Issues in the Design of the New Elexicon Energy CIR Framework

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1. Introduction and Summary

Introduction

Ontario Energy Board ("OEB") proceeding EB-2025-0312 concerns an application by Elexicon Energy Inc. ("Elexicon Energy," "Elexicon," or "the Company") to rebase its rates and establish a new Custom Incentive Rate-Setting ("CIR" or "Custom IR") framework. Incentive ratemaking ("IR") is called performance based ratemaking or "PBR" in some jurisdictions. The Company's proposed framework is a multiyear rate plan ("MRP") that would cover the five years from 2027 to 2031. The plan has an attrition relief mechanism ("ARM") that takes the form of a Custom Revenue Cap Index ("CRCI") with some novel features. Clearspring Energy Advisors ("Clearspring") has provided supportive statistical cost research for the proposal.

The Elexicon Energy proposal and supporting evidence merit careful scrutiny for reasons that include the following.

- The Company serves an important area of economic growth in Ontario.
- ARM design innovations are proposed that could subsequently be used by other Ontario utilities.
- Containment of power distribution charges is important to Ontario customers during a potentially costly energy transition.

Pacific Economics Group Research LLC ("PEG") has for many years been North America's leading consultancy on the design of IR plans. We are experts on utility cost benchmarking and the price and productivity trend research that are used to design some of these plans. In addition to Ontario, we have played a prominent role in IR in Alberta and several other North American jurisdictions. OEB Staff retained PEG to provide an independent appraisal and commentary on Elexicon Energy's CIR evidence. The goal is to assist the OEB in selecting an appropriate CIR plan for the Company, not to change the general approach to CIR in Ontario.

This report presents our analysis of the proposed CIR framework. Following a brief summary of our findings, Section 2 discusses the evolution of the OEB's ARM design policies and implications for Elexicon Energy's next plan. Section 3 outlines Elexicon's new CIR proposal. In Section 4 we briefly consider Elexicon's case for a new approach to IR. Section 5 critiques the CRCI, while Section 6 discusses

the heavy reliance on cost forecasting for capital revenue escalation and considers alternative approaches. A brief discussion of PEG's credentials is provided in the Appendix. A companion Empirical Report details our productivity trend and benchmarking research prepared for OEB Staff in this proceeding. The views expressed in these reports are those of the author.

Summary

The OEB's Evolving IR Policies

CIR in Ontario has typically involved complex hybrid ARM designs that entail indexing of the OM&A revenue requirement and heavy reliance on multi-year cost forecasts to escalate capital revenue. Many CIR plans have also featured a clawback of capital cost underspends. OEB panels have on several occasions taken exception to extensive reliance on capital cost forecasts and asked distributors proposing such ARMs to go in a different direction in their next CIR application.

A policy consultation to consider reforms to the Renewed Regulatory Framework ("RRF") is on the horizon. However, the OEB has been open to the evolution of the ARMs used in CIR without a generic proceeding and these innovations can inform deliberations in generic proceedings. The approved innovations have included revenue caps (rather than price caps) and supplemental capital revenue stretch factors. Some innovations have been proposed by distributors and others by OEB Staff and intervenors. If Elexicon can propose innovative ARM designs in this proceeding, other parties should be able to do so as well.

Elexicon's CIR Proposal

The CIR proposal of Elexicon Energy features a mix of conventional features and "targeted evolutions" to CIR that address unique pressures that the Company faces. The CRCI formula for base revenue escalation is

$$CRCI = I_n - X + G + IPD_{oma} + RGF$$

The I_n and X factor terms are as customarily used in Ontario IR. The G (growth) factor is the growth in an index of growth in the Company's operating scale. IPD_{oma} is an input price differential ("IPD") that helps the index track the trend in the prices of OM&A inputs. A clawback mechanism that would asymmetrically share most capex underspends with customers. An earnings sharing mechanism would asymmetrically share surplus earnings exceeding a 100 basis point deadband with customers. *RGF* is a Revenue Growth Factor that would convert what appears to be index-based revenue escalation into an

ARM in which revenue growth is based primarily on forecasts of OM&A and capital cost growth alike. A 0% productivity growth factor and a 0.15% stretch factor would slow growth in total cost growth.

The proposed *G* (growth) factor) and input price differential for OM&A revenue ("IPD_{OMA}") in the CRCI formula only make sense if the $I_n - X + G + IPD_{oma}$ formula is ultimately used to escalate OM&A revenue.

PEG Critique: CRCI

The proposal to escalate OM&A revenue using a cost forecast rather than an index is ill-advised. It runs contrary to the concerns about forecasting in the decisions of OEB panels in numerous CIR proceedings and also seems unwarranted. The proposed index would yield more revenue escalation than the Company forecasted. This calls into question both the design of the revenue escalation index and the Company's proposal not to use it for OM&A revenue escalation.

The panel is likely to sanction the use of cost forecasting to escalate capital but not OM&A revenue. PEG therefore considers in the report whether an $I_n - X + G + IPD_{oma}$ formula would be reasonable in an application to OM&A revenue. Over the years that the Renewed Regulatory Framework has been in effect, CIR applicants have taken pains to show that I – X formulas yield insufficient escalation for *capital* revenue but have generally neglected the reasonableness of this same formula in an application to *OM&A* revenue.

Section 2.1 of PEG's Empirical Report sheds light on this complicated issue. We show that a comprehensive revenue cap index such as Elexicon Energy proposes can be decomposed into indexes applicable to OM&A and capital revenue. The OM&A index would depend on the industry trend in the partial factor productivity of OM&A inputs while the capital index would depend on the industry trend in the partial factor productivity of capital. This result could be useful in an application to Elexicon Energy. The capital index would be used to determine the supplemental revenue needed but capital revenue could still be based in substantial measure on forecasted capital cost growth.[1]

PEG presents the results of new research on the productivity trends of Ontario electricity distributors in the Empirical Report. The featured sample period is 2014-2024, the 11 (growth rate) years for which data are available under the RRF. Using simple (arithmetic) averaging of the results for

[1] It could also be based on historical own-cost trending as discussed further below.

Ontario distributors, we found that the OM&A productivity of these distributors has averaged 0.25% annual growth whereas capital productivity has averaged 0.04% growth and the total factor productivity of the distributors averaged 0.15% growth. OM&A and total factor productivity trends were more rapid using cost-weighted averages while the capital productivity trends were slower. However, cost-weighted averages are much more sensitive to the productivity trends of a few companies.

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

PEG agrees with Clearspring that the OEB's I factors for power distributors tend to understate OM&A input price inflation. However, Clearspring proposes a 0% productivity factor based on (outdated) total factor productivity research and its proposed G factor is based on total cost research and tends to overstate the effect of forecasted output growth on the OM&A of Elexicon Energy due to improper cost elasticity weights.

Our proposed resolution is to use separate indexes to escalate the OM&A and capital revenue requirements of Elexicon Energy. The productivity factor for the OM&A revenue escalation formula would reflect the 0.25% OM&A productivity trend of Ontario power distributors while the productivity factor for capital revenue escalator would reflect the 0.04% capital productivity trend. The more conservative simple-weighted averages of productivity growth rates are recommended due to the sensitivity of cost-weighted averages to results for a few large companies. Should the panel opt to continue with a single productivity offset, we recommend the 0.15% annual TFP trend for the RRF period. An IPD should be permitted only if paired with an OM&A-specific G factor and based on historical data.

A capital-specific G factor would be used in the capital revenue escalation index. This index would be used only to test the eligibility of the Company for supplemental revenue. Capital revenue would be reduced by an X factor consisting of the Ontario capital productivity trend (if deemed to be positive) and the stretch factor.

PEG also recommends consideration of closing the gap between capital index growth and forecasted capital cost growth by one of the following two means:

- Use the forecast-based RGF approach for capital, but slow capital revenue growth by adding an incremental capital stretch factor to the formula. There is now ample precedent for this approach in Ontario.
- Allow only a share of the difference between the growth of the capital index and forecasted capital cost growth to be recovered in rates.

Alternatives to Cost Forecasting for Capital Revenue

The prominent role which cost forecasting plays in CIR to escalate capital revenue has long been criticized by intervenors and witnesses for OEB Staff. Concerns include weakened capex containment incentives and the high regulatory cost, uncertainty, and risks of information asymmetry when appraising the reasonableness of utility capex forecasts. We show in the Empirical Report that the TFP trend of larger distributors that typically operate under CIR has been slower than that of the industry as a whole, and declining capital productivity is the biggest problem.

The forecasting approach to ARM design has been used by MRP practitioners that include Great Britain, New York, and Minnesota. However, other MRP practitioners have balked at relying heavily on cost forecasts. In addition to indexing the OM&A revenue requirement, some of these regulators have relied on historical own-cost trending of capital cost. This approach, which is used in Alberta, California, and Massachusetts, can entail basing budgets for many kinds of plant additions in the out years of a rate plan on the utility's recent average historical plant additions, with possible escalation for construction cost inflation and growth in operating scale. In Alberta and Massachusetts, this approach has been labeled the "K-bar" approach.

We developed a straw man alternative ratemaking treatment of capital wherein we separate Elexicon Energy's proposed capital projects into those that would be addressed by forecasts and/or deferral and variance accounts and others that would be addressed by historical own-cost trending. We generally avoided own-cost trending for asset categories where capex growth was either forecasted to accelerate markedly or to be highly uncertain due to the energy transition or other reasons. For asset categories that we recommend addressing with trending, we calculated the average historical capital expenditure, net of customer contributions, over the five-year 2020-2024 period as adjusted to 2024 dollar and output levels. For each of the "out" years of the proposed CIR term (2028-2031), we escalated the capex averages from 2024 levels to the applicable years based on the growth in input

prices and operating scale. Escalation for operating scale relied on growth in a scale index with weights that are based on PEG's econometric capital cost research which is discussed in the Empirical Report. The inflation-adjusted historical average capex deemed prudent that we nominate for this treatment is less than the Company's proposed capex in these years by approximately 21%.

Our straw man approach does not entail calculation of a specific K-bar term and can dovetail with the general CRCI approach that Elexicon has proposed. Capital revenue growth would still be slowed by the stretch factor and capital productivity factor (if positive).

2. Incentive Regulation in Ontario

In this section we present a high-level review of OEB incentive ratemaking policies that have a notable bearing on Elexicon Energy's CIR proposal. The focus is on the design of the ARM that escalates rates between rebasings. Statements of particular relevance to the Elexicon Energy proposal are boldfaced in this review.

The Early Years

Rates of Ontario power distributors were for many years regulated by Ontario Hydro. The OEB approved its first-generation generic incentive ratemaking mechanism ("1st GIRM") for provincial power distributors for an initial 2000-2002 term. This mechanism was an MRP featuring a price cap index with an I-X formula and an earnings sharing mechanism ("ESM"). The OEB subsequently delayed implementation of the 1st GIRM to 2001 and removed the ESM. The 1st GIRM was later extended to March 2005 to afford distributors more time to "explore the incentives for improvements and savings provided by the current PBR regime." However, Bill 210, enacted in December 2002 froze existing distributor rates until May 2006 unless approval was otherwise granted by the Minister of Energy. Rate rebasing applications were filed in 2005 and decided in early 2006.

Between 1999 and 2006, it follows that Ontario power distributors operated without a rebasing or ESM. During these years, distributors had strong incentives to contain costs and some may have responded by deferring some capital expenditures. This encouraged some deferring distributors to seek extra funding for capex in later years.

The 2nd GIRM used 2006 rates as a starting point. The OEB introduced staggered plan terms allowing approximately 1/3 of distributors to rebase rates each year between 2008 and 2010.[2] Utilities had up to 3 years on a new price cap index.

The 3rd GIRM also featured a price cap index and its term was initially fixed at four years.[3] In a subsequent letter, the OEB discussed its expectations that distributors would not rebase rates prior to the end of the plan term.

[2] Due to the staggered nature of rate reviews, a handful of utilities were on 2nd GIRM as late as 2011.

[3] Some companies operated under 3rd GIRM as early as 2009, depending upon when their rate rebasing occurred.

> The Board's rate-setting policies are such that distributors are expected to be able to adequately manage their resources and financial needs during the term of their IRM plan. The Board's multi-year rate setting approach does contemplate that some distributors may legitimately need to have their rates rebased earlier than originally scheduled, by making provision for an "off-ramp."[4]

Toronto Hydro ("THESL") nonetheless obtained rebasings of its rates for 2008, 2010, and 2011.[5] In its 2008 rebasing proceeding, that company initially requested approval of an MRP based entirely on cost forecasts. This was rejected by the OEB on several grounds.

> In the Board's opinion, the Applicant's proposal does not meet a number of the key elements of its multi-year rate setting plan. First, multi-year regulation seeks to balance ratepayer and shareholder interests through the imposition of **explicit productivity goals**. This means that the multi-year plan should encourage productivity improvements within the Utility, and should ultimately share those gains with the ratepayers. In the Board's plan, this is accomplished through the use of an **offsetting productivity factor (the X-factor)**, which **provides a sharing of the benefit of efficiency gains to ratepayers immediately**. The Board simply could not see any discernable productivity driver within the Applicant's proposal. That is not to say that the Applicant is not concerned about productivity, but simply that there is no transparent reflection in its multi-year rate plan that addresses the issue. The Applicant's plan contains steady increases in spending in each of the three years, but there is **no explicit or measurable incentive to productivity**, nor any mechanism which would capture such gains in any year over the period.
>
> Second, multi-year regulation should provide for a timely review of the extent to which the company is performing to its forecasts. Under the Applicant's proposal **there appears to be no check as to the accuracy of its forecasts** until the year following the last year of its program; namely, 2011. While this is not problematic under the Board's plan where rates based on one year's forecast are subject to a formulaic adjustment which includes the productivity incentive, here the Applicant has based its proposal on forecasts, each dependent in some measure on the previous year's forecast, with the result that **each additional year's forecast is subject to increasing uncertainty**.[6]

In this proceeding, the OEB ultimately approved rates for two forward test years (2008 and 2009) on the basis of cost forecasts. The issue of whether THESL should be required to operate under 3rd GIRM was discussed in subsequent applications. In a 2011 rate case decision, the OEB stated that

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[4] Ontario Energy Board, "April 20, 2010 Letter to All Licensed Electricity Distributors Re: Early Rebasing Applications," pp. 1-2.

[5] THESL initially requested three fully forecasted test years for rate years 2008-2010 based on forecasts. The OEB rejected this proposal, instead approving 2008 and 2009 rates based on cost forecasts.

[6] Ontario Energy Board (2008), May 15, 2008 Decision in EB-2007-0680, pp. 4-5.

