HYDRO ONE INTERROGATORIES ON THE PACIFIC ECONOMICS GROUP REPORT

M1-HON-2

References: Exhibit M1, Pages 10-11

Interrogatories:

Please list any and all cases where PEG was the consultant for an energy utility (gas, electric, or a combination) where a "hybrid" approach to O&M and capital in a multiyear rate plan was proposed, and provide any PEG reports from those cases. For the definition of "hybrid" we use PEG's definition found on p. 34 of their EEI paper "Alternative Regulation for Emerging Utility Challenges: 2015 Update" where it states: "A hybrid approach to ARM design was developed in the US that involves indexing of revenue for O&M expenses and forecasts for capital cost revenue."

a) Would PEG consider Hydro One's proposal in the current case to be a "hybrid" plan?
b) Have any other hybrid plans in the US included a "supplemental stretch factor" on capital?
c) Has PEG in its prior work for utility clients or the EEI ever recommended a supplemental stretch factor on capital in a hybrid multiyear rate plan? If so, please provide.

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

a) In a multiyear rate plan, a hybrid attrition relief mechanism ("ARM") is one in which escalation of allowed revenue (or rates) is independent of the subject utility's actual cost growth during the plan, but different methods are used to escalate different revenue (or rate) components. In California, for instance, the component of a utility's allowed revenue which addresses operation, maintenance, and administration ("OM&A") expenses has in some plans been escalated by a revenue cap index, while the component that addresses capital cost has been subject to predetermined "stairstep" escalation (e.g., 3% in 2021, 5% in 2022, etc.).

   The Custom IR plan proposed by Hydro One for its transmission services essentially combines a multiyear rate plan (with a revenue cap index) for OM&A expenses with cost of service regulation for capital cost (as provided for through the proposed C-factor along with the I – X revenue cap escalation). This is a hybrid approach to *rate regulation* but not a hybrid *attrition relief mechanism*. Precedents for this general approach to regulation include the "Targeted

O&M PBR" plan of Consumers Gas (dba Enbridge Gas Distribution) and several generations of alternative regulation plans for Green Mountain Power and Vermont Gas Systems.

b) PEG is unaware of any approved multiyear rate plans ("MRPs") in the United States which has a hybrid ARM with a supplemental stretch factor just for capital revenue. The likelihood of such terms is reduced by the fact that hybrid ARMs typically do not index capital revenue. Capital revenue is instead typically escalated on the basis of cost forecasts or an assumption that recent historical capex levels will continue. Capital revenue requirements may nonetheless have been lean in some of the approved ARMs, thereby benefiting customers.

   As noted in the response to part a) of this question, the Company's proposed Custom IR plan effectively combines a revenue cap index for capital revenue with a cost of service treatment of capital. Since the proposed X factor is zero, a supplemental stretch factor for capital is one way to bring the regulatory system more in line with the Board's Custom IR guidelines. The Board has previously approved an S factor for distributor services of Hydro One and one has been proposed by PEG for the second Custom IR plan of Toronto Hydro.

c) PEG has provided reports or testimony on several occasions for an energy utility proposing an MRP with a hybrid ARM. They have in these instances never recommended a supplemental stretch factor for capital. One reason is that PEG's evidence in several of these proceedings did not pertain to ARM design (e.g., it fulfilled commission requirements to file a productivity study or focussed on benchmarking). Even where PEG's evidence did address ARM design, the ARM's treatment of capital was independent of the Company's actual cost growth during the plan. This reduced concerns about capex containment incentives. PEG has twice testified (in Hawaii and Vermont) in support of a hybrid regulatory system that could be construed, with the benefit of hindsight, as combining an ARM for OM&A revenue with a cost of service treatment of capital. PEG did not address the ratemaking provisions for capital in these cases. Hawaii's commission was unhappy with the high capex under these plans and ultimately imposed a more comprehensive revenue cap index.

In light of the answers to parts a)-c), the request to provide PEG's evidence for all of these cases cannot be addressed within a reasonable time and with reasonable effort. Please see Table HON-2 for a list of cases where PEG provided substantive support for a utility proposing a hybrid *attrition relief mechanism* or other regulatory system in the past 15 years. Please see HON-2 (Exhibit L1/Tab 1/Schedule 2) part c), Attachments A-G for copies of PEG's reports in those proceedings.

