ENERGY PROBE COMPENDIUM #4
PANELS 4 & 5

EB-2019-0082

IN THE MATTER OF *the Ontario Energy Board Act, 1998* ("Act");

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an order or orders made pursuant to section 78 of the Act approving rates for the transmission of electricity.

Hydro One Transmission
X-Examination Compendium #4
Energy Probe Research Foundation

October 29, 2019

EB-2019-0082 Hydro One Transmission-Energy Probe Compendium #4 Panels 4 and 5

Exhibit A Tab 4 Schedule 1Pages 7/8

Table 2: Summary of Revenue Requirement Components ($ Million)

Line		Reference	2020	2021	2022
1	Rate Base	C-1-1	12,374.5	13,093.3	13,916.7
2	Return on Debt	E1-1-1	330.6	349.8	371.8
3	Return on Equity	E1-1-1	444.5	470.3	499.9
4	Depreciation	F-6-1	474.6	505.2	530.9
5	Income Taxes	F-7-2	48.3	59.4	64.8
6	Capital Related Revenue Requirement		1,298.0	1,384.7	1,467.4
7	Less Productivity Factor (0.0%)			-	-
8	**Total Capital Related Revenue Requirement**		**1,298.0**	**1,384.7**	**1,467.4**
9	OM&A	F-1-1	375.8	381.1	386.4
10	**Total Revenue Requirement**		**1,673.8**	**1,765.8**	**1,853.8**
11	Increase in Capital Related Revenue Requirement			86.7	82.7
12	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			5.18%	4.68%
13	Less Capital Related Revenue Requirement in I-X			1.09%	1.10%
14	**Capital Factor**			**4.09%**	**3.59%**

Table 3: Custom Cap Index (RCI) by Component (%)

Custom Revenue Cap Index by Component	2021	2022
Inflation Factor (I)	1.40	1.40
Productivity Factor (X)	0.00	0.00
Capital Factor (C)	4.09	3.59
Custom Revenue Cap Index Total	5.49	4.99

Exhibit I Tab 02 Schedule 4 Witness: Steve Fenrick

ENERGY PROBE INTERROGATORY #4

Reference:A-04-01-01 p.18,19 and 37

Interrogatory:

Preamble:

However, it is likely that this output growth term will be very close to zero in the CIRperiod (see Table 8). The flat or declining nature of peak demands, due to conservation and demand management (CDM) plans and energy efficiency technology gains, makes it very likely that the maximum peak demand will be flat. Further, the total kilometres (KM) of transmission lines are projected by Hydro One to remain very close to current levels. Thus, the output growth rate will be essentially zero for each year of the CIR period.

a) Did Hydro One Provide a Peak demand forecast for the CIR period to PSE? If so please provide a copy.

b) Why does PSE use the assumption that peak demand growth (MW) will be flat given the negative load forecast (MWh), or will the System Load Factor change with load?

c) If the growth factor is negative what will be the impact on the CIR Formula and Revenue Requirement in 2021 and 2022?

d) Please provide a sensitivity analysis that shows this based on Hydro One Transmission peak demand data.

Response:

a) Yes.

Page 2 of 2

Forecast of Transmission Annual Peak and Kilowat Hours Transmitted

Year	Annual Peak (MW)	Annual Kilowatt Hours Transmitted
2017.00	22,178	135,104,305,239
2018.00	21,982	134,166,584,139
2019.00	21,763	132,844,060,731
2020.00	21,482	131,937,328,494
2021.00	21,439	130,803,164,625
2022.00	21,367	129,967,320,536
2023.00	21,291	129,104,753,912

Note. All figures are weather-normal.

b) The output quantity index is comprised of the maximum peak demand and the total kilometres of transmission line. The definition of the maximum peak demand is the highest peak demand value for the transmission system that has occurred from 2004. Please see pages 24 and 25 of the PSE report for the definition of the maximum peak demand variable. Given the definition of the variable, the maximum peak variable will not decline during the forecasted period.

c) The growth factor will not be negative but is projected to be essentially zero.

d) Please see the response to part c.

PSE REPORT EB-2019-0082 Hydro One Tx

PSE Power System Engineering, Inc.

Full-service consultants

Filed: 2019-03-21
EB-2019-0082
Exhibit A-4-1
Attachment 1
Page 1 of 59

Transmission Study for Hydro One Networks:

Recommended CIR Parameters and Productivity Comparisons

Prepared by:

Power System Engineering, Inc.
January 24, 2019

1 Executive Summary

This report has been revised from the Power System Engineering, Inc. (PSE) report filed in the Hydro One Sault Ste. Marie LP (SSM) application found in EB-2018-0218. Our recommendations regarding the customer incentive regulation parameters remain unchanged and our findings are similar to the report previously filed. No changes to the study have been made except the modifications which are listed and explained below.

1. Hydro One Networks provided PSE with a revised business plan that includes modified OM&A and capital spending levels for the projected years of the study.
2. A second modification has occurred due to PSE identifying peak demand data that was incorrectly reported by the three Southern Companies (Alabama Power, Gulf Power, and Mississippi Power) included in the sample. This data has now been corrected.[1]
3. The third modification are slight revisions in plant additions in 2016 and 2017 made by Hydro One.
4. The incentive regulation period moves to 2020 to 2022 which means the OM&A spending is now escalated for 2021 and 2022 by I-X using the 2020 test year expenses rather than 2019.
5. Two minor corrections in the code were made relative to the prior research. The first is we are now calculating the asset prices prior to 1963 in calculating the capital benchmarks. The second is including only the observations in the TFP sample when aggregating the TFP components.[2]

These five modifications have been incorporated into this revision and are the only changes made to the dataset and study methodology relative to the research filed EB-2018-0218 and EB-2018-0130.

1.1 Overview of Study

Power System Engineering, Inc. (PSE) was engaged by Hydro One Networks, Inc. (Hydro One) to conduct an empirical study of Hydro One's transmission operations. The three main areas studied were:

1. Total cost levels,
2. Total factor productivity (TFP) trends, and
3. Custom incentive regulation (CIR) parameters.

Results from the first two areas (total costs and TFP) informed the recommended CIR parameters.

For the first area, PSE conducted an econometric benchmarking study of Hydro One's total costs. For the second area, TFP, we calculated the TFP trend of both Hydro One and that of the U.S. electric transmission industry. To develop recommendations for Hydro One's CIR parameters,

[1] This adjustment moved the TFP annual trend upwards by around 0.42%.

[2] Both corrections had a minimal impact on the results with the effect of the change being a slightly lower TFP trend by around 0.16%.

Extract PSE REPORT

1.2 Total Cost Benchmarking: Findings

Using a sample of 57 transmission utilities, PSE estimated a translog total cost econometric model that captures the relationship between total transmission costs and a set of variables. The variables are described in Section 3.2 . As required by accepted best practice, all first order variables are signed according to theory and are statistically significant at a 90% level of confidence. PSE applied the translog functional form, which is the same functional form we used in Hydro One's distribution total cost benchmarking study.

However, the explanatory variables are different, and the distribution sample included numerous U.S. rural electric cooperative distributors to help capture the impacts of a distribution system serving low customer density areas. The variables included in the total cost model are illustrated in the following figure. These variables (also known as cost drivers) are included in the total cost model to correlate total cost with the variables and enable adjustments for the specific service territory circumstances encountered by Hydro One. For a more detailed description of the included variables, please see Section 3.2.

Extract PSE Report Page 16

$$Growth\ Revenue = I - X + O \qquad \text{[Equation 9]}$$

A "stretch factor" is sometimes added to the escalation formula to challenge (or stretch) the utility to achieve TFP gains above and beyond the industry TFP expectation. A positive stretch factor slows allowed revenue growth in a manner that shares with customers the financial benefits of the utility exceeding the industry TFP trend. Within 4GIR, the stretch factor is informed by econometric total cost benchmarking evidence, because an inefficient firm can more easily cut costs and ramp up TFP trends than an efficient utility can.