THESL had made a "choice to approach the Board's ratemaking processes in a manner that is contrary to the Board's rate setting policies."[7] The OEB continued:

> In order to justify its approach, THESL posits that two separate frameworks exist and that it has been operating within one of them, that being a cost of service framework. THESL argues that it would be inappropriate for the Board to now treat it as though it were operating within the other framework, that being an IRM framework. . .
>
> The Board's rate setting policies are not composed of the two separate frameworks that THESL describes. As stated above, the Board has clearly articulated the mechanics of the multi-year rate setting plan and its expectations of distributors. . .
>
> THESL has pointed to situations in which the Board's multi-year rate setting plan has not been strictly adhered to in support of its position that its view of the framework is one that the Board should accept. While the Board accepts that there have been deviations from the Board's stated multi-year rate setting plan, including the acceptance of THESL's non-conforming applications in the past, the Board considers the April 20, 2010 letter to be a clear and explicit statement of the Board's expectations of distributors on a going forward basis...[8]

A THESL application for an MRP with an ARM based on forecasts for the 2012-2014 period was dismissed at the preliminary issue stage.[9] Instead, THESL's rates for those years were set according to the provisions of 3rd GIRM.

No special ratemaking provisions for capital were discussed in the OEB's 1st GIRM decision. In the proceeding to approve 2nd GIRM, a Hydro One witness proposed a Capital Investment ("CI") Factor for supplemental capital revenue that would have functioned much like the C-factors approved in later years. This proposal was rejected due to a lack of perceived need but distributors were permitted to file a rate case early. The OEB expressed concerns about special ratemaking provisions for capital in its decision.

> In a capital-intensive business such as electricity distribution, containing capital expenditures is a key to good cost management. **The addition of a capital investment factor would mean that incentive under the price cap mechanism would be significantly reduced because the factor would address incremental capital spending separately and outside of the price cap. Further, it would unduly complicate the application, reporting, and monitoring requirements for 2nd**

[7] Ontario Energy Board (2011), *Partial Decision and Order* in EB-2010-0142, July 7, p. 8.

[8] *Ibid,* pp. 9-10.

[9] Ontario Energy Board (2012), Decision With Reasons and Order on the Preliminary Issue, January 5, p. 18.

Generation IRM because it would require special consideration to be implemented effectively.[10]

Supplemental capital funding in the 2nd GIRM was limited to a funding adder related to smart meters.[11] A true up between revenues received through this adder and actual revenue requirements resulting from smart meter implementation would occur at a later time. Recovery of a distributor's actual smart metering costs was not permitted until the costs had been reviewed for prudence.

The 3rd GIRM contained a supplemental revenue mechanism for capital called the Incremental Capital Module ("ICM"). The OEB described the ICM in its decision as "reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[12] The OEB set a high bar for ICM approval as amounts were required to exceed a materiality threshold, meet three need criteria, and be prudent. The materiality threshold was determined formulaically and was intended to be a level of total plant additions materially higher than that funded by the price cap index, depreciation, and growth in billing determinants. The "dead zone" in which extra capital cost was ineligible for supplemental revenue was initially fairly wide. Smart meter riders also continued during the 3rd GIRM.

Renewed Regulatory Framework

The RRF that is currently used in Ontario ratemaking resulted from initiatives the OEB began in 2010 to review their policies on ratemaking, distribution system planning, and performance measurement. At an early stage of the RRF proceeding, the OEB stated that the goal of the RRF is "to support cost-effective modernization of the network while at the same time controlling rate and/or bill impacts on consumers."[13]

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[10] Ontario Energy Board, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 37. Filed December 20, 2006.

[11] A funding adder was effectively a rate rider that allowed the distributor to recover additional revenues. These revenues would address costs resulting from smart metering activities.

[12] Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 31. Filed September 17, 2008 in EB-2007-0673.

[13] Ontario Energy Board, *Renewed Regulatory Framework for Electricity Frequently Asked Questions*, filed in OEB Case EB-2010-0379, November 8, 2011, p. 1.

In an early presentation to stakeholders, OEB Staff provided an overview of the RRF proceedings, its objectives, and guiding concepts. While regulatory cost was not treated as an objective of the RRF, it was discussed as one of its guiding concepts.

> Regulatory frameworks should be sustainable. And, in practice, a framework should be predictable and understood by stakeholders, and **capable of being implemented through efficient & effective regulatory processes**.[14]

Three kinds of MRPs are available to distributors under the RRF: a fourth-generation of generic IR (now called "Price Cap IR" or 4th GIRM), the Annual IR index, and Custom IR. Each distributor can request its preferred ratemaking approach.[15] Distributors are also required to periodically file distribution system plans ("DSPs") and most do so with their rebasing.

Price Cap IR

Under price cap IR, rates in the later years of a plan are escalated by an I – X formula where I is an inflation factor that is calculated as a weighted average of the growth rates of the average weekly earnings of all employees in Ontario and Canada's gross domestic product implicit price index for final domestic demand. The weights for these two indexes were the typical shares of direct labor OM&A expenses and other costs in the total cost of the base rate inputs of medium and large distributors. These shares are 30% for labor and 70% for other costs.

An Advanced Capital Module ("ACM") was developed subsequent to the development of the RRF to address concerns that distributors were strategically bunching capex around the year of the rebasing and not in accordance with a prudent asset management program. ACMs are generally very similar to ICMs, the key difference being that ACMs can only be requested at rebasing, while ICMs are now only available for capex that was unforeseen at rebasing or for distribution system plan capex that was significantly higher than forecasted. The OEB in its decision discussed the advantages of the ACM.

> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to

[14] Ontario Energy Board Staff, "Stakeholder Conference on Development of a Renewed Regulatory Framework: Board Staff Presentation on Staff's Approach to the Consultation and the Issues," February 2, 2011, filed in OEB Case 2010-0377, slide 9.

[15] Ontario Energy Board, Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012.

> facilitate **enhanced pacing and smoothing of rate impacts**, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.
>
> The ACM approach should also **facilitate regulatory efficiency** by placing the requirement to establish the need and prudence for any additional incremental capital spending within a cost of service proceeding. This is well suited to such forms of review and when the five-year DSP is tested. Consequently, largely mathematical calculations of ACM/ICM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years.
>
> When coupled with the requirement for five-year DSPs and other policies that impose discipline upon distributors in their planning, the ACM should **reduce incentives for clustering capital projects around the rebasing year.** Further, this also provides options for distributors to recover costs for discrete capital projects when they are needed throughout the Price Cap IR cycle….
>
> The ACM approach will also assist in large part to preserve the **regulatory efficiency** of IR applications, as many qualifying capital projects should be identifiable through the DSP. More importantly, it provides greater assurance of recovery for prudent and appropriately prioritized capital projects regardless of when the investments might be made. The Board would also expect **improved performance with respect to capital forecasting** both in terms of timing of and the level of projects, taking into account bill impacts on customers as well on the financial, human and other resources of the utility to carry out its capital projects as planned.[16] [Emphasis added]

In its decision to implement an ACM option, the OEB reduced the dead zone for ACMs and ICMs alike, limited the scope of ICMs, and added a means test to prevent capital module requests from distributors that are overearning by more than 300 basis points.

Custom IR

In the OEB's RRF Report of the Board, Custom IR was described as an approach to ratemaking in which a "distributor-specific rate trend is determined by the Board that is informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts."[17] The OEB acknowledged that "The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant."[18]

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[16] Ontario Energy Board, Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, EB-2014-0219, September 18, 2014, pp. 11-12.

[17] OEB, Renewed Regulatory Framework, op. cit., p. 13.

[18] *Ibid*., p. 19.

The OEB's Rate Handbook provides the following additional guidance for utilities requesting CIR.[19]

> **The annual rate adjustment must be based on a *custom index* supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; *explicit financial incentives* for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, *must be incorporated through a custom index or an explicit revenue reduction over the term of the plan* (not built into the cost forecast).**
>
> **The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. *If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service*.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be *higher*, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.[20]** [Emphasis added]

Subsequent CIR Decisions

Horizon Utilities (2014)

Horizon Utilities was the first power distributor to receive approval of a CIR plan. This plan was outlined in a settlement. The budget for OM&A was informed by parties' estimates of inflation, growth, productivity, and a stretch factor. Capital costs were also forecast, and a variance account was established to return capital revenue requirement underspends due to underspending on plant additions to customers. An asymmetric ESM provided customers with a 50% share of all overearnings, while a targeted performance incentive mechanism ("PIM") was established to penalize the company if its cost performance deteriorated sufficiently to move them out of their current stretch factor cohort in the OEB's annual benchmarking studies.[21] During the course of this plan, Horizon merged with Enersource Hydro Mississauga and PowerStream, creating Alectra Utilities.

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[19] OEB, *Handbook for Utility Rate Applications*, October 2016, pp. 18-19 and 24-28.

[20] *Ibid*., pp. 25-26.

[21] CIR plans have fixed the productivity and stretch factor values during the term of the plan.

Hydro One Distribution (2015)

In 2013 Hydro One requested a 5-year CIR plan with an ARM that Hydro One described as being based on a "forecast cost of service,"[22] the OEB approved only three years and stated the following.

> **Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation. All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service.**
>
> Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behavior similar to that seen in commercially-oriented, consumer market-driven companies. **Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation….**
>
> **The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are *external to the company***. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.
>
> **The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company**. Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.[23] [emphasis added]
>
> It is notable that the OEB questioned the incentive power of a forecasted ARM.

Toronto Hydro (2015)

In 2015, the OEB approved a CIR plan for Toronto Hydro[24] that included several provisions used in some subsequent plans. The approved plan had a nearly 5-year term and a hybrid ARM design achieved by adding a custom capital ("C") factor to a price cap index formula. The C factor ensured capital revenue growth equal to the approved forecast of capital cost growth less the sum of a 0%

[22] EB-2013-0416, Exhibit C1, Tab 1, Schedule 1, p. 1.

[23] Ontario Energy Board, *Decision*, EB-2013-0416/EB-2014-0247, March 12, 2015, pp. 13-14.

[24] EB-2014-0116

productivity factor and a stretch factor linked to total cost benchmarking. The mathematical formula for the C factor was reasonable but not intuitive. A symmetrical ESM addressed non-capital related earnings variances outside of a 100-basis point dead band. A variance account refunded the entirety of any capital cost underspends to customers. The OEB cut Toronto Hydro's proposed capex budget by 10% annually for the plan IR term without specifying which proposed components were disallowed.

The first Toronto Hydro CIR decision also provided general commentary on what the OEB expected Custom IR to entail:

> Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. . . **The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests**.[25] [Emphasis added]

Presumably then, the OEB was open to further innovations in CIR intended to better align customer and utility interests. The OEB further stated that:

> Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement. The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.[26]

The OEB also commented on the challenge of processing THESL's application, which included multi-year capital cost forecasts.

> The record in this case is one of the largest that the OEB has ever seen. **It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity . . . which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application**.[27]

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[25] *Ibid*., p. 4.

[26] *Ibid*., p. 5.

[27] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015, p. 2.

In light of these remarks, it seems desirable to consider how to make Custom IR more mechanistic, incentivizing, and fair to customers while still ensuring that it is reasonably compensatory over time for efficient utilities.

Hydro Ottawa (2015)

In 2015 Hydro Ottawa obtained approval of a CIR plan that was outlined in a settlement. The ARM was a revenue cap with a hybrid design. After rebasing, the OM&A revenue requirement was escalated based on a forecast of inflation minus X (combined productivity/stretch factor) plus forecasted growth in operating scale. The OM&A escalator was updated for the last two years of the plan to reflect new inflation data. The capital revenue requirement was based on a forecasted rate base for each year without adjustment for productivity or stretch factors.

Variance accounts were instituted to refund cumulative capital cost underspends to customers due to capital additions that were less than forecast. There were two accounts created to address the costs of the new operating centers and administrative facilities. The first addressed costs up to a cap, which the OEB had determined to be prudent. The second addressed costs above that cap, which would be addressed in the next rate rebasing. A penalty-only PIM was established that would penalize the company if its cost performance deteriorated during the plan term, as measured by annual benchmarking studies undertaken by PEG.

PowerStream (2016)

The OEB rejected a CIR proposal for PowerStream in EB-2015-0003. This proposal featured forecasts of OM&A expenses and capital cost for the entire 5-year plan term. OM&A expenses would only be adjusted for inflation if the OEB's inflation factor was more than 200 basis points higher than the inflation assumption in PowerStream's budget. The OEB provided a lengthy list of its concerns with PowerStream's CIR proposal in its rejection.

> PowerStream's approach to determining its customers' needs and establishing its future revenue requirement is not likely to result in advancing the OEB's policy objectives as set out in the RRF… over the five-year period of the application. PowerStream has not embedded financial incentives for continuous productivity improvement into its revenue requirement calculation or internal benchmarking that tracks year over year continuous productivity improvement. It has also not demonstrated sufficiently that its proposed increased capital investment levels will

> bring value to its customers and has not engaged customers in a way that provides useful input into the development of its business plans.[28]

Hydro One Distribution (2019)

The OEB approved its first CIR plan for Hydro One Distribution in EB-2017-0049. This plan featured a revenue cap index formula with a C factor and a clawback of capital cost underspending. A growth factor was not included in the formula.

This decision also revealed a wariness on the part of the OEB with respect to multi-year capex forecasts and the related C factor. The OEB disallowed $300 million (about 8.4%) of Hydro One Distribution's capex forecast. The OEB also adopted an **incremental capital stretch factor** of 0.15% that applied solely to the C-factor beyond the 0% productivity factor and the 0.45% stretch factor that applied to the entire revenue requirement and was informed by econometric benchmarking research.[29] This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[30] The OEB was also influenced by Hydro One Distribution's prior capital overspending and comments by OEB Staff's expert witness (PEG) that the C-Factor and clawback of capex underspends led to imbalanced incentives to contain capex and OM&A expenses.[31]

In accepting Hydro One's revenue cap approach to ARM design, the OEB stated that

> Under the Custom IR option, it is open to a utility to propose options as long as all requirements of the Custom IR framework have been met. It is, by its own definition, a custom approach to rate-setting.[32]

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[28] Ontario Energy Board (2016), "Decision and Order EB-2015-0003 PowerStream Inc. Application for electricity distribution rates for the period from January 1, 2016 to December 31, 2020," p. 3.

[29] These incremental capital stretch factors have gone by different names for each distributor that has had them approved. For simplicity, we will use the term incremental capital stretch factor.

[30] OEB, Decision and Order, EB-2017-0049, March 7, 2019, p. 32.

[31] *Ibid*., p. 32-33

[32] *Ibid.* p. 24.