Table HON-2

Substantive PEG Testimony in Support of Utility Hybrid Ratemaking Proposals

Jurisdiction	Year	Service	Client	Proceeding Identifier
Colorado	2017	Electric	Public Service of Colorado	Colorado Public Utilities Commission Proceeding No. 17AL-0649E
Colorado	2017	Gas	Public Service of Colorado	Colorado Public Utilities Commission Proceeding No. 17AL-0363G
Hawaii	2009	Electric	Hawaiian Electric, Hawaiian Electric Light, Maui Electric	Hawaii Public Utilities Commission Docket No. 2008-0274
Maine	2013	Electric	Central Maine Power	Maine Public Utilities Commission, Case 2013-00168
Massachusetts	2010	Gas	Boston Gas	Massachusetts Department of Public Utilities D.P.U. 10-55
Vermont	2008	Electric	Central Vermont Public Service	Vermont Public Service Board Docket No. 7336
Victoria, Australia	2004	Electric	SPI Networks	Essential Services Commission of Victoria Electricity Distribution Price Review 2006-10

M1-HON-4

Reference: Exhibit M1, page 56

Preamble: PEG discusses its approach to capital cost and quantity.

Interrogatories:

a) Please confirm that for the US sample and for Hydro One, PEG: (1) separated out the transmission capital and general capital, and (2) applied different depreciation rates and service life assumptions to each.

b) Please provide the depreciation rates used for transmission capital and general capital for the US sample and for Hydro One. If these are different for the MFP and benchmarking research, please provide the rates for each study.

c) Was this a modification from PEG's HOSSM benchmarking and productivity research? If yes, why was this change made?

d) Did PEG also disaggregate Hydro One's capital into its transmission and general components? If yes, please describe how this was undertaken. If not, please describe why not, and whether the failure to disaggregate would jeopardize the cost comparability between Hydro One and the rest of the sample.

e) In what year did PEG levelize the capital price for Hydro One and the US sample?

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

a) This statement is confirmed.

b) The depreciation rates used for the US were 2.88% for transmission and 9.17% for general. The rate used for HON was 3.30% and implicitly reflects combined transmission and general plant.

c) Yes. Separate ratemaking treatment of transmission and general plant for the U.S. utilities improves the accuracy of the U.S. MFP trend calculations and the cost calculations used in the econometric research.

d) No. The data provided by Hydro One did not make this separation possible. PEG believes that the advantages of disaggregation of the U.S. data offset the disadvantage of any reduction in cost comparability. PEG is not aware of any comparability problem.

e) PEG levelized the capital price index in 2012.

M1-HON-5

Reference: Exhibit M1, page 22

Preamble: PEG states that PSE's parameter estimates are degraded by not using PEG's older capital data, which goes back to 1964. PSE instead used data beginning in 1989, as this is the first year for which data is readily electronically available for the sample.

Interrogatories:

a) Does PEG believe that any possible inaccuracy resulting from the 1989 capital benchmark year used by PSE is mitigated by the fact that plant additions for the years before 1989 are substantially depreciated by the later years in the sample?

b) In PEG's response in PEG-HOSSM-6j in the HOSSM Case, PEG showed results that moving from PEG's 1964 benchmark year to the 1989 benchmark year changed Hydro One's results for 2019-2022 only about two percentage points, from -12.35% to -14.65%? Does PEG have reason to believe the impact is larger now? If so, please quantify.

c) PEG and PSE produce nearly identical industry MFP growth rates over the sample period of 2005 to 2016: PEG reports an industry MFP decline of -1.47% and PSE reports an industry MFP decline of -1.45%. Given the large capital share found in the transmission industry, if this really was an important issue, would PEG expect the results to be different between the two consultants?

d) PEG needed to correct certain errors in the HOSSM Case, due to incorrectly using its 1964 data. This substantially impacted the results from PEG's original research. In fact, once these corrections were made by PEG in the HOSSM Case, the total cost results for HOSSM were changed past the 4GIR threshold where a 0.15% stretch factor would be appropriate. Given this history of errors in the HOSSM Case with this data, and the fact that this data is not electronically available for download, but must be manually found and entered and cannot be readily verified by an external consultant, what assurances can PEG give that this data is now fully accurate and trustworthy?