Once we insert the stretch factor (SF) term, we have the following equation.

$$Growth\ Revenue = I - X - SF + O \qquad \text{[Equation 10]}$$

As stated in Section 1.4 the output growth factor (*Growth O*) will be close to zero every year (see Table 8). For example, average annual growth rates from 2020 to 2022 of KM of Line, Maximum Peak Demand, and Output Quantity Index are 0.02%, 0.00%, and 0.01%, respectively. Furthermore, the existence of a Capital Factor should capture the anticipated capital cost impacts of output growth. Thus, if we drop the output term from the equation we get:

$$Growth\ Revenue = I - X - SF \qquad \text{[Equation 11]}$$

Hydro One is proposing to add a Capital Factor term that accounts for additional capital spending. When this term is added, we arrive at the following equation, which was the recommendation in Section 1.4 .

$$Growth\ Revenue = I - X - SF + Capital\ Factor \qquad \text{[Equation 12]}$$

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Table 4 List of Utilities in Benchmarking Sample

Company	Most Recent Peak Demand (MW)	Company	Most Recent Peak Demand (MW)
Alabama Power Company	12,328	Kansas Gas and Electric Company	2,604
ALLETE (Minnesota Power)	1,520	Kentucky Utilities Company	5,370
Arizona Public Service Company	7,906	Louisville Gas and Electric Company	2,989
Atlantic City Electric Company	2,673	Mississippi Power Company	2,692
Avista Corporation	2,310	Monongahela Power Company	2,053
Baltimore Gas and Electric Company	6,601	Nevada Power Company	6,996
Black Hills Power, Inc.	977	New York State Electric & Gas Corporation	2,967
Central Hudson Gas & Electric Corporation	1,088	Niagara Mohawk Power Corporation	8,578
Central Maine Power Company	1,550	Northern States Power Company - MN	10,357
Cleco Power LLC	3,509	Oklahoma Gas and Electric Company	6,649
Commonwealth Edison Company	21,175	Orange and Rockland Utilities, Inc.	1,435
Connecticut Light and Power Company	6,087	PacifiCorp	18,583
Consolidated Edison Company of New York, Inc.	12,663	PECO Energy Company	8,364
Delmarva Power & Light Company	4,114	Potomac Electric Power Company	5,786
Duke Energy Carolinas, LLC	23,622	PPL Electric Utilities Corporation	7,216
Duke Energy Florida, LLC	12,082	Public Service Company of Colorado	7,604
Duke Energy Indiana, LLC	7,282	Public Service Company of New Hampshire	2,366
Duke Energy Ohio, Inc.	5,308	Public Service Electric and Gas Company	9,800
Duke Energy Progress, LLC	14,355	Rochester Gas and Electric Corporation	1,601
Duquesne Light Company	2,826	San Diego Gas & Electric Co.	4,343
El Paso Electric Company	1,877	South Carolina Electric & Gas Co.	5,266
Empire District Electric Company	1,114	Southern California Edison Company	23,687
Florida Power & Light Company	25,797	Southern Indiana Gas and Electric Company, Inc.	1,217
Gulf Power Company	2,752	Southwestern Public Service Company	6,003
Hydro One Transmission	**23,213**	Tampa Electric Company	4,453
Idaho Power Co.	4,359	Tucson Electric Power Company	4,356
Indianapolis Power & Light Company	2,670	Union Electric Company	7,768
Jersey Central Power & Light Company	5,955	West Penn Power Company	3,954
Kansas City Power & Light Company	3,714		
Sample Average Peak =	**6,956**		
Number of Utilities =	**57**		

Extract PSE Report

2.2.4 Growth in Output

The last term in the revenue escalation formula is the growth in output. This term is not included for price cap indexes, because output growth will automatically increase revenues; this is because a utility's revenues are prices multiplied by billing determinants. However, as we showed in the index formula at the beginning of this section, in a revenue cap context the output growth term should be considered.

However, it is likely that this output growth term will be very close to zero in the CIR period (see

Page 18 of 59

Table 8). The flat or declining nature of peak demands, due to conservation and demand management (CDM) plans and energy efficiency technology gains, makes it very likely that the maximum peak demand will be flat. Further, the total kilometres (KM) of transmission lines are projected by Hydro One to remain very close to current levels. Thus, the output growth rate will be essentially zero for each year of the CIR period.

The existence of the capital factor is another reason we recommend not including the output growth factor in the formula. The capital factor incorporates any expected capital costs resulting from output growth. This makes including the output factor somewhat redundant when the capital factor is also present in the formula. However, PSE felt it was important to mention this output growth term in the discussion, for the sake of accuracy and completeness. In the case of a revenue cap formula where the output growth factor is not expected to be zero and a capital factor is not present, an output growth factor should be included in a revenue adjustment formula.

Output Growth = Not included in formula

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Table 5 Econometric Model Parameter Estimates

Total Cost Model Estimates

VARIABLE KEY

KM = Total transmission Kilometres of line
D = Maximum peak demand
Tx = Percent of transmission plant in total electric utility plant
Cap = Average capacity (MVa) per substation
Sub = Number of transmission substations per KM of line
Volt = Average voltage of transmission lines
CS = Construction standards of building transmission pole
UG = Percent of transmission lines underground
Trend = Time trend (current year minus 2003)

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM	0.359	18.840	CS	0.240	6.100
KM*KM	0.120	4.670			
KM*D	-0.378	-5.370	UG	0.885	3.650
D	0.622	20.960	Trend	0.012	5.290
D*D	0.362	13.670			
			Constant	11.650	116.880
Tx	0.513	16.460			
			Adjusted R-Squared	0.923	
Cap	0.144	6.810			
			Sample Period:		2004-2022
Sub	0.104	7.300	Number of Observations		732
Volt	0.214	10.050			

Extract PSE REPORT

Table 2 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,319,202	$1,500,514	-12.9%
2005	$1,372,128	$1,638,703	-17.8%
2006	$1,453,435	$1,773,126	-19.9%
2007	$1,586,919	$1,916,996	-18.9%
2008	$1,669,115	$2,108,130	-23.4%
2009	$1,783,173	$2,194,844	-20.8%
2010	$1,805,110	$2,206,257	-20.1%
2011	$1,984,174	$2,448,930	-21.0%
2012	$2,112,358	$2,584,997	-20.2%
2013	$2,097,031	$2,562,385	-20.0%
2014	$2,120,542	$2,620,081	-21.2%
2015	$2,227,713	$2,750,068	-21.1%
2016	$2,281,074	$2,876,130	-23.2%
2017 (projected)	$2,335,312	$2,995,513	-24.9%
2018 (projected)	$2,428,965	$3,118,802	-25.0%
2019 (projected)	$2,450,120	$3,229,926	-27.6%
2020 (projected)	$2,540,451	$3,344,163	-27.5%
2021 (projected)	$2,643,498	$3,462,904	-27.0%
2022 (projected)	$2,744,777	$3,586,170	-26.7%
Average % Difference			
2014-2016			**-21.8%**
2020-2022			**-27.1%**

Figure 2 Hydro One's Cost Performance 2004-2022

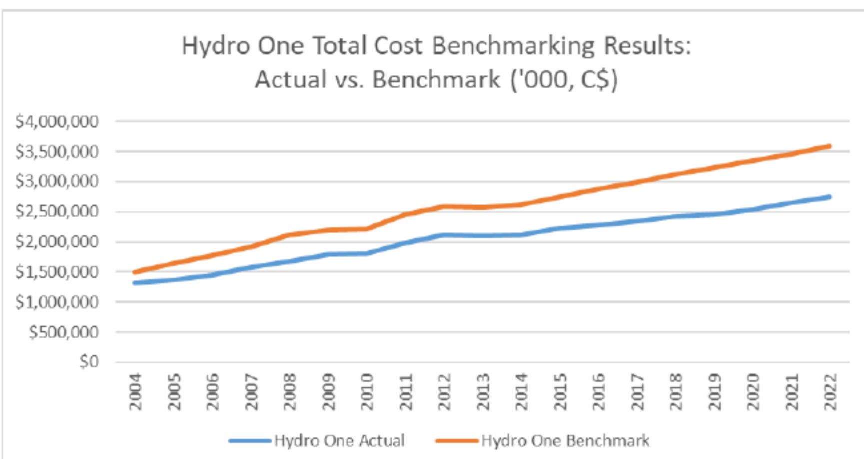


Table 2 and Figure 2 show that Hydro One's total costs have been below the benchmark value since 2004. In 2016, Hydro One is approximately $600 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to around $840 million by 2022, assuming Hydro One's application is approved in full. Throughout the 2020-2022 CIR period, Hydro One's projected total costs are 27.1% below benchmark expectations.