Toronto Hydro (2019)

In 2019 the OEB approved another CIR plan for THESL that applied to the 2020-2024 period. This plan was broadly similar to that company's prior plan. The ARM took the form of a custom price cap index with an $I - X + C - G$ formula, where I was the OEB-approved inflation factor for power distributors; X was the sum of a 0% productivity trend and a 0.60% stretch factor based on benchmarking evidence; and C caused capital revenue to reflect the growth in the forecasted capital-related revenue requirement index reduced by both the X factor and an **incremental capital stretch factor** of 0.3%.[33] Other features of the plan included an asymmetrical ESM for overearnings, a refund of capital underspends, and a symmetrical variance account for externally-driven capital.

During the proceeding, parties questioned the need for Toronto Hydro to continue using Custom IR to determine rates and the incentive properties of Toronto Hydro's Custom IR plan framework. For example, in OEB Staff's view, Toronto Hydro's custom price cap index was nearly a multi-year cost of service and that it lacked a sufficient productivity incentive.

> In its decision, the OEB expressed concerns about Toronto Hydro's approach to Custom IR.
>
> The RRF objectives of customer-focused outcomes and continuous improvement were not particularly well serviced under Toronto Hydro's 2015-2019 Custom IR framework. Toronto Hydro made significant investments in its system resulting in increases to rates and declining cost performance. **The OEB will be making several changes to Toronto Hydro's Custom IR proposal to increase compliance with the objectives set out in the Renewed Regulatory Framework….**
>
> The OEB does not agree that the proposed Custom IR framework provides the benefits to ratepayers suggested by Toronto Hydro compared to a standard IRM application….
>
> The OEB notes that **the Custom IR approach taken has required extensive evidence and time to consider the details provided. Toronto Hydro is encouraged to consider an alternative approach in the future that might be more efficient in establishing the revenue requirement for the base year and following years as well as meeting OEB RRF objectives, and improving the balance of risk between customers and the utility. Toronto Hydro should not assume that future panels will continue to accept Toronto Hydro's current proposed Custom IR framework**.[34] (emphasis added)

[33] To make this a proper price cap index, growth was subtracted from this formula.

[34] Ontario Energy Board, Decision and Order EB-2018-0165 Toronto Hydro-Electric System Limited, December 19, 2019, pp. 23-24.

The OEB also discussed the need to add an incremental capital stretch factor.

> The OEB accepts a C-factor but requires an incremental stretch factor on capital of 0.3% be applied. It is a fundamental component of the OEB's RRF that utilities must demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on system reliability and quality objectives. In addition, the OEB notes that pacing and prioritization is an important aspect of an efficient capital plan.[35]

Hydro Ottawa (2020)

A second-generation CIR plan was approved for Hydro Ottawa in 2020. The terms of this plan were outlined in an OEB-approved settlement. The ARM has once again been a hybrid revenue cap. OM&A escalation has been based on a revenue cap index with an $I - X + G$ formula. Here I was the standard OEB inflation factor, updated annually. X was the sum of a 0% productivity factor and a 0.45% stretch factor. The growth factor G was fixed at 0.34%. The I factor has been updated each year while the X and G factors have been fixed for the plan term. The capital revenue requirement has once again been based on a cost forecast, but capital revenue requirement growth has been reduced by the X factor and an incremental capital stretch factor of 0.15%.

Variance accounts would refund to customers the capital revenue requirement from any capital addition underspends for most kinds of capex, while capital additions associated with third party requested relocations or residential service expansions have been subject to a symmetrical reconciliation. The variance account for contributions made to Hydro One for transmission investments was retained. A variance account to address certain cloud computing costs was adopted. The ESM asymmetrically shares only surplus earnings. Penalty-only PIMs were established for system reliability and the unit cost performance for wood pole and underground cable replacement investments (e.g., if the cost per wood pole replaced exceeds a target, Hydro Ottawa must pay a penalty).

In its decision approving the plan, the OEB expressed a concern about Hydro Ottawa coming in repeatedly with requests for CIR plans. The OEB stated that "any future Custom IR application needs to be justified and **the OEB needs to be satisfied that other rate-setting options have been considered**."[36]

[35] *Ibid.* pp. 40-41.

[36] OEB, Decision and Order in EB-2019-0261, November 19, 2020, p. 12.

Hydro One Networks (2022)

In 2022 the OEB approved a second-generation CIR plan for Hydro One Networks.[37] The plan was outlined in a settlement amongst parties that provided base rate escalation using the growth in a revenue cap index with an *I – X + C* formula.[38] The C factor continues to be informed by a forecast of capital cost growth that is adjusted for agreed to reductions (12.2% reduction of capex from Hydro One's original proposal) and an **incremental capital stretch factor** of 0.2%.

There were several noteworthy differences in this plan. For example, the C-factor is updated annually to reflect the latest actual inflation (e.g., the company included a placeholder of inflation that is subsequently updated in annual filings). The clawback of capital cost underspends was not retained. Variance accounts address the costs of second-generation AMI deployment, facility relocations, and some customer-requested distributed energy resource ("DER") upgrades and connections.

Notably, the settlement included a requirement for Hydro One as part of its next rebasing proceeding to "**consider potential alternative approach(es) for establishing the revenue requirement and/or rates for the years following the base year**, while meeting OEB Renewed Regulatory Framework … objectives and striking an **appropriate balance of risk between customers and the utility**. **If Hydro One applies for another Custom IR in its next cost-based rate application, it will provide evidence regarding potential alternative approach(es) that were considered and why they were rejected**."[39]

Toronto Hydro (2024)

The OEB approved a third-generation CIR plan for Toronto Hydro in 2024. This plan features a Custom Revenue Cap Index with an *Inflation – X + Revenue Growth Factor* ("RGF") formula. The RGF effectively results in a hybrid revenue cap design. In years after the rebasing the OM&A revenue requirement is escalated by the standard OEB inflation factor for power distributors less *X* plus a 0.41% growth factor (*G*). Growth of the capital revenue requirement is based on a forecast of *real* capital cost growth that is escalated for inflation and reduced by the X factor. The new plan features a revenue

[37] A second-generation CIR plan was also approved for Hydro One Networks' transmission in 2022. This discussion focuses solely on the distribution plan that resulted.

[38] Decisions where the OEB approved a settlement have featured relatively few discussions about whether a CIR framework is appropriate.

[39] OEB, Settlement Proposal in EB-2021-0110, October 24, 2022, pp. 26-27.

decoupling mechanism where forecasted load growth is trued up to actuals, but only when this favours customers. The variance account that refunded capital underspends to customers in the prior plan has been discontinued. New variance accounts address capital costs of certain DER, load growth, and externally-initiated plant relocation and expansion projects. There is a symmetrical variance account for costs of non-wires solutions.

Hydro Ottawa (2026)

Hydro Ottawa has requested a 3rd generation CIR plan for the 2026-2030 period. The panel has approved a partial settlement that outlines important plan provisions.[40] A rebasing will set rates for the first year of the plan. The ARM will once again take the form of a hybrid revenue cap, with the OM&A revenue requirement updated annually by an index with an $I - X + G$ formula. The capital revenue requirement will be based on a forecast, reduced from the company's proposal and adjusted to reflect a stretch factor and an incremental capital stretch factor.[41] The X and G terms of the OM&A revenue cap will be fixed for the term of the plan, while the inflation factor would be updated annually.

Symmetrical variance accounts will be established for costs of non-wires solutions projects net of any external funding, transmission contributions to Hydro One Networks, and capex for plant relocations, residential subdivisions, and new commercial developments. The previously effective variance account to refund the revenue requirement impact of capital underspends for most kinds of capital projects will be discontinued.

The parameters of the ESM will be dependent on the company's performance in annual benchmarking studies. If Hydro Ottawa is in cohort 5 (e.g., one of the worst performers in Ontario), the ESM will share all overearnings equally with customers. If Hydro Ottawa is in any other cohort, earnings sharing will begin once earnings exceeded 150 basis points above the allowed ROE.

[40] Some issues left for hearing include the appropriate level of OM&A expense for the test year and the proposed shared services cost allocation.

[41] In theory, the stretch factors for OM&A and capital revenues could differ. However, this was not the case in this proceeding.

Recent OEB IR Pronouncements

New Incentive Framework

The OEB issued a Strategic Blueprint in 2017 outlining their expectations on the need for regulation to evolve to meet a changing energy industry. Industry changes envisioned in the Strategic Blueprint included innovation enabled by smart grid and challenges due to climate change policy.

In its Strategic Blueprint decision, the OEB discussed its expected outcomes from the Renewed Regulatory Framework stating the following:

> Our expectation has been that the [Renewed Regulatory Framework] would drive:
> - Stronger customer engagement by utilities
> - More robust system planning and regional planning
> - A stronger focus by utilities on long-term value for consumers.[42]

The OEB acknowledged that it should assess whether further changes to ratemaking are needed. The OEB expressly ruled out adopting a new business model for utilities at this time but also ruled out adopting a "wait and see" approach.

As a result of the Strategic Blueprint, the OEB convened consultations in 2019. These considered utility remuneration and development of a regulatory framework to facilitate the investment and operation of DERs. These proceedings were subsequently merged into the Framework for Energy Innovation, which focused on DER-related issues.

The OEB's decision in this consultation included the following findings.

1. The OEB will allow distributors operating under Custom IR to request supplemental funding during the course of the Custom IR plan term for capital investments that would enable DER adoption by consumers for their own purposes.
2. The OEB has outlined options for utilities to propose incentives for deploying 3rd party DERs as non-wires alternatives. Distributors will be allowed to apply for deferral accounts for qualifying projects that occur between rebasings (qualifying projects proposed at rebasings will need to be incorporated into expected spending). For projects where an incentive is requested, it may take one of three forms: a shared savings mechanism, a traditional PIM

[42] Ontario Energy Board, *Strategic Blueprint: Keeping Pace With an Evolving Energy Sector*, 2017, p. 6.

(e.g., fixed incentive payment for exceeding a target) or a management fee. The OEB has issued a report on filing requirements for potential DER incentives.

The OEB subsequently amended the distribution system code to allow distributors to request management fees for deploying 3rd party DERs to meet distribution system needs. The management fee is set by default as 25% of the payment value for the 3rd party DER, with management fees capped at 50% of the forecasted net benefits from the DER deployment.

Innovation Sandbox

In 2019 an "Innovation Sandbox" grew out of a report to the OEB chair from the Advisory Committee on Innovation. One of the recommendations from this report was to "provide a means by which both utilities and unregulated entities are encouraged to discuss specific regulatory obstacles with the OEB, in order to allow near-term deployment of innovations while longer term regulatory reforms are implemented."[43] The regulatory sandbox is an opportunity outside of rebasings for "innovators" (not necessarily just distributors) to propose pilot projects. Supplemental funding is not always provided.

PIMs

In a 2023 report to the Minister of Energy, the OEB indicated that it intends to

> Review the elements used in its incentive rate-setting mechanisms and examine distributor spending patterns to identify where changes or incremental incentives are warranted….
>
> This work will become part of a broader planned initiative to review the elements that together comprise the incentive rate-setting mechanisms under the Renewed Regulatory Framework for Electricity. This includes, but is not limited to, the review of productivity and stretch factors employed in adjusting rates in years two through five of a utility's rate plan.[44]

The OEB also noted its interest in developing a performance incentives regime for power distributors, stating:

> In our current framework, a relatively small percentage of distributors' revenues is determined as a function of their measured performance (within a range of 0.6 per cent of expected annual revenues, implemented through the stretch factor adjustment to a distributor's rates under incentive rate-setting options such as the Price Cap).

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[43] Advisory Committee on Innovation (2018), "Report to the Chair of the Ontario Energy Board," November, p. 19.

[44] OEB, *Improving Distribution Sector Resilience, Responsiveness and Cost Efficiency*, 2023, p. 38.

> We believe there is an opportunity to go further, with a durable framework for performance incentives that comprises a larger share of revenue for distributors. Through the design of complementary incentive mechanisms, the OEB can enable a transition from reputational incentives (i.e., the distributor scorecard) toward the greater use of financial incentives that result in increments (or decrements) to a distributor's revenues based on results.[45]

The Minister of Energy, in his letter of direction to the OEB, endorsed these proposals.[46]

The OEB opened a consultation on remuneration and PIMs in late 2024. In May 2025 the OEB Staff released a discussion paper outlining four potential PIMs. These PIMs would focus on distributor performance on its load factor, system reliability, and timeframes for DER interconnections.

Next Generation Rate Framework

In January 2026 the OEB opened a policy consultation to update the rate-setting framework for electricity distributors. The OEB's proposed scope for this consultation includes updates to the total cost benchmarking and total factor productivity studies; incorporating PIMs into the rate-setting framework; consideration of refinements to the three available rate-setting methodologies "to strengthen incentives, level the playing field for solutions, share risk, and/or mitigate risk due to uncertainty"[47]; and to consider alternative approaches for setting the revenue requirement. The OEB considers that this will be a refresh of the existing rate framework rather than a radical redesign of it.

Summing Up

This review of the OEB's ARM design policies has several implications for the Elexicon Energy proceeding.

- CIR has typically involved hybrid ARM designs in which the revenue requirements for OM&A and capital have different escalators in the years following the rebasing year. Effectively, the OM&A revenue requirement has been escalated by an index while escalation of the capital revenue requirement has mainly been based on multi-year capital cost forecasts.

[45] *Ibid,* pp. 39-40.

[46] Ontario Energy Minister Todd Smith, "Letter of Direction to the Ontario Energy Board," November 29, 2023, p. 6.

[47] Ontario Energy Board, "January 8, 2026 Letter Re: An Integrated Approach to Utility Remuneration – Next Generation Rate Framework (EB-2026-0002)," Appendix A, p. 4.

- The OEB's recommendations of a "custom index" and external productivity growth offsets in ARM design have encouraged distributors to develop index-like formulas with C factors or revenue growth factors that effectively replace capital revenue escalation based on indexing with escalation that is primarily based on cost forecasts. Capital revenue requirement growth has in most plans been nominally slowed by a productivity factor and stretch factor but the productivity factor has been zero. Custom IR has thus typically entailed "phantom" productivity growth offsets and no role for inflation indexing in limiting capital revenue escalation.
- As multi-year forecasts of capital cost came to play a central role in CIR ARM design, PEG's view is that OEB panels became increasingly disenchanted with this approach and outspoken in their requests for alternative ARM design methods. In addition to noting high regulatory cost, the OEB has on several occasions made statements implying that a forecasted ARM yields weaker performance incentives than an indexed ARM.
- Notwithstanding the OEB's expressed misgivings about forecasting, capex forecasts are still a central feature of utility CIR proposals, and forecasts of OM&A costs are increasingly commonplace in these proposals as well.
- In most of the CIR plans approved to date, an $I - X$ formula that may also include a growth factor has effectively escalated the OM&A revenue requirement. Here I is the OEB's approved inflation factor for power distributors. The reasonableness of this index formula in an application to OM&A specifically has often been assumed rather than demonstrated even though distributors have been quick to question its reasonableness in an application to capital specifically.
- Some distributors have recently questioned whether $I - X + G$ escalation is sufficient for OM&A revenue. Some of these distributors have requested a cost-forecast basis for OM&A revenue growth while others have proposed tinkering with the index formula to make it more OM&A specific.

