SCHOOL ENERGY COALITION INTERROGATORIES

M-SEC-1

Reference: [Ex. M, p.19, A-SEC-18]

Interrogatory:

SEC is seeking to understand the various possible sample periods, and the implications of each. Please advise if there is a long record (perhaps 40 years or more) of U.S. transmission productivity trend data that can be used to identify empirically the ebbs and flows of external factors influencing industry productivity as a whole. If there is any such record, please provide it, along with any information in the expert's possession explaining the external factors at play and how they influenced each change in the trends. Please describe any mathematical methods that can be used to identify/select a sample period that is properly representative of past trends.

Response:

The following response was provided by PEG.

PEG is unaware of any study of U.S. power transmission productivity that spans such a long sample period. However, it is known that U.S. transmission capital expenditures were much lower for many years after 1990 than they have been in recent years.[1] An EIA study shows that total expenditures by major US electric utilities on transmission increased from $9.1 billion (2019 dollars) in 2000 to $40 billion in 2019.[2] In recent years, the rate of increase in transmission spending has been decreasing. The increased spending may reflect various factors such as a transmission capex cycle and weaker capex containment incentives in recent years due to the increasing use of formula rates and the ROE premiums that the FERC has offered under the terms of the Energy Policy Act.

While many utility X factor witnesses today tout measures of "pure" industry productivity that yield more negative productivity trends but are only loosely tied to ratemaking realities PEG has, on several occasions, undertaken research that could be used to

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[1] Kirby, B., "Barriers to Transmission Investment", Presentation at Federal Energy Regulatory Commission Technical Conference, April 22, 2005.

[2] https://www.eia.gov/todayinenergy/detail.php?id=47316

customize productivity growth targets in IR proceedings. PEG presented a "start date analysis" in research for Board Staff in IRM3.[3] This had the goal of identifying a long-term productivity trend. PEG began by identifying the appropriate variables to be used in the start date analysis by determining if there was a statistically significant relationship between various variables and TFP levels. This research showed that cooling degree days, heating degree days, and the unemployment rate were the appropriate variables to use. The start date analysis compared the relative difference between the unemployment rate, cooling degree days, and heating degree days for the years between 1990 and 1996 to the endpoint 2006 values. The past year that was the most similar across these three metrics was the proposed start date. In its decision the Board decided to use the full sample period, rather than the timeframe indicated by the start date analysis.

In 2007, PEG developed an econometric method to create custom productivity growth targets for Enbridge and Union Gas.[4] These targets were useful because the productivity drivers facing these utilities (e.g., rapid growth in Toronto and Ottawa) were very different from those facing gas utilities in adjacent American states. This research was the basis for an article in the *Review of Network Economics*.[5] In the recent Hawaiian PBR proceeding, PEG again used econometrics to fashion custom productivity growth targets for the three Hawaiian Electric companies.[6]

Econometric approaches to X factor customization build on the key result of economic theory that the cost of an enterprise is a function of input prices, operating scale ("*Outputs*", which may be multidimensional), and miscellaneous other external business condition variables ("*Other Variables*"). This relationship may be expressed in general terms as

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[3] Kaufmann, L., Hovde, D., Getachew, L., Fenrick, S., Haemig, K., Moren, A., (2008), "Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario Report to the Ontario Energy Board." Filed in Ontario Energy Board EB-2007-0673, p. 60-63.

[4] Lowry, Mark N., Hovde, David, Getachew, Lullit, and Fenrick, Steve, "Rate Adjustment Indexes for Ontario's Natural Gas Utilities, EB-2007-0606/0615, November 20, 2007.

[5] Lowry, Mark N. and Getachew, Lullit, "Econometric TFP Targets, Incentive Regulation and the Ontario Gas Distribution Industry," *Review of Network Economics*, Vol. 8, Issue 4, December 2009.

[6] Lowry, Mark N., Hovde, David, and Kavan, Rebecca, "New X Factor Research for HECO," Hawaii PUC Docket 2018-0088, May 13, 2020.

$$Cost = f(Input\ Prices,\ Outputs,\ Other\ Variables,\ Time). \qquad [1]$$

We can measure the impacts of business conditions on utility cost by positing a specific form for the cost function and then estimating model parameters using econometric methods and historical data on utility operations. Here is a simple example of an econometric cost model which has two outputs, two other business condition variables, and a trend.

$$\ln Cost^{Real} = \hat{\beta}_0 + \hat{\beta}_1 \times \ln Output_1 + \hat{\beta}_2 \times \ln Output_2 + \hat{\beta}_3 \times \ln Other_1$$
$$+ \hat{\beta}_4 \times \ln Other_2 + \hat{\beta}_T \times Trend \qquad [2]$$

Here, $Cost^{Real}$ is real cost, the ratio of cost to an input price index. The $\hat{\beta}$ terms are econometric estimates of cost model parameters. This model has a double log functional form in which real cost and the values of business condition variables are logged. With this form, parameter estimates $\hat{\beta}_1$ to $\hat{\beta}_4$ estimate the elasticities of cost with respect to the four business condition variables. The term $\hat{\beta}_T$ is an estimate of the parameter for the trend variable in the model. This parameter would capture the typical net effect on utility cost trends of technological progress and changes in cost driver variables that are excluded from the model.

Econometric cost research has several uses in the determination of X factors for a company like Hydro One. In the case of our illustrative model, econometric estimates of output variable parameters can be used to construct an output quantity index with the following formula:

$$growth\ Outputs^C = [\hat{\beta}_1 / (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_1 + [\hat{\beta}_2 / (\hat{\beta}_1 + \hat{\beta}_2)] \times growth\ Output_2. \qquad [3]$$

This formula states that output index growth is an elasticity-weighted average of the growth in the two output variables. Indexes of this kind have been used in the productivity research of PEG and Clearspring in this proceeding. They can also serve as the scale escalator of a multidimensional revenue cap index. If the RCI formula lacks such an escalator, the expected growth in the output index during the term of the IR plan can provide the basis for an X factor adjustment.

