-1.88%**	**-3.00%**	**-1.27%**
2011-2015	**1.6%**	**-1.6%**	**3.6%**	**0.6%**	**-1.07%**	**2.12%**	**-3.00%**	**-0.17%**	**2.15%**	**-1.27%**

[fn] The output measure for these calculations was the growth in the number of Hydro One customers.

HYDRO ONE NETWORKS IR #22

22. Reference: Exhibit M1, page 11

a. Has PEG used Handy-Whitman indexes for productivity or benchmarking studies in the past?
b. If so, approximately how many studies in the past ten years have used the Handy-Whitman indexes?
c. If so, please provide copies of the studies.

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

a. Yes. PEG has used Handy-Whitman utility construction cost indexes ("HWIs") in all of their productivity and benchmarking studies that consider the capital cost performance of U.S. utilities. Due to growing concerns about their accuracy, however, PEG made an adjustment to the HWIs for gas utility construction in their recent research and testimony for the OEB in the ongoing Amalco (Enbridge Gas Distribution/Union Gas) proceeding (EB-2017-0306/EB-2017-0307).

   In productivity and benchmarking studies of Canadian *electric* utilities, PEG personnel have typically used the Statistics Canada Electric Utility Construction Price Index ("EUCPI") for distribution systems. In productivity and benchmarking studies of Canadian *gas* utilities, PEG personnel used HWIs until Dr. Melvin Fuss, a distinguished Toronto economist and consultant for Union Gas, suggested use of implicit capital stock deflators in a 2007 OEB proceeding. Mr. Fenrick, then an employee of PEG, was a listed author of our final report.

b. With numerous other information requests that must be answered, PEG has not undertaken this calculation, which is time consuming to undertake given the large number of studies that must be reviewed

c. PEG does not believe this request is reasonable. They have acknowledged the use of HWIs in all US studies and carefully documented the asset price deflators used in Canadian studies in response to HONI-23. Answering the question would only shed light on the mix of US and Canadian studies we do.

HYDRO ONE NETWORKS IR #23

23. Reference: Exhibit M1, page 11

Please provide a list of all North American productivity or benchmarking studies conducted by PEG and include the asset price inflation measure used by PEG for each.

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

PEG lists productivity and benchmarking studies of Canadian utilities which are in the public domain and the asset prices used in Table HONI-23. It can be seen that PEG has typically not used Handy Whitman indexes in its recent productivity and benchmarking studies of Canadian utilities.

Table HONI-23

PEG's North American Transnational and Canadian Productivity Trend and Cost Benchmarking Studies [1,2]

Year	Project/Client	Lead Author	Type of Study	Gas or Electric?	Asset Price Deflator
2003	Enbridge Gas Distribution	Lowry	Benchmarking	Gas	HWIs for US and Canadian companies
2004	Enbridge Gas Distribution	Lowry	Benchmarking	Gas	HWIs for US and Canadian companies
2007	Ontario Energy Board	Lowry	TFP trend	Gas	**US**: HWIs **Canada**: Statistics Canada implicit price index of capital stock for natural gas distribution, water, and other systems
2008	Ontario Energy Board - Benchmarking	Lowry	Benchmarking	Electric	Not applicable, study only applied to OM&A expenses
2008	Ontario Energy Board -IRM3	Kaufmann	TFP trend	Electric	**Canada**: Statistics Canada implicit price index of capital stock for natural gas distribution, water, and other systems **US**: HWIs
2011	Gaz Metro (Task Force)	Lowry	TFP trend	Gas	**Canada**: Statistics Canada implicit price index of capital stock for natural gas distribution, water, and other systems **US**: HWIs
2011	Ontario Energy Board - IR Assessment	Kaufmann	TFP trend	Gas	**Canada**: Statistics Canada implicit price index of capital stock for natural gas distribution, water, and other systems **US**: HWIs
2012	Gaz Metro	Lowry	TFP trend	Gas	**Canada**: Statistics Canada implicit price index of capital stock for natural gas distribution, water, and other systems **US**: HWIs
2013	Ontario Energy Board - 4th GIRM	Kaufmann	Benchmarking & TFP trend	Electric	Statistics Canada EUCPI for distribution systems
2013	Consumers' Coalition of Alberta	Lowry	O&M PFP trend	Electric & Gas	Not applicable, study only applied to OM&A expenses
2014	Oshawa PUC Networks	Lowry	Benchmarking & TFP trend	Electric	**Historic**: Statistics Canada EUCPI for distribution systems **Forecast**: Conference Board of Canada's forecast of Implicit Price Index - Gross Fixed Capital Formation, Engineering Structures, Electric Power Generation, Transmission and Distribution (Canada).
2015	Ontario Energy Board - Toronto Hydro Custom IR Application	Kaufmann	Benchmarking	Electric	**US**: HWIs **Canada**: EUCPI
2016	Ontario Energy Board -OPG IR Application	Lowry	TFP trend	Hydroelectric generation	**US**: HWIs **Canada**: HWIs for hydroelectric generation in the North Central US, adjusted for the difference between US and Canadian inflation
2018	Ontario Energy Board - Amalco Price Cap IR Application	Lowry	TFP trend	Gas	**Canada**: Statistics Canada implicit capital stock deflator for the utility sector, **US**: HWIs
2018	Utilities Consumer Advocate of Alberta	Lowry	Benchmarking & TFP trend	Electric	**Canada**: Statistics Canada implicit capital stock deflator for the utility sector, **US**: HWIs
2018	Ontario Energy Board - Hydro One Networks Custom IR Application	Lowry	Benchmarking & TFP trend	Electric	**Canada**: Statistics Canada implicit capital stock deflator for the utility sector, **US**: HWIs

[1] PEG believes that there are numerous benchmarking and productivity trend studies of US utilities that featured the Handy Whitman index as the asset price deflator. Due to time constraints, those studies are not included on this table.

[2] The table excludes projects where data from North American utilities were used in productivity and benchmarking studies for clients that are outside North America.

HYDRO ONE NETWORKS IR #24

24. Reference: Exhibit M1, page 18

Please update Table 1 that provides the Ontario TFP trend estimates for the more recent 2011 to 2015 period.

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

The requested results are provided in Table HONI-24 below.

Table HONI-24

Analysis of PSE's Ontario Productivity Study

	OM&A		Capital		TFP	
	Incremental Impact	Revised Trend	Incremental Impact	Revised Trend	Incremental Impact	Revised Trend
PSE Productivity Trend (2011-2015)		-3.58%		-2.59%		-2.96%
Adjustments and Corrections						
Data Comparability Issues						
CIAC	na	-3.58%	0.43%	-2.16%	0.25%	-2.71%
Smart Meter OM&A	0.55%	-3.03%	na	-2.16%	0.23%	-2.48%
Smart Meter Capital	na	-3.03%	0.22%	-1.94%	0.13%	-2.36%
Transition to IFRS Accounting Changes	2.13%	-0.90%	na	-1.94%	0.90%	-1.46%
Sample and Merger Issues	0.02%	-0.89%	0.02%	-1.93%	0.02%	-1.44%
Exclude Norfolk	0.00%	-0.90%	0.00%	-1.94%	0.00%	-1.46%
Include Lakeland/Parry	0.02%	-0.89%	0.02%	-1.93%	0.02%	-1.44%
Total Impact of Adjustments and Corrections [A]	**2.70%**	**-0.89%**	**0.66%**	**-1.93%**	**1.52%**	**-1.44%**
Methodological Upgrades						
Labor Price Index [B]	-0.03%	-0.92%	na	-1.93%	-0.02%	-1.45%
Asset Price Index: Replace EUCPI	na	-0.92%	0.36%	-1.56%	0.17%	-1.29%
Use Utility Sector Capital Stock Deflator [D]	na	-0.92%	0.36%	-1.56%	0.17%	-1.29%
Use Northeast HW index adjusted for PPP	na	-0.92%	1.85%	-0.07%	1.12%	-0.34%
Output Quantity Adjustment	0.37%	-0.55%	0.37%	-1.19%	0.37%	-0.92%
Conservation adjustments to volumes and peaks	1.29%	0.37%	1.29%	-0.28%	1.29%	0.00%
Customer only index [C]	0.37%	-0.55%	0.37%	-1.19%	0.37%	-0.92%
Total Impact of Proposed Upgrades [E]=[B+C+D]	**0.34%**		**0.73%**		**0.52%**	
Total Impact of All Adjustments and Upgrades [A+E]	**3.03%**	**-0.55%**	**1.40%**	**-1.19%**	**2.05%**	**-0.92%**

HYDRO ONE NETWORKS IR #25

25. Reference: Exhibit M1, page 14

On page 11 of the report, Dr. Lowry states: "Under Canadian GAAP, distributors were permitted to capitalize more costs than are permitted under IFRS." Please provide and describe the evidence used as the basis for this statement.

a. If it is assumed that the move to IFRS caused less capitalization of costs, would PEG expect lower capital costs under IFRS compared to the hypothetical where Canadian GAAP had remained in place?

b. If so, what effect on the Ontario industry TFP trend would this lower capitalization likely have had?

   i. If this cannot be exactly quantified, what general direction would lower capitalization have on the industry TFP trend?
   ii. Would lower capitalization of costs move capital costs in the opposite direction of the OM&A IFRS adjustment suggested by PEG in Table 1?