- A logical next step in the design of ARMs for CIR is to consider what rate and revenue cap indexes are appropriate for OM&A and capital revenue specifically. PEG has discussed this option in prior testimony on behalf of OEB Staff.[48]
- The OEB has only provided general guidelines for CIR and has been open to diverse and evolving plan designs in utility-specific rate-setting proceedings. The approved innovations have included revenue caps, the addition of growth terms to revenue cap indexes, and incremental capital stretch factors. Some plans have included clawbacks of capital cost underspends while others have not. Elexicon Energy proposes ARM design innovations in this proceeding.
- Some innovations have been proposed by distributors and others by OEB Staff and intervenors. It would therefore be unreasonable for Elexicon Energy to propose ARM design innovations that benefit the Company while maintaining that any changes proposed by OEB Staff or intervenors can only be considered in a generic proceeding.
- CIR and the Ontario approach to IR generally were developed before some IR mechanisms used today were well-established. These mechanisms include historical own-cost trending approaches to ARM design that we discuss in a later section.

[48] See, for example, Exhibit M in EB-2019-0261 and PEG's Plan Design report in EB-2025-0252.

3. Elexicon Energy's CIR Framework Evidence:

Background

Elexicon Energy is the fourth largest municipally-owned distributor in Ontario, serving about 180,000 customers in a non-contiguous service area east of Toronto. The Company resulted from an amalgamation of Whitby Hydro and Veridian Connections. The currently effective rate plan was determined in the 2018 OEB decision approving the amalgamation. This plan took the form of Price Cap IR and featured a 10-year term. Rates were not rebased to Elexicon Energy's cost in the proceeding that approved this plan. Harmonization of rates between the predecessor companies also did not occur, resulting in Elexicon Energy operating with multiple (or several) rate zones. PEG understands that the Company thrice requested and received approval of supplemental capital revenue through an incremental capital module during the plan and once through a Z factor application. Elexicon Energy reports in the instant application that it underearned in every year of the 2020-2024 period, with underearnings exceeding 400 basis points for the 2022-2024 period. The underearning was sufficient enough for the Company to file a rebasing application two years early.

Like many Ontario distributors, Elexicon Energy is grappling with challenges of the energy transition. Elexicon also serves some of the fast-growing communities that are important to Ontario's economic growth. The Company expects brisk growth in operating scale during its new plan.

Summary of Elexicon Energy's CIR Evidence

Elexicon Energy is proposing a Custom IR plan that "reflects a continuation of the OEB's performance-based regulatory model", but that has also "been purposely designed to support Elexicon's unique and pressing needs as a utility."[49] Supportive statistical cost research has been provided by Steven Fenrick, a Principal Consultant of Clearspring Energy Advisors, while supportive evidence on inflation expectations was provided by Power Advisory LLC. Here are some key provisions of the Company's proposal.

- The term of the plan would be the five years from 2027 to 2031.

[49] Exhibit 1, Tab 5, Schedule 1, pp. 2-3.

- Base rates for 2027 would result from a cost of service rebasing using a fully-forecasted test year.
- Base rates in the last four years of the plan would be escalated by a Custom Revenue Cap Index with an $I_n - X + G + IPD_{oma} + RGF$ formula. Here is an explanation for the terms in this formula.
  - I_n would be the time-variant and annually updated OEB Inflation Factor for power distributors. This is a cost-weighted average of recent historical inflation in the gross domestic product implicit price index for final domestic demand ("GDP-IPI-FDD") for Canada and Ontario average weekly earnings.
  - The X factor would be the sum of a fixed **0.0%** Productivity Factor and a fixed Company-specific Stretch Factor of **0.15%** that would be based on Clearspring cost benchmarking evidence.
  - *G*, the Growth Factor, would be fixed at **2.48%** and is intended to compensate Elexicon Energy for the cost impact of growth in its operating scale. This proposal is based on econometric cost research by Clearspring.
  - *IPD* is an Input Price Differential that would compensate Elexicon Energy for the tendency of I_n to understate the Company's OM&A input price inflation. The proposal to fix the IPD at **0.25%** during the plan is based on inflation research by Clearspring.
  - A Revenue Growth Factor would *effectively* swap out growth in the revenue cap index with growth in the Company's Service Revenue Requirement ("SRR") which would encompass its OM&A expenses as well as its capital cost (net of other operating revenue) less the X factor. The Capital-Related Revenue Requirement ("CRRR") would be based on traditional capital cost accounting.
- An Earnings Sharing Mechanism would asymmetrically share earnings exceeding the target rate of return on equity by 100 basis points 50/50 between the Company and its customers.
- A Capital In-Service Addition Variance Account ("CISAVA") would asymmetrically return to customers any cumulative positive difference between the proposed capital revenue requirement and actual capital cost due to variances between forecasted and actual additions

during the plan term outside of a 2% deadband. This account excludes capital that is tracked in other proposed accounts.[50]

- A Demand-Related Work Variance Account would symmetrically share variances in the capital-related revenue requirement associated with the Customer and Generation Connections, externally initiated plant relocations, and system expansions capital programs. If this variance account is not approved, Elexicon has requested variance account treatment for the increase in costs due to changes in Ontario policies promoting housing development that reduce customer contributions for new connections.
- A Non-Wires Solutions Deferral Account would address the costs associated with implementing non-wires solutions during the plan term. Non-wires solutions may include energy efficiency, demand response, distribution system efficiency (e.g., reduced distribution losses), energy storage, generation, or managed charging of electric vehicles.
- Costs eligible for variance account treatment that is separate from the CRCI would include those for variances between amounts included in rates and actual cash payments made for pension and other post-employment benefit costs; variances between forecasted and actual capital contributions to Hydro One; stations projects not included in Elexicon's Substation Growth program, OEB cost assessments; low-income energy assistance program emergency financial assistance grants; support for designated broadband projects; and changes in taxes and payments in lieu of taxes due to changes in tax rates or tax rules not otherwise incorporated in the rate plan.
- Elexicon has proposed not to use its lost revenue adjustment mechanism during the CIR plan. A new variance account would be established to account for differences in the volume and timing of revenues of new large volume customers from Elexicon's forecast.
- Conventional off-ramp and Z factor provisions are also proposed.

[50] 1-Staff-24, part a.

4. Elexicon Energy's Rationale for CIR

Elexicon discusses many drivers underlying the need for CIR in its filing. The Company is unusual in that it is an amalgamated entity that has requested rebasing early due to chronic underearning. Elexicon has underearned in every year since its formation in 2019 and its underearnings in the 2022-2024 period have been large enough to trigger the OEB's off-ramp provision. Nevertheless, Elexicon claims that it has achieved efficiencies during its current MRP through reductions in staff and consolidation of systems.

One major theme in its discussions of need is to "address the declining reliability of its distribution system."[51] Elexicon's SAIDI and SAIFI performance reportedly deteriorated between 2020 and 2024. One of the drivers of the SAIDI performance was an increase in outages due to defective equipment. Elexicon states that 36% of its assets "are in fair, poor or very poor condition."[52] A sizable percentage of Elexicon's assets have exceeded their useful lives or will do so in the next five years. The condition of the Company's assets may be due in part to an Elexicon policy that "limited funding for the planned replacement of aging and deteriorating distribution and station equipment" during its current MRP.[53] Elexicon further claims that the proposed uptick in replacement investments "will direct spending to those assets which are most likely to fail and result in outages for customers" but that its spending will not be sufficient to "reduce the proportion of assets in poor and very poor condition" due to concerns about affordability.[54]

Another claimed driver is the forecasted growth in the population of Elexicon's service territory. Several portions of its service territory, containing most of Elexicon's customer base, are expected to have brisk population growth. Elexicon is expecting its total customer growth to accelerate from 1.4% per year during the 2020-2024 period to about 1.9% during the proposed CIR term.[55] This is expected to lead to new customer connections and growth in peak demand during the CIR term.

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[51] Exhibit 1, Tab 4, Schedule 1, p. 16.

[52] Exhibit 1, Tab 4, Schedule 1, p. 18.

[53] Exhibit 1, Tab 4, Schedule 1, p. 18.

[54] Exhibit 1, Tab 2, Schedule 1, p. 14.

[55] Exhibit 2B, Tab 1, Schedule 1, p. 10.

The Company has also experienced increasing demand for new connections from large volume customers, particularly in the Pickering and Whitby areas. Elexicon reports that the number of large customer connections requests more than doubled in the 2022-2024 period. The company indicates that some of this is due to "new distribution centres and manufacturing facilities attracted by efficient access to the Greater Toronto Area and major highways."[56] Elexicon's peak demand is expected to grow by 3.15% on average over the CIR plan term.[57] In addition, Elexicon is expecting a rapid uptake in electric vehicle adoption, with the number of EVs in its service territory expected to more than double over the CIR term.[58]

The Company claims that it is facing serious capacity restraints that limit its ability to connect new customers. For example, 76% of Elexicon's municipal substations have less than 1,000 kVA of available capacity and 70% of the transformer station feeders supplying municipal substations have less than 1,000 kVA of available capacity.[59] This is driving a need for substation upgrades and new substations. Some of Elexicon's service territory is served at lower voltages which cannot support larger connections.

Elexicon proposes rapid growth in its capital cost during the new plan due to high capital spending. Net plant additions are forecasted to be about 282% higher in nominal terms during the CIR plan than the recent 2020-2024 historical average. [60] System service plant additions, net of CIAC, accounts for about 32% of proposed net plant additions, while approximately 37% of the net plant additions is for system renewal and another 21% is for system access.[61]

Elexicon also discusses the need for increased OM&A spending to account for various factors that include increased staffing and operations to accommodate the company's capital plan and address capacity and load growth; increased vegetation management and asset maintenance; being in a better position to meet customer expectations on communications; and higher IT costs related to cybersecurity

[56] Exhibit 2B, Tab 1, Schedule 1, p. 1.

[57] Exhibit 1, Tab 5, Schedule 1, Appendix A, p. 30.

[58] Exhibit 3, Tab 1, Schedule 1, Appendix A, p. 108.

[59] Exhibit 2B, Tab 1, Schedule 1, pp.15-16.

[60] 2B-SEC-35

[61] 2B-SEC-35

and modernization. Elexicon forecasts its OM&A expenses to average 3.8% annual growth during its proposed plan."[62] However, PEG reviewed the trend in Elexicon's OM&A forecast and found that OM&A expenses rose most rapidly in the test year, with growth decreasing rapidly after the test year.

Energy Transition

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. The transition would also likely entail increased reliance on intermittent renewable sources of power supply such as wind and solar energy. Distributed solar power generation and storage would likely proliferate. Most end users are expected to continue relying exclusively on power delivered by distributors and many "prosumers" would also want system access. The pace of the energy transition is uncertain, relying as it does in a democracy like Canada's on voter as well as customer preferences.

This analysis has a number of implications for power distributor ratemaking:

- Power distributors play a key role in the energy economy and their role will likely increase in the energy transition. They would eventually need to expand capacity substantially while maintaining or improving reliability and accomplishing these goals at reasonable cost. Cost effective accommodation of growing demand and increased reliance on intermittent renewables would likely require investments in smart grid facilities as well as delivery capacity.
- Investments needed to support the energy transition cost effectively are difficult to predict accurately. This increases the operating risk of distributors. MRPs can add to the risk but are nonetheless desirable to the extent that they strengthen utility performance incentives and streamline ratemaking.
- Increasing the role of cost forecasting in ARM design is one possible way to make multi-year rate plans work better during the energy transition. Many jurisdictions in the early stages of the energy transition already used forecasted ARMs and continue to do so. Great Britain is a notable example. In Canada, British Columbia's commission recently paused the

[62] Exhibit 10, Tab 1, Schedule 1, p. 5.

implementation of an indexed ARM for BC Hydro based in part on the perceived challenges of the energy transition, stating the following.

> The Panel acknowledges the increasing cost uncertainty that BC Hydro is facing as a result of the energy transition that was not present to the same extent at the time the PBR Report Decision was issued in December 2021. The Panel is persuaded by the evidence provided by BC Hydro in this proceeding of legislative and mandate changes since December 2021 that increase cost uncertainty and cast doubt on whether PBR would be an effective regulatory regime for BC Hydro at this time. This is because the increased cost uncertainty will likely result in more costs that would need to be forecast outside of the PBR formula, as those costs are driven by external factors that are outside of BC Hydro's control. Therefore, given the increased uncertainty that BC Hydro is facing and changes in circumstances since 2021, the Panel is not convinced that the adoption of what would be a new and untested regulatory regime for BC Hydro is warranted at this time.
>
> The Panel cautions that this determination should not be construed as a commentary on or rejection of PBR as a regulatory incentive mechanism, nor as criticism of the BCUC's PBR Report Decision which was based on facts and circumstances that existed more than two years ago. As parties are aware, PBR has been successfully implemented and endorsed by the FortisBC utilities for decades in British Columbia, to the mutual benefit of both their ratepayers and shareholders. There may well come a time when BC Hydro will want or be driven to embrace a similar incentive regime, whether due to the need for greater cost containment or other reasons.[63]

BC Hydro will continue to file periodic rate cases with multiple forward test years and will file a report about the feasibility of implementing PBR in December 2028.

On the other hand, energy distributors will continue to undertake many activities that are substantially unrelated to the transition. There is merit in streamlining the ratemaking process for these activities and maintaining strong cost containment incentives. Alternatives to forecasting and variance accounts can be useful in efficient regulation during an energy transition.

[63] BCUC (2024), BC Hydro and Power Reconsideration of the Performance Based Regulation Report Order G-388-21, Decision and Order G-73-24, p. 7.

5. PEG Critique: Parameters of the Custom Revenue Cap Index

PEG notes the following concerns about Elexicon Energy's proposed custom revenue cap index.

ARM Design Overview

The proposed ARM of Elexicon Energy is unusually reliant on cost forecasts. The Company proposes to use forecasts to escalate both OM&A and capital revenue whereas most CIR plans only use forecasts to escalate capital revenue. In addition, between the CRCI and RGF, the Company's proposed G and IPD terms are effectively netted to zero, as they are subtracted in the calculation of the RGF, but treated as positive values in the CRCI.[64] Figure 1 compares the base revenue requirements, defined as the service revenue requirement net of other revenues, resulting from application of the proposed CRCI if Elexicon's cost forecasts alone were used. Growth in the CRCI is equal to the growth in the service revenue requirement less Elexicon's proposed X factor, which Elexicon confirmed in response to 1-CCC-6, part c. Assuming that the industry TFP growth trend is 0%, the X factor would only be 0.15%.

