TORONTO HYDRO-ELECTRIC SYSTEM LIMITED INTERROGATORIES

L1.INTERROGATORY M1-TH-001

Reference: Exhibit M1 *PEG Report, p. 7, last bullet point:* "*The calculation of capital costs for the utilities in the econometric study sample is inaccurate.*"

Is the basis for this statement due to PSE having used a 1989 capital benchmark year for the U.S. sample rather than PEG's 1964 benchmark year?

Response to TH-001: The following response was provided by PEG.

The use of a 1989 benchmark year for the U.S. utilities is certainly one of PEG's concerns about PSE's capital cost data. Other concerns include the following:

- PSE used 2002 rather than 1989 as the benchmark year for the calculation of Toronto Hydro's capital quantity index.
- A U.S. construction cost index was used to deflate PSE's plant additions.
- Capital gains were not considered.

L1.INTERROGATORY M1-TH-002

Reference: PEG Report, p. 7, last paragraph: "Recent research on the cost of U.S. power distributors suggests that their multifactor productivity ("MFP") growth trend has been positive."

Please provide the research report or reports that form the foundation for this assertion.

Response to TH-002: The following response was provided by PEG.

Two reports form the foundation for this assertion: Dr. Lowry's recent testimony for the Massachusetts Attorney General and his report for Lawrence Berkeley National Laboratory. These reports are provided as Attachments PEG-TH-002 (a-b).

L1.INTERROGATORY M1-TH-003

Reference: *PEG Report, p. 7, third paragraph: "PEG also developed experimental models to evaluate Toronto Hydro's projected/proposed operation, maintenance, and administrative ("OM&A") expenses, capital cost, and capital expenditures ("capex")."*

Please define what PEG means by experimental in this context.

Response to TH-003: The following response was provided by PEG.

Econometric models of these costs have rarely been considered in OEB proceedings. However, an econometric benchmarking model of OM&A cost was considered in EB-2006-0268 and relied on to set stretch factors for Ontario power distributors in the OEB's 3rd Generation IRM proceeding, EB-2007-0673.

PEG's current models have not previously been vetted. Additionally, there is not a large literature available on econometric modelling of power distributor capital cost or capex.

L1.INTERROGATORY M1-TH-004

Reference: *PEG Report, p. 21, third paragraph: "However, we do not believe that PSE has the urban challenge appropriately modelled."*

Please confirm Toronto Hydro's understanding that PEG inserted the same percentage congested urban variable in their total cost model that PSE used.

Response to TH-004: The following response was provided by PEG.

PEG did use PSE's congested urban variable in its four cost models, as noted on p. 42 of its March 20 report.[1] However, PEG did not use any quadratic or interaction terms in their models which included this variable.

[1] Exhibit M1

L1.INTERROGATORY M1-TH-005

Reference*: PEG Report, p. 22, fourth bullet point: "We are not convinced that an undergrounding variable is needed in a total cost model that includes an urban challenge variable."*

a) Please explain why an undergrounding (or overhead) variable is needed in PEG's OM&A model despite that model also containing the percent congested urban variable.

b) Please explain why an undergrounding (or overhead) variable that is interacted with the service territory that is not congested urban is needed in PEG's OM&A model.

Response to TH-005: The following response was provided by PEG.

a) The OM&A model is a restricted or short run cost function, like those discussed in Hal Varian, *Microeconomic Analysis*, Second Addition, New York, W.W. Norton Co., 1984, p. 21. In such a model, the quantity of capital is theoretically a cost driver, and the extent of system overheading is an important dimension of the capital quantity. OM&A expenses should be greater the more extensive is overheading and the parameter estimate for this variable was positive and highly significant.

b) Overheading should have a greater impact on OM&A expenses the larger is the area served that is not congested urban. The non-urban area served should have a larger impact on OM&A costs the greater is overheading. This "two-way" analysis suggests that this interaction term should have a positive parameter estimate, and it does.

L1.INTERROGATORY M1-TH-006

Reference: *PEG Report, p. 22-23, last bullet point.*

a) Please explain the equation used by PEG to calculate the plant additions back to 1989 for Toronto Hydro despite plant addition data not being directly available.

b) Please provide the basis for each of the assumptions in the equation used to calculate the plant additions for Toronto Hydro.

c) Please provide a comparison of the assumptions (e.g., retirement percentage assumption) in the equation with the average values in the U.S. sample used by PEG in each year from 1989 to 2002. If some years are not available, please provide the years that are available.

d) Does PEG have concerns regarding the accuracy of the calculated plant additions for Toronto Hydro since these are not directly observed and require assumptions that are not required for the rest of the benchmarking sample?

Response to TH-006: The following response was provided by PEG.

a) Gross additions are equal to smart meter additions plus additions other than smarter meter additions. The calculation for additions other than smart meter additions is as follows

$$XKA_t = \begin{cases} XKG_t - XKG_{t-1} + 0.50\% * XKG_{t-1} & 1990 \le t \le 1997 \\ \dfrac{XKG_{2002} - XKG_{1997} + 0.50\% * XKG_{1997}}{5} & 1998 \le t \le 2002 \\ XKG_t - XKG_{t-1} + 0.5\% * XKG_{t-1} & 2003 \le t \le 2012 \end{cases}$$

where

XKA_t = Gross Additions in year t
XKG_t = Gross Plant exclusive of customer contributions for all years and changes in meter plant since 2006.

The method described above was used to calculate gross plant additions for the IRM-4 benchmarking work which was the source of the THESL plant additions data used by PEG prior to 2013.

Smart meter capital expenditures were generally deferred by Ontario utilities and not allowed to be included in reported power plant and equipment ("PP&E") until approved by the OEB. Therefore, changes in gross plant will not pick up deferred smart meter additions as long as they are deferred. To properly pick these up, the changes from the 2006 level of meter PP&E

were removed from the total PP&E from 2007 onward so that the calculation would not count any changes in meter plant in the calculation. OEB staff sought additional information from distributors on smart meter capital expenditures in the form of a one-time data request to support the IRM-4 work. The capital expenditures on smart meters were added to the non-smart meter gross additions as calculated above to obtain a total that included meters. For calculations and additional information please see the IRM-4 working papers at:

http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379%20PEG%20TFP%20and%20BM%20database%20calculations.xlsx

In preparing responses to these questions, PEG noted some inconsistencies with its data and methods relative to that used by PSE. Although PEG does not believe the data used by PSE are preferable in all cases, they have nonetheless made some upgrades to its calculation of Toronto Hydro's plant additions based on this review. The upgrades included excluding customer contributions from gross plant additions to align with U.S. practice and adding high voltage plant that was excluded in the IRM-4 benchmarking work. PEG also noted that the smart meter additions reported by THESL in the PSE working paper were more complete than what were provided to OEB staff in the IRM-4 data request. The overlapping values were similar and PEG replaced the smart meter series with the THESL/PSE values in the upgraded calculation. Please see the response to Exhibit L1/Tab 1/Schedule 26 (d) for the results of this upgrade and additional discussion.

b) Assumptions implicit in this calculation are that adjustments to plant are zero or negligible, 0.5% of gross plant is retired every year on average, and that the changes in plant additions between 1998 and 2002 were plausible and did not suggest an accounting change (i.e., a revaluation of gross plant).

c) The table below provides average values of the pertinent variables for the 79 U.S. companies in PEG's sample. 1995 is the earliest year for which PEG has gathered and processed these data.

Year	Gross Plant [A]	Retirements [B]	Adjustments	Retirement Rate [B/A]
1995	1,351,128,192	11,831,750	-137,478	0.88%
1996	1,523,230,080	11,487,571	53,200	0.75%
1997	1,542,963,840	12,381,169	31,667	0.80%
1998	1,623,891,456	12,436,483	-161,176	0.77%
1999	1,753,740,800	17,923,638	-31,489	1.02%
2000	1,841,995,904	15,276,538	-434,891	0.83%
2001	1,932,299,008	17,635,228	-2,490,070	0.91%
2002	1,980,192,128	14,832,606	-224,000	0.75%
Average			**-424,279.63**	**0.84%**

It can be seen that the average retirement rate for U.S. companies is somewhat higher than that calculated for Ontario distributors.

d) PEG believes that changes in gross plant value can be relied upon to produce accurate values of (gross additions – retirements) and plausible values of gross plant additions so long as the gross plant values can be relied upon. Although necessary for the calculation, estimated gross plant additions are typically not that sensitive to the assumed retirement rate.

L1.INTERROGATORY M1-TH-007

Reference*: PEG Report, p. 23, first bullet point continuing from previous page: "…a 1964 benchmark year is feasible for the U.S. distributors."*

a) Please provide the raw data source for the capital calculations for all the sampled utilities from 1964 to 1989.

b) Please list the mergers adjusted for in PEG's capital data from 1964 to 2017.

c) Please re-run the PEG total cost model using a 1989 benchmark year rather than the 1964. Please provide a revised Table 10, "Year by Year Total Cost Benchmarking Results", showing the change in results.

Response to TH-007: The following response was provided by PEG.

a) The 1964 plant values and 1964-1994 plant additions were taken from published documents under the title *Financial Statistics of Major U.S. Investor Owned Electric Utilities* and predecessor publications such as *Statistics of Electric Utilities in the United States*. These documents are available at Federal Depository Libraries, including that of UW-Madison.

b) Please see Attachment PEG-TH-007 (b).

c) Please see Attachment PEG-TH-007 (c) for the requested run. The parameter estimates and scores for Toronto Hydro are modestly different from those in the model based on a 1964 benchmark year. The latter model has a considerably higher Wald statistic (which summarizes the overall significance of the cost model).

L1.INTERROGATORY M1-TH-008

Reference: *PEG Report, p. 24, second paragraph: "Alternative asset price indexes are available. … Our research showed that this index tracked the EUCPI in its good years better than the HWI with a PPP adjustment."*

a) Please state the basis for how PEG knows when the EUCPI was in its "good years".

b) Please provide a table from 1964 to 2017 showing the EUCPI index, the implicit price index for the capital stock of the utility sector used by PEG, and the North Atlantic HWI for Total Distribution.

c) Please list the utility industries that are included in the implicit price index used by PEG for the asset price index.

d) Please provide what percentage of each industry comprises the asset price index used by PEG. If exact percentages are not known, please provide an estimate based on PEG's experience.

Response to TH-008: The following response was provided by PEG.

a) The choice of a new deflator for plant additions of Ontario power distributors was a major focus of PEG's work for Board Staff in the recent Hydro One Distribution IRM proceeding.[1] A report on this work was attached to PEG's response to HONI 14 in that proceeding.[2] A discussion of the EUCPI can be found on pp. 1-8 of this document. On p. 6, PEG notes its concern about "the recent slow growth of the labor price sub-index". This subindex was compared to other pertinent labor price indexes. PEG further notes on p. 6 that "trends in the labor price indexes were broadly similar through 2001, after which the EUCPI labor price subindex grew much more slowly than all of the other indexes and declined in several years." PEG states on p. 8 that "the EUCPI produced reliable results only through 2001. Alternative asset price deflators can be usefully appraised by their ability to track the EUCPI during this period." Another concern is that the distribution EUCPI did not consider prices of advanced metering infrastructure.

b) Table 1 provides data from 1962 to 2017 (insofar as they are available) on the EUCPIs for Distribution Systems and Substations, the implicit capital stock deflators for the utility sectors of Canada and Ontario, and on the North Atlantic Handy Whitman Index for Total Distribution Plant ("HWI") and its product with the summary Purchasing Power Parity between Canada and the U.S. ("HWI x PPP").

---

[1] EB-2017-0049.

[2] EB-2017-0049, Exhibit L1/Tab 8/Schedule HONI-14 Attachment.