In a seminal paper by authors that included University of Toronto economists, Denny, Fuss, and Waverman provided the additional useful result that, for a cost model like [2], growth in a company's multifactor productivity ("MFP") can be decomposed as follows.

$$growth\ MFP = [1 - (\hat{\beta}_1 + \hat{\beta}_2)] \text{ x } growth\ Outputs$$
$$- (\hat{\beta}_3 \text{x } growth\ Other_1 + \hat{\beta}_3 \text{ x } growth\ Other_2) - \hat{\beta}_T. \qquad [4]$$

The first term in [4] is the economies of scale that are realized due to output growth. These economies are greater the smaller is the sum of the cost elasticities with respect to output ($\hat{\beta}_1$ + $\hat{\beta}_2$) and the greater is output index growth. Relation [4] also shows that if a change in the value of a business condition variable like *Other₁* raises cost it slows MFP growth. If the trend variable parameter estimate has a negative (positive) value it would to that extent raise (lower) MFP growth. Formulas like [3] and [4] can be generalized to models with additional outputs and other business condition variables.

Econometric cost research and an equation like [4] can be used to identify MFP growth drivers and estimate their impact. Given forecasts of the change in output and other business conditions, an equation like [4] can also provide the basis for MFP growth targets that are specific to the expected business conditions of a utility that will be operating under PBR. For example, we can make projections that are specific to Hydro One during the four indexing years of its CIR plan. These are effectively projections of the MFP growth that typical utility managers would achieve if faced with Hydro One's business conditions.

For the simple model detailed in equation [4] the MFP growth projection formula would be

$$\widehat{MFP}^{C}_{HONI} = \left[1 - \left(\hat{\beta}_1 + \hat{\beta}_2\right)\right] \text{x } \overline{trend\ Outputs}_{HONI} - \left(\hat{\beta}_3 \text{ x } \overline{trend\ Other}_{1,HONI}\right) +$$
$$\left(\hat{\beta}_4 \text{ x } \overline{trend\ Other}_{2,HONI}\right) - \hat{\beta}_T \qquad [5]$$

Here $\widehat{MFP}_{HONI}$ is the projected annual MFP growth trend (average annual growth rate) for Hydro One during the final four years of its new plan. The variable $\overline{trend\ Outputs}_{HONI}$ is the expected growth trend in Hydro One's output index. $\overline{trend\ Other}_{1,HONI}$ is the expected growth trend for Hydro One in each external business condition l that is included in the model.

In an application to Canadian telecommunications Denny, Fuss, and Waverman, *op. cit*., were the first to use econometric research and a formula like [4] to decompose MFP growth. A simple version of this method was also used in a few California proceedings before PEG became its chief practitioner in the regulatory arena.

MFP growth projections have several advantages in the design of an X factor for Hydro One. They are useful for ascertaining the reasonableness of an X factor which is based on more conventional industry productivity trend research. Moreover, the projection can pertain to the specific costs that the revenue cap index will address.[7] Despite being customized to Hydro One's business conditions, the use of these projections would not weaken the Company's cost containment incentives since they reflect only the cost impact of external business conditions.

Transmission Productivity Drivers

The usefulness of MFP growth projections depends on the sophistication with which the drivers of MFP growth are modelled. In the case of power transmission the relevant drivers of MFP growth have in recent years included the following:

- growth in operating scale
- need for replacement capex (aka "repex")
- prevalence of severe storms and wildfires
- change in reliability and resiliency standards
- changes in the technologies for providing utility services

Some of these conditions affect the MFP growth of utilities more than others. For example, MFP growth is especially sensitive to repex for several reasons.

- Utility technology is capital-intensive.
- Highly depreciated assets valued in *historical* dollars are replaced with assets which are valued in *current* dollars, are designed to last for decades, utilize new

[7] For example, it is easy to remove pension and benefit expenses from the definition of cost if these expenses are going to be Y factored in the IR plan.

technologies, and must conform to the latest performance standards. These standards typically exceed any that were previously applicable.

- There is typically no counterbalancing growth in measured output.

Other kinds of capex may also improve system capabilities in ways that are not captured by the output index.

Details of the HECO Research

Guided by the above analysis, PEG in the recent HECO PBR proceeding developed an econometric model of VIEU total base rate input cost. An important focus of this research was the development of an appropriate age variable for the econometric work. To the extent that assets near and then exceed their average service lives ("ASLs"), cost tends to rise due to a greater need for repex. If the need for repex increases, intuition suggests that MFP growth will slow.

Standardized data on the age of assets are, unfortunately, not readily available for a large sample of U.S. electric utilities. However, extensive data have been available for many years on the value of gross additions to various kinds of electric utility plant. We used these data to develop a repex requirement indicator ("RRI") for transmission and distribution ("T&D") assets. This variable indicated how the need for T&D repex varies between utilities and changes over time.

The need for repex was modeled as a 13-year moving sum of the quantity of gross plant additions made ASL years ago, six years further into the past, and five years forward into the future. For each asset *j* in year *t-s* let $VKA_{j,t-s}$ be the *value* of gross plant additions, $XKA_{j,t-s}$ be the *quantity* of plant additions, and $WKA_{j,t-s}$ be the value of the corresponding regional Handy-Whitman indexes ("HWIs") of electric utility construction costs. The repex requirements index for asset class *j* in year *t* $RRI_{j,t}$ then had the formula

$$RRI_{j,t} = \sum_{s=ASL-6}^{ASL+6} XKA_{j,t-s} = \sum_{s=ASL-6}^{ASL+6} {VKA_{j,t-s}}\Big/{WKA_{j,t-s}} = \sum_{s=ASL-6}^{ASL+6} {VKA_{j,t-s}}\Big/{WKA_{j,t-s}}$$

PEG calculated RRIs for transmission and distribution separately and then calculated the summary RRI for T&D by summing the separate T&D RRIs.

$$RRI_{TD,t} = RRI_{T,t} + RRI_{D,t}.$$

Capacity Addition Variable

PEG also calculated a variable, *MWadd*, that was a moving sum of the megawatts ("MW") of generation capacity additions in the last ten years.

$$MWadd_t = \sum_{s=10} MW_{t-s} \sum_{s=10} MW_{t-s}.$$

We expected that cost will be higher the higher is the value of *MWadd*.

Model Estimation

To estimate the parameters of the new VIEU cost model PEG used data from 45 utilities. Details of the new cost model are reported in Table 4. Please note the following key results.

- T&D system age had a positive and highly significant impact on cost. A 1% increase in the RRI typically increased cost by about 0.10%. This means that an increase in RRI_{TD} tended to slow MFP growth.
- Recent generation capacity additions also had a statistically significant positive cost impact. A 1% increase in recent capacity additions typically raised cost by about 0.05%. This means that growth in recent capacity additions tended to slow MFP growth.
- The parameter estimate for the trend variable was also positive and statistically significant. It indicates that the cost of sampled utilities tended to *rise* by 0.25% annually for reasons that were not explained by the business conditions included in the model.