Response to HONI-25: The following response was provided by PEG.

a. Yes.

b.

   i. Capex should fall, slowing capital quantity growth and accelerating TFP growth. However, this is unlikely to offset the effect on TFP growth of higher OM&A expenses in the shorter term. The reason is that the percentage impact on the capital quantity is far smaller than the percentage impact on the OM&A quantity. PEG undertook econometric work that showed a statistically significant impact of IFRS transition on O&M cost but not on capital cost which was consistent with the above logic.

      The rationale for not doing the capital adjustment in this proceeding is the low expected impact and that the O&M adjustment was only attempted to estimate the one-time impact of the transition as opposed to imputing all future values without IFRS. In addition, a proper adjustment to capital would have been more difficult because timing matters more for capital than O&M.

   ii. Yes.

HYDRO ONE NETWORKS IR #26

26. Reference: Exhibit M1, page 18

On pp. 9 and 10, the PEG report states, "We found that HWIs and EUCPIs both have drawbacks. Both were designed many years ago and have some cost-share weights and inflation subindexes that are now quite dated." Please provide any data or documentation for this claim, regarding both the HWI and EUCPI cost-share weights and inflation subindexes. Please further describe why these are now dated.

Response to HONI-26: The following response was provided by PEG.

Please see our response to HONI-14.

HYDRO ONE NETWORKS IR #27

27. Reference: Exhibit M1, page 15

On p. 12, PEG states: "PSE found that the addition of reliability and safety variables to the scale index accelerated the estimated TFP trend of Hydro One over the full sample period by a substantial 90 basis points. We believe that system capabilities that depend on smart grid facilities (e.g., the quality of metering and the ability of distribution systems to handle 2-way power flows) are also legitimate candidates for inclusion in an elasticity-weighted output index."

a. Does PEG believe that the reliability and safety adjustments made by PSE are legitimate candidates for inclusion in an elasticity-weighted output index?

b. Do the PSE adjustments for reliability and safety provide a more complete portrayal of cost efficiency trends than the unadjusted TFP trends without those adjustments?

Response to HONI-27: The following response was provided by PEG.

a. Please see our response to HONI-11
b. Please see our response to HONI-11.

HYDRO ONE NETWORKS IR #28

28. Reference: Exhibit M1, page 17

On p. 14 of the report, PEG states: "If not now, it will soon be time to incorporate the full cost of AMI into calculations of the productivity trends of Ontario power distributors. This complicated exercise is beyond the scope of this project." PSE appreciates this is a complicated issue and beyond the scope of this project. If a customer-only output index were used, (or an elasticity-weighted output index that did not incorporate the potential benefits of AMI), would incorporating the full cost of AMI since 2007 for the Ontario industry into the TFP calculation likely increase or decrease the calculated Ontario TFP estimate?

Response to HONI-28: The following response was provided by PEG.

The estimated TFP growth trend would likely be slower if the full cost of AMI were included but the benefits were not. The net impact would depend in part on the capital cost specification. Neither the geometric decay nor the COS specifications that PEG has used in its TFP research remove the remaining capital cost of older meters when they are replaced.

HYDRO ONE NETWORKS IR #29

29. Reference: Exhibit M1, Page 17

Please provide the source and any calculations of the contributions in aid of construction (CIAC) that were removed from the cost data by PEG in 2013-2015 for the Ontario industry.

Response to HONI-29: The following response was provided by PEG.

Please see the working papers provided in response to HONI-9.

HYDRO ONE NETWORKS IR #30

30. Reference: Exhibit M1, Page 17

Please provide the source and any calculations of the smart meter OM&A and capital costs that were removed from the cost data by PEG in 2013-2015 for the Ontario industry.

Response to HONI-30: The following response was provided by PEG.

Please see the working papers provided in response to HONI-9.

HYDRO ONE NETWORKS IR #31

31. Reference: Exhibit M1, Page 17

Did the removal of smart meter expenses that PEG conducted for the Ontario TFP trend include the removal of meter reading expenses?

Response to HONI-31: The following response was provided by PEG.

No.

HYDRO ONE NETWORKS IR #32

32. Reference: Exhibit M1, Page 17

Does PEG believe there is an inconsistency in the cost definition in the TFP research when the start year of 2002 contains all metering costs, but subsequent years have a large portion of metering costs subtracted?

Response to HONI-32: The following response was provided by PEG.

Yes. However, the output of the AMI is also excluded, and the AMI depreciate at a brisk pace.

HYDRO ONE NETWORKS IR #33

33. Reference: Exhibit M1, Page 20

On page 17 of the report, in discussing the Ontario TFP estimate PEG states: "This leaves us at -0.25%. This is our best current estimate of the cost efficiency trend of Ontario power distributors. However, other drivers of cost such as reliability, safety, and metering capabilities are excluded from the analysis."

a. Does the -0.25% estimate of Ontario TFP imply that, according to PEG's best estimate, there is already a 0.25% implicit stretch factor when a 0.0% productivity factor is used?

b. We note PEG is stating that other outputs could be incorporated into the TFP analysis in the future. Please answer the following questions on a general basis; we understand that more research would be necessary for you to answer on a more specific basis.

   i. For a price cap plan, what would PEG's suggested output index consist of?
   ii. For a revenue cap plan, what would PEG's suggested output index consist of?
   iii. In measuring the trend in distributor performance, what would PEG's suggested output index consist of?

Response to HONI-33: The following response was provided by PEG.

a. Yes. However, PEG does not believe that its research in this proceeding to update the productivity trends of Ontario power distributors was sufficiently advanced to conclude that there is really a 0.25% implicit stretch factor. PEG's recent study of U.S. power distributor TFP for Berkeley Lab found a 0.23% trend over a similar 2001-2014 sample period.

b.
   i. When productivity research is used to calibrate the X factor of a price cap index, the output index is typically a revenue-weighted average of growth in billing determinants.
   ii. When calibrating the X factor of a revenue cap index, the output measure should be consistent with any growth term that is utilized in the revenue escalation formula. The growth escalator should reflect trends in important cost drivers but will typically not include usage variables.
   iii. In measuring the trend in distributor cost performance, the output index should be elasticity-weighted and include a wide range of pertinent output variables.

HYDRO ONE NETWORKS IR #34

34. Reference: Exhibit M1, Page 21

Please confirm that Table 2 found on page 18 of the PEG report does not include the PSE-adjusted TFP estimates that incorporated reliability and safety into the output index.

Response to HONI-34: The following response was provided by PEG.

Dr. Lowry confirms this exclusion.

HYDRO ONE NETWORKS IR #35

35. Reference: Exhibit M1, Page 22

On p. 19, PEG mentions that OM&A expenses, capital costs, and capital expenditures ("capex") were not separately benchmarked by PSE.

a. Please confirm these categories were not separately benchmarked in the 4th Generation IR benchmarking conducted by PEG. Also please confirm that in the 4th Generation IR benchmarking, only total cost was benchmarked and used as the basis for determining the stretch factor.

b. How would PEG envision using the component OM&A, capital, and capex benchmarking models in the framework of an incentive regulation plan?

c. Did PEG estimate and put together these component models and results for Hydro One? If so, please provide the models and results.

Response to HONI-35: The following response was provided by PEG.

a. Dr. Lowry confirms these statements. However, the OEB has begun a project on activity and program benchmarking ("APB") of power distributor cost.

b. The ultimate use of APB has not been fully considered, but APB is certainly pertinent in the periodic rate applications of distributors.

c. PEG did obtain benchmarking results for the OM&A expenses, capex, capital cost, and total cost of Hydro One in a recent project for Alberta's Utilities Consumer Advocate. However, the client has not permitted us to share the results.

HYDRO ONE NETWORKS IR #36

36. Reference: Exhibit M1, Page 22

On p. 19, PEG states: "PSE's benchmarking results are improved by an optimistic forecast of Hydro One's OM&A expenses. These expenses appear to have been forecasted using an inflation – 0.45% formula that includes no growth factor."