Table 1
Alternative Utility Asset Price Deflators[1]

	EUCPIs[2]			Implicit Capital Stock Deflators		Handy-Whitman Index	
				Utilities (Current Methodology[3])		Total Distribution Plant[4]	
Year	Distribution Systems [A]	Substations [B]	Average [A+B]/2	Canada	Ontario	North Atlantic Region	NA Region with PPP Adjustment
1962	1.6%	4.6%	3.1%	1.8%	2.2%	1.7%	1.0%
1963	0.5%	2.4%	1.5%	2.2%	2.0%	0.0%	0.7%
1964	2.1%	4.7%	3.4%	3.1%	3.3%	3.4%	4.4%
1965	2.0%	4.9%	3.5%	5.7%	6.0%	3.3%	4.0%
1966	4.9%	3.9%	4.4%	5.5%	4.6%	3.2%	4.6%
1967	3.8%	-1.3%	1.2%	4.3%	4.1%	4.6%	6.1%
1968	-0.9%	-3.0%	-2.0%	1.1%	0.9%	4.4%	3.2%
1969	4.1%	2.2%	3.1%	5.0%	4.1%	5.6%	4.9%
1970	7.3%	9.8%	8.6%	5.7%	6.3%	9.0%	4.6%
1971	3.7%	5.0%	4.3%	5.2%	5.2%	7.1%	6.9%
1972	4.3%	3.3%	3.8%	5.7%	4.6%	5.6%	7.1%
1973	8.8%	6.6%	7.7%	7.3%	6.9%	8.3%	12.2%
1974	18.5%	20.1%	19.3%	17.3%	17.1%	16.6%	22.1%
1975	11.6%	15.8%	13.7%	14.7%	15.2%	14.2%	15.5%
1976	5.6%	6.8%	6.2%	7.3%	6.3%	4.3%	8.0%
1977	6.4%	3.9%	5.2%	6.7%	6.5%	4.8%	5.4%
1978	7.1%	7.3%	7.2%	8.3%	8.3%	4.6%	4.2%
1979	12.7%	9.5%	11.1%	10.1%	10.1%	10.3%	11.9%
1980	13.1%	10.5%	11.8%	10.3%	10.3%	7.2%	8.2%
1981	8.6%	8.9%	8.7%	11.0%	11.0%	8.3%	9.4%
1982	8.9%	9.1%	9.0%	7.4%	7.7%	6.2%	8.7%
1983	4.1%	1.7%	2.9%	3.5%	3.3%	3.7%	5.4%
1984	4.3%	4.3%	4.3%	3.4%	3.6%	2.7%	2.6%
1985	5.0%	1.4%	3.2%	3.1%	3.3%	2.2%	2.3%
1986	2.3%	3.4%	2.9%	4.2%	5.3%	1.3%	2.3%
1987	3.0%	7.2%	5.1%	2.8%	2.3%	0.8%	3.0%
1988	5.9%	7.3%	6.6%	3.7%	2.9%	7.2%	8.1%
1989	3.8%	7.6%	5.7%	2.8%	2.9%	5.8%	6.5%
1990	3.1%	0.7%	1.9%	4.6%	4.3%	2.7%	2.4%
1991	-0.8%	-4.3%	-2.6%	-0.9%	-1.2%	2.6%	2.3%
1992	2.3%	0.1%	1.2%	-0.8%	-0.4%	1.2%	0.5%
1993	2.5%	3.0%	2.7%	0.3%	-1.5%	2.6%	1.6%
1994	5.4%	4.6%	5.0%	3.7%	3.6%	3.1%	2.4%
1995	7.6%	3.6%	5.6%	1.7%	1.8%	3.0%	3.1%
1996	-0.1%	0.0%	0.0%	3.0%	2.7%	1.6%	1.6%
1997	1.2%	1.7%	1.4%	3.6%	5.4%	1.5%	1.0%
1998	4.0%	4.9%	4.4%	3.2%	3.4%	2.3%	1.0%
1999	2.7%	1.0%	1.8%	0.8%	1.1%	0.7%	1.2%
2000	2.0%	1.6%	1.8%	1.9%	2.3%	2.6%	5.6%
2001	0.7%	2.3%	1.5%	2.1%	1.4%	2.9%	2.4%
2002	0.7%	1.9%	1.3%	0.5%	-0.5%	3.2%	3.9%
2003	0.1%	-3.0%	-1.5%	-0.8%	-0.2%	2.0%	1.7%
2004	0.4%	1.1%	0.8%	3.3%	2.8%	6.3%	6.9%
2005	1.9%	1.8%	1.9%	2.9%	1.3%	8.0%	6.4%
2006	6.4%	3.8%	5.1%	3.7%	1.3%	10.1%	9.4%
2007	4.4%	5.1%	4.7%	3.8%	2.7%	10.7%	11.3%
2008	1.0%	5.6%	3.3%	6.2%	6.4%	8.9%	10.7%
2009	0.5%	1.3%	0.9%	3.0%	4.5%	2.7%	0.0%
2010	2.6%	-0.1%	1.2%	1.0%	1.1%	3.5%	5.1%
2011	3.2%	1.7%	2.4%	2.4%	1.6%	4.8%	6.3%
2012	0.9%	0.4%	0.6%	2.7%	1.2%	4.3%	4.7%
2013	-0.8%	0.8%	0.0%	2.9%	3.1%	3.3%	1.6%
2014	0.1%	3.5%	1.8%	2.7%	3.1%	2.9%	3.4%
2015	na	na	na	2.7%	3.3%	2.1%	3.5%
2016	na	na	na	1.7%	1.6%	1.2%	1.0%
2017	na	na	na	1.2%	0.7%	2.8%	3.4%
Annual Average Growth							
1962 - 2013	**4.1%**	**4.0%**	**4.1%**	**4.3%**	**4.1%**	**4.8%**	**5.3%**
1962 - 2001	**4.8%**	**4.7%**	**4.8%**	**4.8%**	**4.7%**	**4.6%**	**5.2%**
2002 - 2017	**1.6%**	**1.8%**	**1.7%**	**2.5%**	**2.1%**	**4.8%**	**5.0%**
2009 - 2017	**1.1%**	**1.3%**	**1.2%**	**2.2%**	**2.2%**	**3.1%**	**3.2%**

Notes

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

[2] Electric Utility Construction Price Index (Statistics Canada, Table 18-10-0047-01, formerly Table 327-0011)

[3] Flows and Stocks of Fixed Non-Residential Capital (Statistics Canada, Table 36-10-0096-01, formerly Table 031-0005)

[4] The column labeled with PPP adjustment were converted to Canadian growth rates using purchasing price parity data from the OECD.

Please note that over the full 1962-2001 period for which the EUCPI was most reliable, the average annual growth rate ("AAGR") in the implicit capital stock deflator for the Canadian utility sector was nearly the same as the average AAGR of the two EUCPI trends.[3] HWI x PPP meanwhile grew considerably more rapidly.

PEG has other concerns about using HWIs in Canadian productivity and benchmarking studies. A big concern is that the HWIs appear to have been constructed using fixed 1973 weights. HWIs have therefore not been updated in nearly 45 years to reflect current cost shares. Moreover, it is possible that the subindexes that compose the HWIs are flawed if they are based on 1973 projects.

Tables 2a and 2b display the growth rates of the HWI subindexes for the various kinds of power distribution assets in the American North Atlantic and North Central regions. Please note the following.

- From 2002 to 2015, the brisk growth in the summary distribution HWIs was due chiefly to brisk growth in just a few subindexes
    - Station equipment (5.0% in North Atlantic region)
    - Underground conductors and devices (6.0%)
    - Line transformers (8.8%)
    - Pad-mounted transformers (5.0%)

  These are all assets with a high copper content.
- The longer-term trends in the various subindexes are more similar.

Table 3 compares the trends in some of the rapidly rising HWI power distribution sub-indexes in the North Atlantic region to trends in other available input prices. Looking at Producer Price Index ("PPI") data on Electric Power and Specialty Transformers from the BLS, for example, a 3.0 percent AAGR from 2002 to 2016 can be noted. This compares to a 8.5 percent AAGR in the HWI for Line Transformers and to a 4.6% AAGR in the HWI for Pad-Mounted Transformers. This difference cannot be explained by rapidly growing labor costs. The BLS Employment Cost Index grew by only 2.5 percent in the Northeast Census region over the same period; nationally, the Employment Cost Index for utility workers increased 3.4 percent on average.

The growth trends of the HWIs for Overhead Conductors and Devices and Underground Conductors and Devices also display faster growth than their respective PPIs. Between 2002 and 2016, these HWIs averaged 4.7 and 5.4 percent growth, respectively. However, during the same span, the BLS PPIs for non-ferrous Communication and Energy Wire, Non-Current-Carrying Wiring Devices, and Current-Carrying Wiring Devices displayed growth trends of 4.3, 3.7 and 2.2 percent, respectively.

[3] PEG used the implicit capital stock deflator for the Ontario utility sector in its benchmarking. The trend in this deflator is slower but may reflect a legitimate regional difference.

Table 2a

North Atlantic Handy-Whitman Distribution and Transmission Growth Trends[1,2]

