PACIFIC ECONOMICS GROUP RESEARCH, LLC
INTERROGATORY RESPONSES

Power Workers' Union

PWU-1
Ref: Statistical Cost Research for the Alectra Utilities CIR Plan, Pages 31-32 of 100
Major Disadvantages
Major disadvantages of Ontario data include the following.

- Many Ontario distributors are transitioning to OM&A inputs such as cloud computing and non-wire alternatives ("NWAs") to growth-related capex. The complication of NWAs can be mitigated by excluding CDM expenses from the analysis.

Question(s):

a) How has the transition to cloud computing been considered in productivity trend calculations?
b) Is it PEG's understanding that the NWA costs are included as CDM expenses in LDC cost data?
c) If an LDC undertakes an NWA project instead of a capital project, does the lower capital cost result in increased capital productivity trends with no corresponding impact to OM&A productivity trends?

Response:

a) Any cloud computing costs that sampled distributors incurred through 2024 are included in the productivity trends.
b) PEG understands that some NWA costs may be treated as OM&A expenses but others may not be.
c) Yes, that would be PEG's understanding if the costs are treated as CDM expenses. In productivity studies used to set productivity factors, it is common to exclude costs that are subject to tracker treatment where practicable.

PWU-2
Ref 1: Statistical Cost Research for the Alectra Utilities CIR Plan, Page 83 of 100

Table 8a

Productivity Growth of Ontario Electricity Distributors 2004-2024

Year	Simple Averages of Annual Productivity Growth Rates			Cost-Weighted Averages of Annual Productivity Growth Rates		
	Total Factor	OM&A	Capital	Total Factor	OM&A	Capital
2004	1.62%	1.90%	0.95%	2.41%	3.91%	-0.28%
2005	-0.16%	1.03%	-0.51%	0.61%	0.87%	0.46%
2006	-1.14%	-2.03%	-0.85%	-1.21%	-3.33%	0.12%
2007	-1.11%	-1.60%	-0.41%	-3.50%	-8.17%	-0.28%
2008	-0.75%	-0.89%	-0.69%	0.57%	1.30%	0.05%
2009	-0.25%	0.26%	-0.47%	-0.86%	-1.79%	-0.21%
2010	0.68%	0.87%	0.69%	0.35%	-1.63%	1.74%
2011	-2.28%	-4.79%	-0.01%	-1.12%	-2.89%	0.20%
2012	-4.39%	-7.52%	0.12%	2.54%	1.34%	3.55%
2013	-1.20%	-1.04%	-1.82%	-2.83%	-4.28%	-1.49%
2014	1.35%	1.71%	0.36%	0.40%	-0.77%	1.49%
2015	-0.08%	0.06%	0.19%	4.09%	6.56%	1.91%
2016	-0.81%	-0.76%	-0.75%	-0.75%	0.57%	-1.88%
2017	-0.25%	0.32%	-0.53%	0.97%	3.59%	-1.31%
2018	0.42%	0.50%	-0.11%	-0.43%	0.20%	-0.97%
2019	0.68%	1.59%	-0.01%	0.58%	2.15%	-0.69%
2020	1.49%	2.60%	-0.11%	1.29%	3.84%	-0.72%
2021	0.56%	0.68%	0.35%	-0.06%	0.39%	-0.42%
2022	-1.08%	-1.92%	0.02%	-1.38%	-2.94%	-0.26%
2023	0.18%	-0.15%	0.63%	-0.53%	-1.35%	-0.02%
2024	-0.74%	-1.80%	0.46%	1.24%	3.25%	0.12%
Average Annual Growth Rates						
2004-2024	-0.35%	-0.52%	-0.12%	0.11%	0.04%	0.05%
2004-2010	-0.16%	-0.07%	-0.19%	-0.23%	-1.26%	0.23%
2014-2024	0.16%	0.26%	0.05%	0.49%	1.41%	-0.25%

Question(s):

a) Please explain why a simple average is more appropriate than a geometric average?
b) Please confirm that simple averages produce higher average annual growth rates than geometric averages within this dataset.
c) Please confirm that outliers such as the OM&A productivity growth rate in 2020 influence average calculations when a simple average is used instead of a geometric average.
d) The average used for the proposed productivity factors is an 11-year average which includes 2014 to 2024.
    a. Please explain why an 11-year average is appropriate.

b. Please confirm the OM&A productivity factor would be lower if any other year other than 2014 was selected as the starting year.
c. Please confirm that if growth rates in 2020 were excluded, the average total productivity factor and OM&A productivity factor would be negative for all timeframes except the selected 2014 to 2024 range.

Response:

a) PEG has not considered a geometric averaging of productivity growth rates and does not recall its use in IR plan design evidence. A simple average of annual logarithmic growth rates is consistent with the way that the index numbers are constructed and the annual growth rates are calculated. It is our understanding that a geometric mean will not work with negative values and there are negative growth rates in this series. Using the table above, the geometric average the 2023 and 2024 values of 0.18% and -0.74% is undefined as it is the square root of a negative number.
b) Please see the response to part a) of this question.
c) PEG reports average logarithmic growth rates and these are insensitive to particular growth rates in the middle of the sample period.

$$(1/N) \times SUM_s^S [\ln(Productivity_{t-s} / Productivity_{t-s-1})] =$$
$$(1/N) \times SUM_s^S (\ln Productivity_{t-s} - \ln Productivity_{t-s-1}) =$$
$$(1/N) \times \ln (Productivity_t / Productivity_{t-S-1})$$

PEG also notes that the pandemic-related surges in OM&A and total factor productivity in 2020 were largely offset by marked productivity declines in the years that followed. These ups and downs are likely related as distributors did "catch-up" work as the pandemic wound down.

d)

a. Reasons for choosing the 11-year 2014-2024 sample period are explained on pages 47-48 of PEG's Empirical Report. PEG normally favors a 15-year productivity trend as the basis for productivity factors because it reasonably balances the need to smooth productivity fluctuations with the need to reflect current and prospective future business conditions that affect productivity growth. However, an 11-year period makes more sense for Alectra Utilities because of special circumstances that include flaws in Ontario data in years before 2013. These flaws notably affect the calculation of OM&A productivity trends that are especially relevant to Alectra Utilitiess CIR proposal.
Were this study hypothetically to be annually updated, PEG would likely add a year to the sample period each year without changing the start year

until a 15-year period was reached. Thereafter, the start date of the sample period would move forward.

Please also note that PEG could have proposed productivity factors based on cost-weighted average productivity trends which are more rapid but did not do so. Moreover, PEG made the extra effort to include 2024 data in the productivity trend calculations even though it slowed the featured OM&A and total factor productivity trends.

b. This statement is confirmed. The 0.23% OM&A PFP trend for the 2017-2024 period is similar to the 0.26% OM&A PFP trend for the 2014-2024 period that is featured in our results.
c. Whether or not this statement is correct, it would be wrong to exclude 2020 while including the subsequent "bounceback" years of productivity declines.

PWU-3

Ref 1: Statistical Cost Research for the Alectra Utilities CIR Plan, Page 9 of 100

PEG counsels against postponing the issue of new productivity factors to a later proceeding. Positive productivity growth targets are now warranted, and customers would benefit at a time of real affordability concerns. Clearspring is quite capable of reviewing new Ontario productivity research in this proceeding.

Ref 2: Statistical Cost Research for the Alectra Utilities CIR Plan, Page 88 of 100

It is also useful to examine productivity trend results by size of distributor which are presented in Table 8c.61 There was a divergence in trends between larger and smaller distributors. For the RRF period from 2014-2024, the average annual TFP growth of small distributors was positive 0.21% whereas medium-sized distributors averaged 0.10% growth and large distributors averaged an annual decline of 0.01%. These trends compare favorably to the earlier periods ending in 2010 for large and small distributors but not for medium-sized distributors due partly to the superior historical performance of these distributors in the earlier period.

Question(s):

a) Please confirm Alectra is a large distributor.
b) If a) is confirmed, please discuss the appropriateness of having a positive industry-wide productivity factor that is applied to one LDC at this time when the productivity of large distributors is declining.

Response:

a) Alectra Utilities is one of the largest distributors in Ontario. However, Alectra Utilities is not very large relative to PEG's sample. Table 6 of PEG's Empirical Report provided comparisons of Alectra Utilities to the norms for PEG's

benchmarking sample in 2023. Alectra Utilities had about 16% more customers than the average sampled distributor and about 10% higher ratcheted peak demand than the average sampled distributor.

b) PEG notes that the cost-weighted trends in the OM&A and total factor productivity of Ontario power distributors were more positive than the simple average trends. The total factor productivity and capital productivity trends of large distributors were negative, but Alectra Utilities is requesting substantially full compensation for its forecasted capital cost growth. The OM&A productivity trend matters more in this proceeding and this was materially positive for large distributors. Note also that the number of large distributors in the sample is small and several large distributors in Ontario operate under CIR frameworks that weaken their capex containment incentives. It is not customary in IR to base productivity factors of large distributors solely on the productivity trends of large distributors.

Alectra Utilities

References:

- **Statistical Cost Research for the Alectra Utilities CIR Plan "PEG Empirical Report"**
- **Issues in the Design of the New Alectra Utilities CIR Framework "PEG Plan Report"**
- **PEG Working Papers**

AUC-1
Question(s):
Please provide the engagement letter and all related materials including any RFP and proposal response, and all written instructions provided to PEG, related to the preparation of PEG's reports.

Response:
"Attachment AUC-1_Request for Services" reproduces the project information and requirements contained in the Request For Services (RFS) issued by the OEB.

"Attachment AUC-1_PEG Research Proposal" is the introduction and proposal from PEG's response to the RFS.

The Services and Deliverables section of the Statement of Work between the OEB and PEG is provided as "Attachment AUC-1_Services and Deliverables".

Written instructions provided to PEG are shown in "Attachment AUC-1_Instructions to PEG".

AUC-2
Ref 1: PEG Empirical Report, p. 6
PEG states, "Clearspring forecasts that Alectra Utilities' total cost efficiency is expected to decline by an average of 1.03% each year during the CIR plan term."

Question(s):
Please confirm that this decline essentially disappears when Clearspring uses the Handy-Whitman indexes as the basis for Alectra's asset price inflation. Please see Clearspring's interrogatory response to 1-Staff-20.

Response:
PEG confirms that the benchmarking in Clearspring's interrogatory response to 1-Staff-20 no longer shows a pattern of declining cost performance in the forecasted years and

instead shows scores that hover within a fairly narrow range. We also note that there is a sizeable change in Clearspring's estimate of Alectra Utilities' historical cost performance which suggests review of the model as a whole would be prudent when considering these results. For reference, here are the original results followed by the 1-Staff-20 interrogatory response version of Clearspring's scores:

Table 4 2019-2031 Total Cost Benchmark Score for Alectra

Year	% Difference from Total Cost Benchmark
2019	-24.2%
2020	-28.1%
2021	-27.1%
2022	-25.4%
2023	-23.6%
2024	-25.0%
2022-2024 average score	**-24.6%**
2025	-24.1%
2026	-25.0%
2027	-23.2%
2028	-22.7%
2029	-21.7%
2030	-20.0%
2031	-19.9%
2027-2031 average score	**-21.5%**

Table 1 - % Difference from Total Cost Benchmark

Year	% Difference from Total Cost Benchmark
2019	-15.9%
2020	-20.1%
2021	-19.6%
2022	-18.3%
2023	-17.1%
2024	-18.8%
2022-2024 average score	-18.1%
2025	-18.8%
2026	-20.3%
2027	-19.5%
2028	-19.8%
2029	-19.7%
2030	-18.8%
2031	-19.4%
2027-2031 average score	-19.4%

AUC-3
Ref 1: PEG Empirical Report, p. 7

PEG lists two larger concerns it has regarding Clearspring's cost benchmarking study. The first mentions that the dataset begins in 2000, and in conjunction with using a single time trend variable, asserts this may not adequately measure recent trends, challenges, and technical change in the industry. The second is not a specific concern regarding Clearspring's total cost benchmarking but rather that Clearspring only provided total cost benchmarking and not OM&A and capital cost benchmarking as well.

