Energy Probe Interrogatories

M1-EP-2

Reference: Exhibit M1, Page 10

Preamble: **"**There is usually a need for utility revenue to grow between rate cases to address the financial attrition that would otherwise result from inflation, demand growth, and other changes in business conditions. In an MRP, this challenge is addressed by the attrition relief mechanism.

An ARM uses predetermined formulas to address attrition drivers and these formulas are not linked to the utility's contemporaneous cost growth."

Interrogatories:

a) Does the inflation factor I in the traditional I-X price cap and revenue cap rate plans provide a utility with compensation for attrition due to inflation in an MRP? Please explain your answer.

b) Does an annual forecast of bill determinants provide a utility with protection from financial attrition due to demand growth in a price cap MRP? Please explain your answer.

c) Does an annual update of the return on equity in an MRP provide a utility with compensation for financial attrition due to changes in business conditions? Please explain your answer.

d) Do deferral and variance accounts, Z-factors, and off-ramps protect a utility from financial attrition due to other changes in an MRP? Please explain your answer.

Responses:

The following response was provided by PEG.

a) Yes. However, the inflation factors used in indexed ARMs are not highly accurate measures of utility input price growth.

b) In a revenue cap index, allowed revenue is converted to rates by taking account of expected billing determinant growth. This does NOT compensate the utility for costs of demand growth. That is why a revenue cap index formula should include a scale escalator.

c) An annual update for changes in the market rate of return on equity would address one source of possible financial attrition. However, the market rate of return sometimes falls rather than rises.

d) Yes. Deferral and variance accounts, Z factors, and off ramps provide protection for attrition due to some other business conditions during a plan.

M1-EP-3

Reference: Exhibit M1, page 13 and Figure 1a

Preamble: "It can be seen that MRPs are now used in numerous states. Energy distributors operate under MRPs in California, Ohio, New York, and New England."

Interrogatories:

a) Please file a table listing states where MRPs have expired including years they were in place, the reasons for expiry, and the rate setting models that replaced them.

b) Please file a table listing states which never had MRP's showing the models used for rate setting.

Responses:

The following response was provided by PEG.

a) A table providing information on approved MRPs for electric utilities is Attachment N1-EP-3. This table is drawn from Table A6 of a report on a survey of ratemaking precedents that PEG recently completed for the Edison Electric Institute. The table includes the jurisdiction that approved the MRP, the term of the plan, the form of the ARM, details on earnings sharing mechanisms, and a case reference. This table includes details of expired as well as current MRPs.

   PEG has not tracked the reasons why each MRP that expired was not replaced but can venture some reasons why this has happened over the years.

   - The MRP was the outcome of a merger settlement and an expectation of short-run merger savings that facilitated agreement on an ARM.
   - The MRP was an ad hoc (e.g., rate case stay out) provision of a rate case settlement
   - There was difficulty in agreeing on an ARM in a subsequent proceeding,

- Succeeding plans had shorter terms and don't qualify as MRPs[1]
- The company changed names (e.g., Sierra Pacific Power) or was merged into another utility (e.g., Central Vermont Public Service).
- The Commission or interested parties may have been unhappy with the outcome of one or more MRPs in their jurisdiction.
- The composition of the Commission may have changed in a way that disfavored MRPs.
- Proceedings to design a new MRP may be underway for a utility with a recently expired MRP or the utility is considering its options.
- Utilities have decided that they can get better financial results without MRPs.

PEG understands that, where MRPs are not renewed, the utility is usually free to file a rate case at any time.

b) Figure 1a in PEG's plan design report indicates American states that have never had an MRP. PEG cannot provide full details of the models of utility rate setting in the time allotted for response to these IRs. However, PEG can provide some high-level details on ratemaking in some of these states.