Year	Total Transmission	Total Distribution	Station Equipment	Poles, Towers & Fixtures	Overhead Conductors and Devices	Underground Conduit	Undeground Conductors and Devices	Line Transformers	Pad-Mounted Transformers	Services-Overhead	Services-Underground	Meters Installed	Street Lighting-Overhead	Mast Arms & Luminaries Installed	Street Lighting Underground
1950	7.4%	5.0%	4.1%	3.1%	6.1%	5.7%	5.8%	4.5%	0.0%	6.5%	2.6%	0.0%	4.7%	na	-2.4%
1951	9.1%	7.1%	9.5%	5.9%	8.5%	5.4%	20.4%	12.4%	0.0%	9.0%	12.1%	0.0%	8.7%	na	9.1%
1952	4.3%	2.2%	1.8%	2.8%	5.3%	2.6%	3.0%	0.0%	0.0%	5.6%	2.2%	0.0%	4.1%	na	0.0%
1953	4.1%	6.5%	5.2%	5.4%	2.5%	2.5%	0.0%	5.7%	0.0%	5.3%	0.0%	4.2%	2.0%	na	2.2%
1954	2.0%	2.1%	3.3%	2.6%	4.9%	4.9%	1.5%	2.7%	0.0%	0.0%	-2.2%	1.4%	5.7%	na	8.2%
1955	3.8%	2.0%	1.6%	2.5%	6.9%	2.4%	4.3%	0.0%	0.0%	7.4%	0.0%	-4.1%	0.0%	na	3.8%
1956	7.3%	5.8%	9.2%	9.5%	8.5%	6.7%	-1.4%	2.6%	0.0%	6.9%	4.4%	4.1%	5.4%	11.6%	1.9%
1957	1.7%	1.9%	5.7%	4.4%	0.0%	4.3%	-13.8%	5.1%	0.0%	-4.5%	-2.2%	5.3%	8.4%	9.0%	-9.7%
1958	3.4%	3.6%	2.7%	2.2%	-2.1%	4.1%	0.0%	-2.5%	0.0%	0.0%	-4.5%	2.5%	4.7%	0.0%	21.9%
1959	0.0%	0.0%	0.0%	2.1%	4.1%	3.9%	3.2%	-3.4%	0.0%	4.5%	2.3%	2.5%	0.0%	-5.9%	0.0%
1960	0.0%	1.8%	-2.7%	4.1%	2.0%	3.8%	1.6%	-1.8%	-3.0%	4.3%	-4.7%	1.2%	-1.6%	0.0%	1.6%
1961	-3.4%	0.0%	-7.2%	0.0%	0.0%	1.8%	-1.6%	-3.6%	-4.1%	0.0%	0.0%	-1.2%	0.0%	0.0%	-3.3%
1962	0.0%	1.7%	1.5%	3.9%	3.8%	3.6%	0.0%	-9.7%	-1.1%	2.1%	6.9%	0.0%	0.0%	-1.5%	0.0%
1963	0.0%	0.0%	-3.0%	1.9%	1.9%	1.7%	1.6%	-5.2%	1.1%	2.1%	2.2%	0.0%	1.6%	0.0%	1.7%
1964	5.0%	3.4%	3.0%	1.9%	3.6%	3.4%	7.5%	0.0%	-5.4%	4.0%	4.3%	0.0%	1.5%	3.0%	0.0%
1965	4.8%	3.3%	2.9%	5.4%	5.2%	1.7%	8.3%	2.1%	0.0%	5.7%	8.0%	0.0%	1.5%	1.5%	1.6%
1966	3.1%	3.2%	1.4%	3.4%	3.3%	1.6%	1.3%	0.0%	3.3%	5.4%	9.2%	0.0%	1.5%	5.7%	7.8%
1967	5.9%	4.6%	6.8%	3.3%	6.4%	3.2%	2.6%	3.1%	3.2%	6.8%	5.1%	1.2%	5.7%	-1.4%	9.9%
1968	2.8%	4.4%	6.4%	3.2%	4.5%	3.1%	-5.3%	5.0%	2.1%	4.8%	6.5%	3.6%	2.7%	0.0%	-4.1%
1969	5.4%	5.6%	2.4%	7.6%	8.5%	5.9%	7.8%	-4.0%	-4.2%	9.0%	6.1%	3.4%	6.5%	5.5%	5.5%
1970	7.6%	9.0%	4.7%	8.5%	13.9%	10.8%	6.1%	1.0%	1.1%	14.6%	7.1%	4.4%	8.5%	16.0%	13.7%
1971	7.1%	7.1%	2.3%	9.0%	9.0%	10.9%	1.2%	1.0%	2.1%	9.4%	5.3%	5.2%	5.7%	5.5%	6.7%
1972	4.4%	5.6%	3.3%	7.1%	3.2%	7.7%	12.0%	-2.0%	2.0%	6.5%	11.1%	1.0%	5.3%	3.2%	5.3%
1973	8.3%	8.3%	8.3%	13.9%	4.1%	6.2%	3.0%	1.0%	1.0%	5.1%	15.1%	1.0%	4.1%	4.1%	3.0%
1974	19.9%	16.6%	19.9%	20.7%	14.0%	10.4%	22.3%	8.6%	3.0%	7.7%	14.0%	6.8%	19.1%	15.7%	18.2%
1975	13.8%	14.2%	13.0%	14.4%	21.8%	8.6%	3.1%	17.6%	1.9%	10.5%	-7.2%	14.7%	19.5%	15.8%	20.3%
1976	4.9%	4.3%	3.5%	0.7%	12.5%	4.8%	3.1%	3.0%	1.9%	6.5%	4.6%	7.0%	5.3%	9.7%	6.6%
1977	5.9%	4.8%	7.4%	3.4%	5.4%	6.1%	5.8%	7.9%	9.8%	6.1%	3.5%	3.7%	6.3%	8.9%	6.8%
1978	3.2%	4.6%	5.6%	5.9%	-3.6%	6.5%	4.8%	6.0%	9.7%	6.4%	6.7%	2.9%	8.7%	7.6%	8.6%
1979	8.3%	10.3%	5.9%	11.4%	7.6%	9.3%	20.7%	5.7%	5.2%	8.6%	7.8%	2.8%	10.5%	9.1%	10.9%
1980	10.3%	7.2%	8.3%	8.2%	10.1%	6.7%	12.4%	0.0%	13.6%	10.2%	17.7%	-1.4%	8.2%	10.7%	7.6%
1981	7.4%	8.3%	7.6%	8.0%	7.8%	6.3%	1.0%	15.3%	15.9%	6.1%	9.5%	10.5%	9.2%	10.9%	8.3%
1982	5.6%	6.2%	8.0%	6.5%	5.5%	5.9%	-0.5%	8.1%	0.0%	6.3%	0.6%	15.6%	6.9%	5.6%	8.0%
1983	3.1%	3.7%	1.8%	2.7%	6.9%	7.6%	1.9%	1.9%	1.6%	4.0%	10.7%	7.2%	1.2%	3.1%	0.8%
1984	2.6%	2.7%	2.2%	3.9%	2.9%	6.1%	0.9%	1.4%	9.7%	9.3%	3.5%	1.5%	5.3%	7.3%	5.2%
1985	2.5%	2.2%	2.2%	2.9%	0.8%	2.7%	3.2%	0.9%	1.4%	0.4%	-8.2%	1.5%	4.3%	4.1%	3.9%
1986	2.1%	1.3%	1.3%	2.0%	0.8%	2.2%	4.9%	0.9%	3.8%	0.4%	-2.7%	2.4%	-0.4%	-2.4%	0.3%
1987	1.2%	0.8%	2.9%	0.4%	-0.8%	2.2%	1.7%	-0.9%	9.7%	1.7%	6.4%	0.0%	-4.3%	-3.5%	-5.0%
1988	10.3%	7.3%	9.7%	6.2%	21.8%	7.4%	1.7%	0.0%	10.7%	11.0%	0.5%	-4.3%	2.6%	1.4%	2.5%
1989	4.3%	5.7%	7.5%	4.1%	1.6%	11.6%	7.6%	5.0%	5.8%	6.4%	14.2%	-6.6%	3.9%	5.8%	3.5%
1990	5.8%	3.3%	7.0%	3.6%	2.2%	-0.7%	4.9%	2.2%	0.7%	0.4%	5.6%	0.5%	3.1%	3.0%	3.4%
1991	3.6%	3.5%	1.0%	6.4%	6.6%	0.7%	4.7%	0.4%	5.5%	3.9%	-6.5%	11.8%	4.6%	4.7%	4.2%
1992	0.3%	-0.3%	0.6%	5.1%	-8.5%	0.7%	0.0%	2.6%	-1.0%	-2.5%	-1.3%	-4.8%	2.5%	3.3%	2.2%
1993	3.1%	2.4%	1.3%	2.5%	5.2%	3.1%	2.1%	0.0%	3.3%	3.8%	1.8%	4.3%	4.9%	3.2%	5.5%
1994	4.5%	3.3%	3.4%	6.8%	4.1%	4.3%	1.0%	2.9%	1.0%	4.4%	5.2%	-6.3%	5.2%	7.0%	4.3%
1995	4.0%	2.9%	5.3%	2.8%	7.7%	1.9%	4.7%	-3.3%	0.6%	4.8%	2.9%	-2.0%	3.9%	2.1%	3.9%
1996	0.8%	1.9%	-0.9%	2.2%	1.6%	1.6%	1.9%	0.8%	3.8%	1.2%	0.0%	3.5%	5.0%	7.1%	5.0%
1997	2.2%	1.2%	1.7%	3.5%	1.8%	2.8%	0.6%	-4.7%	0.9%	1.8%	2.0%	8.5%	2.0%	1.7%	2.1%
1998	3.0%	2.4%	4.2%	1.3%	3.5%	2.4%	1.9%	1.3%	0.6%	1.5%	-2.4%	0.9%	0.8%	-0.7%	1.0%
1999	0.3%	0.6%	1.3%	1.8%	-3.5%	2.9%	3.1%	0.4%	0.9%	1.2%	-0.4%	-3.6%	2.0%	1.0%	2.2%
2000	5.4%	2.9%	1.3%	1.8%	8.1%	3.7%	1.2%	0.9%	0.9%	2.9%	5.6%	-1.4%	1.7%	1.2%	2.2%
2001	2.2%	2.3%	2.1%	2.2%	2.8%	3.0%	-1.5%	3.8%	5.8%	2.0%	-0.4%	12.4%	2.6%	1.7%	3.1%
2002	1.9%	3.9%	1.0%	4.1%	2.7%	5.5%	3.0%	4.0%	3.6%	3.3%	5.3%	13.9%	6.2%	2.8%	6.8%
2003	0.0%	1.3%	1.3%	1.4%	2.0%	-0.3%	0.6%	2.0%	-1.4%	1.6%	0.4%	3.5%	5.2%	2.0%	6.3%
2004	9.0%	6.5%	11.2%	3.4%	6.8%	4.3%	6.5%	4.5%	24.1%	6.0%	2.9%	12.4%	2.5%	2.6%	2.0%
2005	6.6%	7.3%	6.4%	5.8%	9.8%	7.3%	10.9%	7.1%	16.7%	7.1%	8.9%	-3.1%	6.0%	9.3%	5.3%
2006	7.3%	10.0%	8.2%	3.9%	11.3%	5.6%	7.8%	23.5%	18.4%	5.0%	22.8%	2.5%	14.9%	10.5%	16.3%
2007	7.5%	9.7%	10.9%	4.9%	8.1%	5.5%	18.4%	14.2%	22.8%	6.7%	-4.6%	3.9%	5.8%	5.7%	6.4%
2008	10.9%	10.0%	7.9%	5.4%	13.1%	6.3%	12.6%	19.3%	-7.6%	6.3%	-0.5%	1.5%	6.7%	0.2%	8.1%
2009	-3.1%	2.6%	3.0%	3.8%	-14.0%	4.3%	9.1%	9.3%	-12.5%	-3.8%	-5.7%	1.5%	11.1%	18.2%	10.5%
2010	4.5%	4.3%	5.7%	2.9%	11.1%	0.9%	-5.0%	9.2%	-2.1%	7.3%	8.1%	4.5%	-3.2%	3.7%	-5.2%
2011	4.7%	5.1%	4.6%	1.2%	7.2%	3.0%	7.7%	4.9%	8.6%	7.8%	14.3%	-2.2%	4.8%	2.7%	5.4%
2012	1.9%	4.5%	4.0%	3.8%	-0.9%	4.3%	9.3%	5.8%	0.8%	0.0%	10.6%	1.1%	4.3%	6.1%	3.9%
2013	1.9%	3.2%	2.3%	1.1%	4.6%	-0.2%	2.0%	8.2%	-2.8%	1.4%	1.9%	1.9%	0.2%	0.0%	0.2%
2014	2.4%	2.7%	2.9%	0.6%	3.7%	2.7%	1.2%	7.2%	-1.7%	4.2%	-9.0%	2.2%	-4.4%	-10.1%	-3.3%
2015	1.7%	2.1%	0.9%	0.8%	2.2%	1.8%	0.5%	4.0%	2.7%	2.9%	4.6%	1.1%	2.0%	2.2%	2.3%
Annual Average Growth Rate															
1950 - 2015	**4.4%**	**4.4%**	**4.2%**	**4.5%**	**5.0%**	**4.4%**	**4.1%**	**3.4%**	**2.9%**	**4.6%**	**3.8%**	**2.6%**	**4.4%**	**NA**	**4.5%**
1962 - 2015	**4.7%**	**4.7%**	**4.5%**	**4.7%**	**5.2%**	**4.5%**	**4.6%**	**3.8%**	**3.7%**	**4.8%**	**4.5%**	**2.8%**	**4.7%**	**4.5%**	**4.8%**
1950 - 1972	**3.7%**	**3.7%**	**2.8%**	**4.3%**	**4.8%**	**4.4%**	**2.9%**	**0.6%**	**-0.1%**	**5.0%**	**3.6%**	**1.5%**	**3.6%**	**NA**	**3.5%**
1973 - 1981	**9.1%**	**8.7%**	**8.8%**	**9.6%**	**8.9%**	**7.2%**	**8.5%**	**7.2%**	**6.9%**	**7.5%**	**8.0%**	**5.3%**	**10.1%**	**10.3%**	**10.0%**
1982 - 2001	**3.3%**	**2.8%**	**3.2%**	**3.4%**	**3.6%**	**3.6%**	**2.3%**	**1.2%**	**3.3%**	**3.2%**	**1.9%**	**2.0%**	**2.9%**	**2.8%**	**2.9%**
2002 - 2015	**4.1%**	**5.2%**	**5.0%**	**3.1%**	**4.8%**	**3.7%**	**6.0%**	**8.8%**	**5.0%**	**4.0%**	**4.3%**	**3.2%**	**4.4%**	**4.0%**	**4.7%**

Notes

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

Table 2b

North Central Handy-Whitman Distribution and Transmission Growth Trends[1,2]