Extract PSE REPORT

Table 8 Outputs for Hydro One

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	20,603	25,414	1.000
2005	20,547	26,160	1.017
2006	20,625	27,005	1.040
2007	20,624	27,005	1.040
2008	20,661	27,005	1.040
2009	20,658	27,005	1.040
2010	20,676	27,005	1.040
2011	20,694	27,005	1.041
2012	20,891	27,005	1.044
2013	20,904	27,005	1.045
2014	20,882	27,005	1.044
2015	20,948	27,005	1.045
2016	20,949	27,005	1.045
2017 (projected)	20,689	27,005	1.041
2018 (projected)	20,965	27,005	1.046
2019 (projected)	20,967	27,005	1.046
2020 (projected)	20,967	27,005	1.046
2021 (projected)	20,970	27,005	1.046
2022 (projected)	20,974	27,005	1.046
Average Annual Growth Rate			
2004-2016	0.14%	0.51%	0.37%
2010-2016	0.22%	0.00%	0.08%
2004-2018	0.12%	0.43%	0.32%
2020-2022	0.02%	0.00%	0.01%

Extract PSE REPORT

1.3 TFP Findings: Industry and Hydro One

Using a sample of 48 transmission utilities, PSE calculated the total factor productivity trend of the industry from 2004 to 2016. This twelve-year period showed an average annual decline in industry-wide TFP, with an annual growth rate of -1.45%.

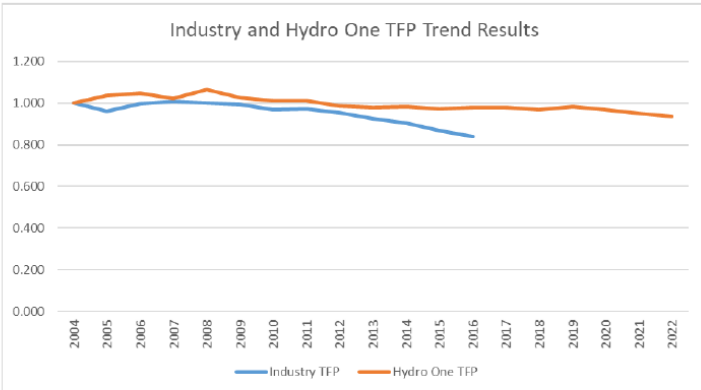
Hydro One's own TFP from the 2004 to 2016 period declined, but at a much slower pace than the industry, with an average annual growth rate of -0.18%. Hydro One's TFP is projected to decrease during the CIR period of 2020 to 2022, with an average annual growth rate of -1.70%.

The TFP results and average annual growth rates are provided in the table and figure following.

Table 3 Industry TFP and Hydro One TFP

Year	Industry TFP Index	Hydro One TFP Index
2004	1.000	1.000
2005	0.960	1.038
2006	0.995	1.047
2007	1.006	1.022
2008	1.000	1.064
2009	0.994	1.025
2010	0.970	1.012
2011	0.972	1.012
2012	0.955	0.988
2013	0.926	0.978
2014	0.903	0.983
2015	0.869	0.971
2016	0.840	0.979
2017 (projected)	NA	0.978
2018 (projected)	NA	0.968
2019 (projected)	NA	0.982
2020 (projected)	NA	0.968
2021 (projected)	NA	0.951
2022 (projected)	NA	0.936
Average Annual Growth Rate		
2004-2016	**-1.45%**	**-0.18%**
2010-2016	**-2.39%**	**-0.56%**
2020-2022	**NA**	**-1.70%**

Figure 3 Industry TFP and Hydro One TFP



Hydro One's long-term TFP trend compares favorably to the industry trend. Hydro One's annual TFP trend is 1.27% higher than the industry TFP trend from 2004 to 2016. The industry has had a consistent decline in TFP since 2004. In Section 6.1, we address some possible causes for negative TFP growth.

PSE Report Pages 51/52

8.1 PSE's recommendations on CIR parameters

PSE recommends the following general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$Growth\ Revenue = Inflation - X - Stretch + Capital\ Factor$

The specific parameter values for each component are as follows:

• PSE recommends an inflation factor calculated using the 4GIR calculation procedures, but with weights of 14% labour and 86% non-labour instead of the 4GIR weights. In 4GIR, the inflation factor is weighted with 30% of the growth in AWE for Ontario and 70% of the growth in GDP-IPI FDD. The AWE accounts for the labour component of total costs and the GDP-IPI FDD accounts for the non-labour component. PSE's recommendation for the electric transmission industry is to calculate the inflation factor with a 14% weight on AWE and an 86% weight on GDP-IPI FDD.

• The PSE X factor recommendation is 0.0%. This is based on the negative industry TFP finding of -1.45%.While a negative X factor could be considered, the 4GIR Decision made clear the Board does not desire to have a negative X factor embedded within the escalation formula. For this reason, PSE recommends a 0.0% X factor, which is the same X factor that is found in 4GIR.

• The PSE stretch factor recommendation is 0.0%. There are two reasons for this recommendation. The first is the "implicit stretch factor" of 1.45%, which is due to the X factor being set at 0.0%. This "implicit stretch factor" is far higher than the 0.33% implicit stretch factor embedded in the 4GIR Decision. The second reason is the total cost benchmarking result that shows Hydro One will be 27.1% below its benchmark costs throughout the 2020-2022 CIR period. The 4GIR Decision would indicate a 0.0% stretch factor. PSE believes this strong cost performance warrants a 0.0% stretch factor.

• PSE recommends not including an output growth factor to simplify the revenue cap formula, since the expected growth rate is close to 0.0%, and due to the possible redundancy of including both an output growth factor and a capital factor.

• The capital factor is based on Hydro One's proposed capital spending needs. PSE is not making any recommendations regarding the magnitude of the capital factor. We do, however, insert the proposed capital spending amounts into the TFP and total cost benchmarking studies, so the Board and stakeholders can ascertain the projected TFP trends and total cost benchmarking scores that result from the proposed level of capital spending

PSE Power System Engineering, Inc.

Full-service consultants

Reply to
PEG's Report ("Incentive Regulation for Hydro One Transmission")

Prepared by:

Power System Engineering, Inc.

October 15, 2019

Extract PSE REPLY REPORT

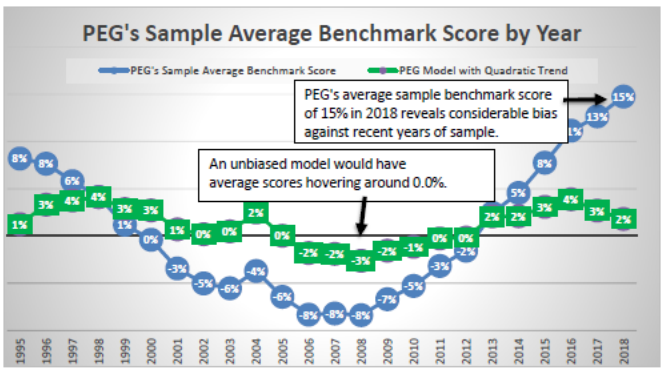
Figure 4 PEG Testimony

MR. SHEPHERD: A quadratic for the trend variable would change the trend variable from a straight line to curved line, correct?

DR. LOWRY: Yes. I mean, why not have that? I mean, I would be more interested in that to some degree than in some of the others. Particularly when you are forecasting outside of the sample period, it might be interesting to have a curvature on that.

When a quadratic trend variable is inserted in PEG's model, and with no other changes made, PEG's bias in each year hovers around the expected 0% value. In 2018, the bias is only 2%. The following graph displays the bias in PEG's reported model (blue line) and PEG's model with the only change made being the insertion of a quadratic trend variable (green line).

