

**PACIFIC ECONOMICS GROUP RESEARCH, LLC
INTERROGATORY RESPONSES**

Pollution Probe

PP-1**Question(s):**

Please provide any comments or recommendations related to opening Rate Base, particularly given that Capital has been overspent for the 8 years.

Response:

PEG has not been retained to review the prudence of Elexicon's opening rate base but provides some results in the Empirical Report that may be relevant to its appraisal. Our understanding is that the reference is to spending more on capex after 2020 than the company forecasted in its 2018 amalgamation proceeding. The Company documented this disparity in Table 2 of Exhibit 1, Tab 4, Schedule 2 in the current proceeding.

As part of its amalgamation application, Elexicon presented forecasts of its OM&A and capex. These were not presented for ratemaking purposes but to show expected benefits from the amalgamation and the feasibility of the proposed ratemaking treatment during the deferred rebasing period.

PEG's benchmarking research suggests that Elexicon was a very good capital cost performer before amalgamation. Its capital cost performance has improved since the amalgamation and this performance should be reflected in the opening rate base. PEG's models take account of surges in North American power distributor construction costs and brisk growth in the Company's operating scale during the 2019-2027 period. They also reflect scale economies estimated to be typical of companies of Elexicon's scale.

PP-2**Question(s):**

- a) What difference in assessment and consideration should be used for this application which is an early rebasing, compare to what would normally occur if Elexicon had waited until the end of its 10-year deferred rebasing period.
- b) What residual merger obligations or benefits should be considered given that two years of the ten year period are being lost, subject to early rebasing.

Response:

- a) Consideration of the need for early rebasing and ensuring customers benefitted from the amalgamation of Whitby Hydro and Veridian Connections was outside of PEG's scope of work for this proceeding. However, PEG believes that the main changes in the assessment of the amalgamation in this proceeding would be to ensure that the early rebasing was appropriate and in the public interest and that

customer benefits are not diminished as a result of the early rebasing.

- b) PEG notes that the reduced period before rebasing reduced the time available to achieve economies. The challenges of the pandemic may have distracted management from this goal. Part of the idea of a lengthy plan term is to stimulate cost containment incentives by giving the amalgamated company time to enjoy the fruits of downsizing efforts.

PP-3

Question(s):

- a) Given that this application is a net increase to the rates previously set for the merged utility, what approach does PEG recommend to assess and validate whether Elexicon has successfully delivered \$34.2M in sustainable synergy savings since merger, and \$5.2M in sustainable annual synergy savings through the integration of the predecessor utilities. [per Elexicon evidence reference 1/1/1, page 4].
- b) If it is not objectively evident that sustainable savings have resulted from the merger, what treatment is recommended for the OEB to consider during this rate term.

Response:

- a) An appraisal of Elexicon's achieved savings from the amalgamation is outside the scope of PEG's work for this proceeding. In EB-2018-0236, the proceeding which led to the approval of Elexicon's amalgamation, the applicants forecast cumulative OM&A savings of \$48.8 million for the 2019-2029 period and annual savings of approximately \$6.6 million that would flow through to customers at rebasing.¹ No capital savings were forecasted.

PEG's cost benchmarking, unlike Clearspring's, included itemized results on OM&A cost efficiency. Our research suggests that the rates of Elexicon customers have for many years reflected good OM&A cost performance. However, there is no evidence of *improved* OM&A cost performance since amalgamation and the Company's forecasted cost in 2027 and later years is commensurate with a marked *deterioration* of performance. This raises concern that customers are not receiving amalgamation benefits. However, it is possible that the deterioration of performance would have been worse for some reason not captured by the model were it not for amalgamation benefits.

- b) Identifying potential solutions to a scenario where sustainable savings resulting from the amalgamation did not materialize is outside the scope of PEG's work in this proceeding.

¹ Ontario Energy Board (2018), "Decision and Order EB-2018-0236 Veridian Connections Inc. and Whitby Hydro Electric Corporation Application for approval to amalgamate and continue operations as a single electricity distribution company", pp. 8-9.

PP-4

Elexicon predicates its early rebasing and application on a higher than typical growth in its service territory and the lack of current ability to meet customer and system needs.

Question(s):

- a) Please explain how Elexicon and its application concurs with or diverges from recent rebasing applications for similar Ontario utilities, on the basis of the issues highlighted by Elexicon (e.g. growth and system readiness).
- b) Please comment on how the current underlying system and performance of Elexicon (vs. peer Ontario utilities) impacts their ability to meet growth and energy transition needs for the future. For example, PEG uses Toronto Hydro's recent rebasing as an example and Toronto Hydro positioned their application as largely status quo since the underlying system is already currently performing adequately as a base for enhancements to support the energy transition (including DERs).

Response:

- a) PEG can only compare Elexicon's rate application to those of three other Ontario power distributors whose rebasing applications we have recently reviewed: those of Toronto Hydro, Hydro Ottawa, and Alectra. PEG believes that the major drivers underlying Elexicon's request are growth in system demand during the plan term and in the need for system renewal (e.g., the need to replace deteriorating assets). Elexicon's demand growth is from economic growth in its service territory and the energy transition.

PEG's understanding is that the need to replace assets is a common driver of capex requests in CIR filings. Rapid demand growth is a less common driver of capex requests. Elexicon appears to be forecasting growth in the number of customers that is quite a bit higher than Alectra, Hydro Ottawa, and Toronto Hydro. Like Elexicon, Alectra forecast significant growth in its system peak demand during the CIR term averaging more than 3% annual growth during the CIR term. Toronto Hydro and Hydro Ottawa forecasted slower growth in system peak demand.

Rapid input price inflation in the years after the Covid-19 pandemic was also commonly discussed in CIR filings. System resilience, particularly from severe storms, was a driver of proposed capex in the CIR applications of Alectra, Elexicon, and Hydro Ottawa.

- b) PEG has not appraised the underlying system of any Ontario power distributor, nor has it appraised their performance on any dimensions other than cost. Elexicon's strong performance in PEG's capital cost model suggests that it has managed its assets effectively, but that an uptick in capex may be needed in the

next five years to replace deteriorating assets, serve growing demand, and add technological capabilities.

PP-5

Question(s):

- a) Please confirm that the early rebasing request by Elexicon following the utility merger is not a normal occurrence in Ontario following a utility merger. If not correct, please provide details.
- b) Does PEG believe that there is sufficient evidence and basis to support the early rebasing request?

Response:

- a) This statement is confirmed. PEG notes, however, that Section 5.3 of the OEB's 2024 *Handbook to Electricity Distributor and Transmitter Consolidations* envisioned the possibility that a merged utility may need to rebase its rates early. Any distributor may request a change in the deferred rebasing period following consolidation after at least 3 years have been completed. The OEB expected that a distributor seeking an early rebasing would provide sufficient reason for its request. Some examples that the OEB provided in the Handbook include "an Asset Condition Assessment that shows significant investment is needed (not known at the time of consolidation), or a significant new requirement imposed that cannot be addressed through existing means."² The OEB also indicated that any changes to a deferred rebasing period should be in the public interest.
- b) PEG declines to answer this question on the grounds that it is outside of the scope of PEG's review and would be difficult to answer in the time available to answer numerous difficult questions.

PP-6

Question(s):

Does PEG believe that there is sufficient unique circumstances to support Elexicon's CIR treatment request for this rate term? If not, please indicate if price cap or revenue cap is more appropriate, and why

Response:

PEG understands the term "Elexicon's CIR treatment request" to mean Elexicon's use of CIR. PEG believes that CIR is warranted for Elexicon for several reasons.

- The Company's capital cost performance has been good for many years.
- The Company has reasonable expectations of rapid demand growth in the next five years.

² Ontario Energy Board (2024), "Handbook to Electricity Distributor and Transmitter Consolidations," p. 20.

- Elexicon's plant additions forecast is not easily accommodated by Price Cap IR or the Annual IR Index.

Please note, however, that PEG is not endorsing Elexicon's plant additions forecast. Moreover, PEG has concerns about the CIR framework that Elexicon has chosen as discussed in its Framework report.

PP-7

Reference: Ontario is engaged in a transition to a lower carbon economy. This transition would likely entail electrification of important economic activities such as transportation and space heating that today rely heavily on fossil fuels for energy. Electrification would substantially increase electricity demand. [PEG Framework Report – Elexicon, page 35]

Question(s):

- a) Please provide the references and basis supporting this statement.
- b) What is the basis for this to impact the Elexicon plan, costs and obligations over the rate term?
- c) Does PEG believe that Elexicon is currently positioned to meet the energy transition needs in its service territory?

Response:

- a) PEG relied particularly on the province of Ontario's integrated energy plan, *Energy for Generations* and discussions by Elexicon in its Distribution System Plan and in Exhibit 1 of its application in this proceeding (e.g., its business plan, early rebasing case, and rate framework). Figure 5 in *Energy for Generations* presents an IESO forecast of electricity demand which indicates that the adoption of EVs will be an important driver of electricity demand growth between 2025 and 2050, while Chapter 5 of that report includes a discussion of the growing impact of heat pumps on natural gas use. One of Elexicon's four strategic pillars, as outlined on pages 26-27 of Exhibit 2B, Tab 1, Schedule 1, is "Enable Growth and Electrification." PEG also relied upon various documents issued by the Ontario Energy Board over the past several years including Reports of the Board in the policy initiatives on Utility Remuneration and Non-Wires Solutions incentives.
- b) For the purpose of this response, PEG focuses primarily upon the issue of increased electrification. PEG understands that power distributors need to make investments to increase capacity to accommodate expected load growth resulting both from electrification and customer growth (e.g., to increase substation and or feeder capacity). PEG believes that increased load growth could reduce the potential rate impacts resulting from these investments, but that conservation and demand management can also play a vital role. PEG believes that concerns

about the need for increased capacity influenced Elexicon's Distribution System Plan, particularly in the forecasted spending on new substations.