Year	Total Transmission	Total Distribution	Station Equipment	Poles, Towers & Fixtures	Overhead Conductors and Devices	Underground Conduit	Undeground Conductors and Devices	Line Transformers	Pad-Mounted Transformers	Services-Overhead	Services-Underground	Meters Installed	Street Lighting-Overhead	Mast Arms & Luminaries Installed	Street Lighting Underground
1950	5.0%	2.5%	5.9%	6.1%	6.3%	5.7%	5.8%	5.6%	0.0%	6.9%	5.4%	0.0%	4.7%	na	0.0%
1951	11.5%	9.3%	9.2%	5.7%	11.4%	5.4%	21.9%	11.3%	0.0%	15.4%	14.7%	0.0%	10.8%	na	9.1%
1952	2.2%	4.3%	3.4%	5.4%	5.3%	5.1%	3.0%	1.0%	0.0%	5.6%	-2.3%	-1.4%	2.0%	na	2.2%
1953	6.2%	6.2%	5.0%	5.1%	5.0%	2.5%	-1.5%	5.6%	0.0%	5.3%	0.0%	4.2%	2.0%	na	0.0%
1954	2.0%	2.0%	3.2%	2.5%	2.4%	4.8%	2.9%	1.8%	0.0%	2.5%	2.3%	2.7%	5.7%	na	10.1%
1955	3.8%	1.9%	3.1%	2.4%	9.1%	4.5%	4.3%	0.0%	0.0%	7.2%	0.0%	-4.1%	1.8%	na	3.8%
1956	7.3%	5.6%	8.7%	6.9%	8.3%	4.3%	-1.4%	2.6%	0.0%	6.7%	4.4%	4.1%	5.3%	9.7%	1.8%
1957	1.7%	3.6%	5.4%	6.5%	-2.0%	4.2%	-13.6%	5.9%	0.0%	-4.4%	-2.2%	5.2%	6.7%	8.8%	7.0%
1958	3.4%	0.0%	2.6%	2.1%	0.0%	4.0%	-1.6%	-2.5%	0.0%	0.0%	-4.5%	2.5%	6.3%	1.4%	5.0%
1959	0.0%	3.4%	1.3%	0.0%	2.0%	1.9%	4.8%	-4.3%	0.0%	4.4%	2.3%	2.4%	-1.5%	-7.2%	0.0%
1960	0.0%	0.0%	-2.6%	4.0%	2.0%	3.8%	1.6%	-0.9%	-2.0%	4.3%	-4.7%	1.2%	0.0%	1.5%	1.6%
1961	-3.4%	0.0%	-8.1%	1.9%	1.9%	3.6%	-1.6%	-3.6%	-5.1%	2.1%	2.4%	-1.2%	0.0%	-1.5%	-1.6%
1962	0.0%	0.0%	1.4%	1.9%	3.8%	1.8%	0.0%	-8.6%	-1.0%	2.0%	4.5%	0.0%	0.0%	-1.5%	-1.6%
1963	0.0%	0.0%	-2.8%	1.9%	0.0%	3.4%	1.6%	-7.3%	1.0%	0.0%	2.2%	0.0%	1.5%	1.5%	1.6%
1964	3.4%	3.3%	2.8%	1.8%	3.6%	1.7%	7.4%	0.0%	-4.3%	3.9%	4.3%	0.0%	1.5%	1.5%	0.0%
1965	4.9%	3.2%	1.4%	3.6%	5.2%	1.7%	6.9%	2.1%	-1.1%	5.6%	8.0%	0.0%	0.0%	1.5%	0.0%
1966	4.7%	3.1%	2.7%	3.4%	3.3%	1.6%	1.3%	1.0%	3.2%	3.6%	7.4%	0.0%	2.9%	5.6%	7.8%
1967	4.4%	4.5%	3.9%	3.3%	6.4%	3.2%	2.6%	4.1%	3.1%	6.8%	5.2%	1.2%	5.6%	-1.4%	11.3%
1968	4.3%	4.3%	3.8%	4.8%	6.0%	4.6%	-2.6%	3.0%	2.0%	6.4%	8.1%	3.5%	2.7%	1.4%	-5.5%
1969	8.0%	9.4%	7.1%	9.0%	13.5%	9.9%	8.8%	-2.0%	-2.0%	14.3%	11.8%	4.5%	8.9%	6.6%	8.1%
1970	8.6%	8.6%	4.5%	10.8%	11.9%	9.0%	5.8%	1.0%	0.0%	14.8%	8.0%	4.3%	9.3%	16.5%	15.6%
1971	6.8%	6.8%	1.1%	7.4%	9.6%	8.3%	0.0%	0.0%	2.0%	7.7%	3.8%	5.1%	4.3%	4.3%	6.5%
1972	3.2%	4.3%	2.2%	5.8%	1.0%	5.5%	11.8%	-2.0%	1.0%	3.1%	8.3%	1.0%	4.2%	2.1%	3.1%
1973	6.2%	5.1%	6.2%	11.7%	1.0%	7.3%	1.0%	0.0%	0.0%	3.0%	12.8%	-1.0%	2.0%	2.0%	1.0%
1974	19.9%	17.4%	19.9%	21.5%	14.8%	10.4%	22.3%	8.6%	3.9%	7.7%	14.0%	7.7%	19.9%	15.7%	18.2%
1975	15.9%	14.8%	14.5%	13.6%	20.9%	8.6%	3.1%	17.6%	1.0%	9.7%	-6.3%	13.8%	19.3%	16.5%	21.0%
1976	4.8%	4.3%	2.8%	0.0%	11.9%	4.0%	3.1%	3.0%	1.9%	6.5%	2.7%	7.0%	5.3%	9.0%	6.5%
1977	6.5%	6.7%	9.8%	5.5%	7.8%	7.6%	6.5%	7.9%	9.8%	9.0%	6.1%	5.1%	8.0%	10.7%	7.9%
1978	3.7%	5.1%	6.6%	7.1%	-2.3%	8.5%	6.1%	6.7%	10.5%	7.6%	6.6%	2.8%	9.0%	8.6%	9.5%
1979	8.1%	9.4%	5.7%	11.7%	6.8%	8.4%	20.3%	5.6%	5.2%	8.3%	8.4%	2.7%	10.3%	8.9%	10.6%
1980	9.5%	7.0%	7.5%	8.5%	9.9%	6.6%	12.2%	0.0%	14.2%	10.5%	16.8%	-1.4%	8.9%	10.4%	7.8%
1981	8.7%	10.0%	8.8%	9.2%	9.0%	7.3%	2.4%	15.8%	16.2%	7.5%	11.1%	11.0%	9.0%	11.9%	8.1%
1982	6.7%	6.0%	9.4%	5.4%	4.9%	6.3%	-1.4%	7.5%	-0.5%	5.0%	0.0%	15.3%	6.3%	5.1%	7.8%
1983	2.6%	2.2%	0.9%	1.7%	5.5%	6.4%	0.9%	1.4%	1.1%	2.4%	9.5%	6.6%	0.4%	1.9%	0.0%
1984	0.8%	1.3%	-0.4%	1.7%	0.8%	3.7%	-0.5%	0.9%	8.7%	6.5%	2.0%	0.5%	4.1%	6.5%	3.7%
1985	1.7%	1.3%	1.7%	1.7%	0.4%	1.4%	2.8%	0.9%	1.0%	-0.4%	-8.2%	1.0%	3.6%	4.1%	3.6%
1986	1.2%	1.3%	1.2%	2.1%	0.8%	1.8%	4.9%	0.5%	3.8%	0.9%	-3.3%	2.4%	0.0%	-2.7%	0.7%
1987	1.2%	0.8%	3.3%	1.2%	-0.4%	3.1%	2.2%	-0.5%	10.2%	2.6%	6.9%	0.0%	-4.3%	-3.5%	-5.0%
1988	11.7%	6.1%	9.9%	4.0%	19.4%	5.9%	-0.4%	-0.9%	10.4%	7.9%	-1.6%	-5.9%	1.1%	0.0%	1.1%
1989	3.2%	4.6%	8.7%	2.7%	1.0%	10.0%	7.8%	4.6%	5.5%	5.8%	14.6%	-7.3%	3.6%	5.9%	2.9%
1990	5.1%	3.7%	7.7%	3.7%	2.3%	-1.1%	4.7%	2.2%	0.4%	0.0%	5.7%	0.5%	2.8%	3.0%	3.1%
1991	2.3%	1.8%	0.0%	3.9%	4.7%	-3.0%	3.4%	0.0%	4.5%	1.1%	-8.9%	11.2%	3.0%	3.5%	2.7%
1992	-0.6%	0.4%	0.3%	6.1%	-8.0%	1.5%	0.4%	2.6%	-0.7%	-1.5%	-0.5%	-4.4%	3.3%	4.0%	2.9%
1993	2.6%	1.4%	0.0%	1.3%	3.6%	2.2%	1.1%	-0.4%	3.0%	2.2%	0.5%	3.9%	4.1%	2.4%	4.7%
1994	5.2%	3.8%	3.3%	7.5%	4.4%	4.7%	1.1%	3.0%	0.7%	4.3%	5.5%	-7.0%	5.7%	6.9%	4.8%
1995	4.7%	3.6%	6.0%	3.0%	8.5%	2.1%	5.2%	-3.4%	0.7%	5.5%	3.1%	-2.1%	4.3%	2.7%	4.3%
1996	1.7%	1.3%	-2.0%	2.6%	1.7%	2.4%	2.0%	0.9%	4.2%	1.7%	0.0%	3.6%	5.2%	7.3%	4.9%
1997	1.7%	1.6%	1.1%	3.9%	1.9%	3.6%	0.7%	-4.8%	0.9%	1.6%	2.5%	9.3%	2.4%	1.7%	2.6%
1998	3.3%	2.2%	5.2%	1.1%	3.5%	2.6%	1.6%	0.9%	0.9%	1.6%	-3.0%	0.5%	0.5%	-0.7%	0.8%
1999	-1.3%	0.0%	0.8%	1.3%	-4.3%	3.1%	2.6%	0.4%	0.6%	0.6%	-0.9%	-4.3%	1.5%	0.5%	1.8%
2000	6.3%	3.0%	0.8%	1.9%	9.2%	3.6%	1.9%	0.9%	0.9%	3.4%	6.3%	-1.5%	2.0%	1.5%	2.5%
2001	3.3%	3.2%	1.8%	3.6%	3.9%	4.1%	-0.9%	4.3%	6.5%	3.6%	0.4%	14.1%	3.4%	2.2%	3.6%
2002	1.7%	3.7%	-1.0%	4.0%	2.6%	6.1%	3.1%	4.1%	3.4%	3.2%	5.5%	13.9%	6.1%	2.8%	7.1%
2003	1.0%	2.7%	0.8%	2.9%	3.5%	1.6%	1.8%	2.4%	-0.8%	3.7%	1.5%	4.3%	6.4%	2.5%	7.3%
2004	8.5%	5.8%	6.3%	2.6%	5.7%	3.9%	5.5%	4.3%	24.1%	4.3%	1.9%	12.3%	1.9%	2.0%	1.6%
2005	6.6%	6.4%	12.1%	5.2%	9.0%	6.6%	10.5%	6.9%	16.9%	6.2%	8.2%	-4.2%	5.7%	9.1%	5.0%
2006	8.5%	11.1%	8.1%	4.9%	12.3%	6.6%	8.5%	24.3%	18.8%	6.3%	24.2%	3.2%	15.6%	11.2%	17.4%
2007	7.3%	8.4%	9.8%	3.5%	7.5%	3.7%	18.3%	14.2%	22.8%	5.5%	-5.5%	3.1%	5.4%	5.3%	5.7%
2008	10.5%	10.3%	7.0%	5.5%	13.6%	5.6%	13.1%	19.6%	-7.7%	7.0%	-0.6%	1.8%	6.9%	0.3%	8.4%
2009	-6.5%	0.9%	2.2%	2.4%	-15.6%	2.4%	8.7%	9.2%	-13.2%	-5.9%	-6.8%	0.6%	11.1%	18.3%	10.2%
2010	4.6%	4.1%	4.7%	1.3%	10.4%	-0.6%	-6.3%	8.8%	-2.9%	5.7%	6.8%	3.8%	-4.4%	3.2%	-6.5%
2011	4.9%	5.0%	3.8%	1.3%	7.5%	2.7%	8.3%	5.1%	8.9%	8.7%	15.3%	-2.6%	4.9%	2.7%	5.6%
2012	0.5%	2.5%	2.2%	1.8%	-3.1%	4.0%	8.2%	5.3%	0.3%	-3.3%	9.4%	-0.3%	3.4%	5.2%	3.2%
2013	2.0%	3.4%	0.9%	1.4%	4.7%	0.6%	2.0%	8.3%	-2.9%	1.2%	1.8%	1.8%	0.3%	0.0%	0.5%
2014	2.1%	2.5%	1.9%	-0.2%	3.4%	2.4%	0.8%	7.4%	-2.1%	3.8%	-10.4%	2.0%	-5.1%	-11.3%	-3.9%
2015	1.7%	2.2%	0.3%	0.5%	2.7%	1.3%	0.7%	4.2%	2.9%	3.8%	5.4%	1.4%	2.3%	2.5%	2.4%
Annual Average Growth Rate															
1950 - 2015	**4.4%**	**4.3%**	**4.0%**	**4.4%**	**4.9%**	**4.3%**	**4.1%**	**3.4%**	**2.9%**	**4.5%**	**3.8%**	**2.4%**	**4.4%**	**NA**	**4.5%**
1962 - 2015	**4.6%**	**4.6%**	**4.2%**	**4.4%**	**5.0%**	**4.3%**	**4.5%**	**3.7%**	**3.7%**	**4.5%**	**4.3%**	**2.7%**	**4.6%**	**4.4%**	**4.7%**
1950 - 1972	**3.8%**	**3.8%**	**2.8%**	**4.4%**	**5.0%**	**4.4%**	**3.0%**	**0.6%**	**-0.1%**	**5.4%**	**3.9%**	**1.5%**	**3.7%**	**NA**	**3.7%**
1973 - 1981	**9.2%**	**8.9%**	**9.1%**	**9.9%**	**8.9%**	**7.6%**	**8.6%**	**7.2%**	**7.0%**	**7.8%**	**8.0%**	**5.3%**	**10.2%**	**10.4%**	**10.1%**
1982 - 2001	**3.2%**	**2.5%**	**3.0%**	**3.0%**	**3.2%**	**3.2%**	**2.0%**	**1.1%**	**3.1%**	**2.8%**	**1.5%**	**1.8%**	**2.6%**	**2.6%**	**2.7%**
2002 - 2015	**3.8%**	**4.9%**	**4.2%**	**2.6%**	**4.6%**	**3.3%**	**5.9%**	**8.9%**	**4.9%**	**3.6%**	**4.1%**	**2.9%**	**4.3%**	**3.9%**	**4.6%**

Notes

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

Table 3

How Handy Whitman Subindexes Compare to Alternative Price Indexes[1] (Growth Rates)