Figure 5 PEG's Sample Average Benchmark Score by Year with Quadratic Trend



By including the quadratic trend variable into the PEG analysis and leaving all other methods the same, we estimate that PEG's Hydro One benchmarking scores for the 2020-2022 period will be lowered from PEG's reported +9.0% score by 25.1%: this one variable addition, with no other changes to PEG's methodology, results in a PEG benchmark score in 2020 to 2022 of -16.1%.[22,23]

5 Concluding Remarks

PSE continues to recommend a productivity factor of 0.0% and a stretch factor of 0.0%, with no other supplemental stretch factors or systematic markdowns that are not connected to the capital needs of the Company. Both PEG and PSE find negative productivity in the transmission industry, and both firms find that a 0.0% productivity factor would already contain a substantial implicit stretch factor. Adding 2017 and 2018 to the sample provides further evidence of negative productivity trends, especially in the most recent years of the sample. With all of this, a 0.0% productivity factor is a difficult and challenging expectation for the company to meet and will likely exceed the productivity of the industry during the 2021 and 2022 years.

After updating the benchmarking dataset to 2018, PSE finds that Hydro One's total costs are 32.9% below benchmark expectations. This is extraordinary cost performance that should be recognized with a 0.0% stretch factor, especially considering Hydro One's proposed progressive productivity component. PEG has produced a model result that is unstable and inconsistent with its own research in the recent HOSSM case. It contains a clear bias against the recent and forecasted years for the entire sample, including Hydro One. When this bias is mitigated and PEG's modeling

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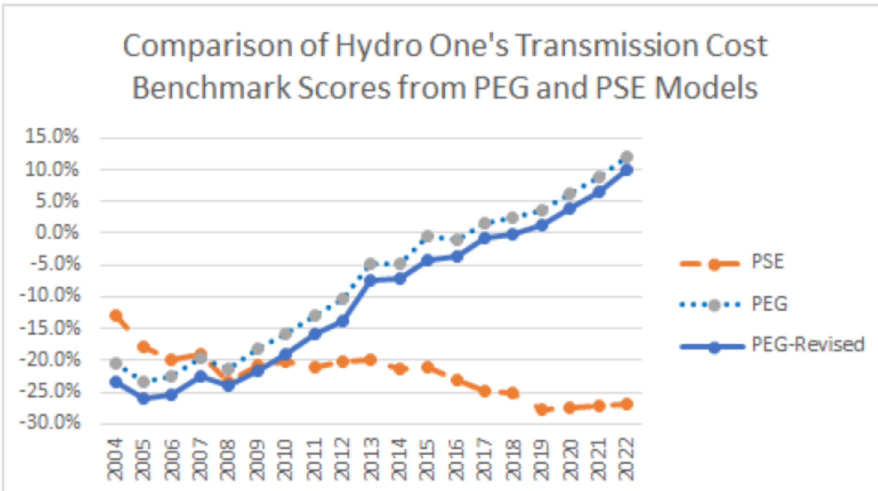
procedure corrected to what it used in HOSSM (or if PEG used the modern approach by using the OLS coefficients that do not require special coding, are transparent, cannot be improved upon, and do not require assumptions by the researcher), PEG's results would also indicate strong cost performance and a stretch factor of 0.0%.

L1-02-05 EP IRR Part a) -Comparison of PSE and PEG Benchmarking Scores

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

a) Here is the requested graph and a pertinent table. This response uses results updated to reflect data changes as discussed in our response to HON-21 (Exhibit L1/Tab 1/Schedule 21). We also present the results originally reported.



PSE HOSSM REPORT EB-2018-0218 Exhibit D-1-1Attachment 1Page 1 of 63

Transmission Study for Hydro One Networks Inc.:
Recommended CIR Parameters and Productivity Comparisons
Prepared by: Power System Engineering, Inc.
May 23, 2018
Filed: 2018-07-26

Extract Table 2

Table 2 Hydro One's Cost Performance 2004-2022

Year	Hydro One Actual Costs (Thousands, C$)	Hydro One Benchmark Costs (Thousands, C$)	% Difference (Logarithmic)
2004	$1,321,847	$1,607,757	-19.6%
2005	$1,374,866	$1,729,615	-23.0%
2006	$1,456,209	$1,844,035	-23.6%
2007	$1,589,793	$1,996,161	-22.8%
2008	$1,672,186	$2,200,213	-27.4%
2009	$1,786,248	$2,293,710	-25.0%
2010	$1,808,049	$2,310,014	-24.5%
2011	$1,987,327	$2,568,490	-25.7%
2012	$2,115,512	$2,723,021	-25.2%
2013	$2,100,004	$2,703,669	-25.3%
2014	$2,123,453	$2,765,321	-26.4%
2015	$2,230,624	$2,908,015	-26.5%
2016	$2,283,979	$3,047,901	-28.9%
2017 (projected)	$2,338,963	$3,174,800	-30.6%
2018 (projected)	$2,430,797	$3,323,325	-31.3%
2019 (projected)	$2,511,095	$3,447,400	-31.7%
2020 (projected)	$2,600,683	$3,573,281	-31.8%
2021 (projected)	$2,695,299	$3,706,040	-31.8%
2022 (projected)	$2,797,680	$3,843,932	-31.8%
Average % Difference			
2014-2016			**-27.3%**
2019-2022			**-31.8%**

Figure 2 Hydro One's Cost Performance 2004-2022

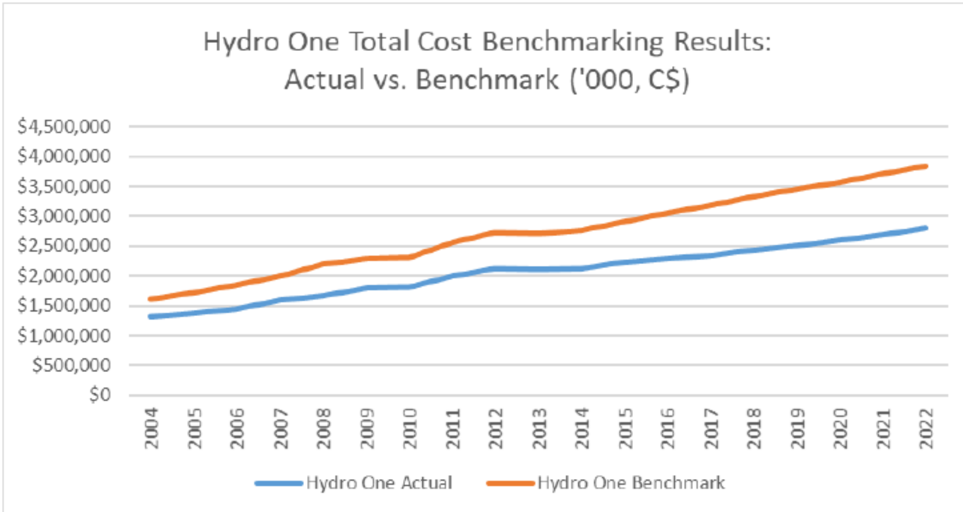


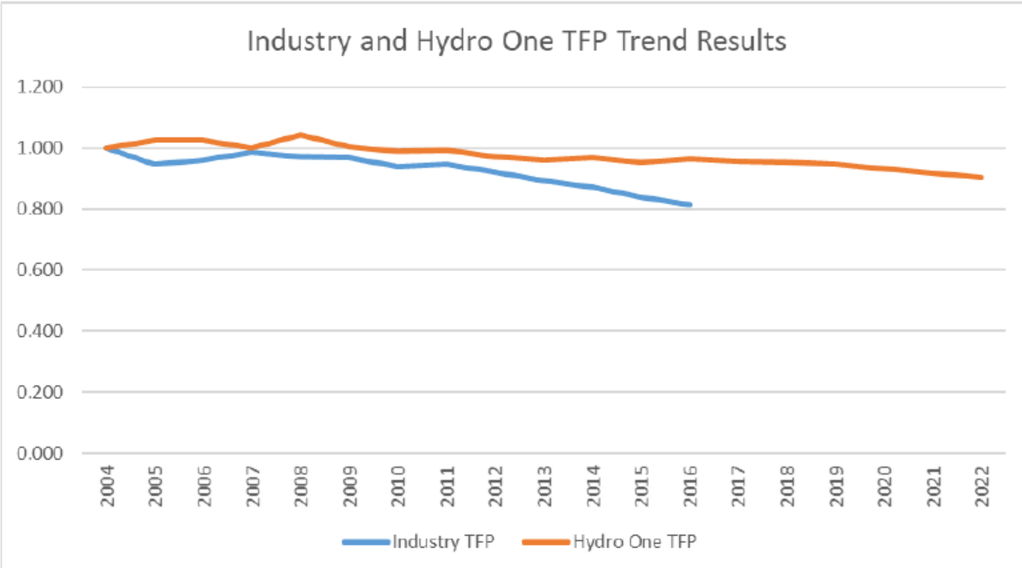
Table 2 and Figure 2 show that Hydro One's total costs have been below the benchmark value since 2004. In 2016, Hydro One is more than $700 million below its benchmark total costs. This difference in Hydro One's actual to benchmark costs is projected to increase to over $1,000 million by 2022, assuming Hydro One's application is approved in full. Throughout the 2019-2022 CIR period, Hydro One's projected total costs are 31.8% below benchmark expectations.