PEG has previously raised a concern that Mr. Fenrick's benchmarking work did not go back far enough and stated this would reduce the precision of the econometric benchmarking model parameter estimates. In EB-2018-0218, Mr. Fenrick put forth a cost benchmarking model that used data from 2004 to 2016 (a 13-year period). PEG listed their concerns on page 14 of its report in that proceeding. The one listed first stated, "The relatively short sample period unnecessarily reduces the precision of the econometric benchmarking model parameter estimates." In that same report, PEG put forth a total cost model that spanned 22 years (1995-2016) and included a single time trend variable. Clearspring's model in this case spans 24 years and includes a single time trend variable.

Question(s):

a) Does PEG continue to maintain that Clearspring's larger dataset of 24 years should be classified as a "large" concern, especially in light of PEG's previous comments and studies?
b) If yes to part (a), is this a change in PEG's thinking or are there specific differences in this case compared to EB-2018-0218 where PEG said datasets with more years produce more precise parameter estimates?

Response:

a) Yes. An excessively long sample period was one of four (not two) major concerns that PEG had with Clearspring's study.
b) The cited EB-2018-0218 study in which PEG used a much longer sample period was performed eight years ago. PEG has in recent years trended towards use of a sample of fifteen or sixteen years where practicable. This strikes a sensible balance between the need for model relevance and the need for a large sample to sharpen the parameter estimates of econometric models. The importance of model relevance has increased with the energy transition and technological changes in the distribution business that may prospectively include artificial intelligence. Please see Table AUC-3 for additional detail on the sample periods in many publicly available benchmarking studies undertaken by PEG. PEG has gathered data for a larger number of peers than Clearspring as alternative to a longer sample period as a way to encourage more precise parameter estimates.

Table AUC-3
Details of Selected PEG Benchmarking Studies

Year	Client	Industry	Jurisdiction	Sample Period	Capital Gains
1996	Boston Gas	Natural gas	Massachusetts	1984-1994 (11 years)	Yes
1997	Atlanta Gas Light	Natural gas	Georgia	1984-1995 (12 years)	Yes
1998	Kentucky Utilities	Vertically integrated electric utility	Kentucky	1992-1996 (5 years)	Uncertain
2002	San Diego Gas & Electric	Natural gas	California	1990-2001 (12 years)	Yes
2002	San Diego Gas & Electric	Power distribution	California	1990-2001 (12 years)	Yes
2002	Southern California Gas	Natural gas	California	1990-2001 (12 years)	Yes
2005	San Diego Gas & Electric	Nuclear power generation	California	1990-2003 (14 years)	Uncertain
2006	Central Vermont Public Service	Power distribution	Vermont	1991-2004 (14 years)	Yes
2009	Oklahoma Gas & Electric	Vertically integrated electric utility	Oklahoma	1995-2007 (13 years)	Not Applicable
2009	Public Service of Colorado	Vertically integrated electric utility	Colorado	1995-2008 (14 years)	Not Applicable
2010	Public Service of Colorado	Natural gas	Colorado	1998-2009 (11 years)	No
2014	Public Service of Colorado	Vertically integrated electric utility	Colorado	1995-2012 (18 years)	Not Applicable
2017	Public Service of Colorado	Bundled power service	Colorado	1996-2016 (21 years)	Not Applicable
2018	Ontario Energy Board- Hydro One Distribution CIR Application I	Power distribution	Ontario	2002-2015 (14 years)	No
2018	Ontario Energy Board - Toronto Hydro Custom IR Application II	Power distribution	Ontario	1995-2017 (23 years)	Yes
2019	Ontario Energy Board - Hydro One SSM	Power transmission	Ontario	1995-2016 (22 years)	Yes
2019	Ontario Energy Board - Hydro One Transmission CIR Application I	Power transmission	Ontario	1995-2016 (22 years)	No
2020	Massachusetts Attorney General	Natural gas	Massachusetts	2003-2017 (15 years)	Yes
2020	Ontario Energy Board: Hydro Ottawa	Power distribution	Ontario	2002-2017 (16 years)	No
2021	Ontario Energy Board: Hydro One Distribution CIR Application II	Power distribution	Ontario	2002-2019 (18 years)	No
2021	Ontario Energy Board: Hydro One Transmission CIR Application II	Power transmission	Ontario	Tx: 2004-2019 (16 years)	No
2021	l'Association québécoise des consommateurs industriels d'électricité and Le Conseil de l'industrie forestière du Québec	Power transmission	Québec	2004-2019 (16 years)	Yes
2023	Consumers' Coalition of Alberta	Power distribution and natural gas	Alberta	Both studies: 2006-2021 (16 years)	Yes
2024	Ontario Energy Board: THESL CIR 3	Power distribution	Ontario	2007-2021 (15 years)	Yes
2024	Ontario Energy Board: Enbridge Gas Inc.	Natural gas	Ontario	2008-2022 (15 years)	Yes
2026	Ontario Energy Board: Alectra	Power distribution	Ontario	2009-2023 (15 years)	Yes

AUC-4

Ref 1: PEG Empirical Report, p. 8

PEG states that the eleven years of productivity trends from 2014 to 2024 have fewer data problems.

Question(s):

a) Is PEG aware of any data problems during this 2014 to 2024 period? If so, please list and describe them.

Response:

a) One small problem with recent Ontario data is the lack of company-specific data on OM&A labor expenses starting in 2023. Another is inconsistent reporting of distribution line lengths.

AUC-5
Ref 1: PEG Empirical Report, p. 9
PEG suggests that new industry productivity factors should be considered in this proceeding.

Question(s):

a) How many months and weeks has PEG been working on this new productivity research?
b) How many person-hours of effort has PEG put into gathering the Ontario dataset, gathering and examining input prices, and conducting the productivity calculations?
c) In doing this above new research did PEG make use of, consider or take into account generic research it was also previously doing in connection with other work for the OEB relating to this topic? If so, in what way was this related research used, considered or taken into account, and when did PEG begin working on this other related generic research?

Response:

a) PEG acknowledges that its new Ontario productivity trend research began in another project for OEB staff. With the permission of OEB Staff, PEG was able to use whatever data or calculations it had available. However, we are unable to comment on the specific details of any ongoing research that is being performed for the OEB that has not yet been made public. The productivity evidence presented for this proceeding is intended to stand on its own merits and PEG does not make any claims about the results being applicable to all Ontario distributors. Productivity evidence for any future generic proceeding would be subject to examination by the parties in that proceeding.
b) Please see the response to part a of this question.
c) Please see the response to part a of this question.

AUC-6
Ref 1: PEG Empirical Report, p. 9
PEG states, "We consider it reasonable for a large distributor such as Alectra Utilities to submit an alternative model in the context of CIR and to base it on U.S. rather than Ontario data."

Question(s):

a) This statement was in context to the benchmarking dataset, however, PEG only provided productivity trend research using an Ontario-only dataset. Does PEG believe U.S. productivity trends are relevant to the productivity factor in the context of Alectra Utilities?

Response:

a) Yes. The OEB has previously decided that the productivity trends of Ontario power distributors were to be the basis for setting productivity factors. However, the productivity trends of US power distributors could also be relevant information for the OEB to consider. We accordingly provided estimates of U.S. power distributor productivity trends in the recent Toronto Hydro CIR proceeding.[1] In the instant proceeding, we have provided estimates of the recent OM&A productivity trends that were proffered by other consultants in the context of incentive ratemaking. These trends are particularly relevant in this proceeding, where Alectra Utilities requests a hybrid attrition relief mechanism that features substantially full compensation for its forecasted capital cost growth and the industry OM&A productivity trends really matter.
Please note that any negative total factor productivity trends that other consultants have recently reported may reflect special features of their study such as the inclusion of recent California data in their sample. California distributors have struggled to address devastating wildfires. Other consultants may also use different capital cost treatments than are commonly used in OEB proceedings. Please also note that in U.S. proceedings quality productivity studies tend to be funded only by utilities.

AUC-7
Ref 1: PEG Empirical Report, p. 10
Equation [2] states that the growth in cost equals the growth in input prices plus the growth in inputs.

[1] Lowry, Mark N., "Statistical Cost Research for THESL's New CIR Plan," in EB-2023-0195, revised October 7, 2024, pp. 68-70.

Question(s):

a) Should the "I" in the I-X escalation formula track the growth in input prices or, alternatively, have an adjustment made to it?
b) In PEG's view has the Board's annual distribution IPI correctly tracked the growth in input prices? Please respond in the context of total costs, OM&A expenses, and capital costs.
c) In PEG's view, what price indexes, weighting, or other alternatives would improve the inflationary tracking within the escalation formula?
d) Equation [3] on p. 10 states that the growth in inputs can be stated as the growth in costs minus the growth in input prices and then Equation [4] provides the equation for productivity being outputs divided by inputs. In PEG's view, should the input price inflation assumptions in the productivity research match the inflation used in the I-X escalation formula? If not, please explain.
e) Did PEG use the Board's historical IPI results as the input price inflation index in its productivity research?
f) If no to part (e), what would the TFP, OM&A PFP, and Capital PFP results be using the Board's historical IPI inflation rates.
g) If no to part (e), please describe the input price indexes used in the productivity research for OM&A labour, OM&A materials and services, and capital and also provide a table with each of their values for 2004 to 2024.

Response:

a) The I factors in the OEB's indexed attrition relief mechanisms ("ARMs", e.g. rate or revenue cap indexes) could in principle be based on a carefully-designed input price index. However, approved I factors typically have simpler designs. In the United States, the GDP-PI is typically the sole inflation measure in indexed ARM formulas while in Canada a weighted average of the GDPIPI^{FDD} and a wage rate index is typically used. Adjustments to the GDPPI are common in the rate and revenue cap indexes of U.S. utilities. However, a big reason for this is that the GDPPI measures the output price inflation of the US economy. This differs from input price inflation by the multifactor productivity trend of the economy. As shown in Table 1 of PEG's Framework Report, MFP growth has been material in the United States but not in Canada.
b) PEG has not carefully measured the difference between the IPI and the input price trend of Ontario power distributors. The issue has not been carefully studied. One reason is that many larger Ontario distributors receive substantially full compensation for their forecasted capital cost. This has reduced their incentive to raise the issue.
c) PEG has not carefully considered this matter but notes that the capital price that mirrors traditional utility cost accounting is quite complex.

d) PEG could not develop a view on this matter in the time available for interrogatory responses but notes that it is not uncommon to use a capital service price in productivity research that is different from that used in IPI construction.
e) No. PEG used a more complicated index that was consistent with its capital cost specification.
f) PEG declines to respond to this question on the grounds that it is not reasonably doable in the time allowed for interrogatory responses. The relevance of the exercise is furthermore unclear.
g) Please see PEG's response to AUC question 20.

AUC-8
Ref 1: PEG Empirical Report, p. 13
PEG states that larger utilities may be less able than smaller utilities to achieve incremental scale economies and that at some level of output the potential for scale economies may be exhausted.