	Relevant BLS Producer Price Indexes					ECI		Select Handy-Whitman Sub-Indexes[8]			
Year	Steel Wire Drawing[3]	Communcation and Energy Wire (non-ferrous)[4]	Non-Current-Carrying Wiring Device[5]	Current-Carrying Wiring Device[6]	Electric Power and Specialty Transformers[7]	Utilities[8]	All Industries in the Northeast[9]	Overhead Conductors and Devices	Underground Conductors and Devices	Line Transformers	Pad Mounted Transformers
	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate
1981		-4.4%	12.8%	na	12.7%						
1982		-2.6%	4.4%	5.0%	6.3%	na	na	5.5%	-0.5%	8.1%	0.0%
1983	-0.7%	-4.0%	2.7%	4.8%	1.9%	na	na	6.9%	1.9%	1.9%	1.6%
1984	1.7%	2.8%	8.1%	3.4%	0.7%	na	na	2.9%	0.9%	1.4%	9.7%
1985	1.0%	0.0%	2.6%	2.7%	1.8%	na	na	0.8%	3.2%	0.9%	1.4%
1986	-0.2%	0.3%	5.5%	2.7%	0.2%	na	na	0.8%	4.9%	0.9%	3.8%
1987	0.2%	1.2%	4.0%	1.0%	1.5%	na	na	-0.8%	1.7%	-0.9%	9.7%
1988	5.6%	17.8%	6.5%	2.8%	2.1%	na	na	18.6%	3.6%	1.7%	9.9%
1989	3.4%	9.5%	7.1%	2.8%	7.5%	na	na	4.5%	6.7%	4.1%	5.7%
1990	1.2%	-6.5%	2.1%	1.7%	5.3%	na	na	0.9%	4.4%	1.4%	2.2%
1991	-1.1%	-7.6%	0.9%	1.8%	2.9%	na	na	3.7%	3.3%	0.3%	3.8%
1992	0.9%	-1.2%	1.9%	1.5%	-0.5%	na	na	-2.3%	1.3%	2.1%	0.1%
1993	2.0%	-1.8%	3.6%	2.5%	-1.5%	na	na	4.6%	1.8%	0.8%	2.8%
1994	4.0%	3.1%	3.2%	0.8%	1.5%	na	na	4.2%	1.2%	2.0%	0.7%
1995	3.2%	5.4%	4.2%	2.5%	2.8%	na	na	6.4%	3.8%	-1.4%	0.6%
1996	-0.1%	-5.2%	3.1%	1.2%	0.7%	na	na	2.0%	2.2%	-1.8%	3.9%
1997	1.3%	-0.5%	3.3%	0.5%	-0.1%	na	na	2.3%	1.0%	-3.8%	1.8%
1998	1.5%	-5.2%	1.3%	-0.8%	0.9%	na	na	2.7%	1.9%	2.2%	0.7%
1999	-2.3%	-0.7%	-1.9%	-0.2%	1.2%	na	na	-2.3%	2.3%	0.5%	0.8%
2000	-0.5%	6.6%	0.6%	-0.5%	2.3%	na	na	5.7%	2.0%	0.4%	0.8%
2001	-1.6%	-5.1%	1.8%	-0.6%	-1.0%	na	na	4.5%	-0.1%	3.5%	4.8%
2002	0.0%	-2.9%	1.5%	-0.3%	-2.0%	4.5%	3.2%	2.7%	1.2%	3.6%	3.6%
2003	1.8%	4.5%	-0.5%	-0.5%	0.1%	3.9%	2.8%	2.3%	1.1%	1.2%	1.6%
2004	23.2%	9.0%	25.8%	2.0%	2.8%	5.6%	3.1%	6.7%	7.2%	5.1%	20.3%
2005	6.9%	16.8%	5.0%	4.2%	9.8%	5.1%	2.5%	10.1%	11.0%	10.4%	17.2%
2006	1.5%	32.6%	7.8%	7.9%	13.3%	9.8%	3.1%	11.0%	11.0%	21.7%	17.7%
2007	1.5%	6.2%	1.9%	5.9%	11.7%	-4.6%	3.3%	8.9%	15.6%	23.6%	15.1%
2008	24.0%	2.3%	8.4%	2.7%	10.5%	3.2%	2.9%	10.9%	12.5%	15.1%	-2.6%
2009	-12.7%	-17.5%	-4.3%	1.8%	-2.7%	2.8%	1.8%	-6.4%	6.5%	3.8%	-5.2%
2010	-1.0%	18.9%	2.6%	0.9%	5.9%	5.2%	1.9%	4.5%	-2.6%	8.4%	-3.7%
2011	6.0%	10.5%	4.6%	2.9%	3.1%	3.3%	1.7%	5.3%	7.6%	5.6%	5.9%
2012	0.3%	-0.3%	2.4%	4.3%	-0.6%	3.2%	1.6%	1.4%	7.0%	6.6%	2.6%
2013	-1.7%	-1.6%	0.7%	1.7%	-0.8%	1.6%	1.7%	4.3%	2.2%	8.0%	-1.9%
2014	-0.5%	-0.4%	0.7%	1.9%	0.2%	2.0%	2.1%	3.7%	1.7%	7.0%	-1.9%
2015	-3.1%	-4.2%	-0.3%	-0.5%	-4.7%	3.1%	2.6%	2.8%	0.3%	4.4%	2.6%
2016	-3.0%	-8.6%	-0.1%	-2.3%	-1.0%	2.6%	2.6%	2.3%	-1.9%	3.2%	-1.7%
Annual Average Growth											
1983 - 2016	**1.8%**	**2.2%**	**3.4%**	**1.9%**	**2.2%**	**NA**	**NA**	**4.0%**	**3.8%**	**4.2%**	**3.9%**
1983 - 2001	**1.0%**	**0.5%**	**3.2%**	**1.6%**	**1.6%**	**NA**	**NA**	**3.5%**	**2.5%**	**0.9%**	**3.4%**
2002 - 2016	**2.9%**	**4.3%**	**3.7%**	**2.2%**	**3.0%**	**3.4%**	**2.5%**	**4.7%**	**5.4%**	**8.5%**	**4.6%**
2009 - 2016	**-2.0%**	**-0.4%**	**0.8%**	**1.3%**	**-0.1%**	**3.0%**	**2.0%**	**2.2%**	**2.6%**	**5.9%**	**-0.4%**

Notes

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

[2] The columns labeled adjusted were converted to Canadian dollars using purchasing price parity.

[3] PPI industry data for Steel wire drawing, not seasonally adjusted (U.S. Bureau of Labor Statistics)

[4] PPI industry data for Other communication and energy wire mfg-Power wire and cable, made from nonferrous metals (purchased wire), not seasonally adjusted (U.S. Bureau of Labor Statistics)

[5] PPI industry data for Noncurrent-carrying wiring device mfg, not seasonally adjusted (U.S. Bureau of Labor Statistics)

[6] PPI industry data for Current-carrying wiring device mfg, not seasonally adjusted (U.S. Bureau of Labor Statistics)

[7] PPI industry data for Electric power and specialty transformer mfg, not seasonally adjusted (U.S. Bureau of Labor Statistics)

[8] Wages and salaries for private industry workers, not seasonally adjusted, Employment Cost Index (U.S. Bureau of Labor Statistics)

[9] Wages and salaries for private industry workers, not seasonally adjusted, in the Northeast census region, Employment Cost Index (U.S. Bureau of Labor Statistics)

Consider next that the United States Bureau of Economic Analysis ("BEA") produces net capital stock datasets similar to the ones generated by Statistics Canada.[4] While PEG does not recommend utilizing the BEA's dataset to calculate an asset price deflator for Canadian TFP research, there are itemized price deflators for electric structures and electric transmission and distribution equipment which also offer a useful comparison to the power distribution HWIs.

The BEA creates capital stock datasets by first collecting information on capital expenditures. For electric services, investment data are gathered from several national agencies and surveys.[5] A description of the capital stocks methodology published in 2003 noted that: "the estimates of investment underlying the estimates of net stocks are developed to be conceptually and statistically consistent with the NIPA estimates of investment as well as with the classifications of the SIC."[6] According to a recent BEA document on private fixed investment, HWIs are used to deflate the prices of electric structures, while producer and industrial product price indexes are used for electrical transmission, distribution and industrial apparatus.[7]

After collecting the necessary data, capital stocks are estimated using the perpetual inventory method.[8] Estimates of the value of capital stocks are published in terms of current cost and chain-type quantity indexes. The chain-type quantity indexes utilize the Fisher ideal index form, the geometric mean of price indexes of Laspeyres and Paasche forms, to remove price effects. Therefore, we can calculate an implicit capital stock deflator by dividing the current cost index by the chained-quantity index.

Table 4 compares the growth rates of the implicit price deflators from electric structures and electrical transmission and distribution equipment to HWIs. Since they use the same price indexes, unsurprisingly, the implicit price deflator for electric structures tracks the HWIs fairly well. There is some divergence in the most recent period. The national average of the total distribution plant HWI had a 1.0 percent higher AAGR than the implicit capital stock deflator for electric structures between 2002 and 2016. However, electric structures may encompass other types of construction such as generation plant that had slow growth rates.

[4]In general, asset depreciation rates were developed by the BEA using the research of Hulten and Wykoff. See *Fixed Assets and Consumer Durable Goods in the United States, 1925-97* (2003).

[5] Specifically, the current methodology uses BEA's *National Income and Product Accounts*; the Department of Energy's *Electric Power Annual* and *Financial Statistics of Selected Investor-Owned Utilities*; the U.S. Department of Agriculture's *Farm Income Statistics, Rural Telephone Borrowers* and *Rural Electric Borrowers*; the Bureau of Census' *Annual Capital Expenditures Survey* and additional unpublished datasets from the Bureau of Census. *Fixed Assets and Consumer Durable Goods in the United States, 1925-97* (2003).

[6] *Ibid.*

[7] Bureau of Economic Analysis, *NIPA Handbook: Concepts and Methods of the U.S. National Income and Product Accounts*, *Chapter 6: Private Fixed Investment* (November 2017).

[8] For a discussion of the perpetual inventory method, please refer to the Flows and Stocks of Fixed Non-Residential section of this report.

Table 4

U.S. Capital Stock Deflator vs Handy-Whitman Indexes[1]

	Handy Whitman Indexes						BEA Capital Stock Deflator		
	Total Distribution Plant			Total Transmission Plant					
	National Average	North Atlantic	North Central Region	National Average	North Atlantic	North Central Region	Electric T&D Equipment	Electric Structures[2]	Average
Year	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate	Growth Rate
1962	0.6%	1.7%	0.0%	0.6%	0.0%	0.0%	-1.1%	0.0%	-0.5%
1963	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	-2.7%	2.1%	-0.3%
1964	2.8%	3.4%	3.3%	3.7%	5.0%	3.4%	0.2%	3.6%	1.9%
1965	3.2%	3.3%	3.2%	4.9%	4.8%	4.9%	-0.1%	2.2%	1.0%
1966	3.4%	3.2%	3.1%	3.9%	3.1%	4.7%	3.6%	0.1%	1.8%
1967	4.7%	4.6%	4.5%	5.2%	5.9%	4.4%	5.1%	6.6%	5.9%
1968	4.3%	4.4%	4.3%	4.0%	2.8%	4.3%	3.0%	5.5%	4.3%
1969	6.5%	5.6%	9.4%	6.5%	5.4%	8.0%	0.0%	4.1%	2.0%
1970	7.8%	9.0%	8.6%	7.7%	7.6%	8.6%	4.2%	8.6%	6.4%
1971	6.6%	7.1%	6.8%	7.2%	7.1%	6.8%	0.6%	8.3%	4.4%
1972	5.0%	5.6%	4.3%	3.8%	4.4%	3.2%	-0.5%	4.3%	1.9%
1973	7.4%	8.3%	5.1%	7.4%	8.3%	6.2%	3.0%	13.6%	8.3%
1974	17.8%	16.6%	17.4%	20.4%	19.9%	19.9%	14.4%	18.1%	16.3%
1975	15.5%	14.2%	14.8%	16.1%	13.8%	15.9%	14.9%	9.2%	12.1%
1976	5.6%	4.3%	4.3%	6.4%	4.9%	4.8%	5.8%	7.5%	6.7%
1977	6.1%	4.8%	6.7%	6.1%	5.9%	6.5%	7.1%	4.1%	5.6%
1978	5.1%	4.6%	5.1%	3.0%	3.2%	3.7%	4.6%	8.4%	6.5%
1979	9.4%	10.3%	9.4%	8.2%	8.3%	8.1%	7.3%	10.4%	8.9%
1980	7.6%	7.2%	7.0%	10.2%	10.3%	9.5%	12.2%	8.8%	10.5%
1981	9.2%	8.3%	10.0%	7.8%	7.4%	8.7%	6.0%	6.5%	6.3%
1982	6.3%	6.2%	6.0%	5.1%	5.6%	6.7%	3.7%	4.1%	3.9%
1983	2.6%	3.7%	2.2%	2.6%	3.1%	2.6%	0.9%	2.3%	1.6%
1984	1.0%	2.7%	1.3%	0.8%	2.6%	0.8%	2.2%	1.9%	2.1%
1985	0.2%	2.2%	1.3%	1.0%	2.5%	1.7%	1.5%	1.0%	1.3%
1986	0.5%	1.3%	1.3%	0.8%	2.1%	1.2%	2.6%	0.8%	1.7%
1987	0.6%	0.8%	0.8%	0.5%	1.2%	1.2%	1.8%	3.6%	2.7%
1988	5.4%	7.2%	6.0%	9.3%	8.8%	9.8%	3.0%	5.9%	4.4%
1989	4.8%	5.8%	4.9%	4.9%	5.6%	4.9%	5.2%	3.7%	4.4%
1990	2.7%	2.7%	2.9%	3.7%	5.0%	3.9%	4.4%	1.3%	2.8%
1991	1.6%	2.6%	1.4%	1.7%	3.1%	1.9%	1.0%	0.9%	1.0%
1992	1.1%	1.2%	1.2%	0.9%	1.8%	1.1%	0.8%	2.4%	1.6%
1993	2.0%	2.6%	2.0%	3.4%	3.5%	3.2%	0.6%	3.9%	2.2%
1994	3.0%	3.1%	3.3%	4.6%	4.3%	4.9%	1.9%	3.4%	2.6%
1995	3.3%	3.0%	3.6%	4.4%	3.8%	4.6%	3.1%	3.3%	3.2%
1996	1.0%	1.6%	1.2%	1.8%	1.3%	1.7%	-0.5%	0.8%	0.2%
1997	0.7%	1.5%	1.4%	1.7%	2.3%	1.9%	-0.1%	3.0%	1.4%
1998	2.3%	2.3%	2.2%	2.5%	2.5%	2.4%	-0.2%	0.7%	0.3%
1999	0.3%	0.7%	0.3%	-0.8%	0.5%	-0.7%	1.1%	2.5%	1.8%
2000	2.3%	2.6%	2.5%	4.7%	4.3%	4.7%	0.9%	3.8%	2.4%
2001	3.2%	2.9%	3.5%	3.7%	3.3%	4.1%	-0.1%	2.8%	1.3%
2002	3.0%	3.2%	3.8%	1.5%	1.9%	2.2%	-1.2%	2.6%	0.7%
2003	2.0%	2.0%	2.8%	0.9%	0.8%	1.5%	0.3%	2.9%	1.6%
2004	6.2%	6.3%	5.6%	7.5%	7.6%	7.3%	2.0%	7.4%	4.7%
2005	7.6%	8.0%	7.7%	7.6%	7.5%	7.8%	3.1%	5.0%	4.1%
2006	10.5%	10.1%	10.6%	8.1%	7.3%	8.3%	5.3%	7.7%	6.5%
2007	10.5%	10.7%	10.1%	7.9%	8.1%	7.8%	4.1%	7.5%	5.8%
2008	9.0%	8.9%	8.8%	8.4%	9.3%	8.9%	3.1%	6.4%	4.7%
2009	2.1%	2.7%	1.3%	-2.3%	-0.2%	-2.7%	0.8%	-4.4%	-1.8%
2010	3.7%	3.5%	3.1%	2.4%	2.7%	1.9%	2.6%	5.9%	4.3%
2011	4.3%	4.8%	4.3%	3.3%	3.9%	3.6%	3.1%	4.6%	3.9%
2012	3.5%	4.3%	3.0%	1.5%	2.5%	1.6%	0.3%	2.2%	1.2%
2013	3.5%	3.3%	3.4%	1.8%	2.0%	2.0%	0.1%	1.5%	0.8%
2014	3.0%	2.9%	2.8%	1.7%	2.1%	1.9%	0.0%	3.4%	1.7%
2015	2.2%	2.1%	1.8%	2.0%	1.9%	1.7%	-1.8%	1.3%	-0.2%
2016	1.1%	1.2%	0.4%	1.6%	1.8%	1.2%	0.1%	2.9%	1.5%
Annual Average Growth									
1962 - 2016	**4.5%**	**4.7%**	**4.5%**	**4.4%**	**4.6%**	**4.5%**	**2.6%**	**4.4%**	**3.5%**
1962 - 1972	**4.1%**	**4.4%**	**4.3%**	**4.3%**	**4.2%**	**4.4%**	**1.1%**	**4.1%**	**2.6%**
1973 - 1982	**9.0%**	**8.5%**	**8.6%**	**9.1%**	**8.8%**	**9.0%**	**7.9%**	**9.1%**	**8.5%**
1983 - 2001	**2.0%**	**2.7%**	**2.3%**	**2.8%**	**3.2%**	**2.9%**	**1.6%**	**2.5%**	**2.1%**
1983 - 2016	**3.3%**	**3.7%**	**3.3%**	**3.1%**	**3.6%**	**3.3%**	**1.5%**	**3.1%**	**2.3%**
2002 - 2016	**4.8%**	**4.9%**	**4.6%**	**3.6%**	**4.0%**	**3.7%**	**1.5%**	**3.8%**	**2.6%**