Figure 1

Comparison of Elexicon Base Revenue Requirements between CRCI and Forecast Revenue Requirements ($ million)[65]

Year	COS Forecast	CRCI Funding	Difference	Difference (%)
2027	144.8	144.8	0.0	100.0%
2028	156.1	155.8	0.3	99.8%
2029	168.8	168.2	0.6	99.6%
2030	180.6	179.8	0.8	99.6%
2031	198.4	197.1	1.3	99.3%

Elexicon Energy is forecasting 3.8% average annual growth in OM&A expenses over the CIR term.[66] However, this is considerably slower than the 4.3% revenue escalation provided by the Inflation – X + IPD + G in Elexicon's CRCI. Elexicon confirmed that the index will provide more than enough funding for OM&A expenses without an input price differential in its response to 1-Staff-19, part a.

[64] Elexicon conceded this in 1-Staff-16, part a.

[65] The source for the data in this table is 1-CCC-6, part c.

[66] Exhibit 10, Tab 1, Schedule 1, p. 5.

Moreover, the growth of these budgets slows considerably after 2027. This suggests that Elexicon's OM&A expenses could reasonably be addressed by an index rather than by forecasts.

PEG believes that the panel may very well approve the use of cost forecasting to escalate the Company's capital revenue but not its OM&A revenue. The question then arises as to whether the proposed $I_n - X + G + IPD_{oma}$ formula would be reasonable in an application to OM&A revenue. Over the years that the Renewed Regulatory Framework has been in effect, CIR applicants have taken pains to show that I – X formulas yield insufficient escalation for *capital* revenue but have generally neglected the reasonableness of this same formula in an application to *OM&A* revenue.

Section 2.1 of PEG's Empirical Report sheds light on this complicated issue. We show that a comprehensive revenue cap index can be decomposed into indexes applicable to OM&A and capital revenue. The OM&A index would depend on the industry trend in the partial factor productivity of OM&A inputs while the capital index would depend on the industry trend in the partial factor productivity of capital. This result could be useful in an application to Elexicon Energy. The capital index would be used to determine the supplemental revenue needed but capital revenue could still be based in substantial measure on forecasted capital cost growth.[67]

Productivity Factor

Clearspring recommends and Elexicon Energy has proposed a productivity factor of **0.00%** based on TFP research that PEG undertook for OEB Staff more than a decade ago in the 4th GIRM proceeding.[68] Clearspring states on p. 2 of its report that "productivity trends in Ontario are likely negative" and that "there is no evidence establishing that the Ontario industry TFP is above zero."

PEG notes that the sample period for the productivity study in the RRF proceeding was the 10 (growth rate) years from 2003 to 2012. The power distributor business has changed significantly in the fourteen years since 2012. Artificial intelligence innovation is on the horizon. Rate regulation has changed in Ontario with the adoption of the RRF, and the data available for calculating productivity trends have improved. In its decision approving the 0% productivity factor in 2013, the OEB stated that

[67] It could also be based on historical own-cost trending as discussed further below.

[68] Pacific Economics Group, "Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board," November 2013.

"total factor productivity will be updated every five years (e.g. the update after 2014 would be in 2019)."[69] This never occurred.

Evidence from various sources detailed in the Empirical Report suggests that a 0% productivity factor is no longer reasonable for Ontario power distributors. Most relevantly, PEG's new Ontario power distributor productivity research has found that during the RRF years, when Ontario data have been less problematic than in earlier years, a simple (arithmetic) average of the TFP growth of Ontario electricity distributors was **0.15%** per annum while OM&A productivity averaged **0.25%** growth and capital productivity growth averaged a slight **0.04%** growth.

Clearspring's productivity factor proposal is all the more controversial because in its customized escalator for OM&A revenue a 0% productivity factor would apply even though the recent industry OM&A productivity growth trend of Ontario distributors has been materially positive. This is unfair to customers because Elexicon Energy is requesting substantially full compensation for the Company's professed inability to operate under an I-X formula. If high capex is required, this should, if anything, accelerate the Company's OM&A productivity growth. The question then arises as to whether it is reasonable to correct a problem that indexation poses for the Company on the capital side while ignoring possible benefits of indexation on the OM&A side. Clearspring conceded that the Company's forecast of capital cost was likely to result in a negative capital productivity trend.[70] Christensen Associates proposed an OM&A-specific productivity factor for an OM&A revenue cap index in testimony for OEB Staff in the recent Hydro Ottawa CIR proceeding.[71]

Applying an OM&A productivity trend to the formula for OM&A rate escalation raises the question of whether any negative trend in capital productivity would need to be added to the Company's forecasted capital cost growth. The answer is no. When the capital productivity trend is negative, it can be resolved that the utility is entitled to supplemental capital revenue only to the extent that its forecasted capital cost growth exceeds the capital revenue escalation index, which has been

[69] EB-2010-0379 Rate Setting Parameters and Benchmarking Under the Renewed Regulatory Framework for Ontario's Electricity Distributors, November 2013.

[70] 1-Staff-15 b).

[71] Crowley, Nick, Dan McLeod, and Xueting (Sherry) Wang, "Evaluation of Hydro Ottawa's Proposed Custom Incentive Regulation Framework," for the OEB, EB-2024-0115, October 14, 2025

boosted by negative industry capital productivity growth. This approach is modelled in Section 2.1 of the Empirical Report.

Input Price Differential

Clearspring calculates an input price differential based on the formula:

IPD = (*Elexicon Labor % - 30%*) * (*AWE growth rate – GDPIPI growth rate*),

where Elexicon's shares of labor and non-labor OM&A expenses are held constant at 2027 values, and the AWE and GDPIPI are forecasted for the 2028-2031 period.

Major Concerns

The following are our biggest concerns about the IPD proposal:

- Clearspring's complaint about applying the standard OEB inflation factor to OM&A revenue is that the 30% weight on the faster-growing labor price index is smaller than it should be in an application to OM&A cost. While that is true, Clearspring does not propose an OM&A-specific productivity factor or G-factor.
- Clearspring's IPD calculation focusses on the OM&A cost share weights for the two subindexes in the OEB's inflation factor formula (wage rate index and GDP-IPI-FDD). Clearspring's calculation of these weights is incorrect in a way that benefits its client. It calculates the labor share as the ratio of labor expenses to total OM&A expenses *less those for outside service providers*. The GDP-IPI-FDD should be a reasonably good proxy for the combined trend in material and service prices. Services do tend to have labor-intensive technologies but so do many goods and services whose prices are tracked by the GDP-IPI-FDD. Clearspring's calculations "effectively assumes that the outputs service expenses have the same proportion of labour expenses as Elexicon."[72]

  IPD calculations are common in the design of rate and revenue cap indexes for U.S. IR plans but not for Canadian plans. There are two salient reasons for this. The GDPPI that is often used in US IR plans measures the output price trend of the U.S. economy. As such, its trend is in theory the difference between the economy's input price and multifactor productivity growth trends.

[72] 1-Staff-20.

The MFP trend of the U.S. economy has been fairly brisk while the MFP trend of Canada's economy is close to zero. This is documented in Table 1. This matters because brisk MFP growth materially slows growth in the GDPPI, making this index less suitable as a measure of input price inflation.

The second reason that IPD calculations are more common in the U.S. is that IR plans there that have indexed ARMs typically use *only* the GDPPI to measure inflation. Meanwhile, the OEB and other provincial regulators in Canada typically use inflation factors based on multiple price indexes that include a wage rate index. The OEB has actually characterized its approved Inflation measure an input price index.[73]

- In response to 1-SEC-23(g), Clearspring provided calculations for an IPD based on more recent forecasts. If updated forecasts are used as the basis for IPD calculations, the IPD would increase from 0.25% to 0.36%. Nevertheless, Elexicon did not propose to update their IPD proposal to reflect the latest inflation forecasts "at this time".[74]
- Elexicon is already expected to receive sufficient funding for OM&A expenses from its proposed CRCI before an input price differential is considered. Elexicon appears to be using the input price differential to ensure that it is fully compensated for its costs in each and every year of the plan, as it said

> While the 5 year CAGR of Elexicon's OM&A forecast is less than I-X+G, this is not the case for each year; most notably 2028 in which forecast OM&A requirements increase by 8.2%.... While I, G and IPD together reflect the growth in OM&A expenditures which would reasonably be expected over a given period of time, actual conditions may vary from

[73] OEB (2013), "EB-2010-0379 Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors," pp. 6-11.

[74] 1-Staff-18, part c.

Table 1

MFP Trends of the U.S. and Canadian Economies

Year	US	CAD
2001	0.40%	-0.07%
2002	1.97%	1.05%
2003	2.31%	-0.66%
2004	2.38%	-0.27%
2005	1.43%	-0.19%
2006	0.32%	-0.64%
2007	0.27%	-1.12%
2008	-0.98%	-2.46%
2009	0.40%	-3.06%
2010	2.48%	0.99%
2011	-0.40%	1.55%
2012	0.68%	-0.64%
2013	0.58%	0.90%
2014	0.60%	1.83%
2015	0.90%	-0.87%
2016	0.01%	0.11%
2017	0.64%	1.44%
2018	0.71%	0.01%
2019	1.20%	-0.50%
2020	-0.56%	0.98%
2021	3.87%	-0.94%
2022	-1.04%	0.60%
2023	1.64%	-1.75%
2024	1.57%	NA
2025	0.83%	NA

Annual Average Growth Rates

2001-2025	**0.89%**	**NA**
2001-2023	**0.86%**	**-0.16%**
2009-2023	**0.78%**	**0.04%**

Sources:
Bureau of Labor Statistics (Series MPU4900012)
Statistics Canada (Table: 36-10-0208-01)
All growth rates calculated logarithmically.

econometric inputs year to year. Elexicon's expenditure forecast is responsive to this dynamic. The practical implication of including the I, G and IPD escalations supported by economic theory in 2029 through 2031 is that these inclusions reduce the incremental escalations required by the Revenue Growth Factor ("RGF"); effectively offsetting incremental capital funding requirements and giving customers the benefit of the forecasted slow-down in OM&A growth in the latter years of the term as the efficiency benefits and improved throughput from Dx Next are more fully realized.[75]

Other Notable Concerns

- Clearspring based its IPD calculations on Conference Board of Canada inflation *forecasts*.[76] In the United States, IPD calculations have almost always used *historical* (e.g., 15-year average) price index trends in IR proceedings. Clearspring confirmed this in its response to 1-Staff-18, part b. Table 2 provides the results of a U.S.-style historical trend comparison. The cost shares are based on the average share of labor in OM&A expenses for Elexicon for the 2019-2023 period, as provided in Clearspring's working papers.[77] It can be seen that the indicated IPD design using the 15-year trend is **0.17%**.
- Clearspring used a forecast of GDP-IPI and not of the GDP-IPI-*FDD* that is used in the OEB's inflation factor formula. Canada's GDP-IPI growth is quite sensitive to inflation in prices of fossil fuels, metals, and other commodities that Canada exports that have little relevance to power distributor cost. That is why the GDP-IPI-FDD is used to compute Ontario inflation factors.
- Clearspring's input price differential calculations rely on the calculation of labor and non-labor shares in a single year, 2027 due to a lack of information on the amount of outside services in OM&A expenses. The calculated share of labor of 84.9% for 2027 is considerably higher than PEG's calculated labor shares. It is unclear if Clearspring's calculated labor cost share is representative for all years.

[75] 1-Staff-19, part b.

[76] Clearspring Report, pp. 31-32.

[77] PEG's calculation of the share of labor excludes pensions and outside services.

Table 2

Alternative IPD Design

Year	Canada GDP-IPI Final Domestic Demand		Canada GDP-IPI At Market Prices		Ontario Average Weekly Earnings		OEB IPI for Electricity Distributors	Custom OM&A Input Price Index for Elexicon Energy	Input Price Differential
	Level	Growth Rate	Level	Growth Rate	Level	Growth Rate			
		[A]				[B]	[C=.7*A+.3*B]	[D=.34*A+.66*B]	[D-C]
2001	74.8		73.1		695.9				
2002	76.6	2.38%	74.0	1.22%	711.0	2.16%	2.31%	2.23%	-0.08%
2003	77.8	1.55%	76.4	3.19%	728.5	2.43%	1.82%	2.13%	0.32%
2004	79.2	1.78%	78.9	3.22%	748.8	2.75%	2.07%	2.42%	0.35%
2005	80.8	2.00%	81.4	3.12%	776.2	3.59%	2.48%	3.05%	0.57%
2006	82.7	2.32%	83.5	2.55%	788.6	1.59%	2.10%	1.84%	-0.26%
2007	84.7	2.39%	86.2	3.18%	819.0	3.78%	2.81%	3.30%	0.50%
2008	86.8	2.45%	89.7	3.98%	838.0	2.30%	2.40%	2.35%	-0.05%
2009	87.8	1.15%	87.6	-2.37%	848.6	1.26%	1.18%	1.22%	0.04%
2010	88.7	1.02%	90.1	2.81%	881.4	3.78%	1.85%	2.84%	1.00%
2011	90.8	2.34%	93.0	3.17%	893.4	1.35%	2.04%	1.69%	-0.36%
2012	92.3	1.64%	94.1	1.18%	905.9	1.39%	1.56%	1.48%	-0.09%
2013	93.9	1.72%	95.8	1.79%	919.9	1.53%	1.66%	1.59%	-0.07%
2014	96.1	2.32%	97.6	1.86%	938.3	1.99%	2.22%	2.10%	-0.12%
2015	97.6	1.55%	96.8	-0.82%	963.2	2.61%	1.87%	2.25%	0.38%
2016	98.6	1.02%	97.5	0.72%	974.1	1.13%	1.05%	1.09%	0.04%
2017	100.0	1.41%	100.0	2.53%	993.1	1.93%	1.56%	1.75%	0.19%
2018	101.6	1.59%	101.7	1.69%	1021.7	2.84%	1.96%	2.41%	0.45%
2019	103.5	1.85%	103.2	1.46%	1049.5	2.68%	2.10%	2.40%	0.30%
2020	105.4	1.82%	104.3	1.06%	1126.1	7.05%	3.39%	5.27%	1.88%
2021	109.4	3.72%	112.5	7.57%	1165.9	3.47%	3.65%	3.56%	-0.09%
2022	116.4	6.20%	121.3	7.53%	1193.5	2.35%	5.05%	3.66%	-1.39%
2023	120.8	3.71%	123.2	1.55%	1232.3	3.19%	3.56%	3.37%	-0.19%
2024	124.8	3.26%	126.6	2.72%	1293.5	4.85%	3.74%	4.31%	0.57%
Average Annual Growth Rates									
Last 20 years (2005-2024)		**2.27%**		**2.36%**		**2.73%**	**2.41%**	**2.58%**	**0.17%**
Last 15 years (2010-2024)		**2.34%**		**2.46%**		**2.81%**	**2.48%**	**2.65%**	**0.17%**
Last 10 years (2015-2024)		**2.61%**		**2.60%**		**3.21%**	**2.79%**	**3.01%**	**0.21%**
Last 5 years (2020-2024)		**3.74%**		**4.09%**		**4.18%**	**3.87%**	**4.03%**	**0.16%**
Standard Deviations									
Last 20 years (2005-2024)		**0.012**		**0.023**		**0.014**	**0.010**	**0.011**	**0.006**
Last 15 years (2010-2024)		**0.014**		**0.023**		**0.016**	**0.011**	**0.012**	**0.007**

Notes

All growth rates calculated logarithmically.