Question(s):
a) Given that Alectra is either the largest or one of the largest distributors in Ontario, is PEG of the view that Alectra's ability to achieve scale economies from growth is lower than the mostly smaller utilities in Ontario, all else being equal?
b) Would the availability of fewer scale economies than the industry tend to reduce the productivity trend expectation for a utility relative to that same industry?
c) PEG further discusses the impact of inefficiency on productivity trends. PEG states, "A company's potential for future productivity growth from this source is greater the lower is its current efficiency." In PEG's view is the inverse of this statement also true? That is, a company's potential for future productivity growth from inefficiency is lower the higher is its current efficiency?

Response:
a) Not necessarily. The contribution of incremental scale economies to productivity growth can be measured as (1 - SUM Output Elasticities) x growth elasticity-weighted output quantity index. The sum of output elasticities may tend to be higher for utilities with larger operating scale. This diminishes opportunities for incremental scale economies.
While Alectra Utilities' size is large compared to most other Ontario distributors, it is not very large compared to the U.S. utilities in our sample. The 2024 custom cost elasticities for Alectra Utilities with respect to customers and ratcheted peak demand are 0.678 and 0.283, respectively. These sum to 0.961, suggesting that there are still some opportunities to realize incremental scale economies.
Continuing productivity benefits from the Company's amalgamation to date along with its expectations of growth and increasing density may allow for additional

scale economies compared to some smaller distributors just beginning to face growth in the form of increasing density. The Company's potential for growth in operating scale likely exceeds that of many Ontario utilities.

b) The availability of fewer incremental scale economies would tend to slow a utility's productivity growth expectation, all else equal. However, as discussed in section 2.1 of PEG's Empirical Report, productivity growth also depends on other factors such as technological change. Alectra Utilities may be in a better position than other Ontario utilities to take advantage of some other productivity growth drivers.

c) Yes. However, even an efficient utility is confronted with a continuing series of new cost challenges over time.

AUC-9

Ref 1: PEG Empirical Report, p. 18

Equation [16a] describes a maximization formula between essentially a capital revenue indexing approach and a capital revenue forecasting approach.

Question(s):

a) Is PEG of the view that the "Inflation" term in Equation [16a] for capital has been adequately tracked by the Board's IPI?

b) In PEG's view, has the poor inflationary tracking performance of capital assets by the Board's IPI contributed to the need for utilities to seek incremental funding in excess of I- X?

c) In PEG's view, would using the historical Handy-Whitman index inflation rates be a far closer approximation of the likely capital inflation encountered by distributors than the Board's IPI? Please give consideration to the historical costs of the rate base and the capital-related revenue requirement and how asset prices today and tomorrow for replacing assets that are 30 years old are impacted by the inflation rates in every historical year during that entire 30-year time span.

Response:

a) This is a complicated empirical issue that PEG has not fully explored in the context of this proceeding. However, please note the following.

   a. Neither Clearspring nor Alectra Utilities have provided persuasive evidence on the magnitude of this problem.

   b. Construction cost and asset price inflation are not the same as capital price inflation. One reason is that capital prices also depend on the rate of return on capital. Another is that traditional utility accounting uses historical valuations of plant.

   c. The approach to capital revenue escalation detailed in [16a] would provide nearly full compensation for Alectra Utilities' forecasted capital cost growth.

b) PEG must answer "not sure" to this question. One reason is that it is not clear how much utilities have anticipated unusually rapid construction cost and asset price inflation at the time of their filings. Few have been sufficiently concerned about capital price inflation to make their capital cost forecasts contingent on an inflation forecast subject to true up. Those that did typically used the IPI for trueups.
c) A Handy Whitman index could play a role in a more accurate capital price index should the OEB seek one. However, the formula could be complex, as seen in Section A.4 of the 2011 PEG report titled "Assessment of Union Gas Ltd. And Enbridge Gas Distribution Inc. Incentive Regulation Plans".[2] The rate of return on capital would also play a role in index design.

AUC-10

Ref 1: PEG Empirical Report, p. 21

PEG states, "The stretch factor term should then reflect an expectation of how the productivity growth of the utility that will be operating under IR (the "subject utility") should differ from the productivity trend of the peer group. This depends in part on how the performance incentives generated by IR --- its incentive "power" --- differ from that generated by the regulatory systems of utilities in the productivity research sample."

Question(s):

a) Given that Alectra is one of the largest distributors (thus reducing available scale economies relative to the sample) in Ontario and has a good starting cost efficiency level, does PEG have an empirical basis to expect that Alectra will outperform the industry's productivity trend, which is already under IR, during the Custom IR period? If so, please provide that empirical basis.

Response:

a) The Company's potential for productivity growth in excess of the Ontario industry norm is unclear. Custom IR guidelines call for a productivity growth target in excess of industry norms. PEG recommends the same low performance-related stretch factor that Clearspring does.

AUC-11

Ref 1: PEG Empirical Report, p. 31

PEG states, "Many Ontario electricity distributors have transitioned to Modified International Financial Reporting Standards ("MIFRS") that, among other things, reduce capitalization of their OM&A expenses. This materially slowed OM&A and total factor

[2] Larry Kaufmann, David Hovde, John Kalfayan, and Matt Makos (2011) " Assessment of Union Gas Ltd. And Enbridge Gas Distribution Inc. Incentive Regulation Plans", September, filed in Ontario Energy Board Case EB-2011-0052.

productivity trends of many distributors during the transition. However, this transition was largely complete by 2013, and the problem can be mitigated by focusing on the years since this occurred."

Question(s):

a) Please confirm that the prior accounting standard that was mostly used in the industry before 2012, GAAP, tended to capitalize more expenses than the current MIFRS?
b) Would the higher capitalization in years before 2012 increase PEG's monetary measure of the capital stock in PEG's productivity research for all years of the sample, including years after 2012, above what they would have been if MIFRS had been the standard for all years?
c) Given the now lower capitalization under MIFRS but the elevated capital stock because of GAAP, would that be expected to increase both the TFP trends after 2012 and the capital PFP trends?

Response:

a) This statement is confirmed.
b) Yes.
c) Yes. However, the higher capitalization prior to 2013 will also slow the cost growth of Alectra Utilities.

AUC-12

Ref 1: PEG Empirical Report, p. 32

PEG states, "However, due to the approach to the restructuring of retail power markets pursued in Alberta, many billing and collection services are provided by other entities that also sell power to end users."

Question(s):

a) Please confirm this would tend to lower the total costs and OM&A expenses of the Alberta utilities included in the sample relative to other utilities, like Alectra, that do provide these services, all else being equal.
b) Are there any controls in the PEG benchmarking models to adjust for this?

Response:

a) This statement is confirmed. However, the sentence in the Empirical Report that precedes the cited one is "In addition to distributing power, [Alberta distributors] own, operate, and read meters and manage metering data." Alberta distributors bill retailers and provide them with detailed information about end users.
b) Yes. PEG has included the customer service and information expenses of the Alberta utilities but not those of Alectra or the U.S. utilities. Please also note that

Alectra Utilities receives a score in PEG's total cost benchmarking study that is very similar to the (favorable) score in Clearspring's model despite the inclusion of Alberta data.

AUC-13
Ref 1: PEG Empirical Report, p. 33
PEG says that the Alberta data only has consistent capital data to allow capital cost and quantity indexes to start in 2004. For comparison, PEG's U.S. dataset has capital data that begins in 1964 and Clearspring's capital data begins in 1947.

Question(s):

a) Is one of the considerations for PEG starting its benchmarking dataset in 2009 due to the fact Alberta utilities do not have capital data available prior to 2004?
b) Is PEG concerned that this recent capital benchmark year may insert a higher level of inaccuracy into its dataset relative to utilities with capital benchmark years beginning in 1964?

Response:

a) This consideration played no role in PEG's decision to use a 15-year sample period for the benchmarking work. However, it is one advantage of not having a longer period.
b) This is one concern about using Alberta data. However, there are several offsetting advantages to using these data that are discussed in Section 3.2 of PEG's Empirical Report. The included Alberta peers are especially useful for benchmarking Hydro One and Ontario's urban distributors.

AUC-14
Ref 1: PEG Empirical Report, p. 33
PEG says that ATCO Electric serves a rural service territory and is an outlier in benchmarking studies that include its data.

Question(s):

a) ATCO does not appear in PEG's benchmarking data sample list. Is the reason why they were excluded because of this outlier result status?
b) Please provide evidence that ATCO Electric is an outlier.
c) Does ATCO tend to have very strong cost performance (i.e., a good benchmark score) or a very poor cost performance score?
d) Please insert ATCO Electric into PEG's benchmarking models and provide the model, ATCO's benchmark score for the most recent three years of data, and Alectra's benchmark scores after ATCO is inserted in the model. We note that the

working papers do not appear to include ATCO data for Clearspring to allow Clearspring to test this statement.

Response:

a) Yes. ATCO Electric has been excluded from the samples for our transnational benchmarking due to extremely poor scores in runs where its data were included. This likely reflects in part our inability to capture special operating challenges in that company's service territory.
b) Please see our response to part d) of this question.
c) Please see the response to part a) of this question.
d) Because we have excluded ATCO from our transnational samples for some time, PEG has not gathered the requisite data to perform this task. We do not expect that the addition of ATCO Electric to the sample would greatly affect the benchmarking score of Alectra Utilities, which is similar to Clearspring's score and quite favorable to the Company.

AUC-15

Ref 1: PEG Empirical Report, p. 36

Under the "Major Disadvantages of U.S. Data" heading the second bullet states, "An econometric cost benchmark tends to be more reliable to the extent that the subject utility faces business conditions near the sample mean. In this regard, it is notable that the average size of companies in the U.S. IOU sample is much closer to that of Alectra Utilities than is the average size in the Ontario sample."

Question(s):

a) Should this bullet actually be in the "Major Advantages" to the U.S. data section?

Response:

a) Yes.

AUC-16

Ref 1: PEG Empirical Report, p. 40 and p. 43

PEG states on p. 40 that Clearspring has moved its methodology to align with PEG in regards to the construction cost trends in Ontario. Clearspring preferred using the Handy-Whitman indexes ("HWI") and PEG preferred using a Canadian specific index. To better align the methodologies, both consultants took 50/50 weights in the most recent CIR applications. However, PEG has now shifted to using only Clearspring's preferred index, which is the Handy-Whitman indexes.

PEG states on p. 43, "Recent research by PEG suggests that it is more accurate to just use the HWI."

Question(s):

a) What caused PEG to now shift to only using the HWI despite its prior arguments against using the index?
b) Did PEG also use the HWI in its Ontario productivity trend research?
c) If yes, did that substantially increase the total factor productivity trends and the capital PFP trends relative to PEG's previously preferred asset price index?
d) Please provide the Ontario TFP trend and capital PFP trend results using PEG's previously preferred asset price index for Ontario.
e) Please provide the recent research by PEG that suggests the HWI is more accurate.

Response:

a) PEG periodically updates its research on the appropriate deflator for Ontario plant additions. Results of this research can be found in "Attachment AUC-16_Ontario Asset Price Indexes."
b) Yes.
c) PEG does not know the answer to this question. The impact of alternative asset price deflators on Ontario productivity trends was never considered.
d) PEG did not undertake this run in the preparation of its report and declines to undertake it now on the grounds that the request is onerous.
e) Please see our response to part a) of this question.

AUC-17
Ref 1: PEG Empirical Report, p. 44
In one of PEG's smaller concerns of Clearspring's research it says that Clearspring's capital cost does not include capital gains.