- c) With the caveat that PEG was not retained by the OEB to appraise Elexicon's positioning with regard to the energy transition, PEG notes that Elexicon's distribution system plan indicates that its grid has numerous capacity constraints on its system and obsolete technology that limit its ability to support additional customer load on portions of its network.³

³Many of these issues are discussed in more detail in the Company's evidence, specifically Exhibit 2B, Tab 1, Schedule 1, Sections 2.2.1, 2.2.2, and 2.2.4.

Elexicon Energy

References:

- Statistical Cost Research for the Elexicon Energy CIR Plan “PEG Empirical Report”
- Issues in the Design of the New Elexicon Energy CIR Framework “PEG Plan Report”
- PEG Working Papers

EE-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 EE-1_Request for Services” reproduces the project information and requirements contained in the Request for Services (RFS) issued by the OEB.

“Attachment EE-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 EE-1_Services and Deliverables”.

Written instructions provided to PEG is shown in “Attachment EE-1_Instructions to PEG”. For the scope of the expert report, refer to OEB Staff_Ltr_Expert_Evid_Elexicon_20260410, which was filed with the OEB on April 10, 2026.

EE-2

Reference: PEG Empirical Report, p. 7

PEG lists two larger concerns on page 7 that it has regarding Clearspring’s cost benchmarking study. The first mentions that the sample selection and sample period are suboptimal. 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.

In PEG’s first concern, it mentions that there are 8 of the 82 sampled U.S. distributors that are smaller than Elexicon. The first concern also mentions Clearspring starting the sample in 2000 and having 24 years worth of observations and includes a single time

trend variable. 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) Please provide the number of utilities in PEG's alternative sample that are smaller than Elexicon in terms of number of customers served in 2023. What percentage of the PEG sample is this?
- b) PEG previously had a concern in EB-2018-0218 that a 13-year benchmarking sample period used by Clearspring was too short when PEG used a 22-year sample period in that proceeding. Now a concern is stated that 24 years is too long and suboptimal despite PEG used similarly long sample periods in some of its past studies. Please provide the rationale for this apparent contradiction.

Response:

- a) In PEG's sample, 11 of the 89 utilities other than Elexicon are smaller, and another 2 companies are only just larger. This corresponds to 14.6% of the sample. We acknowledge that the operating scale of Elexicon is far from the norm for PEG's U.S. sample, as it is for Clearspring's sample.
- b) The cited EB-2018-0218 study in which PEG used a much longer sample period was performed eight years ago. PEG has typically used shorter samples for econometric model estimation and a 15-year sample is typical. 15 years typically strikes a sensible balance between the need for model relevance to current business conditions and the need for a large sample to sharpen the parameter estimates of econometric models. The importance of model relevance has increased with technological change in the distribution business and changes in asset age, and the energy transition is a looming challenge. Please see Table EE-2 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 an alternative to a longer sample period as a way to bolster the sample size and thereby improve the precision of parameter estimates.

Table EE-2
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
2026	Ontario Energy Board: Elexicon	Power distribution	Ontario	2009-2023 (15 years)	Yes
2026	Ontario Energy Board: OPG	Hydroelectric power generation	Ontario	2004-2024 (21 years)	Yes

EE-3

Reference: PEG Empirical Report, p. 9

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

data problems than the preceding years and suggests that new industry productivity factors should be considered in this proceeding.

Question(s):

- a) Is PEG aware of any data problems during this 2014 to 2024 period? If so, please list and describe them.
- b) Please confirm that the 2014 productivity trend is constructed as the growth rate in productivity from 2013 to 2014.
- c) How many months and weeks has PEG been working on this new productivity research?
- d) How many person-hours of effort has PEG put into gathering the Ontario dataset, gathering and examining input prices, and conducting the productivity calculations?
- e) 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?
- f) PEG only provided an Ontario industry productivity trend study as the basis for its productivity factor recommendation. Does PEG believe U.S. productivity trends are relevant to the productivity factor in the context of Elexicon Energy?

Response:

- a) Apart from lack of good Canadian construction cost indexes and the inability in any year to easily remove pension and other benefit expenses from the costs of all Ontario distributors, PEG is not aware of any major problems with Ontario power distributor operating data during the 2014-2024 period. In footnote 3 on page 9 of the PEG Empirical Report, we state that "The most relevant small remaining problems are the lack of company-specific data on OM&A labour expenses beginning in 2023 and the inconsistent reporting of distribution line lengths."
- b) The 2014 productivity growth rate pertains to productivity growth from 2013 to 2014.
- c) PEG acknowledges that its new Ontario productivity trend research began in another project for OEB Staff. This research, started in early 2025 and paused several times, was not solely focused on productivity trends. Staff granted PEG permission to use in the Elexicon project whatever data or calculations it had available from the 2025 work. 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.

Please note also that the productivity evidence presented in 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.

- d) Please see the response to part c of this question.

- e) Please see the response to part c of this question.
- f) Yes. The OEB decided in EB-2007-0673 that the productivity trends of Ontario power distributors were to be the basis for setting productivity factors in power distributor IR Plans. However, PEG believes that the productivity trends of US power distributors could also be relevant information for the OEB to consider, especially in the design of CIR plans. PEG accordingly provided estimates of U.S. power distributor productivity trends in the recent Toronto Hydro CIR proceeding.⁴ In the instant proceeding, PEG has also provided estimates of recent OM&A productivity trends of energy distributors that have recently been proffered by other witnesses in the context of incentive ratemaking.

Please note that any negative total factor productivity trends that other consultants have recently reported may reflect special features of their study such as a focus on distributors in the northeast U.S. or the inclusion of recent California data in their sample. California distributors have in recent years struggled with devastating wildfires and high expenditures to prevent their recurrence. 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 studies of productivity trends tend to be funded only by utilities and to that extent may have downward biased results.

EE-4

Reference: PEG Empirical Report, p. 11

Equation [2] states that the growth in cost equals the growth in input prices plus the growth in inputs.

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

⁴ Lowry, Mark N., “Statistical Cost Research for THESL’s New CIR Plan,” in EB-2023-0195, revised October 7, 2024, pp. 68-70.

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.

Response:

- a) In the design of I factors for attrition relief mechanisms ("ARMs") with index formulas, a balance has traditionally been struck between simplicity and the desire to track utility input price trends accurately. In lieu of a complex inflation index driving the time-variant I factor, regulators have usually used simpler inflation indexes. Some have added an adjustment term to the ARM formula that is based on a periodic review of the accuracy of the inflation index driving the I factor.

For example, we discuss in Section 2.1 of our Empirical Report how in the United States the gross domestic product price index ("GDPPI") is typically the sole inflation measure in an indexed ARM. This is a macroeconomic inflation index that summarizes the trend in the economy's output prices. The GDPPI therefore tends to understate the input price inflation of the economy by the multifactor productivity ("MFP") trend of the economy. Since this trend is brisk, it is common (e.g., in Massachusetts) to use a productivity *differential* in US indexed ARM formulas that is the difference between the MFP trends of the utility industry and the economy.

An ARM that combines the GDPPI with a productivity differential captures the trend in the U.S. economy's input prices reasonably well. However, the question remains as to whether it adequately captures *utility* input price inflation. The technologies of energy distributors are capital intensive, and cost is particularly sensitive to growth in distribution equipment and construction prices. These concerns have led to proposals to add input price differentials ("IPDs") as well as productivity differentials to U.S. formulas for indexed ARMs. These proposals have engendered controversy in some U.S. proceedings, although several have nonetheless been approved.

In Canadian IR there has to date been less concern about the adequacy of inflation measures used in ARM formulas for reasons that include the following.

- The MFP trend of Canada's economy is much slower than that in the States, as we show in Table 1 of PEG's Framework Report. This lessens concern about the use of macroeconomic inflation measures in ARM design.
- In Canadian IR, the I factor is typically the average growth in a macro inflation measure and a labor price index that uses utility cost-share

weights. This also mitigates concern about the need for an input price differential. The inflation measure used in Ontario is actually called an Input Price Index ("IPI").

- Canadian utilities have successfully prevailed upon regulators to provide them with capital revenue growth that is commensurate with capital cost forecasts. Terms in many ARM formulas that in Ontario have been called variously "capital factors" and "revenue growth factors" have eliminated the role of I in capital revenue escalation.
- Canadian utilities have rarely complained about the inadequacy of I factor as a measure of OM&A price inflation. This could reflect the reasonableness of I as a measure of OM&A price inflation but may also reflect the general tendency to base the productivity factor applicable to OM&A revenue on *total factor* productivity rather than the *partial* factor productivity of OM&A inputs. Recent research by PEG suggests that the OM&A productivity growth of power distributors has been materially positive in the last ten years.

On the other hand, prices of power distribution equipment and construction have surged in recent years, and some Ontario distributors that include Elexicon have recently raised this as an issue in their rate applications.

PEG has the following general comments on this matter.

- The chief area of concern about the accuracy of the IPI (or of the GDPIPIFDD which is the designated proxy for the capital price in the IPI formula) is its ability to track capital price inflation.
- In the Framework Report, PEG acknowledged that the IPI tends to modestly understate OM&A price inflation but took exception to the small specific IPD^{OM&A} proposed by Clearspring.
- The adequacy of IPI (or of the GDPIPIFDD subindex) as a measure of *capital* price inflation is a complicated and potentially controversial issue for reasons that include the following.
 - Capital prices are complex functions of asset price indexes and the rate of return on capital. There is no consensus on how best to measure these prices. The choice of the asset price index alone has been an area of debate in some Ontario CIR proceedings.
 - The capital service prices that are commonly used to calculate productivity growth are very different from the capital prices implicit in traditional capital cost accounting. Most notably, the former prices reflect a *replacement* valuation of plant whereas the latter reflect an *historic* valuation.

It's therefore not enough to just compare the IPI to measures of asset price inflation as Elexicon did in Exhibit 1 Tab 5 Schedule 2 and Clearspring did in Section 4.5.1 of its report in this proceeding.