Average weekly earnings data sourced from Statistics Canada. Table 14-10-0223-01 Employment and average weekly earnings (including overtime) for all employees by province and territory, monthly, seasonally adjusted

Gross Domestic Product Implicit Price Index data sourced from Statistics Canada Table 36-10-0106-01 Gross domestic product price indexes, quarterly

Weights for Elexicon's WOM are based on the average of Elexicon's 2019-2023 cost shares excluding pensions: 66% labor, 34% M&S.

Inclusion of GDP-IPI at Market Prices data was to allow comparisons of the GDP IPI FDD and the alternative price index that Clearspring used in its input price differential calculations.

Pink shading indicates recession years in Canada.

Pacific Economics Group Research, LLC

G Factor

Clearspring's proposed G factor is a weighted average of the forecasted growth in customers and peak demand. The elasticity-share weights for each output come from Clearspring's econometric total cost model. When asked if the use of elasticity weights from a *total cost* model in an application to *OM&A* revenues was appropriate, Clearspring stated that:

> Clearspring is skeptical in regard to using OM&A cost models in setting parameters within a price or revenue cap index. Accounting differences in capitalization policies and substitution decisions between OM&A and capital will distort these disaggregated models. These issues are mitigated when using a total cost model approach.[78]

We acknowledge that accounting differences raise concerns about the accuracy of OM&A cost models if used for *benchmarking* but believe that econometric estimates of OM&A output elasticities are reasonably accurate.

Major Concerns

PEG has long acknowledged the reasonableness of including a growth factor in revenue cap index formulas. We proposed one based on customer growth in the recent THESL CIR proceeding.[79] Furthermore, in a revenue cap index the inclusion of an escalator for growth in operating scale is consistent with cost theory and this theory specifically calls for an elasticity-weighted scale index. Scale escalators have been approved by regulators for use in the revenue cap index formulas of several approved MRPs.[80]

Our chief concern with Clearspring's G factor calculation is that any $I_n + IPD_{OMA} - X + G$ formula is likely to apply only to OM&A revenue because the panel is likely to reject escalating OM&A revenue based on an OM&A cost forecast. In that context we have a concern about basing the G factor on econometric total cost rather than OM&A cost research for two reasons. First, our econometric benchmarking research for this proceeding demonstrates the plausible result that the elasticity of *total* power distributor cost tends to be much higher with respect to peak demand than is the elasticity of

[78] 1-Staff-17, part a.

[79] EB-2023-0195, Exhibit M1, p. 86.

[80] It is also germane to note that revenue per customer decoupling is widely used in the United States to regulate gas and electric utilities even in the absence of an MRP. This provides automatic revenue requirement escalation for growth in the number of customers between rate cases.

OM&A expenses with respect to peak demand. This reflects the need for substations and other capital equipment to handle peak loads. The other reason is that Elexicon Energy forecasts its peak demand to grow considerably more rapidly than the number of customers it serves during the years of its proposed plan.

A more OM&A-specific growth factor can be developed using elasticity estimates from an econometric OM&A cost model. Mr. Fenrick has neglected to provide such a model in his evidence. However, PEG has developed an OM&A-specific growth factor in Table 3 using the OM&A cost output elasticity estimates detailed in the Empirical Report using the same customer and peak load projections used by Clearspring. It can be seen that our alternative methodology would yield a growth factor of **2.16%** instead of the **2.48%** produced by Clearspring's method.

Table 3

Alternative G Factor Design

Year	Customers			Ratcheted Peak Demand			G Factor Annual
	Number	Growth Rate [A]	Weight [B]	MW	Growth Rate [C]	Weight [D]	Growth Rate A*B+C*D
2027	189,833			814			
2028	193,280	1.80%	76%	839	3.02%	24%	2.09%
2029	196,883	1.85%	76%	865	3.08%	24%	2.15%
2030	200,624	1.88%	76%	895	3.42%	24%	2.26%
2031	204,398	1.86%	76%	923	3.07%	24%	2.15%
Average		**1.85%**			**3.15%**		**2.16%**

Notes:

Elasticity weights calculated using PEG's econometric OM&A cost model.
Source for customer data: Table 6c.
Source for ratcheted peak demand: Table 6c.
All growth rates calculated logarithmically.

PEG Recommendation

PEG's recommendation to the Elexicon Energy panel is to require different and consistent index formulas for escalating OM&A and capital revenue in the out years of the plan. The index formula for OM&A revenue should include an OM&A-specific productivity growth target and may also reasonably include an OM&A-specific inflation measure provided that it is paired with an OM&A-specific scale

index. This would make OM&A revenue escalation more consistent with OM&A cost drivers without weakening the Company's cost containment incentives.

Whatever customization is applied to the OM&A revenue requirement escalator should in principle also apply to the index designed for capital revenue escalation. Elexicon Energy would still be entitled to the difference between forecasted capital cost growth (as possibly modified by the OEB) and the capital revenue requirement index. Capital revenue would be reduced by an X factor consisting of the capital productivity trend of Ontario distributors (if deemed to be positive) and the stretch factor. Should the panel elect not to pursue OM&A- and capital-specific escalators for Elexicon Energy, PEG recommends setting the productivity factor at the 0.15% TFP growth trend for the RRF period.

6. PEG Critique: Role of Capital Cost Forecasting

Overview

Elexicon Energy's proposal also raises other IR plan design issues. Most notable is the proposal to effectively base the entirety of its revenue requirement on cost forecasts (less a small stretch factor knockoff) and to claw back 98% of any capital cost underspends to customers. These plan design features raise many concerns that PEG has discussed in past CIR proceedings.[81]

Forecasting Pros and Cons

We begin by reviewing pros and cons of using forecasting in revenue escalation.

Forecasting Pro

One important advantage of forecasting is its ability to tailor ARMs to various cost trajectories. For example, a forecasted ARM can provide timely funding for an expected capital cost surge such as Elexicon proposes. Another advantage is that capital cost forecasts are made using familiar capital cost accounting.

Forecasting Con

Uncertainty and Information Asymmetry

The biggest challenge with forecasted ARMs may be the difficulty of establishing a just and reasonable multi-year cost forecast. The efficient future cost of service is usually uncertain and uncertainty increases with the length of the MRP term. For example, capital cost forecasts can be wrong about inflation.

The inflation uncertainty problem can be mitigated by making forecasts of capital costs, capital expenditures, or gross plant additions contingent on an inflation assumption that is later trued up to actuals. The OEB has approved explicit true ups of forecasted inflation to actuals for the C factor in the current CIR plan of Hydro One networks and the RGF factor in the current CIR plan of Toronto Hydro.[82] Advanced and incremental capital modules also feature an implicit true up of inflation assumptions to

[81] See, for example, PEG's plan design discussions in the recent THESL (EB-2023-0195) and Alectra (EB-2025-0252) proceedings.

[82] EB-2021-0110 and EB-2023-0195. Elexicon has also proposed an inflation true up for its proposed RGF.

actuals. The forecasted revenue requirements of British power distributors for the MRP plan term are approved in real terms that are subsequently adjusted to account for inflation. Many capital cost trackers in the US implicitly true up inflation assumptions to actuals as part of a prudence review.

We are also concerned that utilities are incentivized to overstate required cost growth. Padding a cost forecast reduces the pressure on the utility to achieve cost savings and can legitimize more capex than it really requires. The utility may also be able to profit in the short term from spending less than it forecasts. Exaggeration of required revenue may reduce the company's credibility in future proceedings. However, the company can always claim that it "discovered" ways to economize. This problem can also be finessed by spending close to the padded forecast, even if it isn't efficient. Concerns about information asymmetries and an uncertain future are often addressed by shortening the plan term and truing up forecasted costs to actual cost.

Cost Containment Incentives

Another concern is the utility's incentive to contain costs when revenue escalation is based on forecasts. A utility is much more likely to undertake a capex surge when it is expressly approved in advance. In the United States, for example, submissions to regulators of distribution system plans have in many cases led to ambitious multiyear capex proposals. Utilities are incentivized to "bunch" their costs in ways that support their proposal to base ARMs on cost forecasts. If, for example, a utility could somehow manage to time its expenditures so that indexing was sufficiently compensatory, it would obtain less revenue. Incentives are further weakened by a clawback of underspends. If forecasting applies only to capital revenue, imbalanced incentives for capital and OM&A cost containment are a real concern. Incentives to contain a forecasted cost in a multiyear rate plan may nevertheless be stronger than under frequent rate cases or two-way variance accounts that fund overspends as well as returning underspends.

Regulatory Cost

Given Elexicon Energy's weak incentive to contain demand-related costs and the Company's incentive to exaggerate cost requirements and bunch costs, stakeholders and the OEB must be especially vigilant about the Company's cost proposal. This raises regulatory cost. The need for the OEB to approve multi-year revenue requirements greatly complicates CIR proceedings and is one of the reasons why the OEB now requires and must review complicated distribution system plans - a major expansion of its workload and that of stakeholders.

Despite the extra regulatory cost, OEB staff and intervenors inevitably struggle to effectively challenge the utility's cost proposal. Some regulatory communities lack the expertise to appraise multi-year cost forecasts. However, many commissions routinely use forward test years in rate cases and some of these use multiple test years. Some commissions also periodically review multi-year business plans of utilities or pay special attention to utility proposals for major plant additions (e.g., in proceedings to approve certificates of public convenience and necessity). Ontario's regulatory community does both.

In summary, a forecasted ARM weakens utility cost containment incentives relative to an indexed ARM and can further jeopardize customer benefits from IR due to the problem of information asymmetry. The utility is incentivized to include a comfortable cushion in its cost forecast. While the proposed clawback mitigates some of the concern about information asymmetries, this further weakens capex containment incentives. The approach to CIR that Elexicon proposes thus undermines the *main potential benefits* of multi-year rate plans -- stronger performance incentives and streamlined ratemaking.

Here are some additional concerns about undue reliance on forecasting that PEG has enunciated in prior CIR proceedings.

- While customers are asked to fully compensate Elexicon for the bulk of its expected capital revenue shortfalls when cost growth is *rapid* for reasons beyond its control, the Company will be under no obligation in the future to return any surplus revenue if it chose to operate under indexing and its cost growth was unusually *slow* for reasons beyond its control. Slow cost growth could occur in the future for reasons other than good cost management. For example, depreciation of surge capex which has provided the rationale for Custom IR will tend to slow future capital cost growth. Over multiple plans, the revenue escalation between rate cases may therefore not guarantee customers the full benefit of the industry's productivity trend, even if it is achievable.
- A related problem is that most of the cost addressed by the RGF and Z factors would be similar in kind to that incurred by the utilities in past and future productivity studies that are used to determine productivity factors. The Company can then be compensated twice for the same cost: once via the RGF and then again by low X factors in past, present, and future IRMs.

- If forecasting applies only to capital, any indexed ARM designed to fund total cost may be overly generous to the costs to which it really applies.
- This overcompensation issue when an indexed ARM is combined with supplemental capital revenue has been debated in several IR proceedings and no consensus has been established regarding its remedy. Some regulators have eschewed X factor adjustments that might address the overcompensation and based X factors on industry productivity trends. However, the Hawaii Public Utilities Commission ruled in a 2020 IR decision that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that some of their major plant additions could be eligible for cost tracking.[83]

Alternatives to the Extensive Use of Forecasting in ARM Design

The preceding discussion has implications for the design of ARMs for Elexicon and other Ontario utilities. Let's start by assuming that the utility does need some form of CIR because its revenue requirement is rising quite a bit more rapidly than the escalation that indexing by itself affords. Elexicon is forecasting rapid cost growth in the next five years. A comprehensive indexed ARM will therefore not be practical for the Company in its next rate plan.

However, there are notable alternatives to the established CIR approach to capital revenue escalation that Elexicon proposes. Many of these have been discussed by PEG in prior reports for OEB Staff.

Reduce the Share of Any Gap Between Indexed Revenue Growth and Forecasted Capital Cost Growth That is Eligible for Supplemental Revenue

This option was discussed in Section 2.1 of our Empirical Report. Rationales for narrowing the gap include the needs for a materiality condition and a strengthening of capex containment incentives. Additionally, there is a dead zone in the incremental and advanced capital modules that are available to distributors under the 4th GIRM. Two approaches to narrowing the gap are discussed: an

[83] Hawaii Public Utilities Commission (2020), Decision and Order No. 37507, Docket No. 2018-0088.

incremental capital stretch factor and a mechanistic sharing of differences. The OEB has approved incremental capital stretch factors for several CIR plans as shown in Table 4.

Table 4

Precedents for Incremental Stretch Factors on Capital

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

Increase the I-X Growth Applicable to Capital

If CIR is premised on the difference between the growth of indexed capital revenue and forecasted costs, any legitimate means of making indexed capital revenue grow more rapidly would reduce the need of utilities to request CIR. Here are some possibilities.

- The inflation measure applicable to capital revenue could be replaced, if it is found to materially understate capital price growth, with an alternative measure that does a better job. This is a complicated empirical issue that has never been properly addressed in the OEB's rebasing/IR proceedings and is perhaps best addressed in a generic IR proceeding. An alternative to a capital-specific inflation index is adding an input price differential ("IPD") term to the index formula. IPDs applicable to *OM&A* revenue have been proposed by Alectra Utilities and Elexicon in their current rebasing/CIR proceedings.
- The partial factor productivity ("PFP") trend of capital in the relevant industry can be used to set the productivity factor for capital if that is slower than the TFP trend. This approach is discussed in Section 2.1 of our Empirical Report and has been advocated by PEG as a witness for Staff in this proceeding and the Alectra Utilities proceeding.