Question(s):

a) Did PEG's 4GIR benchmarking and productivity research on behalf of OEB Staff include capital gains?
b) Please describe how the capital gains term is calculated.
c) Has PEG put forth previous CIR research or studies that did not include capital gains? If so, please advise which ones.
d) Please detail the argument to include capital gains in capital costs in light of how capital costs are calculated for utility revenue requirements.
e) Is there typically a capital gains component in the revenue requirement of electric utilities?
f) If yes, is it a typically large component of the capital cost portion of an electric distribution utility's revenue requirement?

g) Is one of the impacts from the capital gains term to lower the proportion of capital costs relative to total costs?
h) In examining the PEG working papers, it appears that in PEG's productivity research the share of capital in total costs is well below the share of OM&A expenses. Is this mostly due to the inclusion of this capital gains term?

Response:

a) No.
b) PEG's capital service price is discussed on pp. 96-97 of the Empirical Report and detailed in the working papers.
c) Yes. PEG's empirical studies in EB-2010-0379 (4thGIR), EB-2014-0116 (THESL 2014 Custom IR application), EB-2017-0049 (Hydro One Distribution 2017 Custom IR application), EB-2019-0082 (Hydro One Transmission 2019 Custom IR application), EB-2019-0261 (Hydro Ottawa 2019 Custom IR application), and EB-2021-0110 (Hydro One 2021 Custom IR application) did not include capital gains. PEG's empirical studies in EB-2018-0165 (Toronto Hydro 2018 Custom IR application), EB-2018-0218 (Hydro One SSM Price Cap IR application), EB-2023-0195 (Toronto Hydro 2023 Custom IR application), and in this proceeding all included a capital gains term. PEG has also included capital gains in other work for the OEB including the recent Enbridge Gas Inc. IR application, the gas Amalco proceeding, and the 2007 gas IR proceeding. Additional examples of PEG's use of a capital gains term in its benchmarking studies can be found in Table AUC-3. In addition, PEG has usually included a capital gains term in its productivity studies in other jurisdictions.
d) In studies of PEG and Clearspring alike, capital assets are valued in current dollars rather than the replacement dollars used in traditional cost accounting. Capital cost performance therefore looms larger than in traditional cost accounting. This can produce less favorable benchmarking scores for utilities with high recent capex and more favorable scores for utilities with recent low capex. Reducing capital cost by the amount of capital gains is a means of reducing the importance of capital cost that is well supported in the academic literature. It is tantamount to basing the return on plant ownership on the real rather than the nominal rate of return. All else equal, capex is more efficient when the real rate of return is low than when it is high. Capital gains do complicate benchmarking, but this should be less of a concern for a utility that is assisted in the benchmarking area by a well-trained consultant or employee.
e) No.
f) Please see the response to part e of this question.
g) Yes, and this is an advantage of capital gains inasmuch as plant is valued in current dollars.

h) It can be the case that included OM&A expenses are higher than capital cost. Capital gains cause capital cost to fluctuate from year to year, but there is a corresponding fluctuation in the capital price. In 2024, 35 of the 53 Ontario distributors had capital cost greater than OM&A. Lower capital cost is due in part to the inclusion of capital gains but also to the exclusion of taxes (which are low for many Ontario distributors). Customer contributions will also tend to hold down capital cost to the extent that they are larger than normal.

AUC-18
Ref 1: PEG Empirical Report, p. 47 Table 1
PEG lists the 53 Ontario distributors included in its productivity trend study.

Question(s):

a) Are the 53 distributors based on how many distributors reported data in 2024?
b) How many distributors were there in Ontario in 2013?
c) In PEG's opinion, are there cost savings typically associated with mergers? If cost savings do result from mergers will those savings have an impact on industry productivity trends?
d) Alectra is listed on Table 1. Is Alectra data included in the productivity trend research?
e) In PEG's 4GIR productivity trend research, the utilities of Hydro One Networks and Toronto Hydro were excluded from the samples. Did PEG continue that approach? If not, why not?

Response:

a) Yes
b) PEG included data from 73 Ontario power distributors in its November 2013 report "Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario : Final Report to the Ontario Energy Board".
c) Yes. Yes.
d) Yes.
e) No. The issue in this proceeding is the determination of a proper productivity factor for Alectra Utilities. In the 4GIR proceeding, the productivity factor was understood to apply to all distributors that did not opt for CIR. It was not crystal clear that it would apply to CIR utilities. Hydro One and THESL at the time had an overwhelming impact on the productivity trend and were likely candidates for CIR. Because Alectra Utilities is now Ontario's second largest distributor, it seems reasonable to PEG that the OEB would be interested in industry productivity trends that included large distributors. PEG has itemized the productivity trends of distributors of different sizes.

AUC-19
Ref 1: PEG Empirical Report, p. 51-52
PEG states that both the ratcheted peak demand and a moving average of recent annual peak demands were considered but the ratcheted peak demand approach received more statistical support.

Question(s):

a) Please describe and provide the statistical support for the ratcheted peak demand.
b) Please confirm that the ratcheted peak demand variable used by PEG can never decline for a given utility, even for utilities that have experienced long-term and sustained peak demand reductions.
c) Please provide the productivity trend results for the TFP, OM&A PFP, and Capital PFP when using a 10-year rolling average.
d) PEG calculated the ratcheted peak demand variable based on the highest annual peak demand since 2002. For utilities with declining peak demands, does the use of the ratcheted peak demand increase their productivity trends upwards relative to using a moving average or annual peak demands?
e) It is understood that, due to the energy transition, utilities are expecting higher peak demands in the future and this is creating a need for increased investment and spending. Would not the inverse be true, that if utilities are expecting or experiencing declining peak demands, their costs would be lower?

Response:

a) There are many ways to evaluate statistical support for econometric model specifications. Especially because the two variables in question are just different structures of the same underlying data, we need to consider our goals in using the model.

   The t-statistic is one measure which can be used to assess a specific variable's significance. While it seems like a straightforward task, it is more complicated to evaluate and interpret the results in this application for 3 main reasons:

   1. There are 3 terms involving the peak variable in each model, each with its own t-statistic.
   2. T-statistics are less reliable and informative in a model with panel data.
   3. Introducing a different peak load variable causes the parameter estimates and t statistics of other model variables to change.

   Those 3 complications apply in this case, as shown in the table below. The t-statistics favor the 10-year rolling average term for the linear parameters, although the capital cost t-statistics are perhaps implausibly high, and for the quadratic term

in the capital cost model. The ratcheted peak term produces higher t-statistics for the quadratic terms in the other two models, and for the interaction term in all but the U.S.-only capital cost model. The parameter estimates of other model variables are also affected.

The table includes models with and without Alectra Utilities. PEG's report presents the model parameter estimate for the entire sample which includes Alectra Utilities. Clearspring presents their model parameters excluding Alectra Utilities. Both consultants calculate rankings out of sample, so this is merely a reporting difference. Both models are shown here for clarity, since Clearspring's answers to model questions all pertain to model parameters excluding Alectra Utilities.

		Peak Variables in Full Sample Models (including Alectra)		**Peak Variables Models Excluding Alectra**	
Variable Details		**Ratcheted**	**10-year rolling average**	**Ratcheted**	**10-year rolling average**
Linear peak parameter (YP)	Total Cost	**0.38**	**0.40**	**0.376**	**0.40**
	t-statistic	21.216	30.613	22.77	32.678
	OM&A Cost	**0.213**	**0.29**	**0.212**	**0.289**
	t-statistic	7.146	11.854	7.215	11.866
	Capital Cost	**0.497**	**0.478**	**0.494**	**0.475**
	t-statistic	30.161	61.618	36.358	69.856
Quadratic peak parameter (YP*YP)	Total Cost	**1.457**	**0.864**	**1.449**	**0.855**
	t-statistic	12.465	10.73	12.087	10.333
	OM&A Cost	**1.591**	**0.706**	**1.588**	**0.701**
	t-statistic	5.804	4.028	5.763	3.948
	Capital Cost	**1.196**	**0.931**	**1.188**	**0.922**
	t-statistic	18.056	19.204	18.422	20.157
Interaction peak parameter (YN*YP)	Total Cost	**-1.389**	**-0.799**	**-1.383**	**-0.791**
	t-statistic	-11.827	-9.598	-11.524	-9.295
	OM&A Cost	**-1.511**	**-0.607**	**-1.508**	**-0.603**
	t-statistic	-5.469	-3.398	-5.434	-3.328
	Capital Cost	**-1.132**	**-0.883**	**-1.126**	**-0.875**
	t-statistic	-18.016	-17.977	-18.28	-18.759

Since it is not enough to just compare t-statistics on individual variables to determine which is the better peak measure, we next consider the adjusted R^2 of the model. Also known as the coefficient of determination, it is a well-known statistic summarizing the strength of the modeled linear relationship between the dependent and independent variables. A single number always between 0 and 1, R^2 summarizes the proportion of the variance in the dependent variable which is

explained by the model's independent variables. It is a handy quick-reference statistic, but in practice it has several major drawbacks. The ones most relevant to this application are its sensitivities to outliers, overfitting, and panel data. Using the adjusted version of R^2 partially addresses the pure overfitting reward in the unadjusted metric, but the correction is quite limited and does not address the other problems. So while in each model the R^2 is a little higher using the ratcheted peak demand variables, we don't consider this to be an especially compelling result.

This brings us to the root mean square error (RMSE) statistic. The RMSE, another standard measure in statistical analysis, summarizes the model fit in terms of the prediction accuracy of the model. It is calculated by squaring the model residuals (the difference in actual and predicted observations), then taking the square root of the mean of those squared residuals. The result is a measure of goodness-of-fit in the units of the dependent variable, with a lower number indicating a better model fit, all else equal[3]. In this application, the goal of PEG's econometric model is to model utility cost as accurately as possible using the appropriate variables[4]. When we compare the RMSE for each of the cost models, identical except for the peak demand variables, we find that the model is always a better fit using the ratcheted peak demand version.

		Peak Variables in Full Sample Models (including Alectra)		Peak Variables Models Excluding Alectra	
Measure of Model Fit		Ratcheted	10-year rolling average	Ratcheted	10-year rolling average
Adjusted R^2	Total Cost	0.97	0.969	0.97	0.969
	OM&A Cost	0.903	0.901	0.903	0.901
	Capital Cost	0.973	0.972	0.973	0.973
RMSE	Total Cost	0.165	0.168	0.165	0.168
	OM&A Cost	0.295	0.299	0.296	0.299
	Capital Cost	0.162	0.164	0.161	0.164

[3] Please note that the RMSE of a model may only be validly used for model comparison if the samples are identical.

[4] It is important to keep in mind that we are specifically modeling using external business conditions; we could produce an even better model fit by including each utility's own actual cost from the prior year, but then we would be erasing most performance differences across utilities and would defeat the purpose of the model entirely.

There is an additional consideration when choosing variables for this type of modeling exercise. The theory supporting the variable is also very important. For the reasons further discussed in parts b) and e), PEG is of the opinion that the ratcheted peak demand is the more relevant measure of peak-related scale as a cost driver.

b) This statement is confirmed. However, actual peak demands of power distributors tend to understate the *maximum potential* peak demand that drives distribution planning and cost. There is thus a tendency for rolling average peak demand to do so as well. The propensity of actual peak demands to understate the total potential varies between utilities. This helps to explain why a ratcheted peak demand produces models with better explanatory power.
Alectra Utilities anticipates brisk peak demand growth in the next five years. Following a downward trend in actual peak demands, a rolling average of peak demand growth will likely understate the Company's maximum potential peak demand in these circumstances. Clearspring does not advocate using a rolling average of peak demand to calculate the proposed G factor for the Company.
Even if distributors maximum potential peak demand were to decline, comparable cost savings will typically not quickly follow suit. Any surplus assets will gradually depreciate, shrinking capital cost, but many will still be maintained. Ontario distributors would surely balk if their revenue requirements were trimmed because their rolling average peak demand was declining. They would say that that supports the case for a negative productivity growth target because cost doesn't fall in lock step.
Please also note that if rolling average peak demand were the correct output measure and it was declining that would raise a concern about the relevance of the historical productivity trend to future business conditions.

c) PEG declines to respond to this question on the grounds that it is not reasonably doable in the time allowed for interrogatory responses.

d) Yes. However, PEG believes that ratcheted peak demand is nonetheless more accurate.

e) The ratcheted peak method mimics a pattern in which capital investments are made at times of increasing peak demand. Once an investment is made, it stays in place and is not destroyed in response to a fall in peak demand. It is true that a fall in peak demand should result in an additional buffer to handle later increases in peak demand. However, this would temporarily result in lower capex needs and not an outright decline in cost.