e) In PEG's response in PEG-HOSSM-6h(ii), PEG stated it has the source data for all the capital data going back to 1964. However, PEG refused to provide this data on the grounds that it was an onerous request for it to provide the source data. This refusal was despite the enormous effort it would require another consultant to track down this 55-year-old data. Please scan and provide PDFs of the source data so it can be verified by another party. If providing the source data is still considered to be onerous, would PEG allow PSE access to PEG's source data, and be allowed to scan the source data themselves?

f) Please describe the process that PEG undertook to gather and process the data going back to 1964. The description should include specific book titles for each year and libraries visited.

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

a) Yes. PEG acknowledges that depreciation of transmitter assets added before 1989 reduces the inaccuracies that result from using a 1989 benchmark year for the capital quantity indexes of U.S. utilities, when an earlier (e.g., 1964) benchmark year is possible. However, there is still an accuracy problem, which looms larger for capital costs and quantities in the early years of the sample period. As discussed in PEG's report, a sample period beginning in 1995 is desirable to calculate the long-run MFP trend of U.S. transmitters and to estimate econometric model parameters more precisely. 1995 is just a few years after 1989. Even if the OEB were to conclude that PSE's 2005-2016 sample period is of greatest interest, it is desirable for them to have an accurate estimate of how U.S. transmission productivity grew before 2005.

b) PEG has no reason to believe that the impact on 2019-2022 benchmarking results is any different from the analysis done earlier during the Hydro One SSM work.

c) There are several differences between the MFP measurement methodologies of PEG and PSE, as discussed further in the response to M1-HON-11. The small difference between the MFP trends of PSE and PEG from 2005 to 2016 may therefore not accurately measure the impact of PEG's earlier benchmark year. Moreover, as PEG noted in their response to part a) of this IR, it is desirable to know the MFP trend of the industry in years before 2005. In the earlier years, MFP results are more likely to be affected by the choice of a benchmark year.

d) The errors mentioned occurred only in the econometric database. Further the errors associated with the 1964 data were not the cause of the "substantial" impact referenced in this question. They were rather due chiefly to raw data previously gathered not being subjected to a standard merger adjustment. PEG has extensive experience with the use of older capital cost data in its statistical performance research.

e) PEG believes that this is an unduly burdensome and unfair data request. The requisite plant addition data for a 1964 benchmark year are available at the University of Wisconsin-Madison and many other large universities across the U.S. PSE has performed several statistical cost studies for large Ontario electric utilities using U.S. data and should have been able to recover the modest cost of gathering these data over the years. In contrast, PSE seems to have expended a great deal of effort to develop business condition variables that reflect special challenges of its clients.

   PSE is essentially asking for data that would be sufficient to replicate PEG's capital quantity calculations. However, PSE has generally not provided comparable detail for the new business condition variables that it develops. See, for example, PEG's response to SEC-1 (Exhibit L1/Tab 4/Schedule 2) in this proceeding. PSE's interest in obtaining these data seems inconsistent with their submission that, due to depreciation since 1989, the data add little value and have little impact.

f) The older data on power distribution gross plant additions which PEG uses were published by the Federal Power Commission and later by the Energy Information Administration under the titles of "Statistics of Electric Utilities in the United States …" or "Statistics of Privately Owned Electric Utilities in the United States …" and "Financial Statistics of Selected Electric Utilities in the United States …". These data were gathered decades ago and PEG is not sure where each book was obtained except that the vast majority came from the Wendt Engineering Library at UW Madison. This library is easily accessible to consultants in the Madison, WI area. Some plant additions data from 1990-1993 were obtained from electronic sources no longer commercially available, but can be verified from the published data.

M1-HON-6

Reference: Exhibit M1, page 22

Preamble:

PEG states that the "short sample period" of PSE unnecessarily reduces the precision of the econometric model parameter estimates. PEG also states that the sample period produces an "inappropriately negative value" for the trend variable parameter.