- A negative productivity factor can be approved if there is strong evidence that the productivity trend of the industry is negative and that trend is applicable to the subject utility. This approach was discussed in Section 2.1 of our Empirical Report. We explain how a negative productivity factor can be reasonably applied in the context of CIR. When a negative industry productivity trend is ignored, utilities are more likely to choose the CIR option. Moreover, they can in some cases legitimately complain that there is an "implicit" stretch factor in the I-X formula. When this is true, it reduces the reasonableness of increasing the stretch factors in their formulas on other grounds.

Reduce the Escalation of OM&A Revenue

We discussed above how the application to OM&A revenue of an indexed ARM designed to escalate the total cost of power distributors may result in overcompensation. Making the OM&A revenue escalator more OM&A specific makes CIR less appealing at the same time that it benefits customers.

Historical Own-Cost Trending

This approach may or may not be considered in the OEB's next generation rate framework initiative, so this proceeding is a good place to continue discussions on its merits. We begin with some real world examples of historical own-cost trending.

California "Old School" Approach

California's commission has required energy utilities to operate under MRPs for decades but does not like to base ARMs on multi-year cost forecasts. Hybrid ARMs have been used in numerous MRPs wherein much of the post-test year OM&A revenue requirement has been indexed. That for capital is based on a calculation that uses traditional cost of service capital cost accounting but includes the simplifying assumption that gross plant additions reflect either the company's approved additions for the first year of the plan or an average of the company's recent historical additions. The plant additions in these calculations have sometimes been escalated for price inflation.

Alberta's K-bar Approach

The Alberta Utilities Commission ("AUC") has approved three rounds of generic MRPs for gas and electric power distributors that it calls PBR plans. A "K-bar" approach to ARM design has been featured in the PBR2 and PBR3 plans that is a variant on the California theme. The commission was

disappointed with some results of the PBR1 plan, where extensive use of capital cost variance accounts weakened the capex containment incentives of distributors and raised regulatory cost. The K-bar approach was originally suggested in the hearing to approve PBR1 by AUC commissioner Moin Yahya, a University of Alberta law school professor who earned a PhD in economics at the University of Toronto.[84] K-bar is a mathematical expression for a value of a K factor term in rate or revenue cap index that is in some sense fixed.

The recently approved PBR3 plan for Alberta energy distributors provides an example of the use of K-bar in the context of an approaching energy transition. PBR3 features a hybrid ARM where rates for energy distributors are escalated by an index and supplemental funding is available for certain kinds of capex. "Type 1" capex is eligible for forecasting with subsequent variance account treatment. In order to qualify as Type 1 capex, a project must have a material effect on the distributor's finances, be required by a third party or directly caused by applicable law related to net-zero objectives, and be extraordinary and not previously included in the distribution utility's rate base. Capex that is not deemed to be of Type 1 is "Type 2" capex and is addressed by the K-bar mechanism. All existing capex programs are treated as Type 2 capex by default.

For Type 2 capex, this mechanism effectively replaces capital revenue based on indexing by capital revenue based on historical own-cost trending. This is a multistep process undertaken for each year of the plan term which begins by identifying the capital revenue generated by going in rates escalated by the indexing mechanism. The next step is to estimate a notional capital revenue requirement needed to fund the Type 2 capex that would be undertaken in a given year. For this, the AUC relies on the five-year average capital additions from the prior plan term (e.g., 2018-2022), which is then escalated by the approved I – X formula and 85% of customer growth. These amounts are then converted into a capital revenue requirement using assumptions about retirements and a mid-year rate base. The K-bar term in the ARM formula then ensures that an amount is added to rates that is the difference between the inflation-adjusted notional capital revenue requirement and the inflation-adjusted capital revenue requirement embedded in going in rates. To the extent that the distributor

[84] AUC proceeding 566, Transcript Vol. 10, April 27, 2012, pp. 1918-1922.

spends less on capital than expected by K-bar, the distributor retains the amount. In other words, there is no clawback of capital underspends.

Massachusetts K-bar Approach

The ARM design for power distributor services of Eversource Energy in Massachusetts is a variant on the Alberta theme. The capital revenue requirement in each out year of the plan is calculated using a *rolling average* of the company's recent plant additions.[85] To reduce the chance that the company may have excessive plant additions, a cap on the amount of annual plant additions supported by K-bar has been established. This annual cap is 10% above the level of annual plant additions that the company forecasted during the proceeding in which the MRP was approved. The prudence of any plant additions subject to K-bar treatment may be investigated at any time and the company has been placed on notice that the regulator may review its capital spending if it determines that the company over-estimated its plant additions forecast and was underinvesting in capital. In return for the supplemental capital revenue that K-bar provides, Eversource agreed to a zero X factor even though the utility had made a case for a negative X factor due to IPD concerns.[86]

Historical Own-Cost Trending Appraisal

Historical own-cost trending can reduce the cost of ARM design and strengthen capex containment incentives relative to a forecast with clawbacks when a utility is expected to need sufficiently high capex for a number of years that an indexed ARM is non-compensatory for capital revenue. However, the incentive impact of the approach weakens if utilities suspect that capital revenue growth in future plans reflects their gross plant additions in the latest plan. The productivity growth of California power distributors has been unremarkable, although this has reflected in part special circumstances such as heightening wildfire challenges.

A paper on a study by PEG that was published in *The Electricity Journal* in 2023 revealed that in PBR1, with its capital cost variance accounts, the capital productivity growth of participating Alberta

[85] Massachusetts Department of Public Utilities, D.P.U. 22-22, 2022.

[86] Recall that this is more of a concession in the United States than in Canada since the GDPPI that is widely used in indexed ARMs in the States tends to materially understate utility input price inflation and this often results in an X factor adjustment that makes it negative.

energy distributors was just as sluggish as in the prior period of frequent rebasings.[87] In PBR2, however, replacement of variance account treatment of supplemental capital revenue with a K-bar caused material acceleration in the capital productivity growth of Alberta energy distributors.

Historical Own-Cost Trending for Elexicon Energy

We could only broach the topic of historical own-cost trending in our report for OEB Staff in the Toronto Hydro CIR proceeding. In this proceeding we have taken further steps to explore the option.

- Elexicon Energy forecasts plant additions in the next five years that are well in excess of its recent historical norms. To the extent that the OEB believes that the rapid proposed cost growth is required and is not merely a manifestation of the asymmetric information problem and zeal for capex, the situation can be finessed using forecasting and/or variance accounts to address some rapidly growing capital costs and then use historic own-cost trending for the residual capital revenue requirement. The OEB may prefer traditional prudence oversight anyways of some rapidly growing costs (e.g., substation capacity capex) that are accorded forecasting and/or variance account treatment. Own-cost trending would materially reduce the role of forecasting in the determination of the Company's revenue requirement.
- We have shown that historical own-cost trending is a well-established alternative to forecasting for capital revenue. Elexicon Energy could be assigned a gross plant additions budget for some asset categories that is similar (in the dollars of the next plan) to their average plant additions during the expiring plan. Either the old school California approach or the Alberta K-bar approach could be used. Either of these approaches should yield considerably more revenue than indexing of capital revenue would.

  The approach to own-cost trending explored here is closer to California's approach than to the Alberta approach and is designed to dovetail with the ARM design approach that Elexicon Energy has proposed. Essentially, the Company would have a CRCI formula with an RGF but historical own-cost trending would be used instead of cost forecasting to establish gross plant

[87] Lowry, Mark N., Hovde, D., Kavan, R., and Makos, M., "Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta," The Electricity Journal, 36 (2023) 107288. https://doi.org/10.1016/j.tej.2023.107288

addition budgets for some asset categories. There would be no explicit K-bar term in the formula. Capital revenue growth would still be reduced by the stretch factor.

- Due to information asymmetry, it is difficult for OEB Staff or intervenors to undertake all of the calculations needed to fully demonstrate the rate or revenue impact of historical own-cost trending for Elexicon Energy. The Company has specialized accounting knowledge that other parties to the proceeding lack. For this reason, we asked Elexicon Energy to demonstrate the revenue requirement impact of implementing a hypothetical own-cost trending example. In its response to 1-Staff-22 part a, the Company refused to consider a scenario involving this approach. Nevertheless, we have endeavored to undertake the first steps.

We flesh out here a straw man proposal in which Elexicon Energy's capital revenue requirement depends on a mix of cost forecasts, some with variance account adjustments, and historical own-cost trending. In its EB-2025-0312 direct evidence, the Company disaggregated its proposed and recent historical capex net of CIAC in ways that support this new hybrid approach.

Ideally, *gross plant additions* net of CIAC would be used for our calculations, which Elexicon provided in response to 2B-SEC-35. PEG ultimately chose not to rely on these data for its K-bar calculations, relying instead on the available capex data filed as part of Appendix 2-AA and Distribution System Plan. PEG found that several of the Company's capital programs had subprograms that merited separate treatment, with one subprogram meriting forecast or Y factor treatment and another meriting own-cost trending treatment (e.g., the Company's Metering & AMI 2.0 program). The available plant additions data did not include this level of detail.

Table 5 below illustrates how some kinds of capex could be subject to forecasting and/or variance account treatment, while other kinds could be accorded historical own-cost trending. The sorting in this table is intended to stimulate thinking. We generally avoided own-cost trending for asset categories where capex growth was either expected to accelerate markedly or to be highly uncertain due to the energy transition or other reasons. Capex categories nominated for own-cost trending are highlighted in yellow in the table. Capex for these categories from 2020 to 2024 was escalated to 2024 dollar and output levels using the Escalation Factors outlined in Table 6a. The average capex for each project (or sub-project) at 2024 levels is then calculated. The escalation factors take account of both inflation and growth in operating scale. For each of the "out" years of the proposed plan (2028-2031),