AUC-20
Ref 1: PEG Empirical Report, p. 52
PEG states, "We used separate but related input price indexes in our benchmarking and productivity trend research. The productivity trend research used input price trend

indexes that are similar to the trend components of the input price indexes we used for benchmarking."

Question(s):

a) For the Ontario productivity trend research, please provide the exact sources and input price indexes used for each cost component of labour, materials and services, and capital.
b) For the U.S. benchmarking dataset, please provide the exact sources and input price indexes used for each cost component of labour, materials and services, and capital.
c) Please provide a table showing the annual input price index values for each component by year for the productivity trend research.
d) Please provide a table showing the annual input price index by year for the total factor, OM&A, and capital productivity trends.
e) Please provide a table showing the annual input price index values for each component by year used for Alectra in the benchmarking research.
f) Please provide a table showing the annual input price index values for each component by year used for Madison Gas and Electric in the benchmarking research.

Response:

a) The sources for the indexes used were described in the Empirical Report on pages 52-54. For additional information, please see "Attachment AUC-20_Supplemental Response-Confidential" that will provide a guide to where the requested information can be found in the confidential working papers. It will make reference to specific values and contents of the working papers and this attachment should therefore be confidential as well.
b) Please see the response to part a.
c) Please see the response to part d.
d) PEG did not produce input price indexes for the industry for the productivity work. The requested table is provided in the response to part a.
e) Please see the response to part a.
f) Please see the response to part a.

AUC-21
Ref 1: PEG Empirical Report, p. 59
PEG lists the cost exclusions to the cost definition for the U.S. utilities. That list includes "sales".

Question(s):

a) Why is PEG excluding sales expenses from the U.S. utility cost definition?

b) Has PEG made this exclusion before in cost benchmarking for CIR applications?

Response:

a) The SST code provided as part of the working papers indicates that sales are included in US cost. The statement on page 59 of the Empirical Report that sales expenses were excluded from the US data is not correct.
b) To the best of our recollection, no, but the inconsequential nature of this matter reduces the reliability of our recollection.

AUC-22
Ref 1: PEG Empirical Report, p. 62
PEG states, "However, recent research by PEG suggests that the GDPPI tends to materially understate the M&S price inflation of U.S. utilities. For the M&S price trends of Alberta utilities we use Statistics Canada's gross domestic product implicit price index for final domestic demand ("GDPIPIFDD") in Alberta. We use the GDPIPIFDD in Ontario for Alectra."

Question(s):

a) Please provide the recent research by PEG that suggests GDPPI tends to understate the M&S price inflation.
b) Did PEG make an adjustment to the GDPPI for U.S. utilities in calculating M&S input price inflation? If yes, please describe.
c) If yes to part (b), did PEG make the same adjustment to the Alberta and Ontario M&S input price. If not, why not?
d) PEG says it used the Ontario GDPIPI^{FDD} for Alectra. Is this the same input price index used for Alectra in the benchmarking and in the Ontario productivity research? If not, please provide a description of the different indexes used for the studies for the M&S input price index.
e) Why did PEG not use the Canadian GDP-IPI^{FDD} that is used in the Board's IPI calculations?

Response:

a) The GDP-PI is a measure of inflation in the economy's output prices. As such, it is slowed by the multifactor productivity trend of the US economy. Table 1 in PEG's Framework Report shows that the multifactor productivity growth of the US economy tends to be brisk, averaging 0.78% growth annually from 2009 to 2023. This means that the GDP-PI materially underestimates the economy's input price inflation. Recent confidential research by PEG for another client found additionally that the GDP-PI tends to materially understate the inflation of utility M&S prices specifically.

b) No. No satisfactory adjustment was identified in time for inclusion in PEG's Alectra Utilities proceeding evidence.
c) Please see the response to part b) of this question.
d) Please see the response to part e) of this question.
e) With the addition of data from Alberta, PEG started using province-specific indexes. The difference between the trend for Ontario and Canada is very small (4bp over 15 years) but larger for Alberta (29bp).

AUC-23
Ref 1: PEG Empirical Report, p. 64
PEG uses a different rate of return for the U.S. utilities compared to Alectra and the Alberta utilities. PEG took a 50/50 average of the rates of return for debt and equity for the U.S. utilities.

Question(s):
a) Does this create different rates of return on capital for the sample and the studied utility?
b) These differences will impact the proportion of capital costs and OM&A costs, correct?
c) Please explain why a benchmarking study that is attempting to estimate the cost performance of the studied utility (Alectra in this case) should not use the same rate of return as the utility being studied?

Response:
a) Yes.
b) Yes.
c) It makes as much sense to have rates of return that vary by jurisdiction at each point of time as it does to have rates of return that vary over time for each sampled company. PEG also notes that this treatment doesn't matter much for benchmarking results because a lower (higher) rate of return lowers (raises) capital cost. The rate of return chiefly affects the weight on capital cost in a total cost assessment.

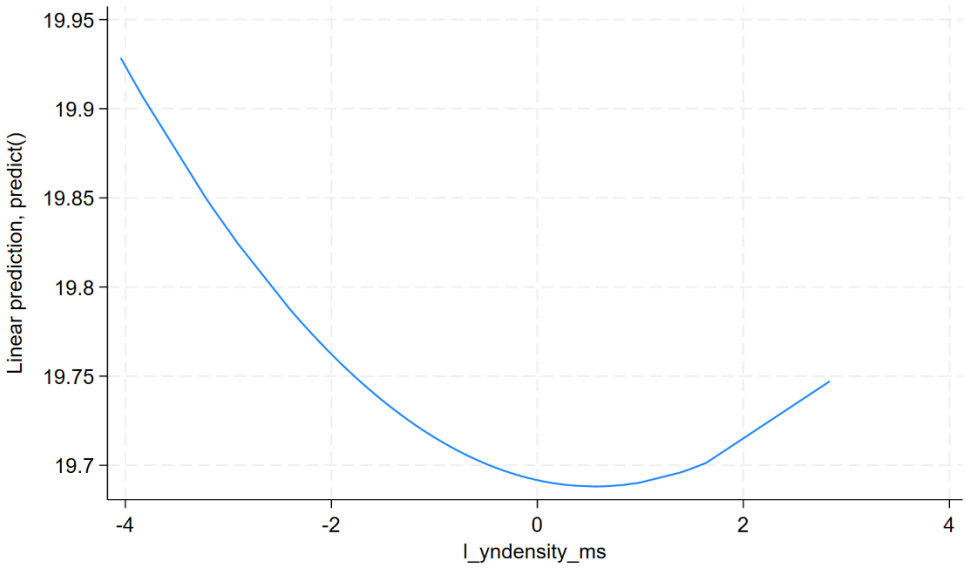
AUC-24
Ref 1: PEG Empirical Report, p. 65
PEG states, "We instead use this variable to create a customer density variable (customers/area). We add a quadratic term to the log linear term to permit the effect of this variable to be non-linear. We expect the sign on the quadratic density term to be positive in all models, and the sign on the linear term indeterminate in all models."

Question(s):

a) Please confirm this is the only business condition variable that also includes a quadratic term.
b) Please explain in more detail why the linear term should not be negative.
c) Would a positive linear coefficient be correctly interpreted to mean that at the mean of the data, increased customer density increases cost?
d) Does PEG agree or disagree that a predominantly rural utility will face higher cost challenges, all else equal, than a utility with average customer density?

Response:

a) This statement is confirmed. We departed from our usual practice of not including quadratic terms for Z variables in our cost models for two reasons. One is that the relationship in question is well known to be nonlinear. The other is that we are using the density variable to reduce the need for second-order scale variables in the models.
b) The linear term would be negative were the data not mean-scaled. Please see the Stata plot below showing the full-sample continuous marginal cost effects of density (the combined effect of the two density terms) in the model. The y-axis is the natural log of real total cost, and the x-axis shows the variable values of meanscaled and logged customer density for all observations in the sample. For reference, the sample mean value of the density variable is located at 0 on the x-axis because the mean value of a meanscaled variable is 1, and the natural log of 1 equals 0.
c)



d) Yes, a positive term indicates that at the sample mean value of the density variable increased density raises cost. As illustrated in part (b), it is important to

understand how a few very dense firms influence where the mean lies within the sample. Most of the sample values fall below the mean for this particular variable.

e) The results graphed in the response to part b) support the idea that distributors with low customer density tend to have higher total costs than those with average density.

AUC-25
Ref 1: PEG Empirical Report, p. 67
PEG states, "We calculated a DER penetration variable which is the ratio of DER generation capacity to maximum peak load. The source of these data for the United States is the Form EIA 861 survey's section on Net Metering and Non-Net Metering Distributed Generation. We obtained analogous data from the Alberta transmission system operator for the Alberta distributors."

Question(s):

a) What historical data source did PEG use for Alectra's DER penetration value?
b) On what basis did PEG escalate DER into the custom IR years of 2027 to 2031 for Alectra?
c) Please describe why PEG believes that DER penetration will impact distribution costs.

Response:

a) PEG used the data from RRR Sections 2.1.14 and 2.1.14.1 for Net Metering and Embedded Generation Information. For data prior to 2015, PEG gathered data from the IESO Contracted Generation data for the pre-2017 FIT and microFIT programs.
b) The DER MW data were held at 2024 levels for Alectra Utilities. The ability to add DERs is dependent on available capacity at the feeder level, so PEG did not have the requisite data to forecast future levels. By keeping the existing level the same, the model results are interpreted assuming the level of DERs is constant amid the Company's forecasted peak demand and customer growth.
c) DER penetration may impact distribution costs, both up and down, in many ways. It may raise costs to the extent that:
    - those DERs contribute to the logistical challenges of the infamous "duck curve" effect, in which demand for power from the grid surges in the evening when usage of power is high but solar generation is weakening.,
    - localized grid upgrades are necessary.

    The second cost impact is worsened when the utility is *obligated* to allow new DER connections even when it necessitates or accelerates (otherwise unnecessary) costly feeder capacity upgrades.

Integrating DERs also has the potential to lower costs to the extent that:

- the utility can effectively utilize them as a grid resource,
- OM&A savings are created through increased reliability or other means,
- the utility is adding DER connections where there is sizeable excess capacity on a feeder.

This list is not exhaustive. PEG looks forward to testing and monitoring energy transition variables in future models as more data become available.

AUC-26
Ref 1: PEG Empirical Report, p. 70
PEG states, "We use an alternative, fully time-variant urban congestion variable (number of skyscrapers) that has a positive value for Alectra Utilities."