Notes

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

[2] "For annual, weighted average of Handy-Whitman construction cost indexes for electric light and power plants and for utility building."

The implicit capital stock deflator for electric transmission and distribution equipment had a consistently slower trend than the distribution HWIs, and this gap has increased over time.

Having reviewed the various options for measuring capital construction prices, PEG concluded that Statistics Canada's ICSD for the Ontario utilities sector is the best option for deflating the values of Ontario power distributor assets. This type of deflator is readily available, the methodology is updated periodically, and they tracked the EUCPI well in the years when it was most reliable.

c) The utilities sector encompasses the electric power generation, transmission, and distribution sectors, natural gas distributors, and water and sewage utilities.

d) PEG does not know the relative size of these sectors.

L1.INTERROGATORY M1-TH-009

Reference*: PEG Report, p. 27, "Alternative Reliability Models", and p. 28, Table 1, "Econometric Model of SAIFI."*

a) Please explain the expectation of the coefficient signs for each included variable for both the SAIFI and CAIDI models.

b) On Table 1, the P-Value for the PCTPOH*PCTFOREST variable is stated as 0.00. The T-Statistic is 1.76. Please confirm that these numbers are correct. If not, please provide the correction.

Response to TH-009: The following response was provided by PEG.

a) PEG believes that SAIFI should be higher

- The smaller is the share of service territory area that is congested urban;
- The greater is the share of distribution assets overhead
- The more extensive is service territory forestation when facilities are overhead;
- The more extreme are temperatures in the service territory;
- The greater is precipitation;
- The greater is the standard deviation of elevation.

CAIDI should be higher

- The greater is the share of service territory area that is congested urban;
- The greater is service territory area per customer served;
- The smaller is the percentage of customers served by AMI
- The greater is the standard deviation of service territory elevation.

The models also contain variables that plausibly drive the reliability metrics but do not have expected signs.

b) The correct p-value is 0.0784.

L1.INTERROGATORY M1-TH-010

Reference: *PEG Report, p. 37, last paragraph: "The sample period for the econometric cost research was 1995 to 2017."*

a) Please state the rationale for beginning the sample period in 1995 for the U.S. sample.

b) Please list all technological or other changes within the electric distribution industry from 1995 to 2019 that PEG is aware of.

c) Does PEG believe that changes within the industry from 1995 to now may have had an influence on OM&A or capital costs?

Response to TH-010: The following response was provided by PEG.

a) Longer sample periods increase the size of datasets available for econometric model estimation. This increases the precision of model parameter estimates. Longer sample periods are also less sensitive to short-term trends in cost and thus encourage an estimate of the trend variable parameter that is more reflective of the long-term cost trend. On the other hand, federal data on power distributor operations were more difficult to gather prior to the mid-1990s when they were first made available electronically.

b) Since 1995 there have been some notable changes in power distribution technology. These include automated metering infrastructure and other "smart grid" technologies. Growth in the demand for power distributor services was slowed by sluggish economic growth and growing demand-side management programs.

c) PEG believes that these developments have had some influence on OM&A and capital cost. For example, slower demand growth reduced opportunities for the realization of scale economies.

L1.INTERROGATORY M1-TH-011

Reference: *PEG Report, p. 38, Table 5, "Sample of Utilities Used in Econometric Cost Model Development."*

a) Please confirm that Consolidated Edison is excluded from PEG's capex model.

b) Please explain why the six Ontario distributors that are included in PSE's total cost model are excluded from PEG's models.

Response to TH-011: The following response was provided by PEG.

a) PEG confirms that Consolidated Edison data were not used in the estimation of its capex model. As stated on page 38 of Exhibit M1, only those utilities with AMI penetration were included in the capex model due to the nature of the PCTAMIGROWTH variable. Consolidated Edison had 0 customers with AMI in every year of the sample period in PSE's working papers.

b) PSE states in its evidence (Exhibit 1B/Tab 4/Schedule 2) in footnote 16 on page 16 that, "In the trial balance data, numerous distributors report zero pensions and benefit costs in accounts 5645 and 5646 (or if not zero, then implausibly low values). For example, in 2016 Enersource reports $62,510 spent on pensions and benefits." Since PEG's models use a definition of cost that excludes pensions and benefits, the Ontario distributors that did not itemize these expenses could not be included in the sample.

L1.INTERROGATORY M1-TH-012

Reference*: PEG Report, p. 39, third paragraph: "Pension and benefit expenses can be removed from the data for Toronto Hydro and American IOUs. We have therefore excluded these expenses from this study."*

a) What amounts for each year were excluded for Toronto Hydro?

b) What was the data source for this information?

Response to TH-012: The following response was provided by PEG.

a) Please see the row titled "Total Pension and Benefits in OM&A" of the table in Appendix A of Technical Conference Undertaking JTC4.14, filed March 4, 2019.

b) Toronto Hydro was the source of these data.

L1.INTERROGATORY M1-TH-013

Reference*: PEG Report, p. 40, second paragraph: "Capital cost was the sum of depreciation expenses and a return on net plan value less capital gains."*

a) PEG did not subtract capital gains in the 4th Generation IR proceeding and in Toronto Hydro's last Custom IR application for the 2015-2019 period. Please confirm this statement and discuss why it is appropriate to change capital cost methodologies now in this proceeding.

Response to TH-013: The following response was provided by PEG.

PEG confirms that it did not include capital gains in its studies in these two proceedings. Arguments in favor of including capital gains in total cost and capital cost benchmarking models include the following.

- Growth in the price of plant additions is a legitimate consideration when judging the efficiency of capital cost management. In theory, the quantity of capital should be larger to the extent that these prices are rising and smaller to the extent that they are falling.
- When plant is valued in replacement dollars, a failure to include capital gains overstates the importance of capital cost management in a total cost benchmarking study.

Arguments against the inclusion of capital gains include the following.

- Capital gains are not considered in cost of service capital cost accounting and their inclusion may undermine the confidence of utilities in a total cost benchmarking exercise.
- The overstatement of capital cost that could result from the exclusion of capital gains can be roughly offset by excluding taxes from the calculations.

L1.INTERROGATORY M1-TH-014

Reference*: PEG Report, p. 40, second paragraph: "The labor price levels for U.S. utilities that we obtained from PSE were escalated by regionalized BLS Employment Cost Indexes for salaries and wages."*

a) Are the Employment Cost Indexes for the U.S. utilities used by PEG specific to the utility industry, economy-wide, or specific to some other industry?

Response to TH-014: The following response was provided by PEG.

a) PEG uses ECIs for the national utility industry and regional ECIs for all industries in the following formula:

growth Regional Utility Labor Price Index
= growth National Utility Labor Price Index + (*growth Regional Comprehensive Labor Price Index*
– growth National Comprehensive Labor Price Index)

The implicit assumption is that regional differences in utility-sector labor prices equal regional differences in multi-sector labor prices. It is desirable for the prices of individual utilities to be as accurate as possible when estimating the parameters of an econometric cost model.

L1.INTERROGATORY M1-TH-015

Reference: *PEG Report, p. 40, second last paragraph.*

a) PEG states that the labour price escalation for Toronto Hydro uses the AWE. Is the AWE that PEG used specific to the utility industry, economy-wide, or specific to some other industry?

Response to TH-015: The following response was provided by PEG.

a) PEG relied on the same AWE in this study as in their 2013 study in 4GIRM. PEG stated on page 19 of its 4GIRM report that

> "PEG believes the best generic and off-the-shelf labor price index to use in our input price and TFP research is average weekly earnings (AWE) for all workers in Ontario.[17] This index reflects labor price trends for both salaried and hourly workers. It also captures Province-wide labor price pressures, not specific developments or labor settlements for Ontario's electricity distribution sector."[1]
>
> [17] Technically, this is the Average Weekly Earnings for the industrial aggregate in Ontario, and the series providing these data on an annual basis is series number 281-0027. It should be recognized, however, that the "industrial aggregate" in Ontario includes goods-making and non-goods making industries.

The updated Statistics Canada series number for AWE is 14-10-0204-01.

[1] Kaufmann, Lawrence, Hovde, Kalfayan, Rebane. *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board.* 2013.

L1.INTERROGATORY M1-TH-016

Reference*: PEG Report, p. 41, "Capital."*

a) Please confirm that PEG uses a different rate of return on capital assumption for Toronto Hydro and for the rest of the U.S. sample. If so, please explain the rationale for having different assumptions on the rate of return in a cost benchmarking study and whether this difference will influence the cost benchmarking results.

Response to TH-016: The following response was provided by PEG.

a) PEG used the same rate of return for all utilities in the sample.

L1.INTERROGATORY M1-TH-017

Reference: *PEG Report, p. 41, second paragraph: "We used the Statistics Canada implicit price index for the capital stock of Ontario utilities to deflate the value of plant additions of Toronto Hydro."*

a) Please provide a link to the source of this data and any calculations required to calculate the index.

b) Does PEG agree that one of the drawbacks of using this index, relative to using the Handy-Whitman indexes, is that the implicit price index is not specific to the electric distribution industry?

c) Is this index an Ontario or Canadian price index?

Response to TH-017: The following response was provided by PEG.

a) This link and calculations were provided in the working papers in the Excel spreadsheet titled "Implicit Capital Stock Deflator." The working papers were filed under confidential seal with the Board. Access to the working papers requires an interested party to file a Declaration of Undertaking with the Board.

b) The fact that this index is not specific to the power distribution industry is not advantageous, as PEG discussed on page 12 of Attachment HONI.14 to its response to HONI-14 in the recent Hydro One Networks Distribution proceeding (EB-2017-0049).[1] On the other hand, the utility sector consists primarily of other "wire and pipe" businesses in which costs are sensitive to trends in labor and materials prices.

c) PEG used the Ontario index in its work in this proceeding.