- Six states and the District of Columbia have approved formula rate plans, which feature comprehensive (or nearly comprehensive) true ups of revenue to costs deemed prudent.
- One state, Nebraska, has no electric investor-owned utilities and PEG has not tracked ratemaking policies in that state.
- The remaining states use some variant of traditional cost of service ratemaking, where utilities file rate cases at irregular intervals using historical, partially-forecasted, or fully-forecasted test years. Some of these utilities have some form of revenue decoupling or capital cost tracking.

[1] In order to be considered an MRP by PEG, the minimum plan term is 3 years.

M1-EP-4

Reference: Exhibit M1, Page 17

Preamble: “To decide on a value for X, regulators will typically want recent evidence on utility productivity trends by considering one or more productivity studies. Trends in the productivity of broad national (or, more rarely, regional) peer groups are commonly used to establish the base productivity trend.”

Interrogatories:

a) If trends in the productivity of utilities are used to establish the base utility productivity trend, would that not create issues of circularity?

b) For example, in Ontario, many distributors have negative productivity which has been used by the OEB to accept zero as the value for X. If the basic objective of incentive regulation is to incent utilities to improve productivity, should the OEB be accepting IR plans where X equals zero?

Responses:

The following response was provided by PEG.

a) There is not a circularity problem so long as the productivity trend of the peer group is not sensitive to the results for each utility operating under an indexed ARM. For example, the productivity growth of class I line haul railroads in the United States soared during a period in which their rates were escalated in accordance with a price cap index formula that included the productivity trends of class I line haul railroads.

b) An externally-based productivity growth target in an indexed ARM formula has little or no effect on the cost performance of utilities to which it applies. It should also be noted that productivity growth depends on trends in external business conditions as well as on trends in utility efficiency. Accordingly, a negative productivity growth target is sometimes warranted. Unfortunately, a negative productivity growth trend does not provide the basis for a productivity growth markdown of forecasted costs. To apply no markdown in this situation is controversial to the extent that the utility is receiving funding for the external cost drivers that drive productivity growth negative.

M1-EP-5

Reference: Exhibit M1, Page 40 and Figure 3a

Interrogatory:

Please file a table listing states where electric revenue decoupling mechanisms have expired including years they were in place, the reasons for expiry, and the models used for rate setting.

Response:

The following response was provided by PEG.

A table identifying utilities that have had electric revenue decoupling mechanisms is Attachment N1-EP-5. This table is drawn from Table A4 of a report on a survey of ratemaking precedents that PEG recently completed for the Edison Electric Institute. The table includes the jurisdiction that approved the decoupling mechanism, the term of the mechanism, the form of any companion revenue adjustment mechanism, and a case reference. Revenue decoupling is used in both multiyear rate plans and in more traditional ratemaking systems that feature irregularly-scheduled rate cases.

PEG has not tracked the reasons why some revenue decoupling mechanisms that expired were not replaced. However, we can provide some general reasons why this has happened over the years.

- The Commission or interested parties may have been unhappy with the outcome of one or more decoupling experiences in their jurisdiction. For example, decoupling was suspended for many years in Maine after it escalated rate growth during a recessionary cycle.
- The utility industry restructured to admit competition and decoupling wasn't deemed warranted thereafter.
- There were questions about the legality of decoupling (e.g., for electric) utilities.
- Utilities lost interest in decoupling because growth in average use accelerated.
- No companion revenue adjustment mechanism (e.g., a customer growth escalator or ARM) was approved, and this led to utility underearning and frequent rate cases.

M1-EP-6

Reference: Exhibit M1, Page 63

Preamble: "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."

Interrogatory:

Does the proposed CIR 2.0 change the balance of risk between customers and the utility compared to the Custom IR approved by the OEB in the EB-2018-0165 Decision? If the answer is yes, does CIR 2.0 increase or decrease the risk borne by ratepayers?

Response:

The following response was provided by PEG.

Three factors suggest that the balance of risk would shift in favor of THESL.