Table 5

Itemized Elexicon Energy Capex Data Could be Used in Own-Cost Trending

	Actual Expenditures					Actual Expenditures Adjusted to Forecasted 2024 Prices and Customers						Forecasts: Bridge Years		Hypothetical Budgets from Historical Own-Cost Trending: Next Plan					Elexicon Forecasts: Next Plan					Next Plan Averages (2028-2031)		
Projects ($M)	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	Average	2025	2026	2027	2028	2029	2030	2031	2027	2028	2029	2030	2031	Hypothetical Own-Cost Trending Budget	Elexicon's Forecast	Comparison
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS							MIFRS	MIFRS						MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	[A]	[B]	[A/B]
System Access																										
A1 Externally-Initiated Plant Relocation	1.9	5.8	8.3	11.6	2.2	2.6	7.3	10.0	13.2	2.2	7.1	2.8	4.6	NA	10.4	10.8	11.3	11.8	5.1	5.8	5.9	6.0	6.0	11.1	5.9	1.87
A2 Customer & Generation Connections	3.8	7.0	9.1	6.8	3.6	5.0	8.9	11.1	7.8	3.6	7.2	6.7	5.4	NA	10.7	11.1	11.6	12.1	7.4	7.8	8.2	8.8	9.0	11.4	8.5	1.34
A3 System Expansion	0.1	0.1	1.5	3.4	13.8	0.1	0.1	1.8	3.9	13.8	3.9	11.6	12.6	NA	5.8	6.0	6.3	6.6	19.3	9.8	7.1	8.5	9.5	6.2	8.7	0.71
A4 Metering & AMI 2.0																										
Metering	1.2	1.1	0.9	1.7	2.2	1.6	1.4	1.0	2.0	2.2	1.6	1.7	1.6	NA	2.4	2.5	2.6	2.8	1.9	1.9	2.0	2.0	2.0	2.6	2.0	1.30
AMI 2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA	0.0	0.0	0.0	0.0	0.0	0.5	6.9	7.1	7.0	-	5.4	0.00
System Access Net Expenditures	7.0	13.9	19.8	23.4	21.8	9.3	17.7	23.9	26.8	21.8	19.9	22.8	24.2	NA	29.2	30.4	31.8	33.2	33.7	25.8	30.1	32.3	33.4	31.2	30.4	1.03
						0.0	0.0	0.0	0.0	0.0	0.0			NA	0.0	0.0	0.0	0.0								
Sub-Total	7.0	13.9	19.8	23.4	21.8	9.3	17.7	23.9	26.8	21.8	19.9	22.8	24.2	NA	29.2	30.4	31.8	33.2	33.7	25.8	30.1	32.3	33.4	31.2	30.4	1.03
ım Renewal																										
R1 Substation Renewal	3.6	2.8	4.6	3.6	8.1	4.7	3.6	5.6	4.1	8.1	5.2	7.3	13.6	NA	7.7	8.0	8.3	8.7	19.6	26.6	21.0	24.3	18.5	8.2	22.6	0.36
R2 Underground System Renewal	4.2	6.9	4.2	1.8	0.9	5.6	8.8	5.0	2.1	0.9	4.5	0.5	0.0	NA	6.6	6.8	7.2	7.5	0.7	9.7	16.7	24.6	32.5	7.0	20.9	0.34
R3 Overhead System Renewal	4.6	7.7	7.2	5.4	4.8	6.1	9.7	8.8	6.1	4.8	7.1	2.6	1.0	NA	10.4	10.8	11.3	11.8	2.6	10.3	13.3	14.7	14.8	11.1	13.3	0.84
R4 Reactive Capital	2.6	1.9	8.3	6.5	10.5	3.4	2.4	10.0	7.4	10.5	6.8	9.7	7.6	NA	9.9	10.3	10.8	11.3	8.4	7.1	5.1	5.1	4.5	10.6	5.4	1.94
System Renewal Net Expenditures	15.0	19.3	24.3	17.3	24.3	19.8	24.5	29.4	19.7	24.3	23.6	20.2	22.2	NA	34.6	36.0	37.6	39.3	31.3	53.7	56.0	68.8	70.2	36.9	62.2	0.59
						0.0	0.0	0.0	0.0	0.0	0.0			NA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0			
Sub-Total	15.0	19.3	24.3	17.3	24.3	19.8	24.5	29.4	19.7	24.3	23.6	20.2	22.2	NA	34.6	36.0	37.6	39.3	31.3	53.7	56.0	68.8	70.2	36.9	62.2	0.59
ım Service																										
S1 Substation Growth	4.4	8.2	17.5	0.8	10.8	5.8	10.4	21.1	0.9	10.8	9.8	1.1	24.5	NA	14.4	15.0	15.7	16.4	35.8	21.6	30.6	21.6	38.3	15.4	27.9	0.55
S2 Grid Enhancements																										
Distribution Modernization	0.9	0.8	0.4	0.5	4.1	1.2	1.0	0.4	0.6	4.1	1.4	9.5	1.3	NA	2.1	2.2	2.3	2.4	0.6	1.2	2.5	4.0	4.9	2.3	3.1	0.72
Station Modernization	0.2	0.8	0.3	3.6	3.6	0.2	1.0	0.4	4.1	3.6	1.9	0.0	0.0	NA	2.7	2.9	3.0	3.1	1.2	1.2	1.4	1.9	2.0	2.9	1.6	1.80
Distribution Capacity and Reliability Enhancements	0.1	0.2	2.7	2.4	2.6	0.1	0.3	3.3	2.7	2.6	1.8	3.3	1.3	NA	2.6	2.7	2.8	3.0	7.0	8.3	5.2	3.1	23.4	2.8	10.0	0.28
S3 Voltage & System Conversion	0.7	1.0	0.1	0.0	0.0	0.9	1.2	0.1	0.0	0.0	0.4	0.0	0.0	NA	0.6	0.7	0.7	0.7	0.0	8.1	7.1	4.8	3.6	0.7	5.9	0.12
System Service Net Expenditures	6.2	10.9	20.9	7.2	21.1	8.2	13.9	25.3	8.2	21.1	15.3	13.9	27.0	NA	22.5	23.4	24.5	25.6	44.6	39.8	46.8	35.4	72.2	24.0	48.5	0.49
						0.0	0.0	0.0	0.0	0.0	0.0			NA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	
Sub-Total	6.2	10.9	20.9	7.2	21.1	8.2	13.9	25.3	8.2	21.1	15.3	13.9	27.0	NA	22.5	23.4	24.5	25.6	44.6	39.8	46.8	35.4	72.2	24.0	48.5	0.49
ıral Plant																										
P1 Facilities Management	0.8	0.8	5.4	1.4	0.7	1.0	1.1	6.5	1.6	0.7	2.2	0.2	0.5	NA	3.2	3.3	3.5	3.6	5.2	2.0	5.4	1.4	0.8	3.4	2.4	1.41
P2 Fleet	0.8	1.6	2.3	1.8	1.2	1.1	2.1	2.8	2.0	1.2	1.8	2.0	1.7	NA	2.7	2.8	3.0	3.1	4.0	3.4	4.6	3.0	2.9	2.9	3.5	0.83
P3 IT Systems	4.2	2.7	3.3	3.0	2.4	5.6	3.4	4.0	3.5	2.4	3.8	1.4	1.3	NA	5.5	5.8	6.0	6.3	2.6	2.1	2.0	2.0	1.5	5.9	1.9	3.11
P4 Equipment	0.2	0.2	0.5	0.4	0.4	0.2	0.2	0.6	0.5	0.4	0.4	0.5	0.2	NA	0.5	0.6	0.6	0.6	1.1	1.3	1.4	0.8	0.8	0.6	1.1	0.54
P5 OT Systems	0.5	1.7	0.9	0.7	0.7	0.7	2.1	1.1	0.8	0.7	1.1	2.0	1.3	NA	1.6	1.7	1.7	1.8	0.8	1.7	3.4	5.3	6.3	1.7	4.2	0.41
General Plant Net Expenditures	6.5	7.0	12.4	7.3	5.3	8.6	8.9	15.0	8.4	5.3	9.2	6.2	5.1	NA	13.6	14.1	14.8	15.4	13.7	10.4	16.8	12.5	12.3	14.5	13.0	1.11
						-	-	-	-	-	-													-		
Sub-Total	6.5	7.0	12.4	7.3	5.3	8.6	8.9	15.0	8.4	5.3	9.2	6.2	5.1	NA	13.6	14.1	14.8	15.4	13.7	10.4	16.8	12.5	12.3	14.5	13.0	1.11
llaneous (Renewables/Lease)	- 0.3	- 0.2	0.0			- 0.5	- 0.2	0.0	-	-	- 0.1			NA	- 0.2	- 0.2	- 0.2	0.2						- 0.2		
Total	34.3	51.0	77.3	55.2	72.5	45.5	64.8	93.6	63.1	72.5	67.9	63.0	78.5	NA	99.8	103.8	108.5	113.4	123.3	129.7	149.7	149.0	188.1	106.4	154.2	0.69
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*	0.3	0.1	- 0.0			0.5	0.1	0.0	-	-	0.1			NA	0.2	0.2	0.2	0.2						0.2		
Total	34.7	51.1	77.3	55.2	72.5	46.0	64.9	93.6	63.1	72.5	68.0	63.0	78.5	NA	99.9	104.0	108.7	113.6	123.3	129.7	149.7	149.0	188.1	106.6	154.2	0.69
By Ratemaking Treatment																										
Subtotal: Own-Cost Trending	27.1	34.3	47.9	39.8	56.2	35.9	43.6	58.0	45.5	56.2	47.8	53.9	46.8	NA	70.3	73.2	76.5	79.9	74.6	84.3	90.6	101.2	103.6	75.0	94.9	0.79
Subtotal: Forecasted/Y-Factored Additions	7.6	16.8	29.4	15.4	16.3	10.1	21.3	35.6	17.6	16.3	20.2	9.2	31.7	NA	29.6	30.8	32.2	33.7	48.8	45.4	59.2	47.8	84.5	31.6	59.2	0.53

Notes:

Data used in calculations are capital expenditures net of customer contributions.

Highlighted rows show those capital projects that PEG believes are appropriate for historical own-cost trending.

Source: Elexicon Appendix 2-AA and Exhibit 2B, Tab 4, Schedule 3, Appendices A-P.

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Table 6a

Calculating the Capex Escalation Factors

Line No.		Actuals					Forecasts						
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Inflation***	4.43%	3.79%	4.14%	5.16%	13.67%	19.18%	7.74%	2.41%	2.79%	1.60%	1.88%	2.05%
2	**Inflation Escalation Factor = (1+I)**	104.43%	103.79%	104.14%	105.16%	113.67%	119.18%	107.74%	102.41%	102.79%	101.60%	101.88%	102.05%
3	**Elexicon Annual Output Growth Rate (OG)**	1.95%	0.62%	0.76%	0.74%	0.65%	1.64%	2.57%	2.41%	2.40%	2.46%	2.64%	2.46%
4	**I+OG Escalation Factor = [1+(I+OG)]**	106.4%	104.4%	104.9%	105.9%	114.3%	120.8%	110.3%	104.8%	105.2%	104.1%	104.5%	104.5%

Notes:

Actual inflation data are available through 2026, however, actual output data are only available through 2024.

The actual inflation data are from the Handy Whitman Index for Total Power Distribution Plant in the North Atlantic region. See Table 6b for additional details.

PEG then escalates the capex averages from 2024 levels to the applicable year using forecasted Escalation Factors.

The Escalation Factors are a function of the OEB's approved I-Factor for power distributors and a forecast of Elexicon's elasticity-weighted output growth. Table 6b provides additional detail on the calculation of the inflation adjustments. The growth in the Handy Whitman Index of Public Utility Construction Costs for Total Power Distribution Plant in the North Atlantic region is used in these calculations for the years for which actual data are available.[88] Where inflation forecasts are required, we use forecasts of GDPIPI inflation from Toronto Dominion Economics and of $AWE_{Ontario}$ inflation that PEG purchased from Signal49 Research (formerly the Conference Board of Canada).

Our elasticity-weighted output growth calculations are provided in Table 6c. The outputs in this table were selected because they were statistically significant output variables in the econometric capital cost model that we presented in our Empirical Report. The elasticity weights are drawn from the same model. PEG also relied on output forecasts provided by Elexicon for these calculations.

At the bottom of Table 5 we report the total value of capex that would hypothetically be accorded forecasting (and in some cases variance account) treatment on the one hand and K-bar treatment on the other. In the right-hand columns it can be seen that the kinds of capex we nominate for forecasting and/or variance account treatment are forecasted to be much higher in the new plan than in the expiring plan. Assume that the Company would receive a capex budget equal to its forecasts. The inflation-adjusted historical average capex that we nominate for own-cost trending is less than the Company's proposed capex by about 21%.

British Remedies

The British regulator, Ofgem, has had extensive experience with forecasted ARMs. The approved revenues of British utilities have often exceeded their actual cost. Due in part to experiences like these, Ofgem has over the years commissioned numerous statistical benchmarking and engineering studies in order to develop an independent view of required cost growth. For many years, Ofgem also used an information quality incentive ("IQI") mechanism to encourage utilities to submit better cost

[88] A sensible alternative would be to use a regional Handy Whitman Index of power distribution construction costs. Forecasts of inflation in these indexes are available from S&P Global.

Table 6b

Calculating the Inflation Adjustments

Line No.		Actuals					Forecasts						
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Average Weekly Earnings (AWE) - Ontario**	7.00%	3.50%	2.30%	3.20%	4.90%	2.20%	2.30%	2.30%	2.30%	2.40%	2.50%	2.50%
2	**Elexicon Proposed Weight - Labor Price**	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
3	**Gross Domestic Product Implicit Price Index for Final Domestic Demand for Canada**	1.70%	3.80%	5.90%	3.70%	3.20%	2.50%	3.00%	1.30%	1.70%	1.90%	1.90%	2.00%
4	**Elexicon Proposed Weight - Non-Labor Price**	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%
	Inflation Adjustment	**4.43%**	**3.79%**	**4.14%**	**5.16%**	**13.67%**	**19.18%**	**7.74%**	**2.41%**	**2.79%**	**1.60%**	**1.88%**	**2.05%**

Notes:
Inflation adjustments are based on inflation data that are lagged by 2 years (e.g., the inflation adjustment for 2026 is based on the inflation that occurred in 2024). As a result, actual inflation adjustments are available through 2026. Inflation adjustments for the 2027-2031 period are based on forecast inflation for 2 years prior to that year (e.g., the forecasted inflation adjustment in 2028 is based on the forecasted inflation that is expected to occur in 2026).

The inflation adjustments for the 2020-2026 period are based on growth in the Handy Whitman Index of Public Utility Construction Costs for Total Power Distribution Plant of the North Atlantic Region.

For the 2025-2031 period, PEG purchased forecasts of the Average Weekly Wages and Salaries per Employee for the Ontario industrial composite from Signal 49 Research.

For the 2025-2031 period, PEG also obtained Canadian GDP deflator forecasts from Toronto Dominion Economics and used that as a proxy for the Canadian Gross Domestic Product Implict Price Index for Final Domestic Demand. Source: https://economics.td.com/ca-forecast-tables#lt-ca

Table 6c

Calculating Output Growth

Line No.		Actuals					Forecasts						
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	**Number of Customers**	169,489	171,564	174,153	176,725	179,017	182,688	186,243	189,833	193,280	196,883	200,624	204,398
2	**Customer Growth**	1.09%	1.22%	1.50%	1.47%	1.29%	2.03%	1.93%	1.91%	1.80%	1.85%	1.88%	1.86%
3	**Weight on Customer Growth**	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%
4	**Peak Demand**	756	720	707	701	714	765	791	814	839	865	895	923
5	**Ratcheted Peak Demand**	756	756	756	756	756	765	791	814	839	865	895	923
6	**Ratcheted Peak Demand Growth**	2.82%	0.00%	0.00%	0.00%	0.00%	1.24%	3.23%	2.93%	3.02%	3.08%	3.42%	3.07%
7	**Weight on Ratcheted Peak**	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%
	Output Growth	**1.95%**	**0.62%**	**0.76%**	**0.74%**	**0.65%**	**1.64%**	**2.57%**	**2.41%**	**2.40%**	**2.46%**	**2.64%**	**2.46%**

Notes:
The source for the number of customers and peak demand data was Clearspring's working papers.
Weights on each output were drawn from the elasticities in PEG's capital cost model.

forecasts. This mechanism rewarded utilities that presented cost forecasts that were similar to or lower than the forecasts Ofgem developed and penalized utilities that presented cost forecasts that were less strenuous than Ofgem's. The IQI also determined the rate at which variances between forecasted and actual costs were shared with customers, with utilities that had more efficient cost forecasts receiving a larger share of cost variances.

The IQI has been replaced by a Business Plan Incentive ("BPI"). The BPI in the current power distributor plans consists of several parts, including penalties for distributors that fail to provide sufficient information to appraise their business plans or that provide unreasonably high forecasts in areas where Ofgem is less confident in its forecasting abilities. The BPI also includes rewards for utilities that propose cost forecasts that are below Ofgem's in areas where Ofgem is more confident in its ability to forecast costs.

Ofgem has also marked down distributor cost forecasts to reflect its assumptions about expected productivity gains. These reflect its expectations about the annual productivity gains that companies can achieve during the term of the MRP based on the available evidence on productivity trends. For the current regulatory system for power distributors, called RIIO-ED2, Ofgem expected that distributors achieve 1% efficiency growth per year that is applied to all controllable costs. The efficiency expectation was not tied to a specific productivity study of British power distributors.

Summing Up

In conclusion, PEG has provided the panel with several defensible means of upgrading the ratemaking treatment of capital for Elexicon Energy. One step would be to add a custom capital stretch factor to the capital revenue escalation formula or a mechanistic sharing of estimated revenue shortfalls. We also encourage the panel to approve a capital-specific revenue escalation index in the mechanism for determining surplus revenue. Capital revenue growth would be reduced by an X factor consisting of the industry capital productivity growth trend (if deemed positive) and the stretch factor. A bigger step would be to reduce the role of capex forecasting by escalating capex budgets for some asset categories using historical own-cost trending. We acknowledge that the scope for doing this in the case of Elexicon Energy is limited by their location on Toronto's periphery during the energy transition.

7. Appendix: PEG Credentials

Pacific Economics Group Research LLC is an economic consulting firm based in Madison, Wisconsin USA. We are the leading North American consultancy on the design of multiyear rate plans and rigorous statistical research on the performances of electric and natural gas utilities. Our personnel have over seventy years of experience in these fields, which have a foundation in economic theory and statistical cost research. Working for an unusual mix of utilities, regulators, government agencies, and consumer and environmental groups, PEG has a reputation for objectivity and dedication to sound research methods. In addition to our numerous Ontario projects, we have done several projects over the years in each of the other three populous Canadian provinces. Our practice has also included many IR and benchmarking projects in the United States

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. A former energy economics professor at the Pennsylvania State University, he has spent more than forty years in the field of energy economics since earning a PhD in applied economics from the University of Wisconsin. A frequent expert witness, his specialties include IR, statistical benchmarking, and studies of energy utility input price and productivity trends.

Dr. Lowry speaks frequently on utility ratemaking and has authored dozens of professional publications. He has coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory and prepared several authoritative surveys on IR and other innovations in ratemaking for the Edison Electric Institute. In the last decade, he has testified on IR in Alberta, British Columbia, Québec, Hawaii, Massachusetts, Minnesota, North Carolina, and Washington state as well as Ontario. A northeast Ohio native, Dr. Lowry now lives in Shorewood Hills, Wisconsin, near Madison.