In its application, on page 19 of Exhibit A, Tab 3, Schedule 1, Hydro One states that "Hydro One is focused on delivering service expected by customers while managing costs and improving operational efficiencies, all within the revenue requirement envelope set by the Custom IR approach."

a. Please confirm that the inflation – 0.45% formula corresponds with Hydro One's proposal for the OM&A escalator formula during the CIR years.

b. Please confirm that Hydro One is not proposing the inclusion of a growth factor that would escalate allowed OM&A higher than the inflation – 0.45% formula.

c. Why is it "optimistic" for PSE to assume Hydro One's OM&A will follow its proposed escalation of OM&A expenses (if allowed)?

d. Does PEG believe OM&A expenses should be allowed to escalate more rapidly than Hydro One has proposed?

e. Please explain why PEG believes the OM&A envelope set by the Custom IR represents "an optimistic forecast" rather than a conscious decision and commitment to finding operational efficiencies.

f. Please explain the incentive a utility would have to lock itself into a 5 year rate structure that underfunds its operating expenses?

Response to HONI-36: The following response was provided by PEG.

a. Dr. Lowry confirms this statement.

b. Dr. Lowry confirms this statement.

c. Dr. Lowry cannot know the full reasons that HONI did not include a growth factor in its revenue cap index, but believes that the Company did not necessarily propose this index because it did the best job of tracking its OM&A expenses.

d. Dr. Lowry believes that it is reasonable to include a growth factor in the RCI if productivity studies used to calibrate the X factor use a consistent output specification. The supplemental revenue may also be offset by a C factor dead band.

e. Dr. Lowry notes only that HONI was incented to understate required growth in its OM&A expenses in PSE's benchmarking study because this could lower its stretch factor. PSE did not have to use the RCI formula in its forecast.

f. Under the proposed plan, Hydro One would be fully compensated for the extent to which its proposed capital cost exceeded its capital revenue. Hence, the proposal to operate under a revenue cap index lacking a scale escalator affected only its OM&A revenue growth. Dr. Lowry has done IRM projects for many utilities and believes that they are often not very good at forecasting their OM&A cost growth.

HYDRO ONE NETWORKS IR #37

37. Reference: Exhibit M1, Page 23

On p. 20, PEG states: "The service territory estimate for Hydro One exceeds the entire land area of Ontario."

a. Please confirm that the PSE estimate does not exceed the total land plus water area of Ontario.

b. Hydro One notes that its assets include submarine (i.e. under-water) cables to provide service to remote locations such as islands. Given that fact and given the approach taken by PSE in their analysis, please confirm that it is reasonable for Hydro One's service territory estimate to exceed the entire land area of Ontario as assets are located in water, as well as on land.

Response to HONI-37: The following response was provided by PEG.

a. This statement is confirmed.

b. The aggregate area of the service territories reported by the other power distributors in Ontario is around 30,000 sq. kilometers. The land area of Ontario is 917,741 sq. kilometers. If the estimates of the other distributors are correct, the residual land area served by HONI is at most approximately 887,000 sq. kilometers. As a former canoe camper in the Georgian Bay region, Dr. Lowry has had some exposure to the challenges of distributing power in rural Ontario, where islands dot many lakes. However, he doubts that the submarine cables required to provide service to islands on Ontario lakes are sufficient to explain why it lays claim to a service territory exceeding the total land area of the province. Dr. Lowry is also concerned that in many remote areas of Ontario, HONI is not now and may never provide distribution service.

HYDRO ONE NETWORKS IR #38

38. Reference: Exhibit M1, Page 23

PSE notes PEG's preference for using line miles per customer, rather than the land area. However, there can be substantial differences in reported line miles, depending on whether the reported line miles are (1) primary-only, or (2) primary + secondary.

a. Is PEG concerned about possible inconsistent reporting by utilities with regard to primary versus secondary miles?

b. Has any attempt been made to correct for these potential inconsistencies?

c. Does PEG know whether the other utilities in the sample are only reporting primary miles and not adding in secondary miles?

d. If some utilities are reporting primary + secondary line miles, and others are reporting only primary line miles, would this likely have the effect of unfairly harming the results of those utilities reporting only primary miles?

Response to HONI-38: The following response was provided by PEG.

a. The line length data PEG used to construct this variable were gathered by the Utility Data Institute ("UDI"). UDI requests distribution overhead pole miles. It explains that

> A pole mile is one mile of overhead (OH) line structures, regardless of how many circuits or conductors are supported by those structures. One mile of poles, whether carrying two 3-phase circuits or a single-phase conductor, constitutes a pole mile.[3]

In requesting total distribution miles, UDI explains that

> Distr (TOTAL) Miles: Sum of (OH) and (UG) miles. Distribution voltages have been classified into the four most commonly used voltage classes (5, 15, 25, and 35 kV). Voltages falling between classifications have been placed in the higher grouping.[4]

These instructions are not crystal clear but seem to request miles of *primary* lines. Furthermore, pole spans carrying secondary lines would not be double counted.

b. PEG did not endeavor to control for this complication.

c. PEG does not know whether other utilities added miles of structures carrying only secondary

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[3] *Directory of Electric Power Producers and Distributors 2000*, 108th Edition, New York: McGraw-Hill Companies, 1999, p. ix.
[4] *Ibid*.

lines.

d. Dr. Lowry confirms this statement.

HYDRO ONE NETWORKS IR #39

39. Reference: Exhibit M1, Page 23

Please provide the report mentioned in footnote 25.

Response to HONI-39: The following response was provided by PEG.

This report was only finalized in February of this year and is still confidential. See also HONI-35 c).

HYDRO ONE NETWORKS IR #40

40. Reference: Exhibit M1, Page 26

PEG notes on p26 of the evidence: "PSE uses peak demand data as a variable in the cost model. Available US data overstate distribution peak demand, since they can include the demand of a utility's wholesale customers. PSE did not adjust these data to make them more accurate. This made the performances of US distributors look better than they actually were."

a. Please confirm that this overstatement of peak demand by US distributors likely harmed Hydro One's benchmarking performance, as calculated by PSE.

b. Please estimate the percentage of wholesale demand by customers in the reported peak demands used by PSE.

c. What adjustment would PEG suggest be made so peak demands are more accurate?

d. Does PEG believe peak demands are an important cost driver for electric distribution?

Response to HONI-40: The following response was provided by PEG.

a. Dr. Lowry confirms this statement but notes that the impact was diluted by the inclusion of REC data in PEG's sample.
b. PEG estimates that the percentage of wholesale demand in the reported peak demands of investor-owned utilities on PSE's sample averaged 5% over the full sample period.
c. PEG estimated distribution peak demands by adjusting the peak demands reported on the FERC Form 1. The Form 1 reported peaks are consistent with the demand generated by company's end use customers plus requirement sales for resale. The latter are firm commitments. The adjustment is to multiply the peak demand by the ratio of end use MWh to the sum of end use deliveries and requirement sales for resale.
d. PEG believes that the expected aggregate coincidental peak demand of local distribution networks is an important driver of power distributor cost. However, in econometric studies, the available peak demand variable is not the expected aggregate coincidental peak demand of local networks and is typically found to be a much less important cost driver than other scale variables, such as the number of customers served.

HYDRO ONE NETWORKS IR #41

41. Reference: Exhibit M1, Page 26

On p. 23 of its report, PEG took issue with PSE applying the same 70/30 weights for labor and materials that were used as the assumption in 4th Generation IR, rather than applying weights directly derived from the US data.

a. Does PEG believe that the direct salaries reported by US utilities incorporate all labor-driven OM&A costs of the utilities?

b. Are there adjustments for outsourcing by PEG that likely take place, but are not reported as direct salaries?

Response to HONI-41: The following response was provided by PEG.

a. Dr. Lowry notes that the costs of the materials and services that utilities purchase have varied labor contents. In some cases the labor content is quite high.

b. PEG does not make adjustments for outsourcing in its cost research. In this study, it used the gross domestic product price index ("GDPPI") to measure the trend in prices of materials and services that utilities use. The GDPPI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services. Since the economy is much more labor-intensive than the utility industry, this index is quite sensitive to trends in labor prices. For example, the slow growth in the GDPPI that has been typical in the years since 2007 has coincided with slow growth in salaries and wages.

HYDRO ONE NETWORKS IR #42

42. Reference: Exhibit M1, Page 26

a. Please provide the source and data for the labor price levelization for Hydro One used by PEG in their total cost benchmarking model.
b. What alternative levelization procedure should PSE have used for Hydro One, in PEG's opinion?