- OM&A revenue would be based on an inflation-adjusted forecast of the Company's OM&A cost instead of an indexed ARM.
- Decoupling would protect THESL from weather-normalized variances between actual and forecasted system use by commercial and industrial customers.
- The DRVA would provide symmetrical variance account treatment for demand-related costs.

THESL would absorb the risk of capital cost that is not demand-related being lower than expected (e.g., the risk of not having many severe storms) but this risk favors the Company.

M1-EP-7

References: Exhibit M1, "PIM Pros and Cons and Performance Metrics in Practice", Pages 47 to 50; and "Performance Incentive Mechanism", Page 70.

Preamble: The following is a quote from "*The Price of Time, the Real Story of Interes*t", by Edward Chancellor, Atlantic Monthly Press, 2022, pages 120 and 121.

> *"Metrics serve to stifle innovation and creativity; they imitate science but resemble faith. When an institution is guided by some specific target, critical judgement is suspended. In the 1970's American social scientist Donald Campbell pointed out that* ***'the more any quantitative social indicator is used for social decision-making, the more subject it will be to corruption pressures and more apt it will be to distort and corrupt the social processes it is intended to monitor."***
>
> Historian Jerry Muller adds a corollary to Campbell's Law, namely *"anything that can be measured and rewarded will be gamed."*
>
> *The most famous target law emerged several decades ago. Charles Goodhart of the London School of Economics observed that whenever the Bank of England targeted a particular measure of money supply, that measure's earlier relationship to inflation broke down.* ***Goodhart's Law states that any measure used for control is unreliable****."*

Interrogatories:

a) Is PEG aware of Campbell's Law and Goodhart's Law?

b) Does PEG agree that if performance measures are used in rate setting, there is a concern that such performance measures could be gamed and become unreliable as expressed by the *Campbell's Law* and the *Goodhart's Law*?

c) Does PEG agree that to prevent gaming of performance measures to ensure their reliability would require detail independent audits of all numerical inputs used in the derivation of actual results of performance measures.

d) Does PEG agree that the use of PIMs in rate setting could result in greater complexity and increased regulatory costs for ratepayers.

Responses:

The following responses were provided by PEG.

a) PEG was not aware of these laws before reading these interrogatories.

b) Yes. One example is that studies of input price and productivity trends have been gamed by utilities with MRPs since indexed ARMs have become popular. In Alberta's PBR1 proceeding, National Economic Research Associates ("NERA") provided an estimate of the long-term (1973-2009) productivity growth trend of U.S. power distributors that was materially positive. NERA's methodology produced downward-biased and negative estimates of productivity growth in more recent years. As witnesses for distributors in Alberta PBR proceedings, the Brattle Group and Christensen Associates proposed to base the X factor on NERA's results for recent sample periods. Using NERA's methodology and a short sample period, Christensen Associates subsequently reported negative power distributor TFP growth trends in calculations in Massachusetts proceedings and published an article on why distributor productivity was declining.[2] They also testified in Massachusetts to pro-utility research results on input price inflation. In one proceeding the X factor for a power distributor was set at -1.56%.[3] When it became manifest that NERA's methodology should not apply to recent sample periods, both consultancies stopped reporting results based on this flawed methodology. In 2022, Christensen Associates reported a 14-year US power distributor TFP growth trend of +0.06% in a Massachusetts proceeding.[4] They recently reported a 0.16% 14-year TFP growth trend for northeast power

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[2] See the testimony of Mark Meitzen in Massachusetts D.P.U. 17-05 and D.P.U. 18-150.

[3] Massachusetts D.P.U. 17-05.

[4] Massachusetts D.P.U. 22-22, Exhibit ES-PBR/TFP-1, January 14, 2022, p. 24.

distributors in another Massachusetts proceeding.[5]

c) Appraisal by independent experts is worthwhile, although their appraisal need not always include an audit. The OEB does this when it retains PEG to appraise statistical cost research evidence of Ontario utilities.

d) Yes. Good PIMs, like good X factors, are difficult to develop. Yet the value of the activities that PIMs address may be less than the cost savings that X factors address. This is one reason why many multiyear rate plans include only a few PIMs.