Interrogatories:

a) Given PEG's concerns for a longer sample period and the availability of the data, why did PEG not add the years 2017 and 2018 to the data sample?

b) Did PEG conduct any preliminary work to update the dataset to 2017 and/or 2018? If so, please provide any preliminary results of that work.

c) In the recent Toronto Hydro proceeding, PEG updated its research to 2017 (all the 2018 data was not yet available but is now). In this Hydro One proceeding, PEG has made a special point about the importance of a longer sample period. Given PEG's concern over a short sample period, please update PEG's MFP and total cost benchmarking study samples to and including 2018. Please revise Table 2, 3, and 5 of the PEG Report accordingly.

d) Both PSE and PEG find the industry has negative productivity trends over the time periods used (2005 to 2016 for PSE, 1996 to 2016 for PEG). PEG finds the industry from 1996 to 2016 has negative productivity growth of -0.25%. However, in PEG's econometric total cost model the trend parameter estimate in the current report is -0.006 (see Table 2 on p. 33 of Exhibit M1). This implies, all else equal, a positive productivity trend over this period of 0.6%. Is PEG concerned that its econometric model trend parameter is not consistent with its own productivity trend research? Please explain and discuss why PEG believes this discrepancy exists.

e) Please confirm that PEG's own research indicates that the transmission industry has had negative productivity growth for the ten most recent years of the sample.

f) Please confirm that out of the last eight years, all years but one had productivity declines lower than -1.00%. In the one year that had the highest productivity growth the growth rate was still -0.66%. However, PEG's model has a trend estimate showing a 0.6% productivity improvement in each year, all else equal. On what basis does PEG think +0.6% is a reasonable estimate of the productivity trend in the forecasted years of 2020 to 2022?

g) Does PEG's benchmark for Hydro One in the forecasted years assume a +0.6% annual productivity improvement?

h) Given PEG's concern over this issue, please re-run the PEG model and add a quadratic trend variable to the model (Trend*Trend). Please provide a revised Table 2 and Table 5 showing the benchmarking model and results.

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

a) At the start of the HOSSM project in late 2018, the requisite transmission operating data for 2018 were unavailable and PEG had not processed the 2017 transmission data, whereas PEG had already gathered these data for earlier years back to 1995. In their proposal to OEB Staff for the HOSSM project, PEG did not include a data update (as PSE had similarly not done a data update for its new evidence) and no budget for such work was provided. For the Hydro One Transmission proceeding, OEB Staff asked PEG to focus mainly on the C factor issue and to limit the expenditure of effort on upgrades and updates to their Hydro One SSM statistical cost research, consistent with the limited updates that PSE had done. PSE also had an opportunity to add additional years of data to its study but did not do so.

b) PEG used 2017 distributor operating data in its cost research for OEB Staff in the recent Toronto Hydro proceeding. However, they have not incorporated 2017 transmission data into their transmission work. Any work by PEG to gather 2018 data has been highly preliminary, not focussed on transmission, and has not been funded by any PEG client.

c) This analysis would require obtaining all of the necessary data for 2018, conducting necessary exploratory data analysis to assess the quality and consistency of the data, and then to update the analyses which PEG has documented in its evidence. PEG believes that this request cannot be addressed within a reasonable time and with reasonable effort within the current schedule for this proceeding.

d) Trend variable parameter estimates can vary from MFP trends because econometric models have different output specifications and include time-variant Z variables. PSE's trend variable parameter estimate of 0.012 compares to an industry MFP trend of -1.45% for the full sample period. The difference is a non-negligible 33 basis points. PEG, like PSE, used data for the econometric work in this proceeding from a substantially larger group of companies than they did for the productivity work because the econometric research does not require *panel* data (a full set of annual observations for each company). Note also that PEG reported productivity results for a *cost-weighted* average of the sampled U.S. utilities whereas the econometric work effectively applies the *same weight* to data from all sampled companies.

e) This statement is confirmed.

f) The +0.60 trend parameter estimate is less sensitive to the special operating conditions of the 2005-2016 period and was rendered more precise by the larger sample period employed in its estimation. Its positive value may indicate that the MFP trend for a larger sample of utilities would be more positive than the trend for the smaller samples used in the MFP research due to data limitations. The productivity trend of sampled utilities has been negative since 2005, but the degree to which this has been due to cost drivers that are relevant to Hydro One is unclear.

g) No. But the 0.60 value of the trend variable is used in the projection.

h) PEG believes that PSE can perform the requested run. While the addition of a quadratic term to the model could slow the Company's cost growth projections, it is not clear whether this is due to cost drivers similar to those facing Hydro One.