PEG also tried to consider the cost impact of transmission line growth. The variable that PEG developed for this business condition did not have statistically significant parameter estimate and was excluded from the model. This is not very surprising in a VIEU model.

On the basis of this research PEG made MFP growth projections for HECO for the four indexing years of the proposed MRP can be found in Table 6. These projections were based on the econometric parameter estimates from our new cost model as well as on Company

Table 4

New Econometric Model of Total Base Rate Input Cost

Explanatory Variable	Parameter Estimate	T-Statistic	P-Value
Number of Customers	0.307	11.744 ***	0.000
Fossil Steam and Other Generation Volume	0.120	8.623 ***	0.000
Mid-Year Generation Capacity	0.194	8.156 ***	0.000
Mid-Year Transmission Line Miles	0.076	8.833 ***	0.000
Ratcheted Maximum Peak Demand	0.098	3.144 **	0.000
Percentage of Capacity Scrubbed	0.155	12.696 ***	0.000
Transmission and Distribution Plant Additions between 7 Years Younger and 6 Years Older than Average Service Life	0.104	6.378 ***	0.000
Percentage of Customers without AMI	-0.035	-1.777 *	0.076
Number of Gas Customers	-0.041	-3.837 ***	0.000
MW of Generation Capacity Added in Previous 10 Years	0.046	3.885 ***	0.000
Constant	20.273	1014.085 ***	0.000
Trend	0.002	2.185 **	0.029
Adjusted R-squared	0.962		
Sample Period	2006-2017		
Number of Observations	540		

*Estimate is significant at the 75% confidence level
**Estimate is significant at the 95% confidence level
***Estimate is significant at the 99.9% confidence level

forecasts of changes in outputs and other cost model business conditions. These projections were specific to the costs that we expected to be addressed by the revenue cap index.

Table 6 shows that, when these business conditions were taken into account, the MFP growth of HECO was predicted to average a 0.63% annual decline in the 2021-24 period. This result was close to the -0.45% MFP trend of the sampled VIEUs which we calculated over the fifteen-year 2003-2017 sample period.

Application of Methodology to Hydro One

This kind of analysis was not undertaken for Hydro One Transmission in this proceeding, for several reasons.

- We did not believe that Hydro One would have the requisite data for the computation of the age variable. Cooperation by the Company was not assured and indeed they did not provide a helpful response to our request for age information.
- This kind of research is costly and experimental, and the budget for this project was limited.
- The OEB has to date shown no interest in the negative X factors that would likely have resulted from such a study.

Table 6

Econometric MFP Projections for HECO

	Incremental Scale Economies				Impact of Other External Business Conditions															Trend Variable Parameter Estimate	Projected MFP Growth Rate
	Sum of Estimated Output Elasticities		Forecasted Scale Index Growth	Incremental Scale Economies	Share of Generation Capacity Scrubbed			Share of Customers without AMI			Percentage Growth in Generation Capacity in Last 10 Years (unweighted)			Transmission and Distribution Plant Additions 7 Years Younger to 6 Years Older than ASL[3]			Number of Gas Customers				
					Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_1$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_2$	Estimated Cost Elasticity[1]	Growth Rate	$Product_3$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_4$	Estimated Cost Elasticity[1]	Growth Rate[2]	$Product_5$		
	[A]	[B=1-A]	[C]	[D=B*C]	ε_1	GR_1	$\varepsilon_1 * GR_1$	ε_2	GR_2	$\varepsilon_2 * GR_2$	ε_3	GR_3	$\varepsilon_3 * GR_3$	ε_4	GR_4	$\varepsilon_4 * GR_4$	ε_5	GR_5	$\varepsilon_5 * GR_5$	J	D - ∑ε*GR - J
Years											**HECO**										
2021	0.794	0.21	0.13%	0.03%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	4.44%	0.46%	-4.09%	0.00%	0.00%	0.25%	-0.68%
2022	0.794	0.21	0.26%	0.05%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	7.67%	0.80%	-4.09%	0.00%	0.00%	0.25%	-0.99%
2023	0.794	0.21	0.29%	0.06%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	3.84%	0.40%	-4.09%	0.00%	0.00%	0.25%	-0.59%
2024	0.794	0.21	0.30%	0.06%	15.53%	0.00%	0.00%	-3.54%	0.00%	0.00%	4.55%	0.00%	0.00%	10.37%	0.73%	0.08%	-4.09%	0.00%	0.00%	0.25%	-0.26%
Averages			**0.24%**	**0.05%**	**15.53%**	**0.00%**	**0.00%**	**-3.54%**	**0.00%**	**0.00%**	**4.55%**	**0.00%**	**0.00%**	**10.37%**	**4.17%**	**0.43%**	**-4.09%**	**0.00%**	**0.00%**	**0.25%**	**-0.63%**

[1] Elasticities drawn from PEG econometric model.
[2] Growth rates are calculated logarthmically.
[3] ASL = Average service life of utility assets

M-SEC-2

Reference: [Ex. M, p.20]

Interrogatory:

Please provide the expert's reasons for believing that the -0.62% base productivity trend of U.S. transmitters for 1996-2019 is reflective of the underlying cost pressures on Hydro One over the period 2023-2027.

Response:

The following response was provided by PEG.

PEG does not have a high level of confidence that the transmission productivity trends of U.S. power transmitters over their full sample period is reflective of the underlying cost pressures facing Hydro One. PEG's recommendation of the 0.62% MFP growth target for Hydro One was based on the following reasoning:

- Our benchmarking research found that Hydro One's total transmission cost efficiency declined at a 0.62% average annual rate over the four most recent historical years from 2015 to 2019. The transmission total cost efficiency of the Company's cost proposal is expected to average a 1.12% annual decline between 2023 and 2027. However, the optimal cost growth could well be less than the Company's forecast.
- The Company will be eligible for supplemental capex funding, so the X factor does not have to ensure that revenue growth has to cover necessary cost growth.
- On page 2 of Exhibit B-2-1, Section 2.1, Hydro One outlines its forecast of capex for the upcoming Custom IR plan. System renewal investments comprise 82% of the transmission capital plan, while system service and system access account for 10% of the capital plan and 8% is general plant. This mix of investments is different than in the U.S., where system extensions to connect renewable generation are more common. Replacement investments make up a lower share of transmission plant additions in the States.
- Markets for transmission services have already been formed in both the U.S. and Ontario. This process is unlikely to be repeated..