Response to HONI-42: The following response was provided by PEG.

a. Please see the working papers provided in Attachment HONI-9 for details of PEG's labor price levelization for Hydro One. It can be seen that PEG did not attempt to improve upon the levelization done by PSE. We were not authorized by OEB staff to prepare a fully independent benchmarking study.

b. Had PEG attempted an upgrade, they would start by examining local wage levels for areas HONI actually serves and compare this to Ontario as a whole. This ratio would be applied to the result of an Ontario vs. US levelization.

HYDRO ONE NETWORKS IR #43

43. Reference: Exhibit M1, Page 26

PEG states that PSE handled the logarithm of business condition variables inconsistently.

a. What did PEG do differently than PSE when PEG handled these variables (e.g., extreme weather and percent of territory that is artificial surfaces) in PEG's model reported in Table 4?

b. Please describe why PEG's approach is better than how PSE handled the variables.

Response to HONI-43: The following response was provided by PEG.

a. Variables that were included in both models were treated the same. PEG took the natural logarithm of all of the variables it added to its model.

b. As a general principle, taking the log of business condition variables wherever practicable increases transparency and objectivity and facilitates comparisons of their effect on costs.

HYDRO ONE NETWORKS IR #44

44. Reference: Exhibit M1, Page 27

On p. 24 of the report, PEG seems to imply that it estimated separate econometric benchmarking models for OM&A expenses, capital cost, capital expenditures, and total cost.

a. Please confirm a separate model was used

b. Please provide the an electronic copy of the models

c. Why were these models not reported in the PEG report?

d. Why would these models provide an advantage when determining the stretch factor over a total-cost-only model?

Response to HONI-44: The following response was provided by PEG.

a. PEG developed separate models for OM&A expenses, capital cost, capex, and total cost in its recent study for Alberta's Utilities Consumer Advocate. OEB staff did not authorize PEG to perform a separate benchmarking study in this proceeding. PEG discusses its work for the UCA in its pre-flied evidence only to inform the OEB that more granular benchmarking results are quite feasible.

b. Working papers for this confidential study for another client cannot be provided. See HONI-35 c).

c. Our study for the UCA is still confidential. See HONI-35 c)

d. Dr. Lowry has not considered the advantages of granular benchmarking in determining a stretch factor. However, he believes that such models will aid the OEB in understanding strengths and weaknesses in a utility's cost performance in rate applications.

HYDRO ONE NETWORKS IR #45

45. Reference: Exhibit M1, Page 27

Please list the utilities excluded by PEG due to large reported transmission/distribution cost transfers.

a. What criteria did PEG use to define "large" and thus exclude these utilities?

b. How did PEG determine these criteria and on what basis?

Response to HONI-45: The following response was provided by PEG.

a. The full list of companies that PEG excluded for transfers and adjustments is as follows:

- Black Hills Power
- Commonwealth Edison
- Consumers Energy
- MidAmerican Energy
- Northern Indiana Public Service
- PPL Electric
- Public Service of New Hampshire
- Puget Sound Energy
- Sierra Pacific Power

The criteria for exclusion was a ratio of cumulative distribution transfers and adjustments to total distribution gross plant of greater than 5% in 2011. An additional criteria is that cumulative transmission transfers and adjustments must be of a similar magnitude and opposite sign. This criterion was last reviewed for 2014 data and no modifications to the list were required.

b. PEG regards this criterion as a sensible rule of thumb for addressing a problem that many consultants overlook. T&D transfers complicate capital cost calculations. The modest number of utilities excluded using this rule should not materially reduce model accuracy.

HYDRO ONE NETWORKS IR #46

46. Reference: Exhibit M1, Page 27

Is the capital data dating back to 1964 that was used by PEG publicly available? If so, please provide the source and data.

Response to HONI-46: The following response was provided by PEG.

PEG did not use its own confidential older capital data in its research for the OEB in this proceeding and so the request for these data is irrelevant, unnecessary, and unrelated to the evidence on the record and that the OEB needs to consider for a determination in this application. As such PEG is not prepared to share these data with other parties. Many of these data can be found in a series of federal government publications that had names such as *Financial Statistics of Investor-Owned Electric Utilities*.

HYDRO ONE NETWORKS IR #47

47. Reference: Exhibit M1, Page 28

On Table 3, PEG reports new 4th Generation IR benchmarking results for Hydro One after correcting for revised high voltage data that Hydro One and PSE discovered unfairly advantaged Hydro One in the 4th Generation IR benchmarking research. While small differences are expected from Exhibit A-05-02-01 put forth by Hydro One, the results nearly match in 2014, but then PEG reports much larger drops than those calculated in A-05-02-01. Why is there such a large drop in the reported performance scores from 2014 to 2015 and from 2015 to 2016?

Response to HONI-47: The following response was provided by PEG.

The calculation revises the HV plant addition data for corrections noted by the company in the years 2014 and 2015. The significant lowering of these values causes plant additions net of HV to rise substantially and become more typical of historical norms. Please see the working papers provided in response to HONI-9 for the calculations and revised data.

HYDRO ONE NETWORKS IR #48

48. Reference: Exhibit M1, Page 28

PEG uses a variable described on p. 25 of the report as "an alternative measure of peak demand." This variable is the volume of deliveries per residential customer in 2015.

a. Wouldn't the percent of residential volume (out of total volume) be a better indicator of peak demand and/or load factor? If so, why didn't PEG use this variable instead?

b. Confirm that a variable attempting to provide an alternative measure of peak demand should also include the total volume of the utility?

c. In an extreme example, a utility could have a very high residential use-per-customer, but only have 10% of its volume be residential. Would PEG expect the peak demand of that utility to be high? Would PEG expect a low load factor in the described case? Does PEG believe C&I volumes and total residential volumes are not important factors in realized peak demands?

Response to HONI-48: The following response was provided by PEG.

a. Dr. Lowry used residential volume per customer as a measure of peak demand, for several reasons.

- The pertinent cost driver is the sum of the expected aggregate coincident peak demands of the local distribution networks.
- This depends chiefly on residential and commercial ("R&C") demand because many large industrial customers take delivery of power directly from the transmission system.
- R&C peak demand depends on the number of R&C customers and on peak demand per residential and commercial customer. The number of R&C customers served is roughly equal to the total number of customers.
- Residential and commercial demand have many common drivers which include humidity, extreme heat and cold, and the number of hours in the year without sunlight.
- The number of commercial customers is not reported consistently.
- This variable had high explanatory power in our recent UCA benchmarking study.

PEG re-estimated the cost model detailed in Table 4 using percent of volume that is residential. It did have a considerably higher estimated cost elasticity and t stat than our variable. However, % of volume that is residential and commercial had an even higher estimated cost elasticity and t stat. Tables HONI-48a and 48b contain results of both econometric runs.

b. Not necessarily. Many large volume customers of U.S. electric utilities take power directly from the transmission system. Moreover, these customers tend to have low load factors.

c. Dr. Lowry acknowledges that some distributors have unusually small residential sectors. For utilities like these, residential volume per customer would be a poor indicator of peak load. Industrial load typically matters less than residential and commercial load.

Table HONI-48a

Econometric Model of Total Cost: % Residential and Commercial Volumes

VARIABLE KEY

N = Number of Electric Customers Served
F = Percent Forestation in Service Territory
CSI = Percent Cost Customer Service and Information Expenses
XW = Extreme Weather
Art = Percent of Territory that is Artificial Surfaces
OHMILES = Overhead Structure Miles per Customer
PCTOH = Percentage of Line Plant that is Overhead
PCTRC = Percent of MWH Deliveries to Residential and Commercial Customers
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.929	140.328	0.000
N*N	0.024	5.087	0.000
OHMILES	0.214	22.148	0.000
OHMILES * OHMILES	0.091	4.909	0.000
PCTRC	0.354	13.819	0.000
PCTRC * PCTRC	0.446	4.486	0.000
F	0.135	30.560	0.000
CSI	0.002	0.717	0.473
XW	0.00002	12.792	0.000
Art	1.655	11.054	0.000
PCTOH	-0.111	-6.625	0.000
Trend	0.000	-0.260	0.795
Constant	11.670	1283.102	0.000

Rbar-Squared	0.961
Sample Period	2002-2015
Number of Observations	942

Table HONI-48b

Econometric Model of Total Cost: % Residential Volumes

VARIABLE KEY

N = Number of Electric Customers Served
F = Percent Forestation in Service Territory
CSI = Percent Cost Customer Service and Information Expenses
XW = Extreme Weather
Art = Percent of Territory that is Artificial Surfaces
OHMILES = Overhead Structure Miles per Customer
PCTOH = Percentage of Line Plant that is Overhead
PCTRES = Percent of MWH Deliveries to Residential Customers
Trend = Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
N	0.931	147.183	0.000
N*N	0.027	6.075	0.000
OHMILES	0.220	22.955	0.000
OHMILES * OHMILES	0.046	3.223	0.001
PCTRES	0.216	7.649	0.000
PCTRES * PCTRES	0.132	1.677	0.094
F	0.156	35.986	0.000
CSI	-0.005	-1.626	0.104
XW	0.00002	12.800	0.000
Art	2.542	15.588	0.000
PCTOH	-0.184	-9.957	0.000
Trend	0.000	-0.109	0.913
Constant	11.660	1201.282	0.000

Rbar-Squared	0.958
Sample Period	2002-2015
Number of Observations	942

HYDRO ONE NETWORKS IR #49

49. Reference: Exhibit M1, Page 29

Why does PEG only include overhead line miles in their density variable, rather than total line miles?