- PEG developed the cost of service (“COS”) approach to measuring capital cost in order to have a way to measure capital prices that is more relevant for utility ratemaking, which uses traditional cost accounting in rebasings. This approach is discussed at a high level in the Appendix to PEG’s Empirical Report. PEG used this approach in some early IR research and testimony for OEB Staff. See, for example, PEG’s report for OEB Staff in the 2007 gas utility IR proceeding and its 2008 report for Staff in the 3rd GIRM proceeding.⁵
- Insofar as capital price inflation is volatile, it is possible that the IPI undercompensates in some years and overcompensates in others but captures the long-term trends accurately.
- The issue of an input price differential (“IPD”) for energy distributors has been addressed in a few OEB proceedings. We mention here IPDs that were approved or proposed even though they likely are not applicable today.
 - The OEB approved a -1.1% input price differential (which accelerated revenue growth) for Union Gas as part of its 2001 decision approving a multiyear rate plan for that company.
 - For the 3rd GIRM for power distributors, the OEB approved a 0% input price differential.
 - PEG computed IPDs in 2007 testimony for OEB Staff in a gas utility IR proceeding. Using the COS capital cost specification, we reported that these would be non-zero but not large (e.g., -0.39% for Enbridge). The plans for Enbridge and Union were the outcomes of settlements and did not include IPDs in the ARM formulas.
 - Jeff Makholm of NERA considered this matter in 2017 testimony for the Ontario gas Amalco and reported no “statistically significant” input price differential.
- PEG also testified to an IPD calculation in 2013 evidence for Central Maine Power. The COS approach to measuring capital cost was used and the proposed IPD was -0.35%.⁶ In a 2019 proceeding in Massachusetts PEG,

⁵ Mark Newton Lowry et al, *Rate Adjustment Indexes for Ontario’s Natural Gas Utilities*, Pacific Economics Group, November 2007 and Lawrence Kaufmann, et al, *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario, Report to the Ontario Energy Board*, February 2008. PEG has also used this approach in regulatory proceedings in several other jurisdictions including Alberta and British Columbia in Canada and the District of Columbia, Maine, Maryland, Massachusetts, and Vermont in the US.

⁶ Since this date, PEG has on several occasions used the alternative Kahn method, which also simulates traditional cost accounting, to calculate X factors that are consistent with traditional cost accounting.

testifying on behalf of the Massachusetts Attorney General testified to a - 0.12% input price differential using a geometric decay capital cost treatment.

- b) PEG believes that the OEB's choice of an IPI was reasonable at the time. The OEB adopted an IPI that would apply to all distributors over an extended period of time. Moreover, there is always a trade-off between accuracy and complexity. We noted above that a macroeconomic price index such as the GDPPI is used by many regulators as the sole inflation measure in an indexed ARM formula. The OEB took one step towards additional accuracy by introducing a labor price index into the IPI formula. Distributors that find that the default IPI is not accurate enough for their situation can opt for CIR and propose alternatives.

All this having been said, inflation in the cost of distribution system equipment and construction has recently been brisk. If the IPI materially understates capital price inflation, a better capital price index could in future applications reduce the need of Elexicon for Custom IR.⁷

PEG has undertaken some calculations in response to this question to assess the recent accuracy of the IPI as a utility price index for Elexicon. These results are preliminary and are not represented as applicable to Ontario distributors generally. In these calculations, we used the COS approach to calculate capital cost, quantity, and price. Please see Attachment EE-4 below for the formulas for these calculations. The plant in the benchmark year was broken down into vintages and each vintage was separately depreciated.

The capital price was computed indirectly as the ratio of the capital cost to the capital quantity. The rate of return was calculated as a 60/40 weighted average of the OEB-approved rate of return targets for long-term debt and equity. The labor price was the average weekly earnings for the Ontario industrial aggregate while the GDPIPIFDD was the proxy for the materials and services ("M&S") input price index.

Using cost-share weights for Elexicon where weights were required in index construction, we calculated the average annual growth rates (growth *trends*) and standard deviations of the growth rates of labor, M&S, combined OM&A, capital, and total factor input prices for the fifteen (growth rate) years from 2010 to 2024 and the twenty growth rate years from 2005 to 2024. We then compared the trends in these prices to the IPI trends using the current IPI formula. The IPI is lagged by two years in conformance with current OEB practice.

⁷ Adding a capital price index to the IPI would raise various questions such as whether stretch factors should be revisited and whether the IPI would escalate OM&A revenue, as it typically does now, when cost forecasts are used to escalate capital revenue.

Please note the following results for the 15-year period. Similar results obtain for the twenty-year period.

- The standard deviation calculations in Table EE-4b-1 reveal that Elexicon's capital price inflation was much more volatile than inflation in the prices of its OM&A inputs. This raises concern as to whether a 15-year average annual growth rate is an adequate measure of the long-term capital price and total factor input price trends.
- The volatility of the capital price was due to the volatility of the change in the rate of return. This volatility was likely exacerbated by our use of the OEB's *prescribed* return on debt rather than the return on *embedded* debt that is more commonly used in OEB rebasings. When we fixed the weighted average rate of return at its 6.47% average value over the sample period, the volatility of capital price inflation was much *lower* than that of OM&A price inflation.⁸ This suggests that a capital price that is consistent with traditional capital cost accounting isn't that sensitive in the short term to a surge in the prices of distribution system equipment and construction. Such surges can however trigger sustained higher capital price inflation.
- Whether or not the rate of return was fixed, we found that the IPI materially understated Elexicon's input price inflation. With a *time-variant* rate of return, for example, the IPI understated total factor input price inflation by 0.91% per annum. With a *fixed* rate of return, the IPI understated total factor input price inflation by an average of 1.23% per annum.
- The IPI was much more accurate as a measure of OM&A price inflation than it was as a measure of *capital* price inflation. With a time-variant rate of return, for example, the IPI understated the capital price trend over the 15 years considered by 1.44% per annum whereas the GDPIPIFDD understated the capital price trend by 1.33% per annum. With a *fixed* rate of return, the IPI understated the capital price trend by 2.05% per annum whereas the GDPIPIFDD understated average annual capital price growth by 1.95% per annum.
- One reason why the OEB IPI does not track current inflation is that the IPI reflects inflation with a 2-year lag and does not contain any revisions to the subindexes that have occurred since the I factor calculation. When PEG constructed an OEB IPI using the OEB methodology save that values of the

⁸ The fixed value of 6.47% is the average from 2005-2024 which includes annually determined values from 2006-2024 and one value for 2005 which had been held constant for many years.

subindexes were revised for new information the alternative index tracked
 Ellexicon's total factor input price trend better by 0.25%.

Table EE-4b-1

Input Price Index Using Ellexicon Data: Time Variant ROR

Year	Input Price Subindex Growth				Share of Ellexicon's Total Cost		Ellexicon Total Factor Input Price Growth
	Labor	M&S	OM&A	Capital	OM&A	Capital	
2004	2.45%	1.75%	2.19%	3.35%	46.5%	53.5%	2.81%
2005	3.15%	2.06%	2.64%	4.52%	44.4%	55.6%	3.67%
2006	2.34%	2.26%	2.18%	-4.56%	46.1%	53.9%	-1.51%
2007	3.83%	2.42%	3.08%	6.50%	43.5%	56.5%	4.97%
2008	3.08%	2.48%	2.65%	3.15%	43.1%	56.9%	2.93%
2009	2.89%	1.12%	2.66%	8.53%	40.3%	59.7%	6.08%
2010	3.80%	1.05%	2.84%	2.57%	41.0%	59.0%	2.68%
2011	1.59%	2.34%	1.44%	0.65%	42.5%	57.5%	0.98%
2012	1.34%	1.61%	1.75%	-3.22%	49.5%	50.5%	-0.93%
2013	1.42%	1.72%	1.46%	1.59%	50.5%	49.5%	1.52%
2014	1.57%	2.29%	1.55%	8.06%	48.7%	51.3%	4.83%
2015	2.70%	1.55%	2.56%	5.77%	48.0%	52.0%	4.22%
2016	2.27%	1.07%	2.00%	2.07%	48.9%	51.1%	2.04%
2017	1.86%	1.38%	1.58%	-2.35%	50.6%	49.4%	-0.39%
2018	2.29%	1.56%	1.99%	7.39%	48.5%	51.5%	4.71%
2019	2.79%	1.90%	2.50%	4.45%	40.5%	59.5%	3.58%
2020	3.27%	1.79%	3.08%	-3.15%	47.9%	52.1%	-0.39%
2021	2.78%	3.75%	2.48%	1.15%	47.7%	52.3%	1.79%
2022	4.04%	6.18%	4.05%	9.47%	44.2%	55.8%	6.98%
2023	2.95%	3.71%	3.96%	17.22%	38.9%	61.1%	11.71%
2024	5.15%	3.20%	4.58%	3.38%	41.7%	58.3%	3.86%
Average Annual Growth Rates							
2010-2024 (last 15 Years)	2.65%	2.34%	2.52%	3.67%	45.9%	54.1%	3.15%
2005-2024 (20 Years)	2.76%	2.27%	2.55%	3.66%	45.33%	54.67%	3.17%
Standard Deviation of Growth Rates							
2010-2024	1.08%	1.37%	1.01%	5.41%	4.01%	4.01%	3.25%