M1-HON-7

Reference: Exhibit M1, page 22

Preamble: PEG says it does not object to the construction standards index variable used by PSE, but notes that it addresses a special cost disadvantage of the company, when special advantages could be ignored. PEG also says it believes that PSE misstated Hydro One's value for the variable.

Interrogatories:

a) What special advantages for Hydro One are being ignored in PSE's model? If there are any, what prevented PEG from inserting them into their own model?

b) Did PSE also construct variables that do not address a special cost disadvantage of the company such as KM of Tx line, Ratcheted maximum peak demand, average substation capacity, number of substations per KM of line, average voltage of Tx lines, percent of KM line that is underground, percent of Tx plant in total plant?

c) In the technical conference, Mr. Fenrick (lead author of the PSE report) stated that PSE examined the transmission service territory of Hydro One and that the current approach of using the retail service territory of Hydro One is a conservative one. The variable value for Hydro One is higher (i.e., more challenging) if the transmission service territory is inserted rather than the retail service territory. Given PEG's concern over this issue, please re-run the PEG model and substitute the value 0.99 for the current value for the construction standards variable for Hydro One and revise Table 5 of the PEG report.

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

a) There are reasons to believe that some transmission cost drivers have been more favorable to Hydro One than the norm for the sampled U.S. utilities. For example, the Company may not in recent years have faced comparable pressures to address bulk power market dysfunction or to increase access to remote renewable generation resources. For whatever reason, PSE and PEG both calculated that Hydro One's transmission MFP growth exceeded the norm for U.S. utilities over the 2005-2016 sample period.

Please also note that PEG's retention for these two transmission IR proceedings did not provide for extensive work to develop new variables or other alternative and exploratory analyses.

b) PEG notes that variables like these are readily calculated from FERC Form 1 data and would be expected in a competently developed transmission cost model.

c) PEG believes that PSE can undertake this run.

M1-HON-8

Reference: Exhibit M1, page 23

Preamble: PEG states that PSE forecasted Hydro One's OM&A expenses to grow by OM&A price inflation during the forecasted time period. PEG further states as follows: "Since the Company's output growth
is expected to be near zero, this implies 0% OM&A productivity growth. However, PSE calculated a 1.11% average annual decline in the OM&A productivity of sampled transmitters." PEG refers to this as a "rosy scenario".

Interrogatories:

a) How did PEG escalate Hydro One's OM&A expenses during the forecasted period?

b) If PEG believes that OM&A expense growth increasing by inflation (assuming zero growth) is a "rosy scenario," does PEG believe it is appropriate to only allow OM&A revenue to be escalated by less than inflation?

c) Given PEG's statement, what does PEG believe an appropriate productivity factor would be for the OM&A portion of the revenue requirement?

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

a) PEG's goal was to benchmark the Company's forecasted/proposed cost. Hydro One's forecasted/proposed OM&A expenses were accordingly used in the analysis.

b) No. The point of mentioning a rosy scenario is that Hydro One used an OM&A cost growth projection that was much slower than PSE's industry average OM&A productivity results would support.

c) The OM&A productivity growth of US transmitters averaged a 0.69% annual decline over the full sample period in PEG's study. However, PEG has not formulated a view as to the appropriate productivity factor for the OM&A portion of Hydro One's revenue requirement.

M1-HON-9

Reference: Exhibit M1, page 24

Preamble: PEG states that only Toronto values were used to levelize the Company's construction cost index, even though much of the transmission system is located far from Toronto.

Interrogatories:

a) What city values did PEG used in their research to levelize the construction costs for Hydro One?

b) Does PEG believe that it may be possible that construction costs for Hydro One are higher than those in the Toronto index, due to the company serving relatively remote and hard to reach areas?

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

a) PEG followed PSE's construction cost levelization method using data provided by PSE which used Toronto as the only city for HON. Despite our stated concerns, we did not prioritize making a change to this part of the work.

b) No. Evidence suggests that they will be lower. Below is a table with construction cost data from the 2012 RSMeans book for every available city in Ontario. It can be seen that Toronto has the highest value. Therefore, if PEG did use a population-weighted average value as they have done in many prior studies, it would result in a lower value for HON and a lower cost performance score.