Question(s):

a) What cities did PEG examine for Alectra?
b) How did PEG escalate the number of skyscrapers for each year through 2031 for Alectra?
c) Is this variable divided by area or some other scale variable or is it just the sum of all 100m and above skyscrapers?
d) If it's just the sum, please explain how a large utility serving a large area with multiple medium-sized cities summing to 50 skyscrapers would have the same congested urban challenge as a utility serving only one metropolitan area in a much more condensed area.
e) Will the marginal costs of adding one skyscraper for a large-area utility (e.g., Pacific Gas and Electric) be the same as that for a one-city utility (e.g. Consolidated Edison)? In PEG's view, should the marginal costs of adding one skyscraper in the model at least be somewhat similar?

Response:

a) PEG included Hamilton, Mississauga, Brampton, Vaughan, and Richmond Hill.
b) The skyscraper variable uses historical data through 2025, then stays at the 2025 number for 2026-2031.
c) No. It is the sum of all 100m and above skyscrapers.
d) While the characterization in the question is *technically* true, it ignores the rest of the model. The parameter estimate for the skyscraper variable is estimated in a model which has several variables related to different aspects of urban and rural challenges.
e) While the estimated marginal cost of skyscraper growth is the same for PG&E and Con Ed, please note that the same model also accounts for non-linear effects of Pacific Gas and Electric's density of 31 customers per square km and

Consolidated Edison's density of 2,190 customers per square km, along with many other characteristics of each company. The plausibly modest but statistically significant parameter on the skyscraper variable serves to further refine the model fit alongside all of the other variables, which results in an improvement in cost predictions for benchmarking.

AUC-27
Ref 1: PEG Empirical Report, p. 71
PEG states, "The parameter estimates for the number of customers and the ratcheted peak demand are highly significant and positive."

Question(s):

a) Please provide the custom elasticities on customers and ratcheted peak demand for Alectra in 2024.

Response:

a) The 2024 custom elasticities for Alectra Utilities on customers and ratcheted peak demand are 0.678 and 0.283, respectively.

AUC-28
Ref 1: PEG Empirical Report, p. 78 Table 6
PEG provides a comparison table for Alectra variable values to the sample mean.

Question(s):

a) Alectra's O&M input price is 113.6% of PEG's sample mean. Is the Alectra input price essentially denominated in Canadian dollars and the sample mean is predominantly in U.S. dollars? Is most of that difference due to currency differences?
b) Please explain why the Alberta sample has an average O&M price in 2023 at 1.320 versus Alectra's 1.045. Is this implying that O&M inputs for Alberta utilities cost around 25% more than Alectra's?

Response:

a) Yes. Each jurisdiction has prices in the local currency, and this is the chief driver of the higher Alectra Utilities input price.
b) Other cost research in which PEG used these data had specifications that included pensions and other benefit expenses. In this research, the labor price levels had markups to reflect the typical ratio of pensions and benefits to salaries and wages when creating price levels for each jurisdiction. The markups were removed for the US and Alectra Utilities but were inadvertently not removed for

the sampled Alberta distributors. This markup was 23% and explains the price differences referenced. Correcting this error should have a small impact of the Alectra benchmarking results because data for only three distributors were affected and Alectra's performance score is only affected by the change in parameter estimates.

AUC-29

Ref 1: PEG Empirical Report, p. 85

PEG states, "Our new research includes these costs, albeit in years in which they cleared smart meter deferral accounts rather than in the years when they were incurred. The first sample year that was free of these clearances was 2014."

Question(s):

a) Please provide a year-by-year detail with costs of when the smart meter deferral accounts were cleared. If this is not possible, please provide the years in which these accounts were cleared.
b) What accounts were these deferral accounts generally cleared into?

Response:

a) It is PEG's understanding that most deferred smart meter costs were cleared by 2012. This corresponded to the termination of the Smart Meter Funding Adder on April 30, 2012 (see Guideline G-2011-0001). PEG does not know how many account clearances there were after 2012 but understands that any extension had to be approved by the OEB and be supported by evidence. To figure out the timing of clearing of the smart meter accounts is a burdensome task and PEG does not have ready access to account 1555 and 1556 data since 2012. The reason why 2014 is the first growth rate substantially free of the transition to smart meters is that 2012 was the year by which most smart meter deferral accounts had been cleared. The 2013 beginning of year capital stock is equal to the end of year 2012 stock which will include the smart meter cost cleared in 2012. Therefore the 2013-2014 growth rate is the first with the 2012 smart meter costs included in cost.
b) It is not known exactly where all the costs were cleared, but because these were meters, it is reasonable to expect that it was account 1860 in most cases.

AUC-30

Ref 1: PEG Empirical Report, p. 87 Table 8b

PEG provides a table showing the outputs and input quantities in its Ontario productivity study.

Question(s):

a) The average annual growth rate of the ratcheted peak demand variable from 2014 to 2024 is listed as 0.21%. What is the average annual growth rate of annual peak demand of the industry without it being ratcheted from 2014 to 2024?
b) Please confirm that the 2024 ratcheted peak demand variable was a maximum of 23 prior years' worth of annual peak demands (from 2002 to 2024) for each utility.
c) Please confirm that the 2013 value of ratcheted peak demand was a maximum of 12 prior years' worth of annual peak demands (from 2002 to 2013) for each utility.

Response:

a) The average annual growth rate of the annual peak demand of sampled Ontario distributors is -0.27%
b) This is correct. The variable is the maximum annual ratcheted peak demands from 2002-2024, all 23 years included.
c) This is correct. The variable is the maximum annual ratcheted peak demands from 2002-2013, all 12 years included.

AUC-31

Ref 1: PEG Plan Report, p. 7

PEG states, "PEG agrees with Clearspring that the OEB's I factors tend to understate OM&A input price inflation."

Question(s):

a) What is PEG's estimate for how much the OEB's distribution IPI is or will understate OM&A input price inflation? What would be the appropriate IPD (or other adjustment) to better align the inflationary relief in the escalation formula with input price inflation?
b) Would PEG further agree that the OEB's I factors have tended to understate capital input price inflation?
c) If yes to part (b), can PEG provide an estimate of the magnitude of the differential between the Board's IPI and asset price inflation? For reference, the electric distribution North Atlantic HWIs have grown approximately 6.5% per year over the last 20 years versus the Board's IPI which is around 2.7%.
d) If yes to part (b), in PEG's view is the large understatement in capital inflation, at least in part, one likely reason distributors need to use custom IR and propose using the capital forecasting approach rather than capital indexing?

Response:

a) If the panel seeks to add an IPD to the attrition relief mechanism for Alectra Utilities, PEG recommends using the **0.20%** historical inflation differential for the last fifteen years ending in 2024. This can be found in Table 2 on page 36 of PEG's Framework Report.

b) This is a complicated empirical issue that PEG has not resolved.
c) Clearspring is clearly capable of making this calculation. PEG once again observes that construction cost inflation is different from capital price inflation. Capital prices also depend on the rate of return and traditional cost accounting does not value plant in replacement dollars.
d) A tendency of the IPI to understate capital price inflation may be one reason why distributors favor a forecasting over an indexing treatment of capital revenue. Unfortunately, the availability of the CIR option has likely also caused larger distributors not to prioritize a campaign to improve the IPI. On the other hand, it is not clear how well distributors have anticipated construction cost runups in advance. Few distributors have submitted multiyear capital cost forecasts that are contingent on an inflation assumption and subject to true up when actual inflation data become available. Those that have made contingent forecasts have typically proposed to true up only to IPI inflation.

AUC-32
Ref 1: PEG Working Papers
PEG produced a new service territory area variable and a new percent forested variable.

Question(s):
a) Please provide the new GIS service territory maps for each utility in PEG's benchmarking sample.
b) Please provide the overlayed forestation maps for each utility in PEG's benchmarking sample.
c) What was the source used for the new service territory maps?
d) Please provide either the map or a link used to the land cover map used for the forestation variable.
e) What are the six land cover categories that were designated as forest?

Response:
a) Please see confidential "Attachment AUC-32a_Service Territory Map-Confidential."
b) Please see confidential "Attachment AUC-32b_Service Territory and Landcover Map-Confidential."
c) Please see page 65 of the "PEG Empirical Report" for a detailed description of the data source and data processing.
d) https://www.cec.org/north-american-environmental-atlas/land-cover-30m-2020/
e) The landcover map linked in our answer to part c) uses the Land Cover Classification System standard. The six categories are:
    a. Temperate or sub-polar needleleaf forest
    b. Sub-polar taiga needleleaf forest

c. Tropical or sub-tropical broadleaf evergreen forest
d. Tropical or sub-tropical broadleaf deciduous forest
e. Temperate or sub-polar broadleaf deciduous forest
f. Mixed forest

School Energy Coalition

M-SEC-1
Ref 1: PEG Empirical Report, p.80
Ref 2: Ex.2B-6-2; Ex.9, Attach 9-10; 4-SEC-87
Ref 3: 2B-SEC-68] In 2025
Alectra made changes to its direct labour capitalization methodology, resulting in increased costs being capitalized.

Question(s):
Please discuss the impact of these changes to capitalization policy during the study period on each of total, capital, and OM&A cost benchmark scores.

Response:
PEG's understanding is that the changes to Alectra Utilities' capitalization policy generally enable the company to capitalize more OM&A expenses (e.g., related to direct labour, benefits, material handling, and fleet costs). This would result in lower OM&A expenses and larger plant additions, increasing capital costs. This presumably would improve the company's performance in OM&A cost benchmarking studies but worsen it in capital cost benchmarking studies. The Company's total cost performance would likely improve, especially in the short run before the incremental plant additions accumulate.

M-SEC-2
Ref 1: PEG Empirical Report, p.80
SEC would like to understand the sensitivity of the benchmarking results to changes in forecast costs during the rate term (2027-2031).

Question(s):
Please provide the change in the 'CIR Period 2027-2031' period total, capital, and OM&A cost benchmark scores for the following the changes:

a) Increase or decrease in Alectra's forecast capital costs each year between 2027 and 2031 of $1M.
b) Increase or decrease in Alectra's forecast OM&A costs each year between 2027 and 2031 of $1M.
c) Increase or decrease in both Alectra's forecast OM&A and capital costs each year between 2027 and 2031 of $1M.
d) Are the impacts of these changes in parts (a)-(c) linear (i.e. a $2M increase in costs will result in double the impact in the benchmark score)?

Response:

For each of these exercises, PEG assumed the $1M changes were to nominal costs. Deterioration in the average scores are positive values and are in red text, and improvements to average scores are negative values and are in green text.

a) Please see the table below:

b)

Capital Cost Model Scores					
Year	**As-reported**	**Plus $1 million in nominal costs in each forecasted year**	**Change (new-old)**	**Minus $1 million in nominal costs in each forecasted year**	**Change (new-old)**
2027	-0.27100	-0.26909	0.00191	-0.27292	-0.00192
2028	-0.28295	-0.28111	0.00183	-0.28478	-0.00183
2029	-0.28107	-0.27932	0.00175	-0.28282	-0.00175
2030	-0.28232	-0.28064	0.00168	-0.28400	-0.00168
2031	-0.29032	-0.28868	0.00164	-0.29196	-0.00164
Average Score 2027-2031	-0.28153	-0.27977	**0.1762%**	-0.28330	**-0.1765%**

c) Please see the table below:

OM&A Cost Model Scores					
Year	**As-reported**	**Plus $1 million in nominal costs in each forecasted year**	**Change (new-old)**	**Minus $1 million in nominal costs in each forecasted year**	**Change (new-old)**
2027	-0.05987	-0.05604	0.00383	-0.06372	-0.00385
2028	-0.03967	-0.03599	0.00368	-0.04336	-0.00369
2029	-0.01828	-0.01474	0.00353	-0.02182	-0.00355
2030	-0.00072	0.00267	0.00339	-0.00412	-0.00340
2031	0.01643	0.01968	0.00326	0.01316	-0.00327
Average Score 2027-2031	-0.02042	-0.01688	**0.3539%**	-0.02397	**-0.3551%**

d) Please see the table below:

Total Cost Model Scores					
Year	**As-reported**	**Plus $1 million in nominal capital and $1 million in nominal O&M costs in each forecasted year**	**Change (new-old)**	**Minus $1 million in nominal capital and $1 million in nominal O&M costs in each forecasted year**	**Change (new-old)**
2027	-0.19957	-0.19702	0.00255	-0.20213	-0.00256
2028	-0.19937	-0.19692	0.00245	-0.20182	-0.00245
2029	-0.18986	-0.18752	0.00234	-0.19220	-0.00234
2030	-0.18360	-0.18135	0.00224	-0.18585	-0.00225
2031	-0.18216	-0.17998	0.00218	-0.18435	-0.00219
Average Score 2027-2031	-0.19091	-0.18856	**0.2352%**	-0.19327	**-0.2358%**

e) No, the impacts are not strictly linear. The benchmark scores, costs, and many of the variables are expressed logarithmically and several non-linear relationships between variables and cost are modeled.