Table EE-4b-2

Tracking Success of IPI and GDPIPIFDD: Time Variant ROR

Year	Ellexicon Total Factor Input Price Growth	OEB IPI	Tracking Success of IPI	Ellexicon OM&A Price	Tracking Success of IPI	Ellexicon Capital Price	Tracking Success of IPI	GDPIPIFDD	Tracking Success of GDPIPIFDD
	[A]	[B]	[B-A]	[C]	[B-C]	[D]	[B-D]	[E]	[E-D]
2005	3.67%	1.84%	-1.83%	2.64%	-0.80%	4.52%	-2.68%	2.06%	-2.45%
2006	-1.51%	2.05%	3.56%	2.18%	-0.13%	-4.56%	6.61%	2.26%	6.82%
2007	4.97%	2.52%	-2.45%	3.08%	-0.56%	6.50%	-3.98%	2.42%	-4.08%
2008	2.93%	2.06%	-0.87%	2.65%	-0.59%	3.15%	-1.09%	2.48%	-0.67%
2009	6.08%	2.83%	-3.25%	2.66%	0.16%	8.53%	-5.70%	1.12%	-7.41%
2010	2.68%	2.42%	-0.26%	2.84%	-0.41%	2.57%	-0.15%	1.05%	-1.53%
2011	0.98%	1.16%	0.18%	1.44%	-0.28%	0.65%	0.51%	2.34%	1.69%
2012	-0.93%	1.87%	2.80%	1.75%	0.12%	-3.22%	5.09%	1.61%	4.83%
2013	1.52%	2.04%	0.52%	1.46%	0.58%	1.59%	0.46%	1.72%	0.13%
2014	4.83%	1.70%	-3.13%	1.55%	0.15%	8.06%	-6.36%	2.29%	-5.77%
2015	4.22%	1.60%	-2.62%	2.56%	-0.96%	5.77%	-4.17%	1.55%	-4.22%
2016	2.04%	2.10%	0.06%	2.00%	0.10%	2.07%	0.03%	1.07%	-1.00%
2017	-0.39%	1.90%	2.29%	1.58%	0.32%	-2.35%	4.25%	1.38%	3.73%
2018	4.71%	1.20%	-3.51%	1.99%	-0.79%	7.39%	-6.19%	1.56%	-5.83%
2019	3.58%	1.50%	-2.08%	2.50%	-1.00%	4.45%	-2.95%	1.90%	-2.54%
2020	-0.39%	2.00%	2.39%	3.08%	-1.08%	-3.15%	5.15%	1.79%	4.94%
2021	1.79%	2.20%	0.41%	2.48%	-0.28%	1.15%	1.05%	3.75%	2.59%
2022	6.98%	3.30%	-3.68%	4.05%	-0.75%	9.47%	-6.17%	6.18%	-3.29%
2023	11.71%	3.70%	-8.01%	3.96%	-0.26%	17.22%	-13.52%	3.71%	-13.51%
2024	3.86%	4.80%	0.94%	4.58%	0.22%	3.38%	1.42%	3.20%	-0.18%
Average Annual Growth Rates									
2010-2024	3.15%	2.23%	-0.91%	2.52%	-0.29%	3.67%	-1.44%	2.34%	-1.33%
(last 15 Years)									
2005-2024 (last 20 Years)	3.17%	2.24%	-0.93%	2.55%	-0.31%	3.66%	-1.42%	2.27%	-1.39%
Standard Deviation of Growth Rates									
2010-2024	3.25%	0.99%	2.91%	1.01%	0.53%	5.41%	5.13%	1.37%	4.88%

Table EE-4b-3

Input Price Index Using Elexicon Data: Fixed ROR

Year	Input Price Subindex Growth				Share of Elexicon's Total Cost		Elexicon Total Factor Input Price Growth
	Labor	M&S	OM&A	Capital	OM&A	Capital	
2005	3.15%	2.06%	2.64%	4.44%	44.4%	55.6%	3.62%
2006	2.34%	2.26%	2.18%	3.50%	46.1%	53.9%	2.90%
2007	3.83%	2.42%	3.08%	6.43%	43.5%	56.5%	4.93%
2008	3.08%	2.48%	2.65%	5.29%	43.1%	56.9%	4.14%
2009	2.89%	1.12%	2.66%	4.13%	40.3%	59.7%	3.52%
2010	3.80%	1.05%	2.84%	4.41%	41.0%	59.0%	3.77%
2011	1.59%	2.34%	1.44%	4.23%	42.5%	57.5%	3.07%
2012	1.34%	1.61%	1.75%	3.44%	49.5%	50.5%	2.66%
2013	1.42%	1.72%	1.46%	3.93%	50.5%	49.5%	2.69%
2014	1.57%	2.29%	1.55%	4.10%	48.7%	51.3%	2.84%
2015	2.70%	1.55%	2.56%	4.48%	48.0%	52.0%	3.55%
2016	2.27%	1.07%	2.00%	4.16%	48.9%	51.1%	3.11%
2017	1.86%	1.38%	1.58%	3.72%	50.6%	49.4%	2.65%
2018	2.29%	1.56%	1.99%	3.85%	48.5%	51.5%	2.93%
2019	2.79%	1.90%	2.50%	4.49%	40.5%	59.5%	3.60%
2020	3.27%	1.79%	3.08%	3.94%	47.9%	52.1%	3.56%
2021	2.78%	3.75%	2.48%	4.52%	47.7%	52.3%	3.55%
2022	4.04%	6.18%	4.05%	4.54%	44.2%	55.8%	4.32%
2023	2.95%	3.71%	3.96%	5.53%	38.9%	61.1%	4.88%
2024	5.15%	3.20%	4.58%	4.95%	41.7%	58.3%	4.80%
Average Annual Growth Rates							
2010-2024 (last 15 Years)	2.65%	2.34%	2.52%	4.29%	45.9%	54.1%	3.47%
2005-2024 (20 Years)	2.76%	2.27%	2.55%	4.40%	45.33%	54.67%	3.56%
Standard Deviation of Growth Rates							
2010-2024	1.08%	1.37%	1.01%	0.52%	4.01%	4.01%	0.73%

Table EE-4b-4

Tracking Success of IPI and GDPIPIFDD: Fixed ROR

Year	Ellexicon Total Factor Input Price Growth	OEB IPI	Tracking Success of IPI	Ellexicon OM&A Price	Tracking Success of IPI	Ellexicon Capital Price	Tracking Success of IPI	GDPIPIFDD	Tracking Success of GDPIPIFDD
	[A]	[B]	[B-A]	[C]	[B-C]	[D]	[B-D]	[E]	[E-D]
2005	3.62%	1.84%	-1.78%	2.64%	-0.80%	4.44%	-2.60%	2.06%	-2.38%
2006	2.90%	2.05%	-0.85%	2.18%	-0.13%	3.50%	-1.45%	2.26%	-1.23%
2007	4.93%	2.52%	-2.41%	3.08%	-0.56%	6.43%	-3.91%	2.42%	-4.01%
2008	4.14%	2.06%	-2.08%	2.65%	-0.59%	5.29%	-3.22%	2.48%	-2.81%
2009	3.52%	2.83%	-0.69%	2.66%	0.16%	4.13%	-1.30%	1.12%	-3.01%
2010	3.77%	2.42%	-1.34%	2.84%	-0.41%	4.41%	-1.98%	1.05%	-3.36%
2011	3.07%	1.16%	-1.91%	1.44%	-0.28%	4.23%	-3.07%	2.34%	-1.89%
2012	2.66%	1.87%	-0.80%	1.75%	0.12%	3.44%	-1.57%	1.61%	-1.83%
2013	2.69%	2.04%	-0.65%	1.46%	0.58%	3.93%	-1.88%	1.72%	-2.21%
2014	2.84%	1.70%	-1.14%	1.55%	0.15%	4.10%	-2.40%	2.29%	-1.81%
2015	3.55%	1.60%	-1.95%	2.56%	-0.96%	4.48%	-2.88%	1.55%	-2.93%
2016	3.11%	2.10%	-1.01%	2.00%	0.10%	4.16%	-2.06%	1.07%	-3.09%
2017	2.65%	1.90%	-0.75%	1.58%	0.32%	3.72%	-1.82%	1.38%	-2.34%
2018	2.93%	1.20%	-1.73%	1.99%	-0.79%	3.85%	-2.65%	1.56%	-2.29%
2019	3.60%	1.50%	-2.10%	2.50%	-1.00%	4.49%	-2.99%	1.90%	-2.59%
2020	3.56%	2.00%	-1.56%	3.08%	-1.08%	3.94%	-1.94%	1.79%	-2.15%
2021	3.55%	2.20%	-1.35%	2.48%	-0.28%	4.52%	-2.32%	3.75%	-0.78%
2022	4.32%	3.30%	-1.02%	4.05%	-0.75%	4.54%	-1.24%	6.18%	1.64%
2023	4.88%	3.70%	-1.18%	3.96%	-0.26%	5.53%	-1.83%	3.71%	-1.82%
2024	4.80%	4.80%	0.00%	4.58%	0.22%	4.95%	-0.15%	3.20%	-1.75%
Average Annual Growth Rates									
2010-2024	3.47%	2.23%	-1.23%	2.52%	-0.29%	4.29%	-2.05%	2.34%	-1.95%
(Last 15 Years)									
2005-2024 (20									
Years)	3.56%	2.24%	-1.32%	2.55%	-0.31%	4.40%	-2.16%	2.27%	-2.13%
Standard Deviation of Growth Rates									
2010-2024	0.73%	0.99%	0.57%	1.01%	0.53%	0.52%	0.75%	1.37%	1.18%

- c) A solution to any tendency of the IPI or its GDPIPIFDD subindex to understate capital price inflation is beyond the scope of PEG's assignment in this proceeding.
- d) The inflation indexes used in productivity research are typically not fully consistent with those used in the I factor determination. One reason is the desire for a simple inflation index that we discussed above. Another is that monetary methods are commonly used to measure capital cost in research on utility TFP trends. These methodologies typically entail a replacement valuation of utility plant and not the historical valuations used in conventional cost accounting. The capital service prices featured in monetary methods were designed by economists to produce a sensible cost-share weight for the capital quantity index and not to determine appropriate inflation relief for utilities. Their use as inflation measures has led to controversy in several IR proceedings. COS formulas have been developed that are more consistent with traditional cost accounting, but these are quite complex and lack intuitive appeal.