[1] Exhibit L1/Tab 8/Schedule HONI-14 and Attachment HONI.14.

L1.INTERROGATORY M1-TH-018

Reference: *PEG Report, p. 42, "Scale Variables."*

a) In constructing the ratcheted peak demand, did PEG use different years for Toronto Hydro and for the U.S. sample in the calculation?

b) What is the start year for determining the maximum demand for the U.S. sample?

c) What is the start year for determining the maximum demand for Toronto Hydro?

Response to TH-018: The following response was provided by PEG.

a) PEG confirms that it used different starting dates in its ratcheted peak demand calculations for Toronto Hydro and the U.S. utilities in its sample.

b) The start year for the U.S. utilities was 1995.

c) The start year for Toronto Hydro was 2002.

L1.INTERROGATORY M1-TH-019

Reference: *PEG Report, p. 42, last paragraph: "The challenge of low customer density is captured by the estimated area served that is non urban."*

a) Given the low amount of congested urban service territory in most of the sample, in PEG's opinion, does this variable essentially measure the scale of the service territory of each sampled utility? If so, why is it not considered a scale variable in PEG's model?

b) Please list the variables that PEG attempted to include in its models and the reasons why each one was excluded.

Response to TH-019: The following response was provided by PEG.

a) PEG acknowledges that this variable is highly correlated with the estimated *total* area of the service territory. This is a scale-related variable but is not treated as a scale variable with commensurate quadratic and interaction terms for several reasons.

   - The total service territory area was not the variable used.
   - The accuracy of the area estimate is in question.
   - The elasticity estimates for this variable are far lower than those for ratcheted peak demand or the number of customers served in both the total cost and the capital cost models.
   - According this variable a translog treatment would add three additional variables to the models.

b) PEG does not keep a record of every variable considered in developing a model and provides the following non-exhaustive table on a best-efforts basis.

Variable	Definition	Reason for Exclusion
NGROWTH	See response to M1-TH-029	Statistically Insignificant
YMYN	UDI Line Mile / Customers	Data Quality in Question
PCTDST	Percent of Plant Distribution	Statistically Insignificant
PCTRURAL	Percent of Service Territory Rural	PSE Data Not Vetted
AREA_RURAL	Sq. km Service Territory Rural	Involves PCTRURAL
AREAYN	Sq. km Service Territory / Customers	Implausibly Signed
PCTRURAL*PCTFOREST	Interaction between percent of service territory rural and percent of service territory forested	Involves PCTRURAL

L1.INTERROGATORY M1-TH-020

Reference: *PEG Report, p. 43, second last paragraph: "The capex models also have variables indicating the growth in operating scale and AMI."*

a) Acknowledging that the congested urban variable was not available to PEG, if the growth in this variable were available, would it have been a reasonable variable to include in PEG's capex model?

Response to TH-020: The following response was provided by PEG.

a) PEG acknowledges that growth in the congested urban and area non-urban variables could reasonably be considered for inclusion in an econometric distribution capex model.

L1.INTERROGATORY M1-TH-021

Reference*: PEG Report, p. 44, first paragraph: "We were more sparing in the use of extra quadratic and interaction terms than PSE was out of concern [Sic] that too many variables reduce the precision of parameter estimates."*

a) Please provide the basis for this statement especially considering the fact the total cost models by both PSE and PEG contain more than 1,300 observations.

Response to TH-021: The following response was provided by PEG.

a) The statement in the reference was motivated by PEG's concern over loss in model precision due to inclusion of several quadratic and interaction terms of business condition variables in PSE's total cost model.[1] Allowing flexibility in the functional form is a benefit of the translog model but comes at the cost of larger variances in the parameter estimates if the population parameters of the extra variables do not have an effect on cost.[2] This is important to consider because in general, studies that use the translog cost functions do not feature quadratic and interaction terms for the business condition variables.[3] It is, moreover, unclear whether the extra variables in a model should include instead a quadratic trend term and/or interactions of the Z variables with output quantities or the trend variable.

Moreover, even in the case that some quadratic terms have non-zero population parameters, it is likely that a quadratic term's correlation with its linear component outweighs its explanatory power of cost, thereby increasing variance estimates by more than any reduction in bias from its exclusion. Even in large samples, adding extra variables to an econometric model can lead to problems of overfit and generally reduce the precision of all parameter estimates. A model is considered "overfit" if it contains one or more irrelevant variables (i.e. a variable that has no effect on cost).[4] Although parameter estimates remain unbiased in this scenario, the model is no longer efficient in the sense of having the smallest possible a priori variances.[5]

PSE's model suffers from this problem. A statistical test[6] was performed on the quadratic terms of the business condition variables in PSE's model and revealed that all but the percent forest and percent congested urban quadratic terms were jointly insignificant. In other words, there is

---

[1] Exhibit 1B Tab 4 Schedule 2, p. 37.

[2] Greene, William. *Econometric Analysis.* 5th Ed., pp. 150-151.

[3] See, for example, Kumbhakar and Lien (2017) and Ferrier and Lovell (1990).

[4] Even if the variable's population parameter is zero, a spurious effect can be identified in model estimation.

[5] See Footnote 2.

[6] A heteroskedasticity-robust Lagrance-Multiplier ("LM") test was performed on PSE data. The null hypothesis that the population parameters on the variables were jointly zero produced a test statistic of 2.66, well below any conventional critical value of a X^2 distribution with 4 degrees of freedom.

statistical evidence that four of these variables together do not have an effect on cost and should be excluded from the model to enhance the precision of the parameter estimates for remaining variables. When these variables are removed, the model variance notably decreases, (i.e. there is less dispersion of cost scores). Low dispersion is desirable in cost benchmarking. Cost performance results are more convincing to the extent that a model predicts cost more accurately.

PEG chose not to specify its model with quadratic terms of business conditions to avoid the possibility of overfitting the model.

L1.INTERROGATORY M1-TH-022

Reference: *PEG Report, p. 44, footnote 42: "Recollecting the recent benchmark years for estimating capital cost in Ontario, the capital cost and total cost benchmarking results are likely to be more accurate in these three years."*

a) Please provide an explanation of what PEG intends to convey with the footnote.

Response to TH-022: The following response was provided by PEG.

PEG notes on page 34 of its March 20 report[1] that the accuracy of cost benchmarking in Ontario is hindered by the recent benchmark year that is to begin the calculation of capital cost. In principle, the accuracy of capital cost and total cost benchmarking will improve over time as the benchmark year recedes into the past and gross plant addition data accumulate.

[1] Exhibit M1

L1.INTERROGATORY M1-TH-023

Reference: *PEG Report, p. 44, Table 10, "Year by Year Total Cost Benchmarking Results."*

a) What data did PEG use to project the input prices for the projected years of 2018 to 2024? Please provide the growth rates used for each component.

b) What projections for the other variables in PEG's models were used for Toronto Hydro for the projected years of 2018 to 2024?

Response to TH-023: The following response was provided by PEG.

a) PEG used the same projections for input prices and other business conditions as provided by PSE in its working papers except that the 2018 actual value of the GDPIPI, the proxy for the Canadian materials price index, was used because it became available during the course of the study.

b) See the response to part (a) of this question.

L1.INTERROGATORY M1-TH-024

Reference: *PEG Report, p. 56, Table 11, "Year by Year OM&A Cost Benchmarking Results"; p. 58, Table 12, "Year by Year Capital Cost Benchmarking Results"; and p. 60, Table 13, "Year by Year Capex Benchmarking Results."*

a) What data did PEG use to project the input prices for the projected years of 2018 to 2024? Please provide the growth rates used of each component.

b) What projections for the other variables in PEG's models were used for Toronto Hydro for the projected years of 2018 to 2024?

Response to TH-024: The following response was provided by PEG.

a & b) Please see the response to part (a) of Exhibit L1/Tab 1/Schedule 23 (PEG-TH-023).

L1.INTERROGATORY M1-TH-025

Reference: *PEG Report, p. 71, third paragraph: "In our econometric work for this proceeding, we have chosen a functional form that is logarithmic only with respect to the two scale variables."*

a) Please provide the full equation estimated for PEG's total cost, OM&A, capital cost, and capex models. Please note which variables were logged in each equation.

b) Why did PEG not use the traditional translog cost function?

c) Please discuss the econometric estimation procedure used by PEG for the total cost, OM&A, capital cost, and capex models, respectively.

Response to TH-025: The following response was provided by PEG.

a) Please see below for the full equations estimated. A variable key is provided for reference.

	Variable	Definition
Dependent Variables	C	Total Cost
	CK	Capital Cost
	CX	Capital Expenditures
	COM	OM&A Expenses
Input Price Indexes	W	Composite Price Index
	WK	Capital Service Price
	WX	Capital Asset Price
	WOM	OM&A Price Index
Other Business Condition Variables	N	Number of Customers
	D	Ratcheted Maximum Peak Demand
	PCTCU	Percent of Service Territory Congested Urban
	PCTPOH	Percent of Plant Overhead
	AREA_OTHER	Service Territory Area Multiplied by (1-PCTCU)
	PCTFOREST	Percent of Service Territory Forested
	PCTELEC	Percent of Customers Electric
	PCTAMI	Percent of Customers with AMI
	ELEVSTD	Elevation Standard Deviation
	NGROWTH	Customer Growth over Ten Years
	DGROWTH	Growth in D over Sample Period
	PCTAMIGROWTH	Growth in PCTAMI (from start of PCTAMI to 2017)
	TREND	Time Trend

$$\ln\left(\frac{C}{W}\right) = \beta_0 + \beta_1 \ln(N) + \frac{\beta_2}{2}\ln^2(N) + \beta_3 \ln(D) + \frac{\beta_4}{2}\ln^2(D) + \beta_5 \ln(N)\ln(D) + \beta_6 PCTCU$$

$$+ \beta_7 \ln(AREA\_OTHER) + \beta_8 \ln(PCTFOREST) + \beta_9 \ln(PCTELEC)$$

$$+ \beta_{10} PCTAMI + \beta_{11} \ln(ELEVSTD) + \beta_{12} TREND + \varepsilon$$

$$\ln\left(\frac{CK}{WK}\right) = \gamma_0 + \gamma_1 \ln(N) + \frac{\gamma_2}{2}\ln^2(N) + \gamma_3 \ln(D) + \frac{\gamma_4}{2}\ln^2(D) + \gamma_5 \ln(N)\ln(D) + \gamma_6 PCTCU$$

$$+ \gamma_7 \ln(AREA\_OTHER) + \gamma_8 \ln(PCTFOREST) + \gamma_9 \ln(PCTELEC)$$

$$+ \gamma_{10} PCTAMI + \gamma_{11} \ln(ELEVSTD) + \gamma_{12} TREND + \theta$$

$$\ln\left(\frac{CX}{WX}\right) = \rho_0 + \rho_1 \ln(N) + \frac{\rho_2}{2}\ln^2(N) + \rho_3 \ln(D) + \frac{\rho_4}{2}\ln^2(D) + \rho_5 \ln(N)\ln(D) + \rho_6 \mathrm{PCTCU}$$

$$+ \rho_7 \ln(ELEVSTD) + \rho_8 \ln(NGROWTH) + \rho_9 \ln(PCTAMIGROWTH)$$

$$+ \rho_{10} \ln(DGROWTH) + \rho_{11} TREND + \varphi$$

$$\ln\left(\frac{COM}{WOM}\right) = \delta_0 + \delta_{\ 1} \ln(N) + \frac{\delta_2}{2}\ln^2(N) + \delta_3 \ln(D) + \frac{\delta_4}{2}\ln^2(D) + \delta_5 \ln(N)\ln(D)$$

$$+ \delta_7 PCTCU + \delta_7 \ln(PCTPOH) + \delta_8 \ln(AREA\_OTHER)$$

$$+ \delta_9 \ln(AREA\_OTHER)\ln(PCTPOH) + \delta_{10} \ln(PCTFOREST)$$

$$+ \delta_{11} \ln(PCTELEC) + \delta_{12} PCTAMI + \delta_{13} \ln(ELEVSTD) + \delta_{14} TREND + \omega$$

where

$\beta_i, \gamma_i, \rho_i, \delta_i$ are parameters to be estimated;

$\varepsilon, \theta, \omega, \phi$ are composite error terms that reflect inefficiency and random noise.

b) PEG amends the record on its statement about the chosen functional form:

PEG Report, p.71 states that "In our econometric work for this proceeding, we have chosen a functional form that is logarithmic only with respect to the two scale variables."

A correct statement is that

"In our econometric work for this proceeding, we have chosen a functional form that is non-linear only with respect to the two scale variables."

c) The econometric estimation procedure was feasible generalized least-squares ("FGLS") with panel-weighted heteroskedasticity-robust standard errors and a Prais-Winsten correction for autocorrelation.