Response to HONI-49: The following response was provided by PEG.

UDI, the data source that PEG used for this variable, requests data on underground *circuit* miles that cannot be meaningfully added to overhead *pole* miles. Since the variable is intended as a measure of the geographic dispersion of customers, dividing overhead pole miles by the total number of customers (including those served by undergrounded systems) is reasonable. Values will be unusually low (high) for urban (rural) areas with extensive (little) system undergrounding.

HYDRO ONE NETWORKS IR #50

50. Reference: Exhibit M1, Page 29

In footnote 37, PEG states that they computed line miles per customer for a single year for each sampled utility. Please provide a list detailing which year was used for each utility in the sample. How did PEG determine which year to use for each utility?

Response to HONI-50: The following response was provided by PEG.

The requested list can be found in Table HONI-50. It can be seen that a year around 2004 was used for most utilities. PEG had data for these years and believes that the value of overhead miles per customer is fairly stable for most utilities. The year 2013 was used for HONI.

Table HONI-50

PEG's Overhead Miles Sources

Company	2005 Platts	PSE Data	2002 Platts	1999 Platts	SEC 10-K Filing (Year)	2014 Platts	Customer Number Year
Union Electric	1	0	0	0	0	0	2004
Appalachian Power	1	0	0	0	0	0	2004
Atlantic City Electric	1	0	0	0	0	0	2004
Avista	1	0	0	0	0	0	2004
Baltimore Gas and Electric	1	0	0	0	0	0	2004
Cleco Power	1	0	0	0	0	0	2004
Connecticut Light and Power	1	0	0	0	0	0	2004
Duke Energy Carolinas	1	0	0	0	0	0	2004
El Paso Electric	1	0	0	0	0	0	2004
Empire District Electric	1	0	0	0	0	0	2004
Florida Power & Light	1	0	0	0	0	0	2004
Georgia Power	1	0	0	0	0	0	2004
Green Mountain Power	1	0	0	0	0	0	2004
Gulf Power	1	0	0	0	0	0	2004
Idaho Power	1	0	0	0	0	0	2004
Indiana Michigan Power	1	0	0	0	0	0	2004
Indianapolis Power & Light	1	0	0	0	0	0	2004
Kansas City Power & Light	1	0	0	0	0	0	2004
Kentucky Power	1	0	0	0	0	0	2004
Kentucky Utilities	1	0	0	0	0	0	2004
Kingsport Power	1	0	0	0	0	0	2004
Louisville Gas and Electric	1	0	0	0	0	0	2004
ALLETE (Minnesota Power)	1	0	0	0	0	0	2004
Mississippi Power	1	0	0	0	0	0	2004
Nevada Power	1	0	0	0	0	0	2004
New York State Electric & Gas	1	0	0	0	0	0	2004
Ohio Power	1	0	0	0	0	0	2004
Oklahoma Gas and Electric	1	0	0	0	0	0	2004
Orange and Rockland Utilities	1	0	0	0	0	0	2004
Pacific Gas and Electric	1	0	0	0	0	0	2004
PECO Energy	1	0	0	0	0	0	2004
Portland General Electric	1	0	0	0	0	0	2004
Potomac Electric Power	1	0	0	0	0	0	2004
Public Service Company of Oklahoma	1	0	0	0	0	0	2004
Public Service Electric and Gas	1	0	0	0	0	0	2004
San Diego Gas & Electric	1	0	0	0	0	0	2004
South Carolina Electric & Gas	1	0	0	0	0	0	2004
Southern California Edison	1	0	0	0	0	0	2004
Southern Indiana Gas and Electric	1	0	0	0	0	0	2004
Superior Water, Light and Power	1	0	0	0	0	0	2004
Tampa Electric	1	0	0	0	0	0	2004
Tucson Electric Power	1	0	0	0	0	0	2004
United Illuminating	1	0	0	0	0	0	2004
West Penn Power	1	0	0	0	0	0	2004
Western Massachusetts Electric	1	0	0	0	0	0	2004
Westar Energy (KPL)	1	0	0	0	0	0	2004
Wisconsin Electric Power	1	0	0	0	0	0	2004
Wisconsin Power and Light	1	0	0	0	0	0	2004
Wisconsin Public Service	1	0	0	0	0	0	2004
Duke Energy Ohio	0	1	0	0	0	0	2004
Duke Energy Indiana	0	1	0	0	0	0	2004
Duke Energy Kentucky	0	1	0	0	0	0	2004
Arizona Public Service	0	0	1	0	0	0	2004
Central Maine Power	0	0	1	0	0	0	2004
Cleveland Electric Illuminating	0	0	1	0	0	0	2004
Duquesne Light	0	0	1	0	0	0	2004
Entergy Mississippi	0	0	1	0	0	0	2004
Jersey Central Power & Light	0	0	1	0	0	0	2004
Metropolitan Edison	0	0	1	0	0	0	2004
Northern States Power - MN	0	0	1	0	0	0	2004
Ohio Edison	0	0	1	0	0	0	2004
Pennsylvania Electric	0	0	1	0	0	0	2004
Pennsylvania Power	0	0	1	0	0	0	2004
Toledo Edison	0	0	1	0	0	0	2004
Alabama Power	0	0	0	1	0	0	2004
Virginia Electric and Power	0	0	0	1	0	0	2004
Public Service Company of Colorado	0	0	0	1	0	0	2004
Niagara Mohawk Power	0	0	0	0	2004	0	2004
Hydro One	**0**	**0**	**0**	**0**	**0**	**1**	**2013**

HYDRO ONE NETWORKS IR #51

51. Reference: Exhibit M1, Page 30

Please provide a sample list for the benchmarking model reported in Table 4 of PEG's report.

Response to HONI-51: The following response was provided by PEG.

The 69 companies in the sample are reported in Table HONI-51.

Table HONI-51

Companies in PEG's Econometric Benchmarking Sample

Alabama Power	Nevada Power
ALLETE (Minnesota Power)	New York State Electric & Gas
Appalachian Power	Niagara Mohawk Power
Arizona Public Service	Northern States Power - MN
Atlantic City Electric	Ohio Edison
Avista	Ohio Power
Baltimore Gas and Electric	Oklahoma Gas and Electric
Central Maine Power	Orange and Rockland Utilities
Cleco Power	Pacific Gas and Electric
Cleveland Electric Illuminating	PECO Energy
Connecticut Light and Power	Pennsylvania Electric
Duke Energy Carolinas	Pennsylvania Power
Duke Energy Indiana	Portland General Electric
Duke Energy Kentucky	Potomac Electric Power
Duke Energy Ohio	Public Service Company of Colorado
Duquesne Light	Public Service Company of Oklahoma
El Paso Electric	Public Service Electric and Gas
Empire District Electric	San Diego Gas & Electric
Entergy Mississippi	South Carolina Electric & Gas
Florida Power & Light	Southern California Edison
Georgia Power	Southern Indiana Gas and Electric
Green Mountain Power	Superior Water, Light and Power
Gulf Power	Tampa Electric
Hydro One Networks	Toledo Edison
Idaho Power	Tucson Electric Power
Indiana Michigan Power	Union Electric
Indianapolis Power & Light	United Illuminating
Jersey Central Power & Light	Virginia Electric and Power
Kansas City Power & Light	West Penn Power
Kentucky Power	Westar Energy (KPL)
Kentucky Utilities	Western Massachusetts Electric
Kingsport Power	Wisconsin Electric Power
Louisville Gas and Electric	Wisconsin Power and Light
Metropolitan Edison	Wisconsin Public Service
Mississippi Power	

HYDRO ONE NETWORKS IR #52

52. Reference: Exhibit M1, Page 27

What data sources did PEG use for the Alberta utilities? Please list all sources and their use in the study.