- e) No. PEG used the GDPIPIFDD to measure M&S inflation but a different labor price index and a capital price index that was consistent with its chosen monetary capital cost specification.
- f) PEG declines to respond to this question on the grounds that it is onerous. It is also unclear how such a calculation would work. The only way to use the historical IPI would be to deflate total cost by the IPI to get the input quantity. The capital cost would be calculated using different prices than the IPI leading to an inconsistent estimation of capital quantity. One could consider using the price indexes in the IPI instead of those used in the study (e.g., GDPIPIFDD for Handy Whitman Index etc.), but if one arbitrarily set the capital service price equal to GDPIPIFDD, one would have to invent an asset price index that would yield the constrained result for the service price. This price index would not correspond to any construction cost measure, and this would then compromise the calculation of capital quantity. There is also no guarantee that a proper cost-weighted input price index resulting from this work would be the same as the OEB IPI because the weights given to labor, M&S, and capital would likely be different.

Attachment EE-4**Cost of Service Approach to Capital Cost Formulas**

The basic idea of this capital cost specification is to decompose the cost of capital as computed under traditional cost of service (“COS”) accounting into a price and a quantity index. The hallmarks of this accounting approach are straight line depreciation and an historic valuation of plant. This approach takes account of the number of years of remaining service life that a capital stock can provide and how the years diminish over time.

Glossary of Terms

For each utility in each year, t , of the sample period let

ck_t = Total non-tax cost of capital

$ck_t^{Opportunity}$ = Opportunity cost of capital

$ck_t^{Depreciation}$ = Depreciation cost of capital

VK_{t-s}^{add} = Gross value of plant installed in year $t-s$

WKA_{t-s} = Cost per unit of plant construction in year $t-s$ (the “price” of capital assets)

a_{t-s} = Quantity of plant additions in year $t-s = VK_{t-s}^{add} / WKA_{t-s}$

xk_t = Total quantity of plant available for use and that results in year t costs

xk_t^{t-s} = Quantity of plant available for use in year t that remains from plant additions

in year $t-s$

l_t = Pro forma rate of return on capital

VK_t = Total value of plant at the end of last year

N = Average service life of plant

WKS_t = Price of capital

Basic Assumptions

The analysis is based on the assumption that depreciation and opportunity cost is incurred in year t on the amount of plant remaining at the end of year $t-1$, as well as on

any plant added in year t . This is tantamount to assuming that plant additions are made at the beginning of the year. This assumption increases the sensitivity of the capital price index to the latest developments in construction costs.

Theory

The non-tax cost of capital is the sum of depreciation and the pro forma opportunity cost that is owed to bond and equity holders.

$$ck_t = ck_t^{\text{opportunity}} + ck_t^{\text{depreciation}}.$$

Assuming straight line depreciation and book valuation of utility plant, the cost of capital can be expressed as

$$\begin{aligned} ck_t &= \sum_{s=0}^{N-1} \left(WKA_{t-s} \cdot xk_t^{t-s} \right) \cdot I_t + \sum_{s=0}^{N-1} WKA_{t-s} (1/N) \cdot a_{t-s} \\ &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} WKA_{t-s} \cdot \frac{(1/N) \cdot a_{t-s}}{xk_t} \end{aligned} \quad [A11]$$

where

$$xk_t = \sum_{s=0}^{N-1} xk_{t-s}.$$

The term xk_t is the quantity of capital remaining from plant additions in all previous years.

We posit that in the interval $[N-1, 0]$,

$$xk_t^{t-s} = \frac{N-s}{N} \cdot a_{t-s}. \quad [A12]$$

The formula for the capital quantity index can then be expressed as

$$xk_t = \sum_{s=1}^{N-1} \frac{N-s}{N} a_{t-s}. \quad [A13]$$

The size of the addition in year $t-s$ of the interval $(t-1, t-N)$ can then be expressed as

$$a_{t-s} = \frac{N}{N-s} \cdot xk_t^{t-s}. \quad [A14]$$

Equations [A11] and [A14] together imply that

$$\begin{aligned} ck_t &= xk_t \cdot \sum_{s=0}^{N-1} \left(\frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \right) \cdot I_t + xk_t \cdot \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s} \\ &= xk_t \cdot WKS_t \end{aligned} \quad [A15]$$

where

$$WKS_t = \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot I_t + \sum_{s=0}^{N-1} \frac{xk_t^{t-s}}{xk_t} \cdot WKA_{t-s} \cdot \frac{1}{N-s}. \quad [A16]$$

$$= \sum_{s=0}^N \frac{xk_{t-s}^{t-s}}{xk_t} \cdot WKA_{t-1} \cdot \left(I_t + \frac{1}{N-s} \right)$$

It can be seen that the cost of capital is the product of a capital price and a capital quantity index. The capital price in a given year is a function of the construction cost index values in the N most recent years (including the current year). The importance of each WKA_{t-s} depends on the share, in the total quantity of plant that contributes to cost, of plant remaining from additions in year $t-s$. This share tends to be larger the more recent the plant addition year (since there is less accumulated depreciation) and the larger were the plant additions in that year. Absent a decline in I_t , WKS is apt to rise each year as the WKA_{t-s} for each of the N years is replaced with the generally higher value for the following year.

Note also that the depreciation rate varies with the age of the plant. For example, the depreciation rate in the last year of an asset's service life is 100%.⁹

EE-5

Reference: PEG Empirical Report, p. 19

Equation [15b] 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? For possible context please refer to Clearspring's report, Section 4.5.1 which contains evidence and a discussion regarding capital inflation relative to 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.

⁹ In contrast, the depreciation rate is constant under the geometric decay approach to capital costing.

Response:

- a) Please see the response to question EE-4 b) above.
- b) The preliminary research presented in response to EE-4 b) above does suggest that a tendency of the IPI to understate capital price inflation could be a reason for Elexicon to need supplemental capital revenue. However, it is not clear how much utilities have anticipated future construction cost inflation at the time of their CIR 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 true ups.
- 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 quite complex. The rate of return on capital might also play a role in index design. PEG has developed COS capital price indexes that are consistent with traditional capital accounting and used these indexes in several early studies for OEB Staff.

EE-6

Reference: PEG Empirical Report, p. 32

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 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 actual cost growth of Ontario distributors. This is thus not a situation where a business condition affects the productivity growth of a peer group but is irrelevant to the utilities to which an indexed ARM applies.

EE-7

Reference: PEG Empirical Report, p. 33

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 Elexicon, that do provide these services, all else being equal.

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 don’t bill end users but do process extensive end user data in order to bill retailers and provide them with detailed information about the grid use of end users.

Please note that PEG has included the customer service and information expenses of the Alberta utilities in its benchmarking study but not those of Elexicon or the U.S. utilities. Please also note that Elexicon 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.

EE-8

Reference: PEG Empirical Report, p. 34

PEG lists several major disadvantages of including Alberta utilities in the benchmarking sample.

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 of 2004 for the Alberta utilities may insert a higher level of inaccuracy into its dataset relative to utilities with capital benchmark years beginning in 1964?
- c) ATCO does not appear in PEG's benchmarking data sample list. Is the reason why they were excluded because of this outlier result status?
- d) Please provide evidence that ATCO Electric is an outlier.
- e) Does ATCO tend to have very strong cost performance (i.e., a good benchmark score) or a very poor cost performance score?
- f) 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 Elexicon'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.
- g) Does the inclusion of the Alberta utilities improve Elexicon's benchmark score or make it worse?
- h) Please provide the benchmark scores of each of the three included Alberta utilities.

Response:

- a) No. 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 in the benchmarking work. On the upside, however, data are available on the gross plant additions of Alberta distributors for all of the historical years thereafter whereas they are not available for Ontario distributors until 2013. PEG also notes that Mr. Fenrick has routinely used a 2002 benchmark year in studies for his Ontario distributor clients, including Elexicon. Other advantages of using Alberta data are discussed in Section 3.2 of PEG's Empirical Report. These include the fact that Alberta peers are particularly useful for benchmarking costs of Toronto Hydro, Hydro Ottawa, and the distributor services of Hydro One Networks.
- c) Yes. ATCO Electric has been excluded from the samples for our three benchmarking models due to extremely poor scores in total cost and capital cost runs where its data were included. The calculation of ATCO's capital stock may require a custom treatment. Poor scores may also reflect our inability to capture with business condition variables the special operating challenges in that company's service territory. In the absence of such upgrades, ATCO's inclusion in the sample may cause estimates of model parameters to be less accurate.
- d) PEG declines to provide runs that include ATCO Electric on the grounds that the request is onerous. We do not expect that the addition of ATCO Electric to the

sample would greatly affect the benchmarking score of Elexicon, which is similar to Clearspring's score and quite favorable to the Company.

- e) Please see our response to part c) of this question.
- f) Please see our response to part d) of this question.
- g) Please see our response to part d) of this question.
- h) For the 3 years ending in 2023, here are the average cost benchmarking scores for the three Alberta distributors included in our sample.

	Average Cost Benchmark Scores 2021-2023		
Company	Total	Capital	OM&A
EPCOR	-27%	-10%	-52%
ENMAX	-14%	1%	-40%
FortisAlberta	3%	21%	-47%

EE-9

Reference: PEG Empirical Report, p. 44

In past proceedings, Clearspring preferred using the Handy-Whitman indexes ("HWI") but was criticized by PEG for using only the HWIs. PEG preferred using a Canadian specific index. However, PEG has now shifted to using only Clearspring's preferred index, which is the Handy-Whitman indexes.

PEG states on p. 44, "Recent research by PEG suggests that it is more accurate to just use the HWI."

Question(s):

- a) Was PEG mistaken in its past criticisms of Clearspring's preferred methodology of using the HWIs?
- b) What caused PEG to now shift to only using the HWI despite its prior arguments against using the index?
- c) Did PEG also use the HWI in its Ontario productivity trend research?
- d) 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?
- e) Please provide a table with PEG's previously preferred index and the HWIs used.
- f) Which index grew faster from 2004 to 2024?
- g) All else equal, will using a faster growing asset price index tend to increase measured productivity trends?
- h) Please provide the Ontario TFP trend and capital PFP trend results using PEG's previously preferred asset price index for Ontario.

- i) Please provide the recent research by PEG that suggests the HWI is more accurate.