M-SEC-3
Ref 1: PEG Empirical Report

Question(s):
Please provide for each year between 2027 and 2031:

a) The change in the benchmark total, capital and OM&A costs, for each 1% change in customers.
b) The change in the benchmark total, capital and OM&A costs, for each 1% change peak demand.
c) The percentage change in the benchmark total, capital and OM&A costs, for every additional customer.
d) The percentage change in the benchmark total, capital and OM&A costs, for every 1 MW increase in peak demand.

Response:

a) Please see the tables in part b).
b) Please see the tables below:

Total Cost Model Scores					
Year	**As-reported**	**1 MW peak demand increase in each year**	**Minus 1% customers in each year**	**Plus 1% peak in each year**	**Minus 1% peak in each year**
2027	-0.19957	-0.19963	-0.19553	-0.20320	-0.19807
2028	-0.19937	-0.19943	-0.19575	-0.20345	-0.19738
2029	-0.18986	-0.18992	-0.18651	-0.19426	-0.18751
2030	-0.18360	-0.18367	-0.18067	-0.18847	-0.18074
2031	-0.18216	-0.18223	-0.17960	-0.18744	-0.17886
Average Score 2027-2031	-0.19091	-0.19098	-0.18761	-0.19537	-0.18851
Change		**-0.007%**	**0.330%**	**-0.445%**	**0.240%**

Capital Cost Model Scores					
Year	**As-reported**	**Plus 1% customers in each year**	**Minus 1% customers in each year**	**Plus 1% peak in each year**	**Minus 1% peak in each year**
2027	-0.27100	-0.27612	-0.28744	-0.27583	-0.28775
2028	-0.28295	-0.28771	-0.29959	-0.28815	-0.29916
2029	-0.28107	-0.28558	-0.29760	-0.28653	-0.29666
2030	-0.28232	-0.28647	-0.29880	-0.28817	-0.29710
2031	-0.29032	-0.29415	-0.30688	-0.29651	-0.30451
Average Score 2027-2031	-0.28153	-0.28600	-0.29806	-0.28704	-0.29703
Change		**-0.447%**	**-1.653%**	**-0.551%**	**-1.550%**

OM&A Cost Model Scores					
Year	**As-reported**	**Plus 1% customers in each year**	**Minus 1% customers in each year**	**Plus 1% peak in each year**	**Minus 1% peak in each year**
2027	-0.05987	-0.06740	-0.05686	-0.06187	-0.06247
2028	-0.03967	-0.04672	-0.03705	-0.04216	-0.04168
2029	-0.01828	-0.02499	-0.01592	-0.02112	-0.01985
2030	-0.00072	-0.00695	0.00123	-0.00408	-0.00169
2031	0.01643	0.01063	0.01801	0.01262	0.01599
Average Score 2027-2031	-0.02042	-0.02709	-0.01812	-0.02332	-0.02194
Change		**-0.667%**	**0.230%**	**-0.290%**	**-0.152%**

c) Please see the tables in part d).

d) Please refer to the tables below:

Total Cost Model Scores			
Year	**As-reported**	**1 MW peak demand increase in each year**	**Plus 1 customer in each year**
2027	-0.19957	-0.19963	-0.19957
2028	-0.19937	-0.19943	-0.19937
2029	-0.18986	-0.18992	-0.18986
2030	-0.18360	-0.18367	-0.18360
2031	-0.18216	-0.18223	-0.18216
Average Score 2027-2031	-0.19091	-0.19098	-0.19091
Change		**-0.007%**	**-0.00004%**

Capital Cost Model Scores			
Year	**As-reported**	**1 MW peak demand increase in each year**	**Plus 1 customer in each year**
2027	-0.27100	-0.27108	-0.27100
2028	-0.28295	-0.28303	-0.28295
2029	-0.28107	-0.28115	-0.28107
2030	-0.28232	-0.28240	-0.28232
2031	-0.29032	-0.29041	-0.29032
Average Score 2027-2031	-0.28153	-0.28161	-0.28153
Change		**-0.008%**	**-0.00004%**

OM&A Cost Model Scores			
Year	**As-reported**	**1 MW peak demand increase in each year**	**Plus 1 customer in each year**
2027	-0.05987	-0.05990	-0.05987
2028	-0.03967	-0.03971	-0.03967
2029	-0.01828	-0.01832	-0.01828
2030	-0.00072	-0.00077	-0.00072
2031	0.01643	0.01637	0.01643
Average Score 2027-2031	-0.02042	-0.02046	-0.02042
Change		**-0.004%**	**-0.0001%**

M-SEC-4
Ref 1: PEG Empirical Report, p.21, 86; PEG Plan Design Report p.6
PEG states that "OM&A and total factor productivity trends were more rapid using cost-weighted averages while the capital productivity trends were slower. Cost-weighted averages are much more sensitive to the productivity trends of a few companies." (PEG Plan Design Report, p.6), and that the "[t]he cost- weighted averages are heavily influenced by the four largest Ontario distributors." (PEG Empirical Report, p.86). PEG also states that it "PEG typically uses size-weighted (even-weighted) averages in X factor studies applicable to larger (smaller) utilities." (PEG Empirical Report, p.21).

Question(s):
a) Please confirm "size-weighted" is the same as "cost weighted"?
b) Considering that Alectra is the second largest Ontario distributor, please explain why PEG nevertheless recommends the simple average rather than the cost-weighted average.

Response:
a) This statement is confirmed. Cost-weighting is one practical means of size weighting. Another sensible approach is to weight by a measure of operating scale such as the number of customers served. Some practitioners add the costs and outputs of sampled utilities into aggregates before calculating productivity trends. This is tantamount to cost weighting input quantity trends while scale-weighting output trends.
b) PEG elected to take a conservative approach to calculating productivity factors for this rate application, which applies only to Alectra Utilities. The alternative cost-weighted averages are more representative of the productivity trend of the Ontario industry because the larger distributors do more of the work in the industry.

However, cost weighting is much more sensitive to results for a few large distributors. OM&A productivity has been volatile in recent years due to the pandemic.

M-SEC-5
Ref 1: PEG Empirical Report, p.9
PEG states: "Larger distributors averaged a TFP decline in the 2014-2024 period despite more rapid OM&A productivity growth than the Ontario norm because this was offset by a material capital productivity decline. The capital productivity decline of large distributors may reflect in part their greater use of supplemental capital revenue mechanisms that have entailed capital expenditures ("capex") forecasts and, in many cases, the clawback of capital cost underspends."

Question(s):
a) If the OEB were to approve rate frameworks that include mechanisms for OM&A spending above I-X (e.g. OM&A G-Factor, IPD, etc.) is that likely to similarly reduce, if not result in a decline, of OM&A productivity?
b) If the answer to (a) is yes, please discuss what mechanisms the OEB can implement in this application.

Response:
a) Assuming no clawback of underspends, an OM&A revenue escalator that is based on customized but external price and productivity trends and growth in the Company's operating scale is unlikely to weaken utility incentives to contain OM&A expenses. However, there is a risk of utility exploitation of information asymmetries to secure a favorable escalation formula.
b) Please see the answer to part a) of this question.

M-SEC-6
Ref 1: PEG Plan Design Report, p.8
PEG states: "Should the Panel elect not to pursue own-cost trending at this time, there remain other ratemaking treatments of capital that merit consideration" including "[u]se the forecast-based RGF approach, but slow capital revenue growth by adding a supplemental capital stretch factor to the formula."

Question(s):
Please provide PEG's recommendation on the specific supplemental capital stretch.

Response:
There are several rationales for including a capital stretch factor in the capital revenue escalation formula.

- It strengthens the utility's capital cost containment incentives, which are weakened by basing capital revenue escalation on forecasted cost, especially when there is a clawback of capex underspends.
- It serves as a materiality condition with a dead zone that is analogous to that in the incremental and advanced capital modules. The absence of this kind of materiality condition in CIR strengthens distributor incentives to choose it over the capital module option. In principle, the custom capital stretch factor should create a dead zone that is at least as large as that in the capital modules.
- It is an alternative to sharing the difference between forecasted cost and the capital revenue that would is generated by rate or revenue cap indexing.

PEG has discussed this matter at greater length on several occasions. See for example our response to SEC-OEB Staff-7 in EB-2019-0261.

Here is a summary of the supplemental capital stretch factors approved by the OEB in past CIR proceedings. Assuming that PEG's own-cost trending proposal for capital revenue escalation is rejected, PEG proposes a 0.30% custom capital stretch factor for Alectra Utilities. This matter merits further attention in any generic proceeding that is held to reconsider the Renewed Regulatory Framework.

Company	**Service**	**Case Number**	**Approved Supplemental Stretch Factor on Capital**
Hydro One Networks	Power distribution	EB-2017-0049	0.15%
Toronto Hydro	Power distribution	EB-2018-0165	0.3%
Hydro One Networks	Power transmission	EB-2019-0082	0.15%
Hydro Ottawa	Power distribution	EB-2019-0261	0.15%
Hydro One Networks	Power distribution	EB-2021-0110	0.20%
Hydro One Networks	Power transmission	EB-2021-0110	0.20%
Toronto Hydro	Power distribution	EB-2023-0195	0.3%
Hydro Ottawa	Power distribution	EB-2024-0115	0.225%

M-SEC-7
Ref 1: PEG Plan Design Report, p.32
PEG summarizes Clearspring's basis for an IPD, which it agrees with in principle, that "applying the standard OEB inflation factor to OM&A revenue is that the 30% weight on the faster-growing labor price index is smaller than it should be in an application to OM&A cost."

Question(s):

a) Please confirm that the inverse would be the case in applying OEB inflation factor to capital costs, if the share of Alectra's non-labour capital costs was higher than 70%.
b) Please explain why the IPD should be based on Alectra's specific OM&A non-labour/labour split and not an external benchmark (e.g. the 30/70% non-labour/labour included in the OEB's annual PEG benchmarking model).

Response:

a) This statement is not confirmed since the weighting of the subindexes in the OEB's approved IPI is not the only issue. The $GDPIPI^{FDD}$ may or may not be a good measure of capital price inflation. As stated elsewhere in PEG's responses to these interrogatories, this is a complicated empirical issue that we have not resolved in this proceeding. Larger utilities have not pressed this issue because CIR compensates them for any inadequacy of the IPI as a measure of capital price inflation.
b) PEG notes that the OM&A non-labour/labour split could reasonably be based on an industry norm. The 30/70 split was developed in 2012 based on an estimate by OEB Staff when distributor salary data were not publicly available. RRR data on the salaries and wages paid to OM&A employees and to New Construction employees are available from 2015-2022. They discontinued the reporting starting in 2023. The use of public information is generally preferable. However, PEG has not considered the sample average OM&A labor cost share that would be indicated for an IPD calculation.