Response to HONI-52: The following response was provided by PEG.

Since Alberta data were not used in PEG's evidence in this proceeding, Dr. Lowry notes only that the Alberta data on utility operations that he used in PEG's recent benchmarking study for the UCA were obtained chiefly from distributor Rule 005 reports to the Alberta Utilities Commission.

HYDRO ONE NETWORKS IR #53

53. Reference: Exhibit M1, Page 30

Was the total cost model in Table 4 estimated with a heteroskedasticity and/or autocorrelation adjustment? If so, please describe the procedure used.

Response to HONI-53: The following response was provided by PEG.

Yes. PEG used a two-step panel-weighted least squares procedure to correct for company-specific heteroscedasticity. There was no correction for autocorrelation.

HYDRO ONE NETWORKS IR #54

54. Reference: Exhibit M1, Page 30

For the Table 4 model in the PEG Report, why limit the volume per residential customer to only the year 2015, rather than having an annual calculation for each year in the dataset?

Response to HONI-54: The following response was provided by PEG.

This approach was used chiefly for two reasons.

- Distribution cost is a function of expected demand, not actual demand.
- Our goal was to capture the impact of drivers of difference in expected residential peak demand per customer, such as climate and real income per household. The differences between utilities in these drivers are fairly stable.

HYDRO ONE NETWORKS IR #55

55. Reference: Exhibit M1, Page 30

For Hydro One's projected OM&A, did PEG use the inflation – 0.45%, or was a growth factor added to the projected OM&A expenses?

Response to HONI-55: The following response was provided by PEG

PEG used the same OM&A cost forecast as PSE in their benchmarking work.

HYDRO ONE NETWORKS IR #56

56. Reference: Exhibit M1, Page 20, 38

PEG mentions on p. 35 of the report: "Utilities can then be compensated twice for the same capex: once via the C factor and then again by a low X factor in this and future IRMs."

c. Would large C factors that produce higher spending than the industry at large tend to harm a utility's benchmarking score over time?

d. Does PEG believe that the stretch factor being calibrated to these benchmarking results helps partially adjust for this possibility (large C factors)?

e. Please confirm the productivity factor contains an implicit stretch factor.

Response to HONI-56: The following response was provided by PEG.

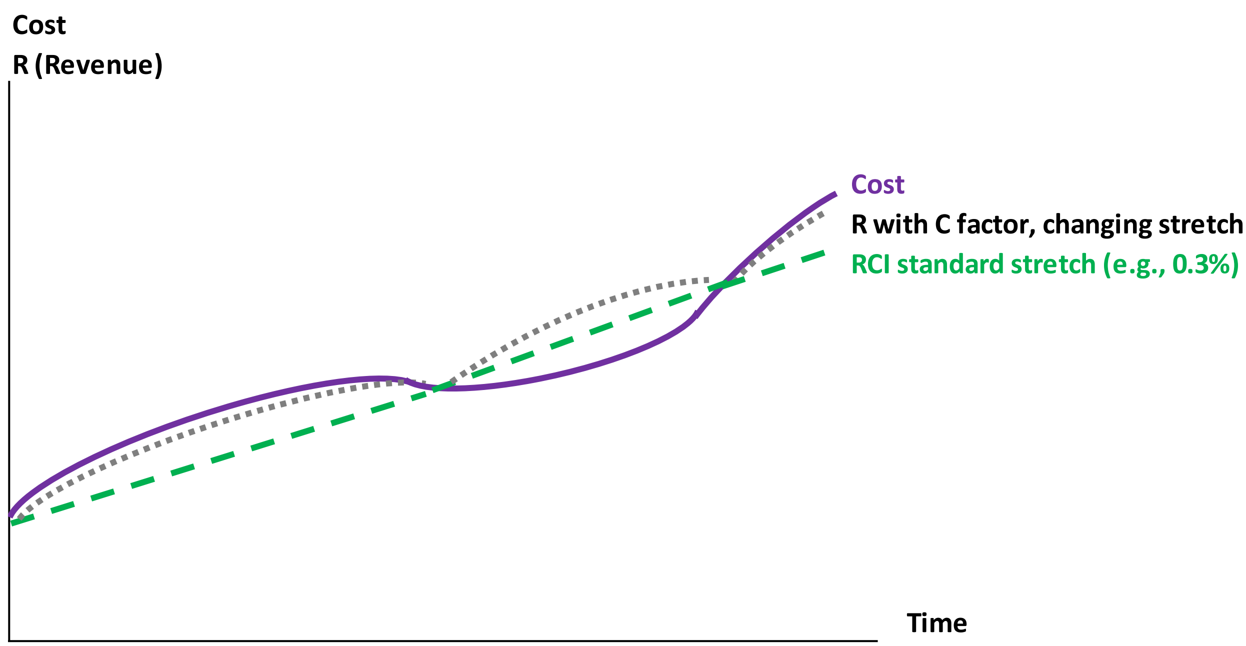
c. Yes.

d. Not necessarily. The stretch factor is designed to penalize (reward) poor (good) cost performance and not to reduce overcompensation. Moreover, it effectively applies only to OM&A revenue and is only operative in years between rebasings.

   To illustrate the limitations of the stretch factor as an overcompensation mitigator, Figure HONI-56 considers the case of a utility that alternates between periods of capex surges and slow cost growth as the surge capex depreciates. During the period of the capex surge a custom stretch factor slows cost growth. However, once cost falls below the norm, the custom stretch *accelerates* revenue growth. Thus, customers never receive the full benefit of the industry productivity trend even though the utility achieves it in the longer term.

   In preparing this figure we abstracted from the complication of periodic cost of service cases.

Figure HONI-56



e. Dr. Lowry cannot confirm this statement based on the evidence submitted in this proceeding. A judgement of this kind which is based on *Ontario* data would require a thorough overhaul of provincial TFP calculations which is beyond the scope of this proceeding. As he noted on page 10 of his report, he found in a recent study for Berkeley Lab that the TFP trend of *U.S.* power distributors averaged 0.23% over the 2001-2014 period.

HYDRO ONE NETWORKS IR #57

57. Reference: Exhibit M1, Page 41

On p. 38 of the report, PEG states: "Any of these dead zone approaches can make customers whole for the addition of a growth escalator to Hydro One's RCI."

a. Does PEG believe that adding a growth escalator is appropriate?

b. If so, why would customers need to be made whole?

Response to HONI-57: The following response was provided by PEG.

a. Yes.
b. HONI offered customers a particular value proposition with its IRM proposal and has portrayed it as containing an implicit stretch factor. It is therefore reasonable for PEG to propose an alternative IRM that does not diminish the value proposition while strengthening performance incentives and possibly also lowering regulatory cost.

HYDRO ONE NETWORKS IR #58

58. Reference: Exhibit M1, page 13

In its report, PEG states that it has concerns with the conclusions of PSE's TFP analysis.
PEG states:

> The biggest driver of the result was TFP declines in excess of 4% in 2012 and 2013. These were chiefly due to sharp declines in OM&A productivity. Over the full sample period, OM&A productivity growth averaged only -0.8% annually despite widespread installation in Ontario of automated metering infrastructure ("AMI") that should have cut OM&A costs. Our Berkeley Lab study found that the OM&A productivity of US power distributors averaged 0.40% annual growth from 2001 to 2014 while capital productivity growth averaged 0.18%.

a) Please confirm that 2012 and 2013 represent years in which a significant amount OM&A costs related to smart meters were included in the cost data for Ontario utilities.

b) Please provide support for PEG's claim that the "widespread installation in Ontario of automated metering infrastructure ("AMI")" "should have cut OM&A costs".

c) Please reconcile PEG's comments regarding expected cost reductions due to smart meters with the observations made by the Auditor General of Ontario in the 2014 audit of Ontario's Smart Metering Initiative.[5] Specifically, the following quote on page 375 of the report:

> With respect to benefits, only 5% of the distribution companies we consulted reported operational savings, mainly from no longer having to send staff to read meters manually, and all of these were of modest size; the other 95% said they realized no savings and their operating costs relating to smart-metering activities since implementation had actually risen.

d) Please provide a copy of the referenced Berkeley Lab study.

e) Please explain whether the peer group in the Berkeley Lab study was subject to similar government-driven policy initiatives as utilities in Ontario such as CDM targets as a

[5] A copy of the report can be found at http://www.auditor.on.ca/en/content/annualreports/arreports/en14/311en14.pdf

condition of license, a mandatory smart meter rollout, requirements to enable the connection of a significant amount of renewable generation, etc. Please comment on whether or not such policy activities could impact TFP performance in a study and could reasonably impact TFP performance for Ontario distributors as compared to their US counterparts.