Extract PSE HOSSM REPORT

Table 3 Industry TFP and Hydro One TFP

Year	Industry TFP Index	Hydro One TFP Index
2004	1.000	1.000
2005	0.945	1.026
2006	0.963	1.024
2007	0.987	1.000
2008	0.971	1.042
2009	0.967	1.003
2010	0.940	0.992
2011	0.946	0.992
2012	0.922	0.971
2013	0.893	0.962
2014	0.871	0.967
2015	0.841	0.956
2016	0.814	0.964
2017 (projected)	NA	0.958
2018 (projected)	NA	0.954
2019 (projected)	NA	0.945
2020 (projected)	NA	0.933
2021 (projected)	NA	0.920
2022 (projected)	NA	0.906
Average Annual Growth Rate		
2004-2016	**-1.71%**	**-0.31%**
2010-2016	**-2.40%**	**-0.47%**
2019-2022	**NA**	**-1.43%**

Figure 3 Industry TFP and Hydro One TFP



Hydro One's TFP trend compares favorably to the industry trend. Hydro One's annual TFP trend is 1.41% higher than the industry TFP trend from 2004 to 2016. Hydro One's projected TFP from 2019 to 2022 remains 0.28% higher than the long-run historical industry trend. The industry has had a consistent decline in TFP since 2004. In Section 6.1, we address some possible causes for negative TFP growth.

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Table 5 Econometric Model Parameter Estimates

Total Cost Model Estimates

VARIABLE KEY

KM = Total transmission Kilometres of line
D = Maximum peak demand
Tx = Percent of transmission plant in total electric utility plant
Cap = Average capacity (MVa) per substation
Sub = Number of transmission substations per KM of line
Volt = Average voltage of transmission lines
CS = Construction standards of building transmission pole
UG = Percent of transmission lines underground
Trend = Time trend (current year minus 2003)

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
KM	0.676	42.770
KM*KM	-0.172	-7.910
KM*D	0.483	7.190
D	0.237	22.970
D*D	-0.259	-7.970
Tx	0.478	11.600
Cap	0.236	11.400
Sub	0.191	16.660
Volt	0.474	27.080

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
CS	0.206	7.140
UG	3.198	11.560
Trend	0.013	10.810
Constant	10.210	122.620
Adjusted R-Squared	0.899	
Sample Period:		2004-2022
Number of Observations		732

Extract PSE HOSSM REPORT

Table 8 Outputs for Hydro One

Year	KM of Line	Maximum Peak Demand	Output Quantity Index
2004	20,603	25,414	1.000
2005	20,547	26,160	1.006
2006	20,625	27,005	1.017
2007	20,624	27,005	1.017
2008	20,661	27,005	1.018
2009	20,658	27,005	1.018
2010	20,676	27,005	1.019
2011	20,694	27,005	1.019
2012	20,891	27,005	1.026
2013	20,904	27,005	1.027
2014	20,882	27,005	1.026
2015	20,948	27,005	1.029
2016	20,949	27,005	1.029
2017 (projected)	20,689	27,005	1.019
2018 (projected)	20,965	27,005	1.029
2019 (projected)	20,967	27,005	1.029
2020 (projected)	20,967	27,005	1.029
2021 (projected)	20,970	27,005	1.029
2022 (projected)	20,974	27,005	1.029
Average Annual Growth Rate			
2004-2016	0.14%	0.51%	0.23%
2010-2016	0.22%	0.00%	0.16%
2004-2018	0.12%	0.43%	0.21%
2019-2022	0.01%	0.00%	0.01%

Extract PSE HOSSM REPORT

9.Transmission Loading Variable

Development of Variable

1. Zones specified by the CSA and NESC were mapped and overlaid with utility service territories.

Industry standards in Canada and the United States dictate minimum requirements for strength of transmission structures, which vary by geographic zone. During design, ice and wind loads are applied to a structure model to analyze strength in terms of percentage of strength capacity used.

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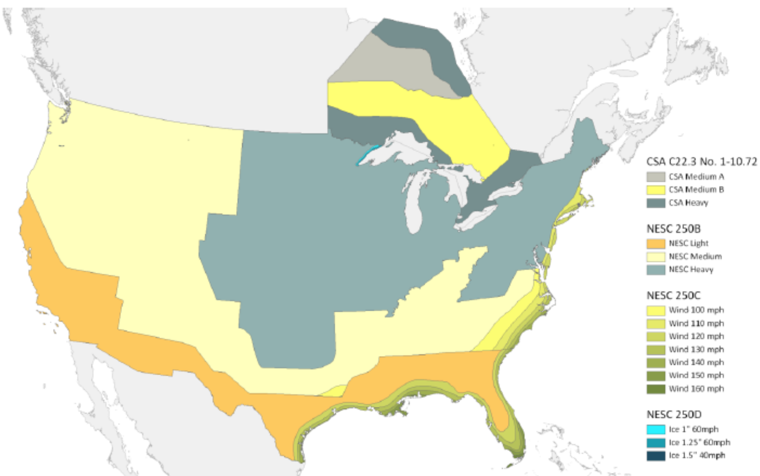
National Electrical Safety Code (NESC) for the United States. The loading zones are illustrated in Figure 8.

Figure 8 CSA and NESC Loading Zones



Utility service territories were overlaid with the above loading zone map. GIS analysis revealed the percentage of a given utility's service territory that fell into each loading zone.

2. Loading capacity was evaluated for a base structure in each zone.

A base transmission structure was identified to represent a typical application throughout the industry. Specifications are outlined in Table 13. Although this structure cannot represent an exact base structure for every utility, it is reasonable for side-by-side comparison of relative structure loading values for utilities in each zone.

3. Loading values were calculated for each utility based on the area and loading percentages.

The area percentages derived from the zone map and utility service territory map were multiplied by loading value percentages from PLS-CADD analysis for each loading zone present in a given utility service territory. These values were summed to produce an overall loading value for each utility. This overall loading value represents (roughly) the minimum design/build structural strength required for the utility's service territory.

Data Sources

1. United States load cases: National Electrical Safety Code (NESC) Rules 250B, 250C, and 250D
2. Canadian load cases: Canadian Standards Association (CSA) Overhead Systems C22.3 No. 1-10 7.2

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Extract OEB Decision HOSSM

5 REVENUE CAP FRAMEWORK

Hydro One SSM proposed that its revenue cap framework include the following revenue cap formula:

$$RR_t = RR_{t-1} \times (1 + (I_t - X \pm Z))$$

where

RR_t is the revenue (requirement) for year t
I_t is the inflation index for year t
X is the X-factor, composed of a base productivity factor and a stretch factor
Z is any qualifying and allowed exogenous factor(s).

Hydro One SSM filed evidence[27] prepared by its consultant, Power Systems Engineering, Inc. (PSE Report) in support of the proposed inflation, base X factor, and stretch factor for the revenue cap plan. PSE's evidence is based on Total Factor Productivity (TFP) and total cost benchmarking analyses comparing Hydro One Network Inc.'s transmission business to that of a sample of U.S. utilities with electricity transmission operations. PSE's evidence also included an analysis and recommendation for a transmission sector-specific inflation factor.

Hydro One SSM submitted that its revenue cap proposal is consistent with the requirements outlined in the OEB's Filing Requirements[28], through: (i) the inclusion of an inflation measure; and (ii) the inclusion of both a productivity and stretch factor informed by benchmarking.[29]

Hydro One SSM's proposed revenue cap framework also included an earnings sharing mechanism (ESM), an incremental capital module (ICM) and Z-factor, which are addressed in subsequent sections of this Decision and Order.