L1.INTERROGATORY M1-TH-026

PEG uses the 2008 version of *R. S. Means Heavy Construction Cost Data* to calculate a 2008 capital levelization year for the U.S. sample that adjusts for the differences in construction costs between utilities serving different geographic areas.

a) Please describe how the 2008 capital levelization was calculated for each utility. Please include in the description what city location factors were mapped to each of the utilities and the city weights used in calculating the levelization for each utility.

b) Please provide the 2008 R. S. Means location factor for Toronto.

c) Please confirm that PEG used the Toronto location factor from the 2012 version of *R. S. Means Heavy Construction Cost Data* as the basis for Toronto Hydro's capital levelization.

d) Please confirm that PEG inadvertently used a different capital levelization year for Toronto Hydro (2012) and for the rest of the U.S. sample (2008) which produces a capital asset price that is not properly levelized for Toronto Hydro relative to the rest of PEG's sample in any year. If the difference was intentional, please provide the basis and rationale for using a different year for a comparative index and how the impacts of escalating the index in each year do not distort the levelization.

e) Please provide a revised Table 6, Table 8, Table 9, Table 10, Table 12, and Table 13 from the PEG Report where no other changes are made to PEG's data and models other than making the capital levelization year consistent for Toronto Hydro and the U.S. sample using 2008 as the levelization year.

f) Please provide a revised Table 6, Table 8, Table 9, Table 10, Table 12, and Table 13 from the PEG Report where no other changes are made to PEG's data and models other than making the capital levelization year consistent for Toronto Hydro and the U.S. sample using 2012 as the levelization year.

Response to TH-026: The following response was provided by PEG.

a) The 2008 capital price levelization for the U.S. companies in PEG's sample was done in a similar manner to that done by PSE. Both consultancies used the RSMeans city cost indexes for total cost. The principal differences are that PEG used multiple cities for each U.S. company and that PEG performed the levelization two years prior to the year listed on the cover of the RSMeans volume. This was done to be in alignment with the date RSMeans ascribes to the city cost indexes. PEG used the 2010 RSMeans volume which states on the page 512 introduction to the city cost indexes:

> *Index figures for both material and installation are based on the 30 major city average of 100 and represent the cost relationship as of July 1, 2008.*[1]

b) The value for Toronto in the 2010 RSMeans book is 110.7. As noted in the response to part (a), this should be the 2008 value.

c) PEG left the PSE data for THESL intact except for specific changes discussed in the report. This included the 2012 city cost index for Toronto used by PSE.

d) PEG confirms that for Toronto Hydro it inadvertently retained the PSE method of using the 2012 RSMeans value to levelize the THESL asset price in 2012. The value from the 2010 book should have been used to do this levelization in 2008 to be consistent with the other U.S. data in the PEG study. Correcting the error of PSE not doing the levelization in 2010 and the error of PEG using the 2012 city cost index instead of the 2008 value affects the PEG benchmarking results. Over the five-year 2020-2024 period, the average total cost benchmarking score for THESL moves from **20.6% to 15.9%,** the average capital cost benchmarking score moves from **43.0% to 36.1%**, and the average capex benchmarking score moves from **21.7% to 14.9%.** The OM&A and reliability models were not affected. These corrections produce no change in stretch factor recommendation. Please see Attachment PEG-TH-026e for the revised results.

   In preparing these responses, PEG also noted some inconsistencies in the plant additions data and methods it had used in its initial study and those used by PSE. After examining the differences, PEG did not find either approach completely suitable. PEG chose to upgrade its calculation of plant additions to address its concerns. The impact of these improvements on the benchmarking results was minor. The performance of THESL changed from 15.9% to 15.6% in the total cost model. The result in the capital cost model changed from 36.1% to 35.7%. The result in the capex model was virtually unchanged. Please see Attachment PEG-TH-026d for the revised results.

e) Please see Attachment PEG-TH-026e.

f) Please see Attachment PEG-TH-026f.

[1] PSE used the 2012 book and does the levelization in 2012 which is two years too late if the relationship in the 2010 book holds for 2012.

L1.INTERROGATORY M1-TH-027

Please describe why PEG's capex model has far fewer observations (1,306) than the other three models (1,907). Besides excluding 1995 to attain the growth rates of certain variables, please provide a list of the exclusions made relative to the other three models.

Response to TH-027: The following response was provided by PEG.

As explained in the footnote to Table 5 of page 38 of Exhibit M1, only those utilities with AMI penetration were included in the capex model due to construction of the variable PCTAMIGROWTH. In the dataset provided to PEG by PSE, Consolidated Edison had 0 for percent of customers with AMI in all years. All other excluded companies are asterisked in Table 5 Exhibit M1 page 38. There were no other exclusion criteria.

L1.INTERROGATORY M1-TH-028

For the capex model, did PEG include general plant additions in the dependent variable for the U.S. sample?

Response to TH-028: The following response was provided by PEG.

PEG confirms that it included an allocated amount of general plant additions in the calculation of the dependent variable for the U.S. sample.

L1.INTERROGATORY M1-TH-029

Please provide the equation for how the variable for "NGROWTH", "PCTAMIGROWTH", and "DGROWTH" are calculated.

Response to TH-029: The following response was provided by PEG.

Here is the formula for the customer growth variable used in PEG's capex model:

$$NGROWTH = \begin{cases} \frac{\mathrm{N}_{i,2012}}{\mathrm{N}_{i,2002}} & i = THESL, t < 2012 \\ \frac{N_{i,t}}{N_{i,t-10}} & i = THESL, t \geq 2012 \\ \frac{N_{i,2005}}{N_{i,1995}} & i \neq THESL, t < 2005 \\ \frac{N_{i,t}}{N_{i,t-10}} & i \neq THESL, t \geq 2005 \end{cases}$$

In words, NGROWTH is the growth rate in customers over ten years.[1] For the first ten years of the sample period, it is held frozen as growth from the start year to the start year plus 10.

Here is the formula for the ratcheted peak demand growth variable used in PEG's capex model:

$$DGROWTH = \frac{D_{2017}}{D_{1995}}.$$

In words, DGROWTH is the growth rate in ratcheted maximum peak demand over the non-forecasted sample period.[1]

Here is the formula for the AMI growth variable used in PEG's capex model:

$$PCTAMIGROWTH = \frac{PCTAMI_{2017}}{PCTAMI_t}$$

where $t = \min_{t \in [1995,2017]} \{t |\ PCTAMI_t > 0\}$.

In words, *t* is the first year of AMI penetration that could be different for each company.

[1] These become growth rates when logged.

L1.INTERROGATORY M1-TH-030

PEG uses a different asset price escalator for Toronto Hydro and the rest of the sample.

a) Please confirm that the capital service price ("wkod" in PEG's code) used by PEG for Toronto Hydro increases by an average of 0.5% per year from 2005 to 2017.

b) Please confirm that every other utility in PEG's dataset has a higher average annual growth rate for the capital service price than Toronto Hydro from 2005 to 2017.

c) Please confirm that Consolidated Edison's average annual growth rate for the capital service price in PEG's dataset from 2005 to 2017 is 4.8%.

d) Please confirm that Madison Gas and Electric's average annual growth rate for the capital service price in PEG's dataset from 2005 to 2017 is 4.4%.

e) Does PEG believe that capital cost increases have been dramatically higher in the United States relative to the City of Toronto? Please explain PEG's rationale for the large discrepancy in the capital price inflation assumptions for Toronto Hydro versus the rest of the sample used by PEG.

Response to TH-030: The following response was provided by PEG.

These answers reflect the upgrades noted in response to question M1-TH-026.

a) PEG confirms this statement is correct.

b) PEG confirms every other utility in its sample period had a higher average annual growth rate for the capital service price than Toronto Hydro from 2005 to 2017.

c) Not confirmed. Consolidated Edison's average annual growth rate of the capital service price from 2005 to 2017 was 7.2%. This reflects rapid growth in the construction cost index over the 2006-2008 period. The relevance of this to the benchmarking of Toronto Hydro's cost is reduced by the fact that the levelization of the asset price takes place in 2008 in the PEG work. The trend in the asset price for Consolidated Edison was 3.08% vs. 2.57% for THESL since 2008. In the capital price, any deviations from this trend due to capital gains are mirrored by adjustments to capital cost.

d) Not confirmed. Madison Gas and Electric's average annual rate of the capital service price from 2005 to 2017 was 6.8%. This reflects rapid growth in the construction cost index over the 2006-2008 period. The relevance of this to the benchmarking of Toronto Hydro's cost is reduced by the fact that the levelization of the asset price takes place in 2008 in the PEG work. The trend in the asset price for Madison Gas and Electric was 2.64% vs. 2.57% for THESL since 2008. In the capital price, any deviations from this trend due to capital gains are mirrored by adjustments to capital cost.

e) PEG has endeavored to use the best available plant addition deflator for each utility. Please see the response to M1-TH-008 for a discussion of its deliberations concerning these deflators.

L1.INTERROGATORY M1-TH-031

PEG employs a number of assumptions in constructing the capital service price for each utility, including the R. S. Means levelization, asset price escalators, rate of return assumptions, depreciation rates, and capital gains.

a) By 2017, Toronto Hydro's capital service price equals 130.2. Please confirm that number accounts for currency differences and can be considered a Canadian input price index.

b) By 2017, there are a number of utilities that have higher capital service price indexes than Toronto Hydro in PEG's dataset. Despite the fact that the indexes are in each country's currency which, given current exchange rates, should increase the value of Toronto Hydro's index. Examples of utilities with higher 2017 capital service prices are Atlantic City Electric, Commonwealth Edison, Connecticut Light and Power, Consolidated Edison, Detroit Edison, Duquesne Light, Jersey Central Power & Light, Kansas City Gas and Electric, etc. Please provide PEG's rationale on why the capital price assumed for Toronto Hydro is below a large portion of PEG's sample despite the exchange rate and Toronto being a large city that is generally understood to have higher price levels relative to most places in the United States.

Response to TH-031: The following response was provided by PEG.

These answers reflect the upgrades stated in response to question Exhibit L1/Tab 1/Schedule 26 (M1-TH-026).

a) Toronto Hydro's capital service price equals 12.33 in 2017. The Company's capital asset price is 139.45 in 2017. PEG confirms that all of Toronto Hydro's input prices, including the capital asset price, account for currency differences and can be considered Canadian input price indexes.

b) The relative value of Toronto Hydro's capital service price should be very sensitive to the level of its construction cost index. The RSMeans city cost indexes are used to compare utility construction costs between cities across the U.S. and Canada. By design, the average value is 100. In 2017, the RSMeans value for the Company was 110.6, meaning that construction costs in Toronto were only 10.6% higher than average (including currency differences). Urban challenges and exchange rates notwithstanding, many areas of the U.S. had higher capital asset prices in 2017 relative to Toronto, including but not limited to: the entire state of New Jersey and cities in California, Illinois, Massachusetts, and New York. The cities included were not limited to the major urban centers but included cities such as Rockford, Illinois, Poughkeepsie, New York and Redding, California. In 2008, Toronto Hydro's RSMeans value was a similar 110.7. This was below the value for PECO Energy (115.3), Orange and Rockland (115.3), Pacific Gas and Electric (115.5), Commonwealth Edison (115.6), and Consolidated Edison (133.2).

Results in the PSE study are not altogether different. By 2016, Consolidated Edison, Pacific Gas and Electric, Commonwealth Edison, and PECO Energy had higher capital asset prices in PSE's working papers.

L1.INTERROGATORY M1-TH-032

PEG began the capital series for Toronto Hydro in 1989 using several assumptions and imputations from PEG's 4th Generation IR research. Examining the data there appears to be an implausible increase in distribution plant additions applied to Toronto Hydro in 1996. Plant additions exceeded $450 million in 1996 in PEG's dataset. This is approximately quadruple the typical number in the 1990's and was not exceeded in any year until 2014. Is this number correct for Toronto Hydro? If not, please provide the revised number. If so, please provide the underlying data and explanation on why PEG believes that Toronto Hydro quadrupled plant additions in 1996 to over $450 million.

Response to TH-032: The following response was provided by PEG.

The cited value does not appear to be implausible to PEG. Two years prior there was a value that was very low and on balance the two average to a more typical value. The early 1990s were recession years and it is not unreasonable that capex would be low. By the mid-1990s, a renewed boom in construction was happening in Toronto. The source of the increase in the additions was due to a large increase in the plant balance for account 75 (using the pre-Accounting Price Handbook/Reporting and Recordkeeping Requirements account numbers) which is Distribution Lines and Feeders – Underground. Subsequent values in this account remained at the higher levels as did the corresponding successor accounts used currently.

The imputation used to calculate gross additions is to add an estimate of retirements to the change in gross plant. The estimated retirement rate was only 0.5%. If retirements were higher than assumed for THESL in this year, it would only lead to an even higher gross additions value. Please see the working papers for IRM-4 for the raw gross plant data from the municipal database in "gross plant data.xls" here:

http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/2012%20PEG%20Working%20Papers%20-%20Part%20I%202013-09-04.zip

THESL is calculated as the sum of its regional offices. The jump occurred in the Toronto office which is consistent with the thesis of a congested urban building boom requiring underground plant which has been a feature of the PSE analysis.