M-SEC-8
Ref 1: PEG Plan Design Report, p.38

Question(s):
Please provide a revised Table 3 that shows what the G-Factor would be back to 2017.

Response:
Please see Table SEC-8 below.

Table SEC-8
Alternative G Factor Design for Alectra Utilities' OM&A Revenue

Year	Customers			Ratcheted Peak Demand			G Factor Annual
	Number	Growth Rate [A]	Weight [B]	MW	Growth Rate [C]	Weight [D]	Growth Rate A*B+C*D
2016	1,026,392			5,778			
2017	1,037,264	1.05%	78%	5,778	0.00%	22%	0.82%
2018	1,046,677	0.90%	78%	5,778	0.00%	22%	0.70%
2019	1,053,678	0.67%	78%	5,778	0.00%	22%	0.52%
2020	1,060,895	0.68%	78%	5,778	0.00%	22%	0.53%
2021	1,068,760	0.74%	78%	5,778	0.00%	22%	0.57%
2022	1,075,666	0.64%	78%	5,778	0.00%	22%	0.50%
2023	1,081,609	0.55%	78%	5,778	0.00%	22%	0.43%
2024	1,086,177	0.42%	78%	5,778	0.00%	22%	0.33%
2025	1,091,472	0.49%	78%	5,815	0.64%	22%	0.52%
2026	1,095,891	0.40%	78%	5,990	2.97%	22%	0.98%
2027	1,100,561	0.43%	78%	6,189	3.27%	22%	1.06%
2028	1,105,574	0.45%	78%	6,416	3.60%	22%	1.16%
2029	1,110,475	0.44%	78%	6,588	2.65%	22%	0.94%
2030	1,115,341	0.44%	78%	6,833	3.65%	22%	1.16%
2031	1,120,186	0.43%	78%	7,061	3.28%	22%	1.07%
Averages							
2027-2031		**0.44%**			**3.30%**		**1.08%**
2017-2024		**0.71%**			**0.00%**		**0.55%**
2017-2031		**0.58%**			**1.34%**		**0.75%**

Notes:

Weights calculated using PEG's econometric OM&A cost model.
Sources for customer data: PEG working papers and Exhibit 1, Tab 3, Schedule 2, p. 3.
Sources for ratcheted peak demand: Calculated from Clearspring working papers and Table 5c of the PEG Framework report.

M-SEC-9

Ref 1: PEG Plan Design Report, p.38

PEG states: "PEG understands that the area data that are readily available are not time-variant. However, the area served does grow over time. Time-variant line length data are available for Ontario power distributors and grow at a similar pace to customer growth."

Question(s):
If line length as part of the G Factor, please provide a revised G-Factor calculation for each year (including all supporting calculations).

Response:
This estimate cannot be provided using the sample that PEG has gathered for this study. Good line length data are unfortunately not readily available for many/most U.S. power distributors.

M-SEC-10
Ref 1: PEG Plan Design Report, p.55

Question(s):
Please provide the specific AWE (Ontario) and GDP-IPI forecasts purchased from Toronto Dominion Economic and Signal49.

Response:
Please see “Attachment SEC-10_Signal49 AWE Ontario Forecast-Confidential” for the AWE (Ontario) forecast purchased from Signal49 Research. Because this file includes the data purchased from Signal49 Research, this file should be afforded confidential treatment. Please see the table below for the GDP-IPI forecast from Toronto Dominion Economics.

Long-Term Canadian Economic Outlook

[Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated]

Economic Indicator	Annual Average							4th Quarter / 4th Quarter						
	25	26F	27F	28F	29F	30F	31F	25	26F	27F	28F	29F	30F	31F
Real GDP	1.7	1.1	1.7	1.8	1.8	1.7	1.7	0.7	1.6	1.8	1.8	1.7	1.7	1.7
Consumer Expenditure	2.3	1.2	1.5	1.7	1.7	1.7	1.7	1.7	1.2	1.7	1.7	1.7	1.7	1.7
Durable Goods	1.6	0.1	1.5	1.7	1.7	1.7	1.7	-1.2	1.2	1.7	1.7	1.7	1.7	1.7
Business Investment	-0.2	0.5	1.6	1.7	1.7	1.7	1.7	-1.2	1.3	1.7	1.7	1.7	1.7	1.7
Non-Res. Structures	1.6	0.6	1.6	1.7	1.7	1.7	1.7	0.6	1.4	1.7	1.7	1.7	1.7	1.7
Equipment & IPP*	-1.9	0.4	1.5	1.6	1.7	1.7	1.7	-2.9	1.2	1.6	1.7	1.7	1.7	1.7
Residential Investment	1.0	-1.3	0.9	1.4	1.6	1.6	1.7	-2.3	-1.1	1.3	1.5	1.6	1.6	1.7
Govt. Expenditure	3.0	3.5	2.8	2.4	2.1	1.9	1.8	2.9	3.3	2.6	2.2	2.0	1.9	1.8
Final Domestic Demand	2.1	1.6	1.8	1.9	1.8	1.8	1.7	1.4	1.6	1.9	1.8	1.8	1.7	1.7
Exports	-1.7	0.8	2.0	2.2	2.3	2.4	2.5	-3.3	1.7	2.1	2.2	2.4	2.4	2.5
Imports	-0.4	0.9	3.7	2.7	2.6	2.6	2.5	-1.6	4.0	3.0	2.7	2.6	2.6	2.5
Change in Non-Farm Inventories (2012 $Bn)	-0.7	-6.6	3.2	7.8	11.0	11.7	12.1	--	--	--	--	--	--	--
Final Sales	2.1	1.8	1.5	1.7	1.7	1.7	1.7	1.4	0.9	1.7	1.7	1.7	1.7	1.7
International Current Account Balance ($Bn)	-30.4	-13.0	-47.5	-56.1	-61.4	-65.0	-67.8	--	--	--	--	--	--	--
% of GDP	-0.9	-0.4	-1.4	-1.6	-1.6	-1.7	-1.7	--	--	--	--	--	--	--
Pre-Tax Corp. Profits	5.7	6.3	-3.3	3.3	3.3	3.0	3.1	3.4	1.3	0.2	3.5	3.1	3.1	3.2
% of GDP	14.1	14.4	13.6	13.5	13.5	13.4	13.3	--	--	--	--	--	--	--
GDP Deflator (y/y)	2.5	3.0	1.3	1.7	1.9	1.9	2.0	2.4	2.2	1.7	1.8	1.9	2.0	2.0
Nominal GDP	4.3	4.1	3.0	3.6	3.7	3.7	3.7	3.2	3.8	3.6	3.6	3.7	3.7	3.7
Labour Force	1.9	0.0	0.1	0.5	0.6	0.6	0.6	1.3	-0.4	0.3	0.6	0.6	0.6	0.6
Employment	1.4	0.2	0.5	0.9	0.7	0.6	0.6	1.3	-0.2	0.6	0.9	0.6	0.6	0.6
Change in Empl. ('000s)	296	42	99	182	155	134	131	261	-38	135	197	137	133	130
Unemployment Rate (%)	6.8	6.6	6.3	6.0	5.9	5.9	5.9	--	--	--	--	--	--	--
Personal Disp. Income	4.7	3.0	3.0	3.6	3.6	3.6	3.6	3.0	2.8	3.4	3.7	3.6	3.6	3.6
Pers. Savings Rate (%)	4.9	4.1	3.7	3.8	3.8	3.7	3.6	--	--	--	--	--	--	--
Cons. Price Index (y/y)	2.1	2.5	2.0	2.0	2.0	2.0	2.0	2.2	2.3	2.1	2.0	2.0	2.0	2.0
CPIX (y/y) **	2.6	2.5	2.0	2.0	2.0	2.0	2.0	2.8	2.3	1.9	2.0	2.0	2.0	2.0
BoC Inflation (y/y) ***	3.0	2.2	2.0	2.0	2.0	2.0	2.0	2.9	2.1	2.0	2.0	2.0	2.0	2.0
Housing Starts ('000s)	258.2	236.4	222.2	226.1	233.7	233.5	233.0	--	--	--	--	--	--	--
Home Prices (y/y)	-1.4	-0.3	2.7	4.6	3.8	3.3	3.3	-1.8	-1.1	4.3	4.4	3.4	3.3	3.2
Real GDP / Worker (y/y)	0.3	0.9	1.2	1.0	1.1	1.1	1.1	-0.5	1.7	1.2	0.9	1.1	1.1	1.1

F: Forecast by TD Economics, March 2026. * Intellectual Property Products. ** CPIX: CPI ex. 8 most volatile components. *** BoC Inflation: Avg. of CPI-trim and CPI-median.

Note: Home price measure shown is the CREA Composite Sale Price.

Source: Statistics Canada, Bank of Canada, CMHC, CREA, TD Economics.

M-SEC-11
Ref 1: PEG Plan Design Report, p.58

Question(s):
Please provide PEG's primary recommendation for the CPCI formula in the format of a simplified formula.

Response:
PEG is unsure of what SEC means by a "simplified formula". Our preferred approach is a variant of the approach discussed on pp. 17-18 of PEG's Empirical Report. This approach avoids the use of an outwardly simple index formula with a "revenue growth factor" or similar term that elides the reality that the applicant is proposing a complicated hybrid approach to ARM design in which there is a sizable role for cost forecasting. A formula like $CPCI = I_n - X + RGF_n$ makes the attrition relief mechanism more rather than less complex.

Setting aside Y factors and Z factors, we recommend that the growth in allowed OM&A revenue be determined by the formula

$$Revenue_t^{OM\&A} = Revenue_{t-1}^{OM\&A} \cdot [1 + I_n - (\overline{Productivity}^{OM\&A} + S) + growth\ G]. \quad [1]$$

Here I_n is the OEB's approved time-variant inflation factor for power distributors. $\overline{Productivity}^{OM\&A}$ is the **0.26%** partial factor productivity achieved by Ontario power distributors in the management of OM&A inputs during the 2014-2024 period. *S* is the 0.15% stretch factor. *G* is the G factor that Clearspring calculated. PEG recommends not including an IPD since the G factor is not also OM&A-specific.

The growth of capital revenue would be determined by

$$Revenue_t^K = Revenue_{t-1}^K \cdot \left(1 + max\left\{\begin{matrix}[I_n - (\overline{Productivity}^K + S) + growth\ G], \\ [growth\ CK^{Forecasted} - S - SK - \overline{Productivity}^K \text{ (if positive)}]\end{matrix}\right\}\right).$$

Here $\overline{Productivity}^K$ is the **0.05%** simple average trend in the partial factor productivity of capital inputs of Ontario power distributors during the 2014-2024 period. *S* is the 0.15% stretch factor. *SK* is a 0.30% capital stretch factor. *G* is the forecasted 1.81% annual growth in the operating scale of Alectra as proposed by Clearspring.

These revenue caps can be converted to price caps by subtracting from allowed total revenue growth the forecasted growth in Alectra Utilities' billing determinants.

PEG notes that formulas that are more favorable to consumers can be reasonably considered. These include the following alternative provisions:

- use an OM&A-specific G factor like that computed in Table 3 on page 38 of PEG's Framework Report;
- compute a productivity trend for OM&A that uses the OM&A-specific output index;
- use the cost-weighted rather than simple average annual growth rates in OM&A and capital productivity; and
- increase the capital stretch factor.