OEB staff retained PEG to review and assess PSE's evidence and Hydro One SSM's revenue cap proposal. The PEG Report contained PEG's evidence[30] with its own TFP and total cost benchmarking analyses.

[27] Exhibit D, Tab 1, Schedule 1, Attachment 1
[28] February 11, 2016, p. 5
[29] Argument-in-Chief, March 29, 2019, p. 10
[30] Exhibit M1

OEB staff submitted that Hydro One SSM's revenue cap proposal is consistent with OEB policy and is appropriate given the OEB's established approach for setting and recovering the costs of electricity transmitters. However, OEB staff took issue with the proposed parameter values of Hydro One SSM's revenue cap proposal.

OEB staff submitted that a revenue cap adjustment formula typically includes a growth factor g. Hydro One SSM's proposal for not including the growth factor was supported by its consultant, PSE.[31] Hydro One SSM claimed that $g = 0$ as there is little growth in demand historically or expected during the term of the plan.

SEC submitted that the Hydro One SSM's proposed approach is consistent with the OEB's expectations in the MAADs decision.[32] Energy Probe submitted that the elements of Hydro One SSM revenue cap framework proposal are reasonable and in accordance with prior decisions and with OEB policy.[33]

PWU submitted that Hydro One SSM's proposed revenue cap framework and associated mechanisms were appropriate, and noted that "[t]he Earning Sharing Mechanism and availability of the Z-factor and Incremental Capital Module (ICM) were approved in the MAADs application [EB-2016-0050] and no changes have been proposed as part of this proceeding".[34]

Findings

The OEB approves the proposed revenue cap formula. The OEB finds the omission of a growth factor in the formula is acceptable for 2019-2026. There was insufficient evidence to justify the incorporation of a growth factor or explore the implications. The inclusion of a growth factor could be considered in a future proceeding after the deferred rebasing period. The OEB notes that the approved price cap framework and formulas for electricity and gas distributors do not include growth factors.

PANEL 5 PEG/ BOARD STAFF

Date Filed: 2019-09-05
EB-2019-0082
Exhibit M1
Page 1 of 76

Incentive Regulation for Hydro One Transmission

5 September 2019

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President

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Extract PEG Report

4. Alternative Empirical Research by PEG

4.1 Benefits of U.S. Data

Most power transmission in the United States is provided by investor-owned electric utilities ("IOUs").[28] These utilities usually also provide distribution services and some also provide generation services. The division between the transmission and distribution systems varies somewhat across the industry.

U.S. data have several advantages in transmission cost and productivity research.

- The federal government has gathered detailed, standardized data for decades on the operations of dozens of IOUs that provide transmission services. These services are broadly similar to those provided by Hydro One.
- IOU cost data are credibly itemized, permitting calculations of the cost of transmission services even for vertically integrated utilities.
- PEG has gathered data on the net value of plant in 1964 and the corresponding gross plant additions since that year. Custom indexes are available on trends in the costs of transmission and general plant construction. These advantages make U.S. data the best in the world for accurate calculation of the consistent capital cost, price, and quantity indexes that are needed to appraise the capital cost and total cost performances of power transmitters.

In contrast, data on the transmission operations of utilities in the various provinces of Canada are not standardized. Consistent data on transmission capital costs are available for numerous years in only a few provinces, and even in these provinces are generally not available before 2000. PSE invited nine Canadian transmission utilities to participate in its study for Hydro One but none complied.

4.2 Data Sources

The source of data on the transmission cost, transmission system scale, and peak demand of U.S. electric utilities which we used in our empirical research was FERC Form 1. Data reported on Form

[28] Some federal and municipal utilities and rural electric cooperatives also provide power transmission services.

Extract PEG Report

Table 3

U.S. Transmission Productivity Results Using PEG's Methods: Cost-Weighted Averages

(Growth Rates)[1]

		Input Quantity Index					Productivity				
		OM&A	Capital			Multifactor	OM&A	Capital			Multifactor
Year	Output Quantity Index		Transmission	General	Capital Summary			Transmission	General	Capital Summary	
1996	1.13%	-0.27%	-0.43%	0.60%	-0.39%	-0.30%	1.39%	1.56%	0.53%	1.52%	1.43%
1997	0.81%	0.63%	-0.51%	-4.34%	-0.58%	-0.71%	0.18%	1.32%	5.15%	1.39%	1.53%
1998	1.39%	0.72%	-1.21%	2.68%	-1.12%	-0.72%	0.67%	2.61%	-1.29%	2.51%	2.11%
1999	1.33%	-5.87%	-1.23%	-2.59%	-1.28%	-1.48%	7.20%	2.56%	3.92%	2.61%	2.81%
2000	0.58%	6.36%	-0.68%	7.64%	-0.50%	0.10%	-5.78%	1.26%	-7.06%	1.08%	0.48%
2001	1.63%	0.39%	-0.27%	14.22%	0.02%	0.04%	1.25%	1.90%	-12.59%	1.61%	1.60%
2002	0.54%	-4.40%	-0.06%	-6.67%	-0.09%	-0.60%	4.93%	0.60%	7.20%	0.63%	1.14%
2003	1.50%	3.46%	-0.36%	1.32%	-0.31%	0.04%	-1.96%	1.86%	0.18%	1.82%	1.46%
2004	0.45%	3.15%	0.18%	1.93%	0.19%	0.65%	-2.70%	0.27%	-1.49%	0.25%	-0.20%
2005	2.34%	6.81%	0.41%	2.35%	0.43%	1.20%	-4.47%	1.93%	-0.01%	1.91%	1.14%
2006	1.63%	1.74%	0.46%	-2.27%	0.43%	0.69%	-0.11%	1.17%	3.91%	1.21%	0.94%
2007	1.02%	5.27%	1.16%	-2.43%	1.07%	1.59%	-4.25%	-0.14%	3.45%	-0.05%	-0.57%
2008	0.45%	3.73%	1.15%	3.15%	1.18%	1.36%	-3.28%	-0.70%	-2.69%	-0.73%	-0.91%
2009	-0.20%	3.18%	2.27%	1.08%	2.24%	2.45%	-3.38%	-2.47%	-1.28%	-2.44%	-2.64%
2010	0.64%	5.83%	1.69%	-0.73%	1.60%	2.31%	-5.19%	-1.06%	1.36%	-0.96%	-1.67%
2011	0.33%	-0.07%	2.31%	0.92%	2.24%	1.86%	0.41%	-1.98%	-0.58%	-1.90%	-1.52%
2012	0.60%	0.30%	1.68%	5.11%	1.68%	1.26%	0.29%	-1.09%	-4.52%	-1.08%	-0.66%
2013	0.25%	2.59%	4.02%	7.73%	4.03%	3.86%	-2.34%	-3.77%	-7.48%	-3.78%	-3.61%
2014	0.79%	-2.39%	3.75%	-0.37%	3.69%	3.10%	3.18%	-2.96%	1.17%	-2.90%	-2.30%
2015	0.62%	-2.80%	4.01%	2.49%	4.01%	3.08%	3.42%	-3.39%	-1.87%	-3.39%	-2.46%
2016	-0.14%	3.88%	3.17%	7.04%	3.21%	3.28%	-4.02%	-3.31%	-7.18%	-3.35%	-3.42%
Average Annual Growth Rates											
1996-2016	**0.84%**	**1.54%**	**1.02%**	**1.85%**	**1.03%**	**1.10%**	**-0.69%**	**-0.18%**	**-1.01%**	**-0.19%**	**-0.25%**
2005-2016	**0.70%**	**2.34%**	**2.17%**	**2.01%**	**2.15%**	**2.17%**	**-1.64%**	**-1.48%**	**-1.31%**	**-1.45%**	**-1.47%**

[1]All growth rates are calculated logarithmically.