M-SEC-3

Reference: [Ex. M, p.22]

Interrogatory:

Please confirm that, to the best of the expert's knowledge, there have been no past periods in which peak demand for a transmitter declined on a permanent (as opposed to temporary) basis. If there have been examples of permanent declines in peak demand, please describe the reasons why that occurred. Please comment on the extent, if any, to which the decentralization of generation and load in Ontario, for example through distributed energy resources, can reasonably be expected to result in structural declines in transmission peak demand in the future.

Response:

The following response was provided by PEG.

The statement is confirmed.

PEG does not believe that distributed energy resources will cause a structural decline in transmission peak demand in the future. To the extent that such resources increase, it will of course slow transmission peak load growth.

Looking forward, transmission peaks may be reduced by more intensive uses of DERs, but ambitious goals for decarbonization of transportation and space heating will tend to bolster demand.

<u>M-SEC-4</u>

Reference: [Ex. M, p.30]

Interrogatory:

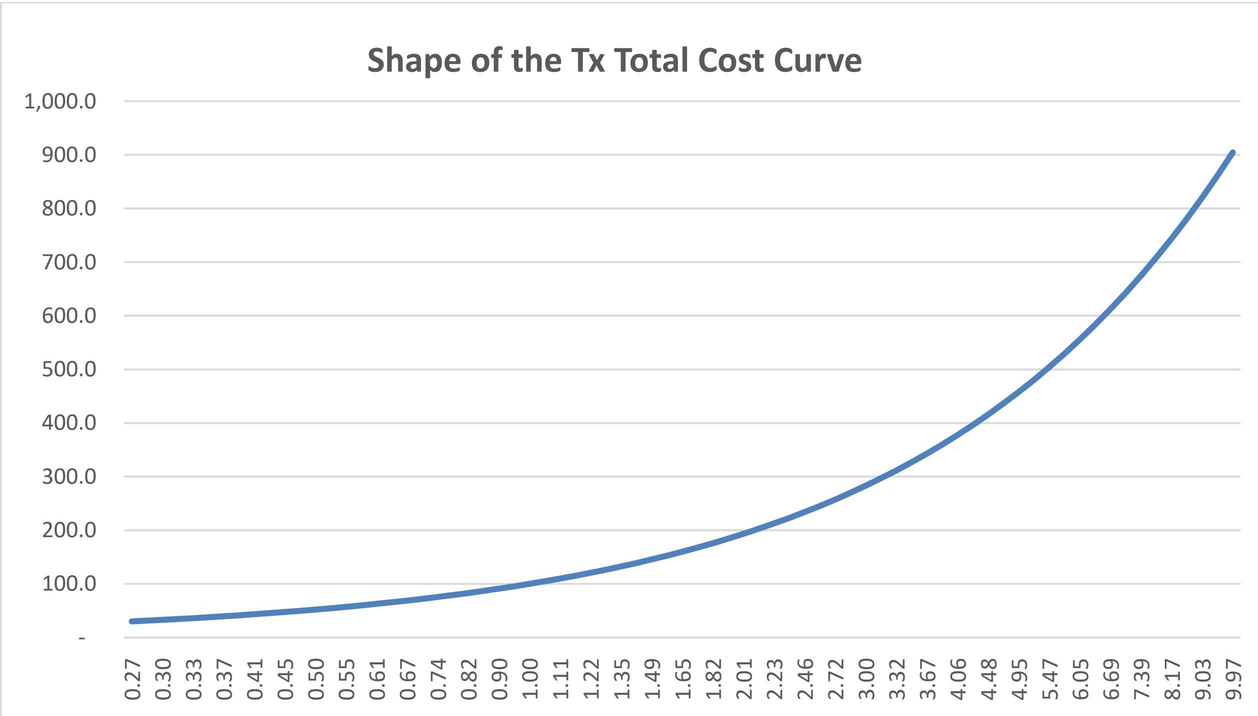
Can the non-linear relationship of cost to the two scale variables be expressed in a curve, either together or for each variable? If so, please provide a graphic illustration of that curve or curves.

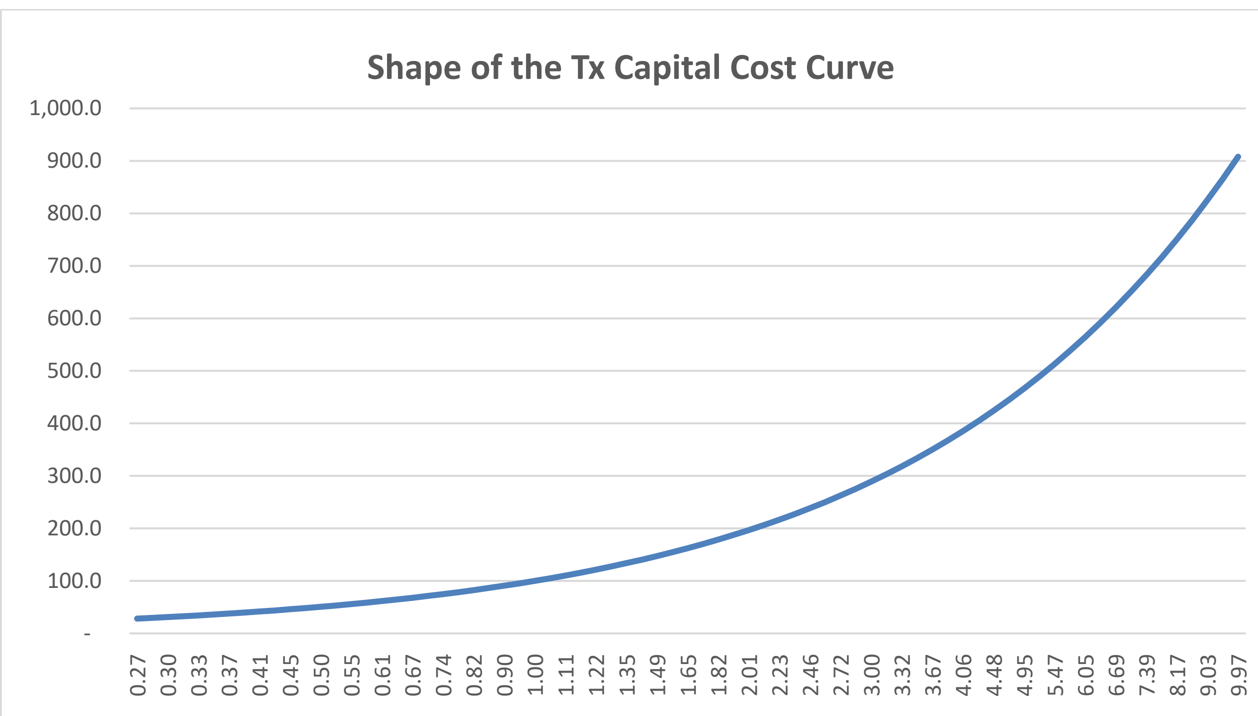
Response:

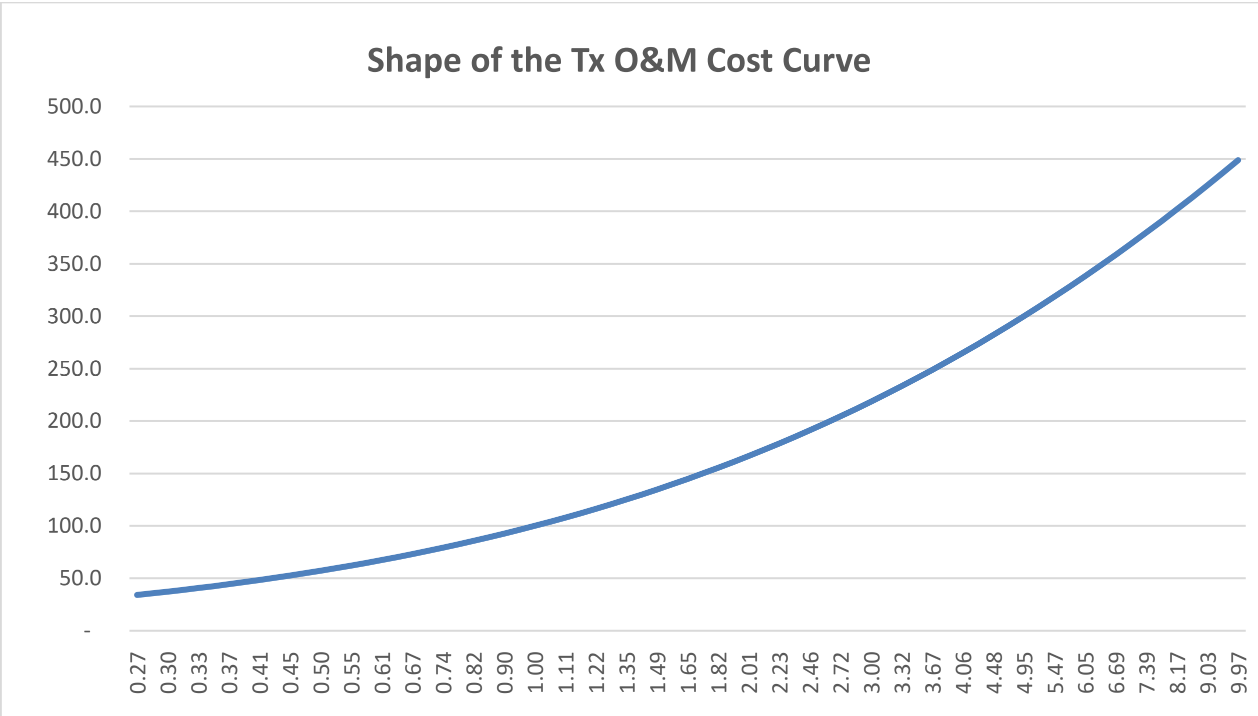
The following response was provided by PEG.

The following curves represent the level of cost that is consistent with a given overall scale of operations. The X-Axis is the ratio of scale to sample average scale. A value of 1.00 indicates a hypothetical company that is exactly average in all scale measures. The Y-Axis represents the level of cost consistent with a given level of scale. A value of 100 indicates the cost of the hypothetical average company. Left of this point indicates a hypothetical company that is a given amount smaller than average scale and the area to the right indicates larger than average scale. The lines were generated using the parameters from the tables as presented in the report. The capital cost curve looks very similar to the total cost curve due to the large percentage of capital cost in total cost.

Other possible versions that allow the different measures of scale to escalate separately are not provided because they would implicitly assume changes in density and would be misleading.


Shape of the Tx Total Cost Curve
1,000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
0.27 0.30 0.33 0.37 0.41 0.45 0.50 0.55 0.61 0.67 0.74 0.82 0.90 1.00 1.11 1.22 1.35 1.49 1.65 1.82 2.01 2.23 2.46 2.72 3.00 3.32 3.67 4.06 4.48 4.95 5.47 6.05 6.69 7.39 8.17 9.03 9.97


Shape of the Tx Capital Cost Curve
1,000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
-
0.27 0.30 0.33 0.37 0.41 0.45 0.50 0.55 0.61 0.67 0.74 0.82 0.90 1.00 1.11 1.22 1.35 1.49 1.65 1.82 2.01 2.23 2.46 2.72 3.00 3.32 3.67 4.06 4.48 4.95 5.47 6.05 6.69 7.39 8.17 9.03 9.97


Shape of the Tx O&M Cost Curve
500.0
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
-
0.27
0.30
0.33
0.37
0.41
0.45
0.50
0.55
0.61
0.67
0.74
0.82
0.90
1.00
1.11
1.22
1.35
1.49
1.65
1.82
2.01
2.23
2.46
2.72
3.00
3.32
3.67
4.06
4.48
4.95
5.47
6.05
6.69
7.39
8.17
9.03
9.97

M-SEC-5

Reference: [Ex. M, p.34]

Interrogatory:

Please calculate the X-factor for the period 2023-27 that would result in Hydro One's cost being 7% above the PEG benchmark in 2027.

Response:

The following response was provided by PEG.

It is fairly straightforward to calculate the X factor that would cause Hydro One's revenue requirement to achieve a 7% score in 2027. In 2023 at the start of the period, Hydro One had a cost performance score of 11.70%. A hypothetical performance of 7% in 2027 implies a performance improvement of 4.7% which is 1.18% per year. The model already accounts for inflation so the remaining amount would be the X necessary to get to 7%.

M-SEC-6

Reference: [Ex. M, p.37]

Interrogatory:

Please recalculate the Cost Benchmark Score for each of 2023-2027 on the assumption that the proposed C-factor is not approved, and therefore capital cost is limited to the proposed cost of service in 2023, and I-X escalator for each of 2024-2027.

Response:

The following response was provided by PEG.