Response to HONI-58: The following response was provided by PEG.

a. Dr. Lowry confirms this statement.

b. Reductions in meter reading and other OM&A expenses have been a core part of utility sales pitches for AMI in many North American jurisdictions. Areas of predicted cost savings have included meter reading and outage response. Dr. Lowry understands that the potential cost savings have been offset for some utilities by communications and software service contracts.

c. These savings may have been disappointing up to 2014 in Ontario and/or been understated by audit participants.

d. Here is a link to PEG's referenced Berkeley Lab report. https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf

e. Dr. Lowry acknowledges that government-driven policy initiatives such as a mandatory smart meter rollout and requirements to enable the connection of renewable generation can slow calculated TFP growth, especially if the output index does not capture the increases in system capabilities. However, many U.S. power distributors have faced similar cost pressures. For example, many U.S. distributors have installed AMI, and penetration of distributed solar generation has been substantial in several states. As well, some U.S. distributors face other special cost pressures such as the need to increase system reliability and resiliency and/or to rebuild systems after devastating storms. Note that CDM expenses were excluded from both the Ontario and the U.S. TFP studies that Dr. Lowry discusses.

HYDRO ONE NETWORKS IR #59

59. Reference: Exhibit M1, page 16

On page 16, PEG notes concerns over the fact that pension and benefit costs are included in PSE's calculations, as they were in PEG's own 4th generation IRM research. Please confirm that pension and benefits costs are usually removed from studies where the peer groups operate in separate jurisdictions that may have materially different compensation levels. Given that all the comparators in the TFP analysis are in the same jurisdiction, Ontario, is there any reason to require that these costs be excluded from the analysis?

Response to HONI-59: The following response was provided by PEG.

Dr. Lowry acknowledges that pension and other benefit expenses are often excluded from statistical cost benchmarking studies. However, these expenses are ideally excluded from a study used to calibrate the X factor of an IRM that Y factors these expenses.

HYDRO ONE NETWORKS IR #60

60. Reference: Exhibit M1, page 16

PEG makes several assertions regarding the inclusion of smart meter costs in PSE's analysis. Does PEG expect that the one-year inclusion of smart meters costs by PSE in 2013 would result in a materially different end-result for the 15-year TFP trend as compared to the more gradual increases in capital quantify growth from 2007 to 2012 hypothesized by PEG in page 17 of Exhibit M1. In other words, please confirm that the impact of a one year spike in cost data as compared to the gradual inclusion of the same total costs over a 5-year period does not materially impact the results an average over a longer time horizon (e.g. 15 years).

Response to HONI-60: The following response was provided by PEG.

Dr. Lowry confirms this statement but notes that the inclusion of smart meter costs by PSE in years after 2013 was a major reason for the markedly negative OM&A and total factor productivity growth reported for the years of the update. This contributes to a potentially false impression that Ontario power distributor TFP growth has recently had a marked downward trend. Please also note that the abrupt inclusion of smart meter costs causes a negative TFP *growth* spike but a lasting supplement to the cost *level*.

HYDRO ONE NETWORKS IR #61

61. Reference: Exhibit M1, page 18

PEG describes the approach it used to adjust for the transition to MIFRS.

a) On p. 15 and 16 of the report, PEG mentions that a 10.1% markdown is the result of a 12.5% reported cost increase, and the fact that 81% of OM&A costs were affected by the issue.
   i. Is PEG saying the transition to IFRS standards caused a 10.1% increase in OM&A costs? If not, please clarify the claim being made.
   ii. Is PEG asserting that the 12.5% increase in OM&A would have been 2.4% without the transition to IFRS?
   iii. Was a similar calculation conducted for capex costs? If yes, please provide.
   iv. In PEG's opinion, would the transition to IFRS standards likely decrease capex costs (as opposed to increasing OM&A costs)?

b) Please describe the OM&A IFRS adjustment in full, including all data and calculations used. Please provide a list of the 14 distributors mentioned along with the derivation of the 12.5% increase to OM&A under MIFRS.

c) Please identify the utilities that had not adopted MIFRS or indicated that they had previously changed their capitalization policy and show how PEG determined that 81% of OM&A costs were impacted by change.

d) The increase in OM&A expenses due a change in capitalization policy would have had a corresponding reduction in Capital costs that are no longer capitalized. What offsetting adjustments did PEG make in its analysis for the capital costs of utilities that transitioned to MIFRS? If no adjustments were made for capital costs, please explain why.

e) Given that a change in capitalization policy involves an offset in costs between capital and OM&A, please explain why it is reasonable that the overall TFP trend for the industry would be materially impacted by such a change?

Response to HONI-61: The following response was provided by PEG.

a. Our research suggests that on average, there is a 12.5% increase in OM&A cost for companies adopting IFRS for the first time. This is due to expensing as opposed to capitalizing overheads and is persistent. The lower 10.1% value reflected some doubt on the part of PEG that all distributors had made the transition by 2015 and therefore an adjustment factor of 12.5% would overstate the cost impact of IFRS. The 10.1% adjustment factor is 81% of 12.5% and implicitly assumes that 19% had no IFRS impact. Because this a one-time adjustment, the impact on the trend is diluted over the number of years in the period considered. We do not confirm the premise of part ii of the question. A similar adjustment was not done for capex because in theory the impact on capital cost will be much lower in the short run. The impact of capitalization policy on O&M expenses was described by several distributors in COS filings which provided the source data for the estimate. These can be found on the OEB website.

b. Please see the working papers provided in response to HONI-9 for the data and calculations. The adjustment modifies the OM&A cost in 2015 for the impact of changed capitalization policy that most distributors implemented between 2011 and 2015. The adjustment is to lower the aggregate industry 2015 OM&A cost by the adjustment factor described above. Because the formerly capitalized overheads are correlated with regular capital spending, the OM&A impact will not be a self-correcting "blip" in the series but rather an increase in one year to a higher level that will persist. Modifying the endpoint provides a straightforward method to estimate the impact on the OM&A cost trend that feeds into the remaining calculations. Had perfect information been readily available for all distributors on this topic, an improved estimate of the impact would individually adjust each distributor's data in the year in which the change occurred and adjust subsequent OM&A cost levels. PEG believes that the method used provides a reasonable estimate of the direction and magnitude of the short-run impact of the change in capitalization policy on productivity.

c. Please see the working papers provided in response to HONI-9.

d. Dr. Lowry believes that the upcoming 5th Generation IRM proceeding is the appropriate venue to finalize calculation of the productivity trends of Ontario power distributors. PEG's goal in this proceeding has been to make sufficient progress down this road to show convincingly that PSE's -0.9% estimate of the TFP trend is likely far off the mark and that the OEB's 0.0% base TFP trend from the 4th Generation IRM proceeding is still serviceable for determining a base TFP growth target for Hydro One's X factor. The main impact of the transition to IFRS accounting in the short run should be on OM&A productivity. Accordingly, it was appropriate for PEG to focus on the OM&A impact.

e. Please see our responses to HONI-25 and to part d) of this question.

HYDRO ONE NETWORKS IR #62

62. Reference: Exhibit M1, page 21

On page 19 of the report, PEG states that it replaced the AWE labor price index with the fixed-weight average hourly earnings in Ontario. Hydro One notes that the AWE labor price index was approved by the OEB as the appropriate labor price index and underpins the inflation factor that is used to set rates for electricity distributors in Ontario.

a. Please provide a table showing the performance over the study period of the OEB-approved AWE labor price index as compared to PEG's proposed fixed-weight average hourly earnings in Ontario.

b. Under 4GIRM Ontario distributors have been subject to an Inflation Factor in which the rate of growth for labor costs, from a rates perspective, was limited to the rate of growth of the AWE labor price index. Would a change in labor price index for the TFP analysis, as proposed by PEG, not introduce an element of bias to the TFP results given that utilities were incented to manage their costs to levels allowable through rates? If not, please explain why not.

Response to HONI-62: The following response was provided by PEG.

a. Table HONI-62 provides the requested data**.** Please note that, in Ontario as well as in Canada as a whole,

- Fixed-weighted average hourly earnings ("AHE") have tended to grow a little faster than AWE.
- AHE growth has tended to be somewhat more stable than AWE growth

b. The incentive for utilities to contain labor costs is, in principle, not affected by the choice of a labor price index for the RCI inflation measures. Utilities should, in any event, find it at least as easy to manage salaries and wages under the AHE, since it is a little more stable than the AWE and has tended to grow a little more rapidly.