Table 4

Hydro One's Transmission Productivity Growth

(Growth Rates)[1]

		Input Quantities			Productivity		
Year	Output Quantity Index	OM&A	Capital	Multifactor	OM&A	Capital	Multifactor
2005	1.43%	-9.42%	0.32%	-1.80%	10.85%	1.11%	3.23%
2006	1.88%	10.14%	-0.22%	2.06%	-8.26%	2.10%	-0.18%
2007	0.00%	10.51%	1.46%	3.62%	-10.51%	-1.46%	-3.62%
2008	0.08%	-15.01%	0.32%	-3.24%	15.09%	-0.24%	3.32%
2009	-0.01%	11.84%	2.49%	4.56%	-11.85%	-2.50%	-4.57%
2010	0.04%	-1.38%	3.87%	2.69%	1.42%	-3.83%	-2.65%
2011	0.04%	-4.07%	3.01%	1.48%	4.11%	-2.97%	-1.44%
2012	0.44%	0.19%	5.68%	4.54%	0.24%	-5.24%	-4.10%
2013	0.03%	2.30%	1.52%	1.68%	-2.27%	-1.50%	-1.65%
2014	-0.05%	-11.22%	2.77%	0.09%	11.17%	-2.82%	-0.14%
2015	0.15%	9.92%	0.71%	2.43%	-9.78%	-0.57%	-2.28%
2016	0.00%	-9.69%	2.14%	-0.03%	9.69%	-2.14%	0.03%
2017	-0.58%	-5.26%	1.77%	0.57%	4.68%	-2.35%	-1.15%
2018	0.61%	-1.97%	3.25%	2.40%	2.58%	-2.64%	-1.78%
2019	0.00%	-16.81%	1.78%	-0.99%	16.82%	-1.77%	1.00%
2020	0.00%	4.06%	2.03%	2.31%	-4.06%	-2.03%	-2.31%
2021	0.01%	-0.10%	3.13%	2.69%	0.10%	-3.12%	-2.68%
2022	0.01%	-0.10%	2.77%	2.38%	0.11%	-2.76%	-2.37%
Average Annual Growth Rates							
2005-2016	**0.34%**	**-0.49%**	**2.01%**	**1.51%**	**0.83%**	**-1.67%**	**-1.17%**
2012-2016	**0.11%**	**-1.70%**	**2.57%**	**1.74%**	**1.81%**	**-2.45%**	**-1.63%**
2021-2022	**0.01%**	**-0.10%**	**2.95%**	**2.53%**	**0.11%**	**-2.94%**	**-2.53%**

[1]All growth rates are calculated logarithmically.

Extract PEG Report

Table 2
PEG's Alternative Econometric Model of Transmission Total Cost

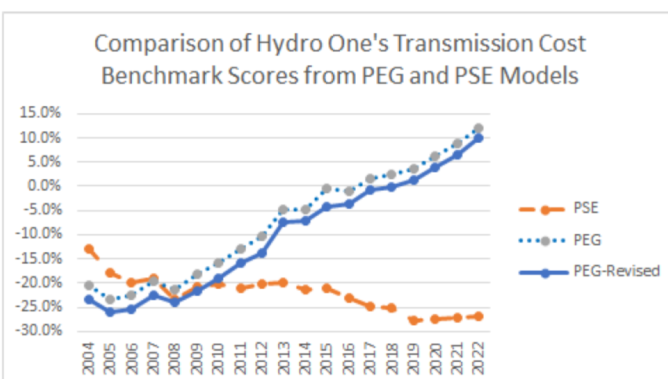
VARIABLE KEY

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

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YL	0.492	26.154	0.000
YL * YL	0.402	14.499	0.000
YL * D	-0.207	-8.447	0.000
D	0.571	30.634	0.000
D * D	0.243	7.307	0.000
MVA	0.044	2.350	0.019
VOLT	0.063	2.076	0.038
CS	0.238	5.239	0.000
PCTPOH	-0.395	-8.340	0.000
PCTPTX	0.140	10.538	0.000
Trend	-0.006	-7.270	0.000
Constant	12.173	695.103	0.000
	Adjusted R^2	0.948	
	Sample Period	1995-2016	
	Number of Observations	1,127	

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

a) Here is the requested graph and a pertinent table. This response uses results updated to reflect data changes as discussed in our response to HON-21 (Exhibit L1/Tab 1/Schedule 21). We also present the results originally reported.



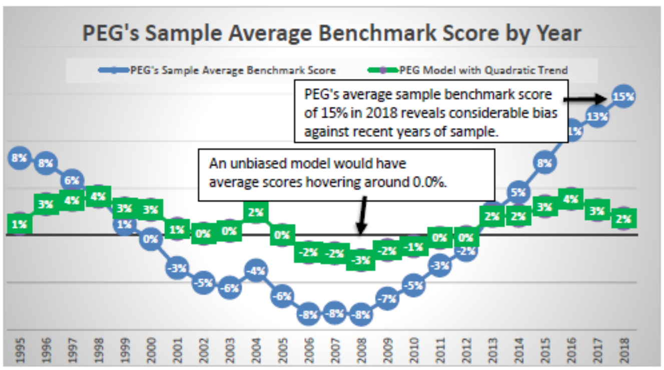
Extract from PSE Reply Report

Figure 4 PEG Testimony

MR. SHEPHERD: A quadratic for the trend variable would change the trend variable from a straight line to curved line, correct?
DR. LOWRY: Yes. I mean, why not have that? I mean, I would be more interested in that to some degree than in some of the others. Particularly when you are forecasting outside of the sample period, it might be interesting to have a curvature on that.

When a quadratic trend variable is inserted in PEG's model, and with no other changes made, PEG's bias in each year hovers around the expected 0% value. In 2018, the bias is only 2%. The following graph displays the bias in PEG's reported model (blue line) and PEG's model with the only change made being the insertion of a quadratic trend variable (green line).

Figure 5 PEG's Sample Average Benchmark Score by Year with Quadratic Trend



By including the quadratic trend variable into the PEG analysis and leaving all other methods the same, we estimate that PEG's Hydro One benchmarking scores for the 2020-2022 period will be lowered from PEG's reported +9.0% score by 25.1%: this one variable addition, with no other changes to PEG's methodology, results in a PEG benchmark score in 2020 to 2022 of -16.1%.[22,23]

5 Concluding Remarks

PSE continues to recommend a productivity factor of 0.0% and a stretch factor of 0.0%, with no other supplemental stretch factors or systematic markdowns that are not connected to the capital needs of the Company. Both PEG and PSE find negative productivity in the transmission industry, and both firms find that a 0.0% productivity factor would already contain a substantial implicit stretch factor. Adding 2017 and 2018 to the sample provides further evidence of negative productivity trends, especially in the most recent years of the sample. With all of this, a 0.0% productivity factor is a difficult and challenging expectation for the company to meet and will likely exceed the productivity of the industry during the 2021 and 2022 years.

After updating the benchmarking dataset to 2018, PSE finds that Hydro One's total costs are 32.9% below benchmark expectations. This is extraordinary cost performance that should be recognized with a 0.0% stretch factor, especially considering Hydro One's proposed progressive productivity component. PEG has produced a model result that is unstable and inconsistent with its own research in the recent HOSSM case. It contains a clear bias against the recent and forecasted years for the entire sample, including Hydro One. When this bias is mitigated and PEG's modeling

procedure corrected to what it used in HOSSM (or if PEG used the modern approach by using the OLS coefficients that do not require special coding, are transparent, cannot be improved upon, and do not require assumptions by the researcher), PEG's results would also indicate strong cost performance and a stretch factor of 0.0%.

Page 45 C Factor Stretch Factor

After considering the pros and cons of these options, we recommend that the OEB add a supplemental stretch factor to Hydro One's C factor calculation and calibrate this factor so that it produces a markdown on plant additions that is similar to that which would be produced by an ACM. We calculate that the analogous stretch factor would average about 0.42%. Details of our calculations can be found in Appendix Section B.4.

Several arguments can be advanced for making the supplemental capital cost stretch factor even higher.

- The Board rationalized the 10% markdown factor for ACMs and ICMs chiefly on the grounds that it may reduce regulatory cost. We have ventured a much wider range of arguments in favor of a markdown.
- As further discussed in Appendix B.4, the 10% markdown factor actually marks down otherwise-eligible capex by considerably less than 10%.

Hydro One should, in our view, be permitted to keep a share of the value of any capex underspends. This would strengthen the Company's incentive to contain capex (but also its incentive to exaggerate its capex needs). We believe that the Company should be permitted to keep 5% of the value of capex underspends.