Table HON-9

RSMeans City Cost Indexes
(2012 Book, 2010 Values)

Ontario	
City	**Total Weighted Average Value**
Toronto	112.3
Sarnia	110.5
Brantford	110.4
Hamilton	109.4
Kingston	109.2
Barrie	109.1
Cornwall	108.7
Oshawa	108.7
Ottawa	108.7
Peterborough	108.6
Owen Sound	108.3
Timmins	107.8
London	107.8
North Bay	107.8
Sault Ste Marie	104.6
Kitchener	103.4
Thunder Bay	103.0
St. Catharines	102.8
Sudbury	102.7
Windsor	102.4

M1-HON-11

Reference: Exhibit M1, page 35

Preamble: PEG's 2005-2016 industry MFP growth rate is equal to -1.47%. PSE's reported MFP growth rate over the same period is -1.45%.

Interrogatories:

a) Would it be PEG's opinion that the PSE and PEG MFP methodologies and results for the US MFP studies are quite similar, other than the sample period employed?

b) Please list any differences in the treatment of capital and OM&A in between PEG's MFP study and total cost benchmarking study (e.g., depreciation rates, cost definitions, etc.).

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

a) PEG's methodology for measuring US transmission productivity growth is similar to that of PSE in some respects but different in others. Here are some notable differences.

   - separate calculations for U.S. utilities of transmission and general plant quantities
   - more accurate depreciation rates
   - considers the trend in general plant as well as transmission plant construction costs
   - OM&A price index cost share weights are company-specific and time-variant
   - labor price indexes are regionalized
   - earlier benchmark year adjustment
   - PEG excluded certain OM&A costs that were sensitive to industry restructuring and reduced cost comparability.

b) Many of the changes made to the benchmarking work in the study for this proceeding were to resolve remaining differences between the benchmarking work and the TFP work. The notable remaining difference is that the TFP work uses 2008 to levelize the asset price index. This should not matter for the calculation of TFP trends.

M1-HON-14

Reference: Exhibit M1, pages 19 and 20

Preamble: One of PEG's critiques of PSE's productivity study is the sample period used. PEG states on p. 20 that transmission capex was boosted during the 2005 to 2016 period due to the need to improve the functioning of bulk power markets and to access remote renewable resources.

Interrogatories:

a) Does PEG believe that system age and aging infrastructure could also have an impact on capex spending and thus cause slower productivity trends?

b) Does PEG believe that the cost pressures that have resulted in strongly negative productivity trends in the transmission industry in recent years will subside by 2021 and 2022?

c) Will aging infrastructure of the transmission system built in the aftermath of WWII and during the increased electrification of society in the 1960s subside by 2021, in PEG's opinion?

d) Will the recent phenomenon of distributed energy resources (such as renewable generation) subside by 2021, in PEG's opinion? Does PEG believe it is possible the trend towards distributed energy resources may accelerate in future years?

e) On p. 47 of a PEG authored publication for the Edison Electricity Institute (EEI) entitled, "Alternative Regulation for Emerging Utility Challenges: 2015 Update", PEG states that formula rates were used by the FERC in an effort to facilitate "urgently" needed investments in the power transmission industry. Please provide all the reasons why PEG stated that investments in the transmission industry were urgently needed.

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

a) We discussed the drivers of productivity growth in section A.1 of our report. This discussion indicates that a need for high replacement capex will tend to slow MFP growth in the short term. The extent to which this has recently slowed MFP growth is unclear.

b) PEG's review of transmission productivity cost drivers suggests the possibility that US transmitter productivity growth may be higher in 2021 and 2022 than the average for PSE's sample period. After all, further adoption of formula rate plans should slow and pressures may not be as strong to improve system reliability or bulk power market performance. The Trump administration may continue, and its policies have generally not encouraged increased reliance on remote renewable generation resources.

c) PEG has not performed an appraisal of this issue. However, if aging infrastructure was not a major driver of negative productivity growth during the 2004-2016 period, it may not be a major driver in 2021 and 2022. PSE has had two opportunities to shed light on this issue but did not do so.

d) Trump administration policy has not encouraged increased reliance on distributed energy resources such as photovoltaic rooftop solar facilities. Distributed generation may nonetheless grow in some regions. This would slow transmission output, but it is unclear how this raises transmission cost. Economies in transmission cost are often portrayed by solar advocates as a component of the "value of solar."

e) PEG has been aware for many years of the need for transmission capex to increase transmission reliability, increase access to renewable resources, and improve the performance of bulk power markets.