Table HONI-62

Comparison of AHE and AWE Growth Trends[1,2,3]

	Average Hourly Earnings								Average Weekly Earnings											
	Canada				Ontario				Canada						Ontario					
	Industrial Aggregate		Utilities		Industrial Aggregate		Utilities[4]		Industrial Aggregate		Utilities		Electric GTD		Industrial Aggregate		Utilities		Electric GTD	
Year	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate
2002	100.1	2.1%	99.9	5.1%	100.1	1.9%	99.8	4.8%	100.0	2.4%	100.0	6.4%	100.0	5.8%	100.0	2.1%	100.0	5.9%	100.0	5.8%
2003	103.1	3.0%	105.1	5.1%	102.8	2.7%	107.4	7.3%	102.7	2.7%	103.1	3.1%	103.6	3.6%	102.5	2.4%	104.0	3.9%	105.4	5.3%
2004	105.9	2.7%	107.0	1.8%	105.4	2.5%	109.3	1.8%	105.4	2.6%	102.0	-1.1%	104.1	0.4%	105.3	2.7%	102.5	-1.5%	104.8	-0.5%
2005	109.3	3.2%	108.9	1.8%	108.8	3.2%	111.5	2.0%	109.5	3.8%	104.7	2.6%	107.8	3.5%	109.1	3.6%	104.6	2.1%	108.7	3.6%
2006	112.1	2.5%	111.2	2.1%	111.3	2.3%	113.6	1.9%	112.2	2.4%	108.7	3.8%	111.0	3.0%	110.9	1.6%	107.4	2.7%	110.4	1.6%
2007	117.2	4.4%	117.4	5.4%	115.6	3.8%	119.3	4.9%	117.0	4.2%	114.0	4.8%	116.2	4.5%	115.2	3.8%	113.8	5.8%	116.1	5.0%
2008	121.4	3.5%	118.9	1.3%	119.3	3.2%	117.6	-1.4%	120.4	2.8%	115.2	1.0%	116.8	0.5%	117.9	2.3%	111.4	-2.1%	111.6	-4.0%
2009	125.0	2.9%	125.8	5.6%	122.8	2.9%	*123.6*	4.9%	122.2	1.5%	121.4	5.2%	121.3	3.8%	119.3	1.2%	120.8	8.0%	118.6	6.1%
2010	129.0	3.1%	129.8	3.1%	127.5	3.8%	129.5	4.7%	126.6	3.6%	127.0	4.5%	126.6	4.3%	123.9	3.8%	121.3	0.4%	118.2	-0.4%
2011	131.7	2.1%	131.8	1.5%	129.6	1.6%	121.8	-6.1%	129.8	2.5%	132.9	4.6%	133.5	5.4%	125.6	1.4%	123.7	2.0%	122.4	3.5%
2012	134.3	2.0%	135.6	2.8%	131.3	1.3%	128.7	5.5%	133.1	2.5%	132.7	-0.1%	133.7	0.1%	127.4	1.4%	123.1	-0.4%	122.9	0.4%
2013	136.5	1.6%	135.0	-0.4%	133.2	1.4%	131.7	2.3%	135.4	1.8%	133.6	0.7%	132.2	-1.1%	129.3	1.5%	127.0	3.1%	124.2	1.1%
2014	139.7	2.3%	141.8	4.9%	135.3	1.6%	141.3	7.0%	139.0	2.6%	143.6	7.2%	144.7	9.0%	131.9	2.0%	138.2	8.5%	138.1	10.6%
2015	143.2	2.5%	138.1	-2.6%	139.0	2.7%	136.2	-3.7%	141.5	1.8%	144.8	0.8%	144.1	-0.4%	135.4	2.6%	139.4	0.8%	137.3	-0.6%
2016	146.0	1.9%	140.6	1.8%	142.2	2.3%	135.4	-0.6%	142.2	0.5%	140.6	-3.0%	139.8	-3.0%	136.9	1.1%	131.4	-5.9%	128.8	-6.4%
2017	149.1	2.1%	148.8	5.7%	144.9	1.9%	140.8	3.9%	145.0	2.0%	150.6	6.9%	150.3	7.2%	139.5	1.9%	138.8	5.5%	135.3	5.0%
Annual Average Growth Rate																				
2002 - 2015		**2.6%**		**2.8%**		**2.4%**		**2.5%**		**2.5%**		**3.0%**		**2.9%**		**2.2%**		**2.4%**		**2.3%**
Standard Deviation																				
2002 - 2015		**0.7%**		**2.4%**		**0.8%**		**3.8%**		**0.9%**		**3.0%**		**3.2%**		**0.9%**		**3.9%**		**4.2%**
Volatility Coefficent[5]																				
2002 - 2015		**0.27**		**0.85**		**0.32**		**1.55**		**0.37**		**1.01**		**1.12**		**0.40**		**1.60**		**1.87**

Notes

[1] All growth rates are computed logarithmically. For example, growth rate of $X = \ln(X_t/X_{t-1})$

[2] Fixed weighted index of average hourly earnings for all employees (Statistics Canada, Table 281-0039).

[3] Average weekly earnings, including overtime, for all employees in current dollars (Statistics Canada, Table 281-0026).

[4] We replaced the missing Ontario 2009 fixed utilities average weekly earnings value with the simple average of 2008 and 2010.

[5] Volatility coefficents are the ratio of the standard deviation to the mean.

HYDRO ONE NETWORKS IR #63

63. Reference: Exhibit M1, page 20

In footnote 21 the PEG report states:

> Adding the impact of CDM on system use had an even larger effect. According to the Ontario Ministry of Energy, the impact of conservation and load control programs has approximately doubled since the 2012 endpoint of the previous study. Should the MW and MWh be adjusted to add back the impact of these programs, the output and TFP trends would be approximately 0.50% higher than measured by PSE.

a. Please provide details regarding the adjustments PEG made for the impact of CDM programs.

b. Distributors in Ontario receive funding from IESO to fund the costs they incur in the deployment of CDM programs. Were these costs factored in to PEG's analysis when it revised the TFP calculation, as shown in Table 1 of the report? If not, would PEG agree that the 0.5% improvement on industry TFP arising from its proposed CDM adjustments to volumes and peaks would be overstated given that the costs associated with providing those programs are excluded from the analysis?

Response to HONI-63: The following response was provided by PEG.

a. Please see the working papers provided in response to HONI-9 for the data and calculations used. Dr. Lowry also notes that the results of this exercise are not a part of our final appraisal of the Ontario TFP trend because the number of customers is the preferred output metric. This exercise was undertaken to provide a means of explaining the sluggish growth in the output quantity index and TFP since the last study was done.

b. CDM costs were excluded from PEG's calculations because they are not addressed by indexing in the contemplated IRM.

HYDRO ONE NETWORKS IR #64

64. Reference: Exhibit M1, page 21

PEG states that it has recalculated Hydro One's productivity trends. PEG states that "we revised PSE's methodology to use the implicit price deflator for the utility sector capital stock and the fixed-weight average hourly earnings for Ontario."

a. Please provide further details regarding the methodology used to recalculate Hydro One's productivity trends.

b. Did PEG make any of the other adjustments outlined in Table 1 of the report? If so, please provide a version of Table 1 for Hydro One's results. If not, please explain why is it appropriate to include those adjustments for the Industry TFP analysis but exclude those changes for its analysis of Hydro One's performance?

Response to HONI-64: The following response was provided by PEG.

a. Please see the working papers provided in response to HONI-9.

b. PEG approached the review of the TFP studies as separate tasks and did not seek to make the scope of adjustments consistent. Several of the Table 1 adjustments used methods that are not intended to apply to individual company calculations.

    i. The sample adjustment is not applicable.

    ii. The IFRS adjustment was calculated based on an industry analysis that did not include HONI.

    iii. The conservation adjustment was also based on aggregate industry data.

    The CIAC and smart meter adjustments were also based on industry averages. However, while preparing responses to these questions PEG discovered that the individual company data were available had we sought to do these adjustments. The working papers contain the required information for these adjustments or other analysis the company wishes to perform.

HYDRO ONE NETWORKS IR #65

65. Reference: Exhibit M1, page 41

The PEG report states:

> "There is a perverse incentive for the Company to contain salary growth but maintain or sweeten benefits"

Please provide any supporting evidence PEG has that indicates pension costs or other benefits have increased for Hydro One.

Response to HONI-65: The following response was provided by PEG.

PEG's quoted comment was about Hydro One's incentives under its proposed Custom IR. It has not appraised the Company's past expenses for pensions and other benefits.