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

October 25, 2019

Christine E. Long
Registrar and Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms. Long:

Re: **Hydro One Networks Inc. (Hydro One)**
Application for 2020-2022 Electricity Transmission Rates
Responses to Interrogatories on the Expert Evidence of Pacific Economics Group Research LLC
Board File Number: EB-2019-0082

Please find attached an Excel spreadsheet containing the detailed calculations of the S-factor as prepared by OEB staff's consultant, Pacific Economics Group Research LLC (PEG). This spreadsheet is related to PEG's proposal of the S-factor as documented in its evidence (Exhibit M1) and also referenced in the response to an interrogatory (Exhibit L1/Tab 1/Schedule 16) from Hydro One Networks Inc. (Hydro One).

The spreadsheet was part of PEG's "working papers", containing a number of spreadsheets, program code, data files and other documentation upon which the Total Factor Productivity and total cost benchmarking analyses in PEG's evidence were based. Confidentiality for the "working papers" was requested for the reasons documented in OEB staff's letter of September 13, 2019, and was granted by the OEB in the Decision on Issues List and Confidentiality issued September 23, 2019.

Counsel for Hydro One advised that Hydro One was seeking the detailed calculations. This was addressed as a preliminary matter on day 3 of the Oral hearing (October 24, 2019). While OEB staff had expected that the material would remain confidential, OEB staff has worked with PEG to isolate the relevant material, and PEG has determined that the spreadsheet with the S-factor calculations may be filed on the public record.

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2300, rue Yonge, 27e étage, C.P. 2319, Toronto (Ontario) M4P 1E4 F 416-440-7656 OEB.ca

Table B1

Resultant C-Factor Under Different S-Factors

C Factor Component (%)	Variable	2021	2022	Average
Increase in Capital RR as a Percentage of Total RR in previous year	C_n	5.18	4.68	4.93
Capital Cost Share	S_{cap}	78.42%	79.16%	78.79%
I	I	1.40	1.40	1.40
S (HON-Tx Proposed)	S_1	0.00	0.00	0.00
S (HON Dx IRM)	S_2	0.15	0.15	0.15
S (ACM Equivalent)	S_3	0.31	0.31	0.31
C Factor: HON-Tx Proposed	$C_1=C_n-S_{cap}*(I+S_1)$	4.09	3.59	3.84
C Factor: S=0.15	$C_2=C_n-S_{cap}*(I+S_2)$	3.96	3.46	3.71
C Factor: ACM Equivalent	$C_3=C_n-S_{cap}*(I+S_3)$	3.84	3.33	3.58

Note: Highlighted cells changed as a result of corrections.

M1-HON-13

Reference: Exhibit M1, pages 60-69

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

Interrogatories:

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

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

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

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

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

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

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

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

PEG IR Response

Table HON-13

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

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

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

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

Empirical Research for Incentive Regulation of Transmission
4 February 2019

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2.3. Hydro One Networks' Cost and Productivity Performance

PSE Research

PSE also calculated the transmission MFP trend of Hydro One Networks over the 2005-2016 period and the MFP trend implicit in forecasted/proposed costs from 2017 to 2022. Over the full historical sample period, the Company's -0.031% average annual MFP growth was more positive than that which PSE reported for the full sample. OM&A productivity averaged 1.07% growth whereas capital productivity averaged -0.58% annual growth. Over the 2020-2022 period the Company's forecasted/proposed costs would produce -1.43% annual MFP growth. OM&A productivity would average 0.12% annual growth while capital productivity would average -1.67% annual growth.

PSE reports that the total transmission cost of Hydro One SSM was a substantial 27.3% below its econometric cost model's prediction on average over the three most recent years for which data are available (2014-2016). The Company's forecasted/proposed total cost is 31.8% below the model's predictions during the first four years of the proposed IRM (2019-2022).

PEG Critique

Our review of PSE's benchmarking work and calculations of Hydro One Networks productivity trends revealed several concerns. Here are the most important ones:

- The relatively short sample period unnecessarily reduces the precision of the econometric benchmarking model parameter estimates.
- Parameter estimates are also degraded by the 1989 benchmarking year for U.S. utilities, which unnecessarily reduces the precision of the capital cost calculations,
- Due to data limitations beyond the control of PSE, the even more recent benchmark year for the Company reduces the accuracy of total cost benchmarking and multifactor productivity results for the Company.
- The capital cost specification excludes capital gains.

Extract PEG HOSSM Report

3. Alternative Empirical Research by PEG

3.1 Data Sources

The source of data on the transmission cost, transmission system capacity, and peak demand that we used in our benchmarking and productivity research is FERC Form 1. Data reported on Form 1 must conform to the FERC's Uniform System of Accounts. Selected Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[4] More recently, these data have been available electronically in raw form from the FERC, and in more processed forms from commercial vendors such as SNL Financial.[5]

Data on U.S. salary and wage prices were obtained from the Bureau of Labor Statistics ("BLS") of the U.S. Department of Labor. The gross domestic product price index ("GDPPI") that we used to deflate material and service expenses of U.S. transmitters was calculated by the Bureau of Economic Analysis of the U.S. Department of Commerce. Data on the *levels* of heavy construction costs in various U.S. and Canadian locations were developed by RSMeans. Data on U.S. electric utility construction cost *trends* were purchased from Whitman, Requardt and Associates. Some of the variables used in our econometric cost model were obtained from PSE working papers we examined in the course of this proceeding.

3.2 Sample

Data for Hydro One Networks and 44 U.S. transmitters were used in our productivity research. Data for Hydro One and 56 U.S. transmitters were used in our econometric research. The sample period for our econometric cost research was 1995-2016. The extra years should increase the precision of the econometric parameter estimates. The full sample period for our productivity research was 1996-2016. This should produce an MFP trend that is more pertinent to the calibration of X factors for Hydro One SSM and Hydro One Networks.

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Scale Variables

Two scale variables were used in our econometric cost modelling: length of transmission line and ratcheted maximum peak demand. We used the alternative peak demand data found on page 401b of FERC Form 1 rather than the peak demand data on which PSE relied. Econometric research revealed that a ratcheted peak demand variable constructed using these data had comparable explanatory power to the variable used by PSE. We followed the PSE practice of according the two scale variables a translog treatment by adding quadratic and interaction terms for these variables to the cost model. The translog functional form is discussed further in Appendix Section B.2.

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Table 1

PEG's Alternative Econometric Model of Transmission Total Cost

VARIABLE KEY

YM =	Miles of Transmission line
D =	Ratched Maximum Demand
MVA =	Substation Capacity per Line Mile in 2010
SUB =	Number of transmission substations per km of line
VOLT =	Average voltage of transmission line
CS =	Construction standards index
PCTOH =	Percent of transmission plant overhead
PCTPTX =	Percent of transmission plant in total plant
Trend =	Time Trend

EXPLANATORY VARIABLE	PARAMETER ESTIMATE	T-STATISTIC	P-VALUE
YM	0.436	23.615	0.00
YM * YM	0.348	18.557	0.000
YM * D	-0.199	-15.290	0.000
D	0.566	34.583	0.000
D * D	0.230	13.164	0.000
MVA	0.027	3.233	0.001
VOLT	0.136	10.505	0.000
CS	0.542	26.962	0.000
PCTPOH	-1.251	-11.970	0.000
PCTPTX	0.273	13.937	0.000
Trend	0.000	0.143	0.886
Constant	12.534	164.241	0.000

Rbar-Squared	0.937
Sample Period	1995-2016
Number of Observations	1215

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Extract PEG HOSSM Report

Transmission Total Cost Performance of Hydro One Networks
Using the PEG Econometric Model

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

Year	Cost Benchmark Score
2004	-23.40%
2005	-27.00%
2006	-26.40%
2007	-21.90%
2008	-24.80%
2009	-18.70%
2010	-17.00%
2011	-16.90%
2012	-13.40%
2013	-11.20%
2014	-11.30%
2015	-8.00%
2016	-9.00%
2017	-8.10%
2018	-6.70%
2019	-4.70%
2020	-2.30%
2021	-0.10%
2022	2.20%
Average 2004-2016	**-17.62%**
Average 2014-2016	**-9.43%**
Average 2019-2022	**-1.23%**

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

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