[5] Massachusetts D.P.U. 23-150, Exhibit NG-MM-NC-1, November 16, 2023, p. 26.

M1-EP-8

Reference: Exhibit M1, *"THESL's CIR 2.0 Proposal"*, Pages 69 to 71

Interrogatories:

a) In PEG's opinion is the proposed CIR 2.0 more complicated or less complicated than the current Custom IR approved by the OEB in EB-2018-0165?

b) In PEG's opinion does the proposed CIR 2.0 provide greater or lower incentives for productivity improvements in capital and OM&A than the current Custom IR?

Responses:

The following response was provided by PEG.

a) The following considerations suggest that the proposed CIR 2.0 is *more* complicated.

   - There is now variance account treatment for demand-related OM&A expenses.
   - A complicated PIM and revenue decoupling have been added.
   - OM&A revenue is based on cost forecasts.

   The following considerations suggest that the proposed CIR 2.0 is *less* complicated.

   - There would be no clawback of any underspends of most capital costs.

b) The following considerations suggest that the proposed CIR 2.0 would yield stronger cost containment incentives.

   - There would be no clawback of any underspends of most capital costs.

   The following considerations suggest that the proposed CIR 2.0 would yield *weaker* incentives.

   - There would be two-way variance account treatment for demand-related costs and this is the cost category expected to grow with the energy transition.
   - OM&A revenue would be based on an OM&A cost forecast.

M1-EP-9

Reference: Exhibit M1, *“THESL’s Rationale for CIR 2.0”*, Pages 72 to 80

Interrogatories:

a) Does PEG agree that Toronto Hydro’s rationale for CIR 2.0 is that Toronto Hydro wants to spend more money than it can get from ratepayers under the current Custom IR?

b) Does PEG agree that Toronto Hydro has not proven why it needs to spend more money than can be obtained if Toronto Hydro used OEB’s Price Cap rate setting method that is used by the vast majority of distributors in Ontario?

Response:

The following response was provided by PEG.

a) CIR 2.0 likely would yield more revenue for the Company than a continuation of CIR 1.0. However, it would also reduce the Company’s operating risk on balance.

b) PEG cannot comment on the merit of the Company’s cost forecasts.

PEG Responses to Environmental Defence

M1-ED-001

Reference: Report, p. 52

Interrogatories:

a) Does PEG agree that Toronto Hydro has a strong incentive to increase capital spending and apply for a high capital budget because it earns a return on rate base?

b) Please discuss the challenges in making a utility indifferent between capital and O&M spending, such as distribution needs that can be met with traditional infrastructure (capital) or non-wires alternatives (O&M).

c) Please summarize how Toronto Hydro's proposals will or will not succeed in making it indifferent between capital and O&M solutions to distribution needs. Please provide detail.

d) Please comment on the pros and cons of adopting a totex / RIIO approach for Toronto Hydro, either in this proceeding or exploring it for the next rebasing period. Please include a discussion of the increasing availability of O&M solutions to distribution needs.

e) Do you believe Toronto Hydro should study and consider a totex /RIIO approach for the next rebasing application?

Responses:

The following responses were provided by PEG.

a) PEG acknowledges that a return on rate base materially strengthens Toronto Hydro's incentive to increase capital spending. However, the strength of this incentive depends on other details of the regulatory system such as whether the initially high cost of investments can be recovered. For further discussion of capex incentives please see our response to part b) of this question.

b) In a competitive market, a firm will tend to choose the cost-minimizing mix of capital and OM&A costs.[1] If it doesn't, it may not survive at market-determined prices. For many businesses, OM&A expenses constitute the vast majority of their costs. Outsourcing manufacturing to China has made the fortunes of many entrepreneurs in recent decades.