PEG recalculated Hydro One cost using the Clearspring data. The 2023 cost value was escalated by I-X using the company inflation assumption of 2.0% and the PEG X of -0.13%. The transmission cost benchmarking model was run using these alternative values resulted in an average 2023-2027 cost performance of -3.7%. The individual year cost performance results are -1.1% -2.3%, -3.7%, -5.1%, and -6.5% for 2023 through 2027 respectively.

M-SEC-7

Reference: [Ex. M, p.38, Technical Conference Transcript, December 16 2021, p.102-3]

Interrogatory:

Please confirm that the Board's actions in approving larger or small increases in opex, whether on cost of service or by formula, can be expected to have a direct result that opex efficiency either improves or declines in response.

Response:

The following response was provided by PEG.

This statement is not readily confirmed without qualification. When the revenue growth of a utility is less than its OM&A cost forecast, its OM&A growth may well turn out to be less than it forecasted. This creates the impression that it has been induced to "trim its sails." However, in a multiyear rate plan with OM&A revenue growth that is not closely linked to cost growth, there is an incentive to cut costs no matter what the revenue growth. Some of the cost reductions may be deferrals until the rate case. For example, vegetation management may be trimmed and in the next rate case it will be claimed that a major push to get caught up on vegetation management may is needed.

M-SEC-8

Reference: [Ex. M, p.41]

Interrogatory:

Please explain why the expert believes the Board should, at this time, move away from its practice of setting the base productivity trend in multi-year rate plans at no less than zero.

Response:

The following response was provided by PEG.

PEG discussed the drivers of productivity growth in Appendix section A.1. They explained that these drivers include changes in miscellaneous business conditions that drive cost as well as changes in cost efficiency. These conditions include higher reliability standards and an increased share of assets that have advanced system age. Thus

> Productivity indexes are imperfect measures of operating efficiency. Productivity can fall (or rise) for reasons other than deteriorating (or improving) efficiency.

In the mathematics provided in response to M-SEC-1 (Exhibit N/Tab 5/Schedule 1), these external productivity growth drivers are the variables $Other_1$ and $Other_2$. It is thus reasonable for the Commission to embrace a negative productivity growth target provided that it is reasonably sure that the external conditions affecting productivity growth are at last as unfavorable for Hydro One as they are for utilities in the productivity study.

When the achievable productivity growth rate is negative, choosing the more realistic target rather than zero reduces the need for supplemental capital funding which, as practiced in Ontario, weakens capex containment incentives and raises regulator cost. It also strengthens the rationale for a supplemental capital stretch factor.

Reduced reliance on supplemental capital revenue can also be encouraged by the following.

- Add a scale escalator to the revenue cap index.
- Consider defensible new inflation measures that may grow more rapidly than the current weighted average of GDPIPIFDD and AWE growth.
- If in the future capital productivity growth is slower than OM&A productivity growth, develop separate RCIs to OM&A and capital revenue.

In an application to Hydro One Distribution, it is notable that there is not extensive evidence to suggest that a 0% MFP growth target is very far from reality. The problem lies on the transmission side, where several consultants have found evidence of negative productivity growth.

M-SEC-9

Reference: [Ex. M, p.49]

Interrogatory:

Please explain the reason for concluding that transmission line length is "highly correlated" with distribution service territory.

Response:

The following response was provided by PEG.

Please see PEG's response to M-Hydro One-21a (Exhibit N/Tab 1/Schedule 21 part a).

M-SEC-10

Reference: [Ex. M, p. 51]

Interrogatory:

Please confirm that the assumption of no trend variable means either a) the business condition variables explain all of the changes in costs, or b) the various factors underlying the trend variable, however large, offset each other so that the net impact is zero.

Response:

The following response was provided by PEG.

PEG clarifies that the finding of a trend variable parameter estimate that is close to zero is an empirical result and not an assumption. This result suggests that, for the sampled utilities over the sample period, the combined impact of various factors have a net effect of zero. The relevant factors include the following.

- Technological change
- Change in the X inefficiency of sampled utilities
- Changes in excluded business conditions
- Corrections for model imperfections (e.g., a poorly measured business condition variable or an inaccurate parameter estimate).

M-SEC-11

Reference: [Ex. M, p.51, 53]

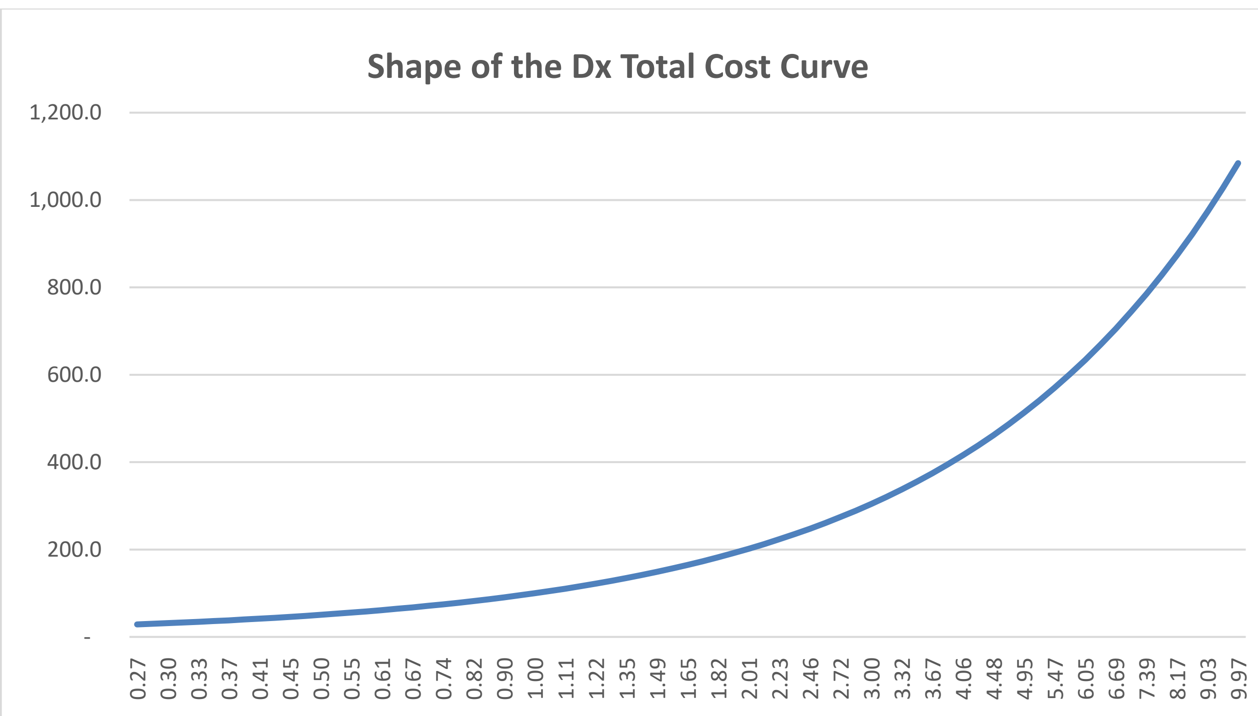
Interrogatory:

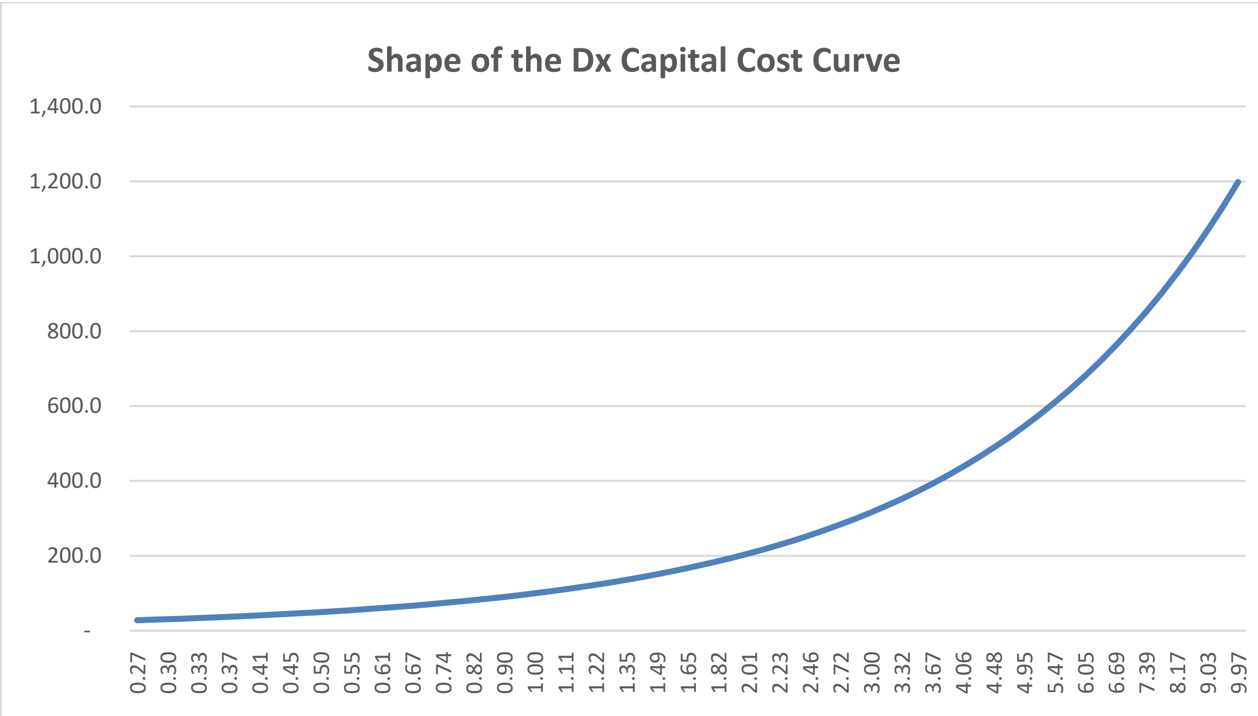
Can the non-linear relationship of capital cost to the three output variables, and of opex to the three scale variables, be expressed in a curve, either together or for each variable? If so, please provide a graphic illustration of that curve or curves.

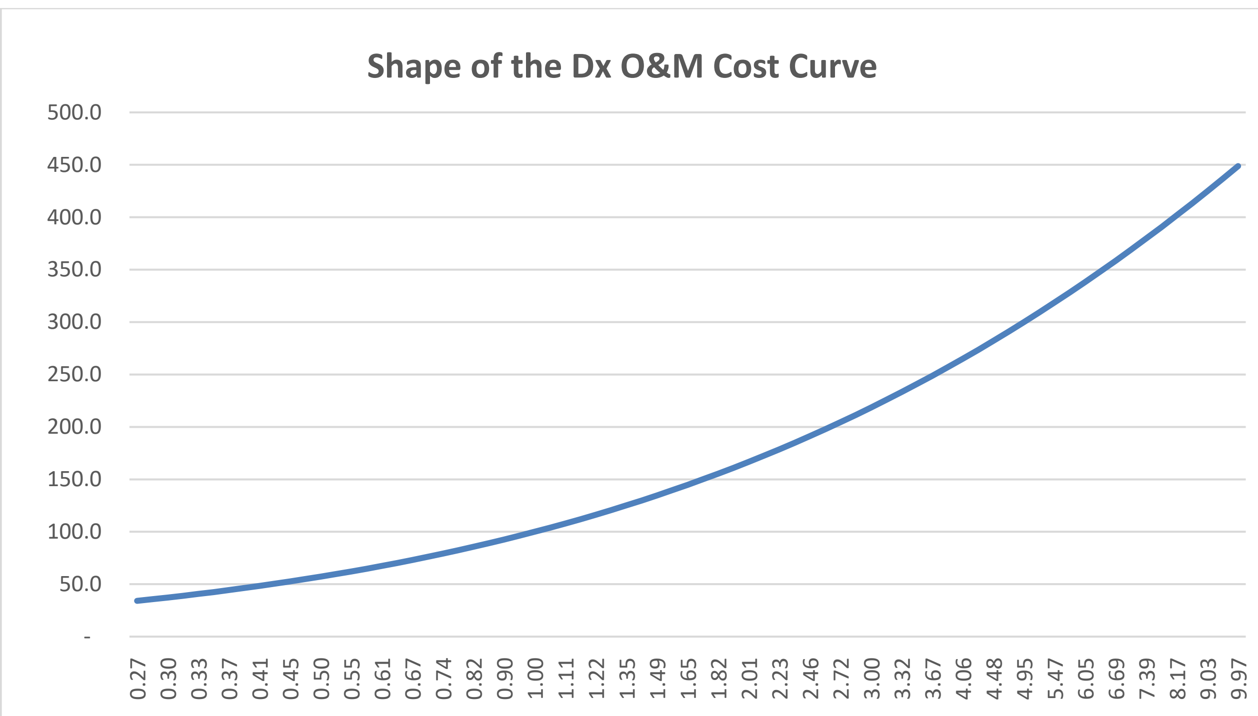
Response:

The following response was provided by PEG.