Response:

- a) PEG's prior advocacy of taking a 50/50 average of the inflation in a Handy Whitman Construction Cost Index and the implicit capital stock deflator for the utility sector of Canada's economy was the decision of a well-informed and disinterested expert on an empirical issue that it periodically revisits. Clearspring's advocacy of an HWI was not accompanied by extensive supportive evidence. PEG acknowledges that new evidence suggests that Clearspring's approach was superior. However, PEG is actually recommending and using HWIs without the PPP adjustment that Clearspring recommended.
- b) PEG's periodic update of its research on the appropriate deflator for the plant additions of Ontario power transmission and distribution utilities suggested that better deflators were available. Results of this research can be found in Attachment "EE-9_Ontario Asset Price Indexes." Please note that this research would also support taking a 50/50 average of the inflation in a Handy Whitman Construction Cost Index and the implicit capital stock deflator for utility sector *machinery and equipment*. The issue of the best asset price index for capital may merit further scrutiny in any proceeding to reconsider the IPI.
- c) Yes.
- d) PEG does not know the answer to this question. The impact of alternative asset price indexes deflators on Ontario productivity trends has not been considered.
- e) Please see Attachment EE-9_Ontario Asset Price Indexes for information on the trends in various asset price trend indexes.
- f) Please see Attachment EE-9_Ontario Asset Price Indexes for information on the trends in various asset price trend indexes.
- g) A faster-growing asset price index will tend to reduce the quantity of estimated plant additions but will also tend to increase the weight on capital, with its slower growing partial factor productivity trend. Also, it's not clear how alternative asset price indexes affect the benchmark year adjustment. Note also that insofar as a rapidly growing asset price index accelerates calculated productivity growth it will also tend to improve the benchmarking scores of larger Ontario utilities and lower their stretch factors. In any event, a Handy Whitman index was advocated by Clearspring.
- h) 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 in the time available to answer numerous difficult questions.
- i) Please see our response to part b) of this question.

EE-10

Reference: PEG Empirical Report, p. 45

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?
- i) Would taking out the capital gains term, lower PEG's TFP trend estimates?

Response:

- a) No.
- b) PEG's capital service price is discussed on pp. 95-99 of the Empirical Report and detailed in the working papers.
- c) Yes. PEG's benchmarking 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. On the other hand, 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 *did* include capital gains. 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 EE-2. In addition, PEG has usually included a capital gains term in its productivity studies in other jurisdictions.

- d) In the utility cost research 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 may therefore loom larger than it does 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 encouraged (discouraged) when the real rate of return is low (high) than when it is high (low). This is one reason why high (low) interest rates tend to slow (accelerate) economic growth. 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. Plant is valued in historic dollars, but this lowers capital cost.
- 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) This sometimes happens since OM&A expenses are volatile and capital cost is also volatile when capital gains are included. Although capital gains cause capital cost to fluctuate from year to year, 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 (although these are low for many Ontario distributors due in part to their public ownership). Customer contributions will also tend to hold down capital cost to the extent that they are large.
- i) PEG has not considered this matter and declines to do so now on the grounds that the request is onerous in the time permitted to answer numerous difficult questions. PEG can confirm that the PFP results suggest that an increase in the weight given to capital should tend to lower TFP trends. Because the subtraction of capital gains will tend to lower the capital service price, removing capital gains would tend to increase the capital service price and capital cost which in turn increases the weight given to capital.

EE-11

Reference: PEG Empirical Report, p. 48 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) Elexicon is listed on Table 1. Is Elexicon data included in the productivity trend research?
- d) 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 the study detailed 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.
- d) No. In the 4GIR proceeding, the productivity factor was understood to apply to all distributors that did not opt for CIR. At that time, it was not clear whether it would also apply to CIR utilities. Hydro One and THESL had a major impact on a size-weighted productivity trend and were likely candidates for CIR.

The issue in this proceeding is the determination of a proper productivity factor for Elexicon, which is proposing CIR. PEG believes that the panel in this proceeding would be interested in industry productivity trends that included CIR distributors, which consist mainly of the larger distributors.

It is difficult to itemize the productivity trends of CIR distributors, but PEG has itemized the productivity trends of distributors of different sizes. PEG also reported simple averages of the productivity trends of Ontario distributors, and these greatly reduce the importance of results for the larger companies.

EE-12

Reference: PEG Empirical Report, p. 52

PEG states that both the ratcheted peak demand and a moving average of recent annual peak demands were considered for inclusion in PEG's research.

Question(s):

- a) 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.
- b) Please provide the productivity trend results for the TFP, OM&A PFP, and Capital PFP when using a 10-year rolling average.

- c) 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?

Response:

- a) This statement is confirmed. Ratcheted peak demand is the featured demand variable in PEG's work for several reasons. First, the *actual* peak demands of power distributors tend to understate the *maximum potential* peak demands that drive distribution planning and cost. There is thus a tendency for rolling average peak demand to do so as well. The understatement of maximum potential peak demand is not the same from company to company.

The tendency of rolling average peak demand to understate maximum potential peak demand will be greater for utilities experiencing a marked acceleration of demand growth. In this regard, it is notable that Elexicon anticipates brisk peak demand growth in the next five years. Clearspring does not advocate using a rolling average of peak demand to calculate the proposed G factor for the Company.

Even if the maximum potential peak demand of a distributor were to decline, comparable cost savings will typically not quickly follow suit. Many surplus assets will continue to 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 or supplemental capital revenue because cost doesn't fall in lock step.

These considerations help to explain why ratcheted peak demand produces cost models with better explanatory power (as measured by a lower root mean squared error) than models with rolling average peak demand.

- b) PEG declines to undertake this task on the grounds that it is onerous in the limited time available to answer several difficult questions.
- c) Yes. However, the reverse could be the case for utilities such as Elexicon that are experiencing brisk demand growth.

EE-13

Reference: PEG Empirical Report, p. 63

PEG states, "However, recent research by PEG suggests that the GDPPI tends to materially understate the M&S price inflation of U.S. utilities."

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) Did PEG use the Ontario or Canadian GDP-IPI FDD for Elexicon?
- e) Did PEG use the Alberta or Canadian GDP-IPI FDD for the Alberta utilities?

Response:

- a) The GDP-PI is a measure of inflation in the economy's output prices. As such, it is slowed by the MFP 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 input price inflation of the U.S. economy. 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 Elexicon proceeding evidence.
- c) Please see the response to part b) of this question. Please also note that an analogous adjustment is not necessarily warranted for Canada because the MFP growth of Canada's economy is much slower.
- d) PEG used GDP-IPI FDD^{Ontario} for Elexicon.
- e) PEG used GDP-IPI FDD^{Alberta} for Alberta distributors.

EE-14

Ref 1: PEG Empirical Report, p. 65

PEG uses a different rate of return for the U.S. utilities compared to Elexicon 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 Elexicon in this case) should not use the same rate of return as the utility being studied?

Response:

- a) Yes.
- b) Yes, although PEG has never considered the consequences of this.
- c) PEG believes that 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. This treatment doesn't matter much for benchmarking results because a lower (higher) rate of return lowers (raises) the capital price as well as the capital cost. The rate of return chiefly affects the weight on capital cost in a total cost assessment. The higher is the rate of return in a given jurisdiction the more important is capital cost containment.

EE-15

Reference: PEG Empirical Report, p. 66

PEG states, "We instead use this variable to create a customer density variable (customers/area) for the year 2023."

Question(s):

- a) Please confirm this is the only business condition variable that also includes a quadratic term.
- b) Is this variable time invariant and set at the 2023 value?

Response:

- a) This statement is confirmed. We departed from our usual practice of not including quadratic terms for any Z variables in these cost models for two reasons. One is that the relationship in question is well known to be nonlinear. Unusually low and high density can both be especially costly. The other reason is that we are using the density variable to reduce the need for second-order scale variables in the models. If doing this requires a quadratic term, we are still increasing degrees of freedom on balance.
- b) Yes, because the area data were time-invariant.

EE-16

Reference: PEG Empirical Report, p. 68

PEG states, "We calculated a DER penetration variable which is the ratio of DER generation capacity to a 3-year rolling average of maximum peak load. The source of these data for the United States is the Form EIA 861 survey's sections 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) Please provide the source link and citation of the data used for Elexicon's DER generation capacity value.
- b) Please provide the source link and citation of the data used for the Alberta utilities DER generation capacity value.
- c) Did PEG escalate Elexicon's DER generation capacity in the years of 2026 to 2031? If yes, please explain the basis for the escalation.
- d) If no to part (c), is it a realistic assumption that Elexicon will have zero growth in DER generation capacity for upcoming years?

Response:

- a) We used the data from RRR Sections 2.1.14 and 2.1.14.1 for Net Metering and Embedded Generation Information, which can be found at <https://www.oeb.ca/open-data/electricity-reporting-record-keeping-requirements-rrr-sections-2114-and-21141-net>. For data prior to 2015, PEG gathered data from the IESO Contracted Generation data for the pre-2017 FIT and microFIT programs. The most recent version of the IESO data can be found at <https://www.ieso.ca/Sector-Participants/Resource-Acquisition-and-Contracts/Contract-Data-and-Reports> at the link titled "IESO Active Generation Contract List."
- b) The data provided by the AESO can be found at the following link: <https://www.aeso.ca/market/market-and-system-reporting/data-requests/> under the 2025 section of Past Data Requests, labeled **Wind and Solar Microgen Capacity by Wire Owner Datafile** [Updated: June 26, 2025]
- c) Yes, PEG kept Elexicon's percentage DER value the same for 2026-2031, which is a generous escalation as Elexicon forecasts dramatic growth in peak demand.
- d) Please see the answer to part c).

EE-17

Reference: PEG Empirical Report, p. 73 Table 3

Question(s):

- a) Please provide the custom elasticities on customers and ratcheted peak demand for Elexicon in 2024.
- b) For each observation in PEG's sample, are there any negative custom elasticities for customers and/or ratcheted peak demand? If yes, please provide how many for each.