Utilities are permitted to provide certain essential services on a monopoly basis subject to a constraint on their revenue. The constraint is, ideally, that revenue not vary much from the prudent cost of service. In practice, revenue tends to track the utility's actual cost of service. Capital cost includes depreciation expense, certain taxes, and the return on undepreciated asset value.

Under most forms of utility ratemaking, capex therefore gives rise to assets on which earnings are typically due for many years. The funding for the remaining annual capital cost is typically ensured after the first rebasing that follows the capex. However, utilities nonetheless do have some incentives to contain capex for reasons that include the following.

- Excessive capex may result in a capital cost disallowance when rates are rebased to cost. This could result from statistical benchmarking or more traditional prudence review methods.
- Revenue may not cover the high initial annual cost (depreciation + return + taxes) of the capex.
- Revenue may not be sensitive to changes in the annual cost of the capex. This creates an opportunity to profit in the short term from capex underspends.
- The allowed rate of return on the capex may be less than market norms on a risk-adjusted basis.

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[1] However, businesses are mindful that their capex creates assets with potential market value.

Operating expense (“Opex”) does not automatically create earnings opportunities like capex can. The revenue requirement funds the expected amount of opex, and some opex is typically accorded variance account treatment. Increasing some kinds of opex can permit capex savings and this makes more sense to the extent that there is some incentive to contain capex.

There are, meanwhile, several reasons why it may be rational to contain opex.

- Excessive opex may result in a disallowance when rates are rebased to cost due to benchmarking or more traditional prudence disallowances.
- The revenue level does not support the optimal amount of opex.
- Revenue may be insensitive to changes in opex. This creates an opportunity to profit in the short term by reducing opex.

If there was a promising strategy to reduce cost by substituting opex for capex, the cost savings would be passed on to customers at the next rebasing. Thus, *the frequency of rate rebasings is a major driver of the tendency of utilities to favor capex over opex.* Under cost plus regulation that included a pro forma return on capital, capex would be the only path to earnings.

It follows that utilities resist outsourcing tasks that require capital that they could own. They will be slow to embrace strategies that substitute opex for capex and quicker to embrace strategies that substitute capex for opex.

How big of a problem is this? The energy transition will entail a substantial increase in the demand for clean energy. Clean energy technologies are capital intensive, and most power will likely be produced at utility scale and delivered to end users using transmission and distribution assets. Utilities want to make investments and can secure financing at low rates.

The gravity of the capex/opex substitution issue depends on the economic substitutability of OM&A and capital inputs. This is a big issue for a utility that must choose between building gas-fired power plants to meet growing demand and purchasing power from generation facilities that are powered by renewable resources and owned by third parties. It is less clear how much OM&A inputs can cost-effectively substitute for power distribution capex. Peak load management is useful only as a substitute for new distribution capacity, whereas a lot of power distribution capex is for capital replacements and smart grid assets. Further, it is unclear how much capacity growth can be forestalled by DERs and DSM. Good facilities maintenance may substitute for some replacement capex but again it is not clear by how much.

The gravity of this issue also depends on whether the alternative to traditional capex can only be provided by customers or third parties. In the case of power supply, for example, renewable generation technologies are highly capital intensive, utility-scale generation often has major cost advantages, and vertically-integrated utilities can and do own utility-scale solar and wind farms. In the case of power distribution, utilities can undertake peak load management and manage OM&A inputs that reduce the need for replacement capex. Some forms of peak load management (e.g., time-sensitive rate designs) do not entail much OM&A spending. Third parties may undertake peak load management and utility-scale clean generation at lower cost than utilities but the question arises “how much lower?”, especially considering that utilities can access capital markets at lower rates.

Our analysis suggests that third parties such as independent power producers, energy service companies, and vendors of distributed solar generation and storage equipment may be strong supporters of opex solutions and the intervenors that champion them.