Below are the same cost curves that were provided in the response to M-SEC-4 (Exhibit N/Tab 5/Schedule 4) but applied to distribution cost. The methodology used was identical.




Shape of the Dx Capital Cost Curve
1,400.0
1,200.0
1,000.0
800.0
600.0
400.0
200.0
-
0.27 0.30 0.33 0.37 0.41 0.45 0.50 0.55 0.61 0.67 0.74 0.82 0.90 1.00 1.11 1.22 1.35 1.49 1.65 1.82 2.01 2.23 2.46 2.72 3.00 3.32 3.67 4.06 4.48 4.95 5.47 6.05 6.69 7.39 8.17 9.03 9.97


Shape of the Dx O&M Cost Curve
500.0
450.0
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
-
0.27 0.30 0.33 0.37 0.41 0.45 0.50 0.55 0.61 0.67 0.74 0.82 0.90 1.00 1.11 1.22 1.35 1.49 1.65 1.82 2.01 2.23 2.46 2.72 3.00 3.32 3.67 4.06 4.48 4.95 5.47 6.05 6.69 7.39 8.17 9.03 9.97

M-SEC-12

Reference: [Ex. M, p. 59, 64-5]
Interrogatory:

Please describe the relationship, if any, between the unfavourable capital cost benchmarking scores of Hydro One and the availability of CIR plans, ICMs, Z-factors, and other capital cost increments in the Board's regulatory structures applicable to Hydro One.

Response:
The following response was provided by PEG.

Hydro One has had recourse in recent years to various provisions for supplemental capital revenue and these provisions have generally involved variance accounts. These provisions may very well have had a deleterious effect on the Company's capital cost efficiency. Other possible reasons for deteriorating capital cost performance include the following:

- "echo" effects from a past periods of major plant additions; and
- inadequate capital cost funding in the early years of the century.

However, PEG found in its distribution benchmarking study that Hydro One's distribution capital cost efficiency was stable and not deteriorating over the course of the expiring CIR.

M-SEC-14

Reference: [Ex. M, A-SEC-35, A-Staff-355, and Technical Conference Transcript, December 16 2021, p. 92-95]

Interrogatory:

Please confirm that utilities with different system age are expected to have different capital cost requirements, which can affect their future productivity trends, and their current econometric cost benchmarking. Please explain how, both for transmission and distribution, the expert has dealt with system age of Hydro One relative to the utilities in the external samples, and compare the treatment of system age by PEG and by Clearspring.

Response:

The following response was provided by PEG.

PEG acknowledges that utilities with different system age can have different capital cost requirements and this can affect their productivity trends and econometric benchmarking scores. Research to better understand the impact of system age on utility cost performance is worthwhile. A major complication of such research is that the age of assets is not an entirely exogenous cost driver. In M-SEC-1 (Exhibit N/Tab5/Schedule 1) PEG detailed some work it did for Hawaiian Electric that attempted to finesse this problem. The age of T&D assets was found to be a statistically significant productivity growth driver.

In this proceeding, neither PEG nor Clearspring featured a cost benchmarking model that included a system age variable. Clearspring did some constructive but inconclusive exploratory research on the relationship between system age and cost. However, this work was inconclusive. A major limitation of this Clearspring work was its focus on the *average* age of assets as opposed to a metric that attempts to measure the cost impact of assets that are near or past the end of their expected service life. In its response to part c of Staff Interrogatory 355 (Exhibit I/Tab 1/Schedule A-CLS-Staff-355) Clearspring declined to calculate a version of its capital age variable that would allow the measurement of cost impacts of assets near or past the end of their expected service lives. Clearspring's focus on average age may have been driven in part by limitations of the available Hydro One data.

M-SEC-14

Reference: [Ex. M, p.63; Ex. G-1-2, p.16,33]

Interrogatory:

Hydro One has proposed two new variance accounts: the Externally Driven Transmission Projects Variance Account and Externally Driven Distribution Projects Variance Account. Please provide the expert's view on these two proposed accounts including views on how it may impact Hydro One's cost control incentives, and the forecast benchmarking results of both PSE and PEG.

Response:

The following response was provided by PEG.

Hydro One's proposed Externally Driven Transmission Projects Variance Account would address the transmission revenue requirement impact of variances between actual additions and those that are included in Hydro One's Transmission System Plan for mandatory transmission construction, expansion, reinforcement, modification and relocation work required by governmental authorities. This would include the costs of new transmission lines required by the Independent Electricity System Operator, as the following statement reveals.

> Given the five-year term for the current application, any future IESO direction, which is not currently contemplated and may have a more significant impact on the proposed capital plan, can be received during the term of the current application. As such, the Externally Driven Transmission Projects Variance Account would ensure that any future IESO direction can be accommodated without having to defer the required investments in system needs.[8]

An Affiliate Transmission Projects variance account was recently approved that addresses the costs of projects undertaken by Hydro One at the behest of the Ontario government or the IESO that are expected to be owned by a new partnership between Hydro One and partners.[9] This account, however, only addressed the cost of transmission lines. To the extent that Hydro One was compelled to invest in a new or upgraded station due to these investments,

[8] Exhibit G, Tab 1, Schedule 2, pp.17-18.

[9] The Waasigan Transmission Line is an example of a project that will be addressed through this account.

those costs would be addressed by Hydro One's proposed Externally Driven Transmission Variance Account.

Hydro One's proposed Externally Driven Distribution Projects Variance Account is more narrow in scope, addressing variances in the revenue requirements of projects for third-party initiated relocations, distributed energy resource connections, or service upgrades to meet the needs of existing customers.

These variance accounts would protect Hydro One from external events that affect capital cost and are beyond their control. The costs might otherwise be recoverable through the Z factor. However, these variance accounts also weaken the Company's incentive to contain these costs. In the absence of these accounts, Hydro One would have more risk if capital cost exceeded the Company's forecast.

M-SEC-15

Reference: [Ex.M, p.10]

Interrogatory:

Please provide a copy of the study referenced in footnote 4.

Response :

The following response was provided by PEG.

A copy of the requested transmission productivity and benchmarking report that PEG prepared for the HQT proceeding is provided as Exhibit N/Tab 5/Schedule 15 Attachment 1.