Response:

- a) The 2024 custom elasticities for Elexicon on customers and ratcheted peak demand are 1.18 and -0.17, respectively. The sum of the custom scale elasticities for Elexicon is 1.01. Clearspring reported its 2024 custom elasticities for Elexicon

as 2.193 for customers, 1.703 for rolling average peak demand, and -0.005 for area, summing to a combined scale elasticity of 3.891. In contrast, Clearspring's custom 2024 elasticities for Alectra were 0.484 for customers, 0.636 for peak demand, and -0.032 for area for a combined scale elasticity of 1.088.

- b) There are 60 negative elasticities for customers and 271 negative elasticities for ratcheted peak demand, out of 1,365 observations for each, meaning that 12% of the individual coefficient elasticities were negative. In contrast, 23% of Clearspring's individual coefficient elasticities were negative. For all of our observations with a negative elasticity, the sum of the two elasticities falls between 0.90 and 1.09. The range of the sum of elasticities for the full sample is [0.89, 1.09].

EE-18

Reference: PEG Empirical Report, p. 87

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 supported by evidence. To figure out the timing of the smart meter account clearance is a burdensome task. 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. Furthermore, the 2013 beginning-of-year capital stock is equal to the end of year 2012 stock which will include the smart meter capital cost cleared in 2012. Therefore, the 2013-2014 growth rate is the first with the 2012 smart meter costs included in cost. The clearance of deferred OM&A in 2013 or later years could have an impact. However, as discussed in part (b), it is difficult to determine how

much has been cleared from these accounts into accounts covered by the PEG study.

- b) The OEB created two accounts for the purpose of deferring smart meter cost. The first is the “Smart Meter Capital and Recovery Offset Variance Account” (1555) which contains capital expenditures. The second is the “Smart Meter OM&A Variance Account” (1556) for other smart meter costs. PEG does not know exactly where all the costs from these accounts went when cleared. It seems reasonable to expect that capital expenditures from account 1555 were recorded in Account 1860 - Meters. In the case of account 1556, PEG would expect that several accounts might be affected. One difficulty in determining the amount of OM&A cleared is that the deferral account used for this purpose (1556) contains both OM&A and certain non-OM&A expenses such as the amortization expenses incurred while the capital cost was deferred. It is not known how much of an observed decline in account 1556 was cleared to OM&A accounts covered by the benchmarking study versus those cleared to amortization accounts which are not used.

EE-19

Ref 1: PEG Empirical Report, p. 90 Table 8b

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

Question(s):

- a) The data in the columns of this table appear to be off, based on Clearspring’s review. Please verify that the first column titled “Output Quantity Index” actually shows customer growth, the second column titled “Customers” actually shows ratcheted peak demand, the third column titled “Ratcheted Peak Demand” actually shows the output quantity index, the fourth column titled “Total Factor” actually shows OM&A input quantities, the fifth column titled “OM&A” actually shows capital input quantities, and the last column titled “Capital” actually shows total factor input quantities.
- b) What is the average annual growth rate of annual peak demand of the industry without it being ratcheted from 2014 to 2024?
- c) 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.
- d) 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 corrected table which we label Table EE-19 is provided below.

- b) The average annual growth rate of the annual (not rolling average) peak demand of sampled Ontario distributors from 2014 to 2024 was -0.27%. This means that peak load declined by only 3% during these years.
- c) This is correct. The value of the variable in each year was the maximum of the annual ratcheted peak demands starting in 2002. In 2024 all 23 years would be considered.
- d) This is correct. The value was the maximum annual ratcheted peak demands from 2002 to 2013, all 12 years included.

Table EE-19

Details of Ontario Power Distributor Productivity Growth

Year	Simple Averages of Annual Growth Rates					
	Output Quantity Index	Scale Measures		Input Quantities		
		Customers	Ratcheted Peak	Total Factor	OM&A	Capital
2004	2.56%	1.75%	3.77%	0.92%	0.64%	1.59%
2005	1.52%	1.38%	1.74%	1.67%	0.49%	2.03%
2006	0.96%	0.75%	1.27%	2.09%	2.98%	1.81%
2007	1.15%	1.45%	0.70%	2.27%	2.76%	1.56%
2008	0.79%	1.05%	0.41%	1.55%	1.69%	1.49%
2009	0.49%	0.71%	0.15%	0.74%	0.24%	0.96%
2010	0.74%	0.88%	0.53%	0.07%	-0.13%	0.05%
2011	0.79%	0.89%	0.65%	3.08%	5.58%	0.80%
2012	0.73%	0.77%	0.67%	5.12%	8.25%	0.61%
2013	0.78%	0.95%	0.52%	1.98%	1.82%	2.61%
2014	0.57%	0.91%	0.07%	-0.82%	-1.23%	0.23%
2015	0.49%	0.76%	0.09%	0.63%	0.54%	0.31%
2016	0.62%	0.99%	0.06%	1.43%	1.39%	1.37%
2017	0.60%	1.01%	0.00%	0.87%	0.30%	1.15%
2018	0.60%	1.01%	0.00%	0.20%	0.11%	0.73%
2019	0.55%	0.79%	0.20%	-0.12%	-1.03%	0.57%
2020	0.86%	0.96%	0.71%	-0.63%	-1.73%	0.97%
2021	0.63%	0.99%	0.11%	0.09%	-0.04%	0.29%
2022	0.69%	1.06%	0.13%	1.77%	2.62%	0.68%
2023	0.96%	1.26%	0.51%	0.79%	1.11%	0.33%
2024	0.66%	0.85%	0.38%	1.41%	2.46%	0.21%

Average Annual Growth Rates¹

2004-2024	0.85%	1.01%	0.60%	1.20%	1.37%	0.97%
2004-2010	1.17%	1.14%	1.22%	1.33%	1.24%	1.36%
2014-2024	0.66%	0.96%	0.21%	0.51%	0.41%	0.62%

¹ Growth rates of individual utilities are even-weighted.

EE-20

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) In PEG's view, 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?
- 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?

Response:

- a) If the panel seeks to add an IPD specific to OM&A prices to the attrition relief mechanism for Elexicon, PEG recommends using the **0.17%** historical inflation differential for the last fifteen years ending in 2024. This can be found in Table 2 on page 44 of PEG's Framework Report.
- b) Please see the response to question EE-4b.
- c) Clearspring is clearly capable of making this simple calculation. PEG cautions, however, 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) Please see the responses to questions EE-4b and EE-5b.

EE-21

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 overlaid 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 EE-21_Service Territory and Landcover Map.
- b) Please see confidential Attachment EE-21_Service Territory and Landcover Map.
- c) Please see pages 57 and 66-67 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

EE-22

Ref 1: PEG Empirical Report, p. 42

PEG states a concern about Clearspring’s Distribution Work Variable

Question(s):

- a) Please confirm that PEG included a similar variable in its recent Alectra benchmarking research in EB-2025-0252.
- b) If confirmed, why did PEG choose to not include this same variable in this proceeding?
- c) Which model is the preferred one by PEG?

Response:

- a) This statement is confirmed.
- b) As the models and dataset for the two proceedings were extremely similar, PEG had the opportunity to do additional consideration and testing of this variable. We initially were willing to use this variable because it is conceptually desirable to control for the extent of subtransmission facilities counted as distribution facilities. While we were not convinced that this was the best variable¹⁰, it appeared to be an acceptable proxy and as it did not have a major effect on the model, we cautiously included it. However, upon revisiting the model for the Elexicon proceeding, we noticed that Clearspring’s assumption of a 100% value of this variable for Elexicon (and Alectra) was not well supported. We considered how we might calculate an appropriate value for Elexicon and the Alberta utilities. Upon

¹⁰ Substation data would be preferred but is very difficult and time-consuming to gather and process these data from the U.S. FERC Form 1 accurately.

testing alternate values based on Elexicon's actual and forecasted high-voltage assets, we discovered this change results in very little difference in PEG's model, but wild swings to scores around +35% for Elexicon in Clearspring's model. In both PEG's and Clearspring's models, the inclusion or exclusion of the variable entirely has little effect on Elexicon's performance. We also noticed and found it counterintuitive that PSE's Dx work variable was a more significant driver of OM&A expenses than it is of capital cost. We concluded that the variable should be omitted.

- c) The Elexicon model is preferred for the reasons stated in the response to part b).

EE-23

Ref 1: PEG Empirical Report, p. 63

PEG discusses the input prices used in its study.

Question(s):

- a) What city or cities were used for Elexicon's labour input price?
- b) What city or cities were used for Elexicon's capital asset price?

Response:

- a) Oshawa
- b) Oshawa

EE-24**Ref 1:** PEG Empirical Report, p. 70

PEG states, “PEG’s input price index for materials and services is quarter-levelized while Clearspring’s is not. Our approach permits M&S prices to be higher where labour prices are higher.”

Question(s):

- a) This states “quarter-levelized” whereas on p. 64 it appears the assumption is 1/3. What is the actual ratio used by PEG?
- b) Did PEG test different proportions?
- c) How did PEG decide on whatever proportion was used?
- d) In PEG’s view, is PEG’s recognition that labour price levels influence M&S input prices a reason to add further weight to the labour portion in the OM&A IPD calculation?

Response:

- a) The “quarter-levelized” language is a typo that reflects an older method that PEG has refined. Previously, an assumption of half services and half local labor was the basis of the “quarter” method. Subsequent research suggests that the share of services in M&S expenses is typically closer to two thirds which, combined with a half local labor assumption, leads to the one third method.
- b) No.
- c) The treatment is based on evidence that two thirds of material and service expenses are services and the sensible assumption that one half of service costs are local labor. One half of two thirds is equal to one third of M&S expenses assumed to be related to local labor.
- d) No. The 1/3 levelization corrects for the fact that we would otherwise assume that M&S prices were the same for each company in a given year. However, we believe that trending M&S prices by a GDPIPIFDD is satisfactory because these indexes are sensitive to the prices of many labor-intensive services (e.g., home health care and assisted living, elementary and secondary education, legal and other professional services).