How then to improve the balance of capex and opex containment incentives?

- A multiyear rate plan strengthens incentives to contain both opex and capex by lengthening the period during which underspends are profitable.

  They can help to balance capex/opex incentives in two ways. A longer plan term increases the period during which the utility can profit from substituting opex for capex. Some ARM designs are insensitive to capital cost growth.

These include those that use indexing or historical own-cost trending.

- Rebasings should feature competent, thorough prudence reviews that include good statistical benchmarking studies.
- Substitution of opex for capex can be further encouraged by variance account treatment of opex substitutes (e.g., NWA expenses), and PIMs, management fees, and pilot programs that focus on substitution.

  A focus on opex/capex substitution should not, however, be pursued at the expense of ways to reduce capex that don't involve much opex. Distribution rate design is a notable example.

c) Many of THESL's proposed plan provisions encourage capital expenditures.

- The capital revenue requirement would be based on a capital cost forecast.
- Demand-related capex is expected to become a major cost driver with beneficial electrification and this would be accorded variance account treatment.
- A component of the PIM is linked to peak load management but the focus is limited to the purchase of flexibility services at a few sites. The PIM does not consider other means of reducing capacity needs such as managed charging of EVs or time-sensitive distribution rates.
- However, THESL does propose to eliminate the clawback on most of its capex.

d) PEG did not participate in the OEB's remuneration proceedings and has never thoroughly considered the totex approach to cost accounting. We are not yet convinced that this is the best means of improving the capex/opex balance. In addition to having not thought through the theoretical issues, we do not know how much success there has been with this accounting approach in Great Britain. The idea has not spread noticeably to other jurisdictions.

e) The OEB could direct Toronto Hydro to submit a study on totex accounting in its next rebasing application. The Company could afford to fund a thoughtful report on the matter by a respected independent expert. However, this is a long time to wait for such a report, which could alternatively be commissioned by the Board or other utilities in the interim.

M1-ED-002

Reference: Report, p. 87

Preamble: An innovation fund seems warranted to encourage use of innovative or promising practices that Toronto Hydro might be disinclined to pursue for various reasons. Other parties should play a role in selecting these projects so that the innovation fund isn't just a source of extra revenue for projects that interest Toronto Hydro.

Interrogatories:

(a) Does PEG have certain kinds of projects in mind that would be of interest to Toronto Hydro but of less interest to customers?

(b) Does PEG believe certain kinds of projects would be the most beneficial to customers to explore?

Response:

The following response was provided by PEG.

a) PEG was not asked by the Board to prioritize analysis of or commentary on the innovation fund.

b) Our analysis suggests that the fund should encourage innovative practices that cost effectively reduce capex.

M1-ED-003

Reference: Report, p. 93

Preamble: Revenue decoupling and high fixed charges both weaken utility incentives to promote beneficial electrification by denying them margins that could otherwise be gleaned between rate rebasings. Alternative means of incentivizing accommodation of beneficial electrification then merit consideration. The options include a PIM, management fees, or variance accounts for incremental costs of beneficial electrification.

Interrogatories:

(a) Please provide a number of examples of the beneficial electrification that could be incentivized.

(b) Please provide some examples of mechanisms that encourage beneficial electrification in other jurisdictions.

Response:

The following response was provided by PEG.

a) Activities that could be incentivized include the following:

- promotion of the availability and efficacy of beneficial electrification (outreach to both customers and beneficial electrification vendors);
- build or facilitate construction of publicly-available charging stations;
- timely provision of upgraded customer connections to support expanded use of EVs and heat pumps;
- efforts to minimize the demand impact of beneficial electrification through rate design or managed loads;
- efforts to ensure that beneficial electrification is deployed equitably (e.g., facilitating deployment of publicly-available charging stations and heat pumps in areas where residents tend to be less affluent).

b) PEG is aware of American states that have approved financial incentives for beneficial electrification. Here are some details on the approved mechanisms in each of these states. It is notable that most of these states have revenue decoupling.