M1-HON-18

Reference: Exhibit M1, page 11, page 42

Preamble: PEG states that customers must fully compensate Hydro One for expected capital revenue shortfalls when capex is high for reasons beyond its control.

Interrogatory:

a) Please clarify PEG's statement and provide examples of situations when ratepayers would fully compensate Hydro One's capital revenue shortfalls.

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

a) There are several reasons that capex may be high for reasons that are beyond the Company's control. Examples include an unusually large number of assets needing replacement, new IESO reliability requirements, and severe storms. Under the proposed Custom IR plan, Hydro One can receive supplemental capital revenue via the C factor, Y factors, and Z factors. Since the proposed X factor is zero and there is no dead zone on the Z factor materiality threshold and no materiality thresholds for the capital-related Y factors, the Company would be fully compensated for approved capex that exceeds normal I-X funding.

M1-HON-19

Reference: Exhibit M1, page 42

Preamble: PEG makes several statements on page 42 of the report.

Interrogatories:

a) On page 42 of the report PEG states that "The Company can then be compensated twice for the same capex: once via the C-factor and then again by low X factors in past, present and future IRMs."

   i. Please clarify this statement and provide examples of how a utility would be compensated twice for the same CapEx.

b) On that page PEG also states that "the Company need not return any surplus capital revenue in future plans if capital cost growth is unusually slow for reasons beyond its control".

   i. Please explain what surplus capital revenue would be owed to customers given: (i) that the proposed capital in-service variance account protects customers over the test period of the application; and (ii) that revenue requirement increases in a future term would be set based on the expected capital cost growth forecast at that time.

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

a) In this and future IR plans for the Company, the X factor term of the revenue cap index would reflect the base transmission MFP trend of a sample of utilities. This trend is slowed by the capex of the sampled utilities. The C factor, Y factors, and Z factors may afford Hydro One supplemental revenue for kinds of capex that are also incurred by other utilities and thereby slow their productivity growth. In the future, Hydro One may not have a C factor and its capital revenue growth between rate cases will depend more on the I - X formula.

b) PEG acknowledges that the CISVA and occasional rate rebasings reduce concern about double counting. However, Hydro One may come to a point where it no longer requests supplemental capital revenue or can no longer obtain it. In that eventuality, its allowed revenue would be escalated by a revenue cap index. The Company would then not be obliged to accept slower revenue growth (e.g., a negative C factor) even if slow cost growth was due in large measure to events beyond its control. There are precedents for special adjustments to revenue cap index formulas when capital cost growth is expected to be slow.[1]

This is an issue right now in a proceeding to consider the IR application of a Hydro One transmission affiliate, the B2M Limited Partnership.[2] This company owns a single 500 kV transmission line. Even though B2M acknowledges in its application that it has "lower OM&A in comparison to other transmitters" and "no forecast capital expenditures during the rate period"[3], the company is proposing a standard revenue cap index with an inflation factor and an X factor based on the industry MFP trend. The Company further claims that "cost efficiencies are available only in respect to a modest portion of OM&A costs"[4] even though its capital productivity is likely to grow rapidly due to depreciation during the plan for reasons that are beyond its control. In contrast, U.S. utilities that just completed large plant additions have sometimes agreed to rate freezes or stayed out of rate cases for several years.

[1] See, for example, California Public Utilities Commission Decision No. 97-07-054, where the Commission increased the X factor to reflect Southern California Gas's forecast of a declining rate base.

[2] EB-2019-0178, Hydro One Networks Inc., on behalf of B2M Limited Partnership, Exhibit A, Tab 4, Schedule 1, filed July 31, 2019.

[3] *Ibid*. p. 4.

[4] *Ibid*.