EE-25**Ref 1:** PEG Empirical Report, p. 77 Table 5

PEG displays its OM&A benchmarking model.

Question(s):

- a) PEG included a skyscraper variable in its OM&A benchmarking model for Alectra but did not include the variable in its OM&A benchmarking model for this proceeding. What caused PEG to change this model that it presented only six weeks prior?
- b) What model is PEG's preferred model?
- c) PEG's model in this proceeding has 15 added observations relative to the one reported in its Alectra research in EB-2025-0252. What utility or utilities were added to PEG's sample and for what years?
- d) What caused the addition of these observations?

Response:

- a) The skyscraper variable did not have a statistically significant parameter estimate in OM&A models that we developed for this proceeding. Since this variable has less of an impact on OM&A expenses than it does on capital or total cost, a small change in the sample could plausibly "tip the scales". The skyscraper variable was statistically supported and thus included in the total and capital cost models for both companies.
- b) Our preferred skyscraper specification for each proceeding is the one with the best combination of statistical support and economic intuition, which is the one we presented in each proceeding.
- c) Eight of the additional observations were for Elexicon from 2009-2016; those years were unavailable for Alectra. Six observations are for Southern California Edison for 2010-2017; they were (unnecessarily) excluded previously. The Elexicon sample also excludes Pacific Gas & Electric starting in 2018 rather than the previous 2017. These were minor changes which were made when PEG reviewed the database anew before incorporating Elexicon's cost and price data for these models. The sample periods for those two U.S. companies are now the same as Clearspring's.
- d) Please see our answer to part c) of this question.

SCHOOL ENERGY COALITION

M-SEC-1

Reference: [PEG Framework Report, p.46]

Question(s):

Please provide a revised version of Table 3 that shows PEG's G-Factor calculation on a total cost basis derived from PEG's economic cost model.

Response:

Please see Table 3 (Total Cost Model) below. Using the elasticities from PEG's total cost model increases the G factor by 21 basis points during the 2028-31 period relative to the results in Table 3 of its Framework Report.

Table 3 (Total Cost Model)

Alternative G Factor Design

Year	Customers			Ratcheted Peak Demand			G Factor Annual
	Number	Growth Rate	Weight	MW	Growth Rate	Weight	Growth Rate
		[A]	[B]		[C]	[D]	A*B+C*D
2027	189,833			814			
2028	193,280	1.80%	60%	839	3.02%	40%	2.29%
2029	196,883	1.85%	60%	865	3.08%	40%	2.34%
2030	200,624	1.88%	60%	895	3.42%	40%	2.50%
2031	204,398	1.86%	60%	923	3.07%	40%	2.35%
Average		1.85%			3.15%		2.37%

Notes:

Elasticity weights calculated using PEG's econometric total cost model.

Source for customer data: Table 6c.

Source for ratcheted peak demand: Table 6c.

All growth rates calculated logarithmically.

M-SEC-2**Reference: [PEG Empirical Report, p.7]****Question(s):**

PEG notes that Clearspring's sample selection are suboptimal for benchmarking Elexicon since "[o]nly 8 of the 82 sampled U.S. distributors have fewer customers than Elexicon, and only an additional 7 companies are larger but still in the same size ballpark." Has PEG undertaken any analysis to determine the impact on the benchmarking results if a smaller sample of U.S. companies, that are closer in size to Elexicon, was used? If so, please provide details.

Response:

No, and we do not recommend doing so. Econometric analysis does not require peer groups, though data used in OLS estimation methods should be checked for outliers to ensure that model parameters are not unduly sensitive to them. Econometric modeling does tend to be most accurate near the sample mean, but that is something to be aware of rather than a major concern if the model performs well.

Our comments on the sample selection are most relevant to the topic of Elexicon filing for Custom IR and commissioning an econometric model for themselves based solely on U.S. distributors. As we discuss in the PEG Empirical Report "Disadvantages" sections on the information available from each jurisdiction, valid use of an international sample requires some tradeoffs to make the data comparable. These tradeoffs should be considered against the Company's reasons for eschewing the available comparable data entirely. Inclusion of data for Ontario as well as U.S. utilities was a valid if costly alternative to sole reliance on U.S. data in an application to Elexicon.

M-SEC-3**Reference: [PEG Empirical Report, p.32]****Question(s):**

PEG notes that one of the disadvantages of using a U.S. sample is that few Ontario distributors use U.S. GAAP, which generally involves more capitalization of OM&A expenses. Please discuss what impact would this have on the benchmarking results for an Ontario distributor's MIFRS.

Response:

As a result of the accounting difference, Ontario distributors will tend to have somewhat poorer OM&A cost scores and somewhat better capital cost scores. It is difficult to say how total cost scores would be affected.

M-SEC-4

Reference: [PEG Empirical Report, p.36]

Question(s):

Ideally, would benchmarking of Elexicon costs use Ontario or U.S. peer utilities?

Response:

PEG is not sure about whether a model based on U.S. data is superior to a new model based on Ontario data in an application to Elexicon. The issue is quite complex. PEG also notes that a model based on Ontario as well as U.S. data would be an option. In any event, a new model based on Ontario data is not currently available. Benchmarking Elexicon using US data is reasonable under the circumstances.

M-SEC-5

Reference: [PEG Empirical Report, p.81]

Question(s):

SEC would like to understand the sensitivity of the benchmarking results to changes in forecast costs during the rate term (2027-2031). Please provide the change in the 'CIR Period 2027-2031' period total, capital, and OM&A cost benchmark scores for the following changes:

Increase or decrease in Elexicon's forecast capital costs each year between 2027 and 2031 of \$1M.

Increase or decrease in Elexicon's forecast OM&A costs each year between 2027 and 2031 of \$1M.

Increase or decrease in both Elexicon's forecast OM&A and capital costs each year between 2027 and 2031 of \$1M.

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:

a.– c. Please see Table M-SEC-5 below.

d. No.

Table M-SEC-5

Incremental Forecast Adjustments						
Change in Forecasted Cost Performance (Negative numbers represent a worsened score)						
	\$1M Increase		\$1M Increase in both OM&A and Capital	\$1M Decrease		\$1M Decrease in both OM&A and Capital
Year	OM&A	Capital	Total	OM&A	Capital	Total
2027	-1.50%	-1.25%	-1.37%	1.53%	1.27%	1.39%
2028	-1.39%	-1.16%	-1.27%	1.41%	1.18%	1.28%
2029	-1.36%	-1.08%	-1.20%	1.38%	1.09%	1.22%
2030	-1.33%	-1.02%	-1.16%	1.35%	1.03%	1.17%
2031	-1.30%	-0.91%	-1.07%	1.32%	0.92%	1.08%

M-SEC-6

Reference: [PEG Empirical Report, p.81]

Question(s):

Please provide for each year between 2027 and 2031:

- The percentage change in the benchmark total, capital and OM&A costs, for each 1% change in customers.
- The percentage change in the benchmark total, capital and OM&A costs, for each 1% change in peak demand.

Response:

- Please see Table M-SEC-6a below. Please note the relative size of the effects for peak and customers; if both customers and peak were to increase by 1% the total change in the forecast would be positive and close to 1%.
- Please see Table M-SEC-6b below.

Table M-SEC-6a

Incremental Forecast Adjustments							
Change in Total Customers							
Year	1% Increase			1% Decrease			
	% Change in Cost:						
	OM&A	Capital	Total	OM&A	Capital	Total	
	2027	1.36%	0.96%	1.15%	-1.35%	-0.96%	-1.15%
	2028	1.33%	0.95%	1.13%	-1.33%	-0.95%	-1.13%
	2029	1.31%	0.93%	1.11%	-1.31%	-0.93%	-1.11%
2030	1.29%	0.92%	1.09%	-1.29%	-0.91%	-1.09%	
2031	1.27%	0.90%	1.07%	-1.26%	-0.90%	-1.07%	

Table M-SEC-6b

Incremental Forecast Adjustments							
Change in Total MW Ratcheted Peak Demand							
Year	1% Increase			1% Decrease			
	% Change in Cost:						
	OM&A	Capital	Total	OM&A	Capital	Total	
	2027	-0.36%	0.06%	-0.13%	0.38%	-0.05%	0.14%
	2028	-0.34%	0.08%	-0.11%	0.36%	-0.07%	0.13%
2029	-0.31%	0.09%	-0.09%	0.33%	-0.08%	0.11%	
2030	-0.29%	0.11%	-0.07%	0.31%	-0.10%	0.08%	
2031	-0.27%	0.13%	-0.05%	0.29%	-0.12%	0.07%	

M-SEC-7**Reference:** [PEG Empirical Report, p.91]**Question(s):**

PEG provides a table showing Ontario productivity growth by distributor size. Did PEG undertake any research regarding the productivity growth of distributors by rate framework (i.e. Price Cap vs. Custom IR)? If so, please provide details.

Response:

PEG does not have any productivity results that correspond to rate frameworks. We believe that it would be difficult to draw conclusions from such an analysis due to a) the small sample size of distributors that operated under CIR and b) the unusual economic

conditions (e.g., the Covid-19 pandemic and the subsequent inflation) that have occurred during several recent years. To date, only five power distributors (e.g., Hydro One Networks, Hydro Ottawa, Kingston Hydro, Oshawa PUC Networks, and Toronto Hydro Electric) have had their rates set under the provisions of CIR. Two of these utilities have only had one plan approved, while Hydro One Networks has had two CIR plans approved and Hydro Ottawa and Toronto Hydro have had three CIR plans approved, though not all of these plans have been completed. This is a relatively small sample for a productivity trend analysis. A further complication is that the CIR plans for Kingston Hydro and Oshawa PUC Networks were not immediately followed by a rate rebasing proceeding.

PEG notes that in the Empirical Report productivity trends are itemized for large utilities, and most of these operated under CIR for much of the 2014-2024 period, the notable exception being Alectra.