- California has used variance accounts for costs of EV programs.
- Colorado has approved variance account treatment of Public Service of Colorado's Transportation Electrification Programs and a PIM for equity-focused transportation electrification programs, which pays the company a fixed amount per charging port installed in disadvantaged communities.
- Massachusetts has relied on variance accounts to support pilot EV programs for two distributors and has approved at least one PIM to support pilot EV programs. In addition, the costs of some heat pump programs are tracked as part of statewide energy efficiency programs. The current demand-side management electric performance incentive mechanism includes incentives for some programs to deploy heat pumps.
- In New York, PIMs reward distributors for deploying heat pumps and EVs. Consolidated Edison's current MRP also includes a PIM for electric vehicle managed charging. Costs of EV programs are addressed via variance accounts. The costs of Consolidated Edison's heat pump program are addressed as part of base rates, with underspends returned to customers.
- In Washington state, Puget Sound Energy has a variance account to address the costs of its transportation electrification plan.

M1-ED-004

Reference: Report, p. 94

Interrogatories:

(a) PEG discusses the benefits of full revenue decoupling over decoupling that only applies to weather-normalized revenue variances. Does PEG agree that weather-related uncertainty and risk is relatively higher now due to climate change?

(b) If full revenue decoupling was achieved for Toronto Hydro this would reduce Toronto Hydro's risk with respect to non-residential demand and customer growth. Please discuss possible some examples of changes to the ratemaking framework or ratemaking variables that could be implemented to the benefit of ratepayers to compensate for this risk reduction. In other words, what could customers reasonably get in return for agreeing to lower Toronto Hydro's risk through full revenue decoupling. Please discuss the magnitude of these compensatory benefits at a high level.

Response:

The following response was provided by PEG.

a) Weather volatility can affect the cost of power distribution and the variability of demand. PEG does not know how climate change has affected the variability of demand or whether this is a particular problem in Toronto.

b) Revenue decoupling can potentially benefit customers in several ways.

- Decoupling is usually approved in the context of declining average use. In the future (if not in the next five years), average use may be flat or increase. Decoupling would pass through margins from load growth promptly to customers.
- Approval of revenue decoupling has sometimes led to a downward adjustment to the allowed ROE. For example, early revenue decoupling

plans for Portland General Electric, Delmarva Power & Light, and Potomac Electric Power coincided with reductions to a distributor's allowed ROE.[2] However, utility cost of capital witnesses often maintain that their peer groups take account of the lower risk from decoupling.

- PEG noted in its plan design (e.g., Framework) report that a prime benefit of decoupling is the reduction of risk it can provide to use rate designs that encourage demand-side management. This could benefit customers directly by giving them a chance to lower bills by shifting loads and indirectly by containing the need for costly capacity additions that would be recovered by higher rates. Yet THESL has an unusually high reliance on fixed distribution charges for residential and small business customers and traditional rate designs for customers with larger loads.

[2] See Oregon Public Utilities Commission Order Number 09-020, Maryland Public Service Commission Order Number 81518, and District of Columbia Public Service Commission Order 15556.

M1-ED-005

Reference: Report

Interrogatories:

a) Please discuss incentive structures that can be put in place to ensure that the electricity infrastructure that Toronto Hydro will build over the rate period will be appropriately sized to ensure that it does not need to be prematurely replaced before the end of its physical lifetime due to demand increases arising from electrification.

b) Please comment on a requirement that Toronto Hydro track premature replacements arising from demand growth and justify its original equipment sizing decision. Please also comment on potentially appropriate consequences for premature replacements due to sizing decisions that were not prudent.

Response:

The following response was provided by PEG.

a) PEG has not considered these matters.

b) With demand growth likely to accelerate due to beneficial electrification, PEG believes that THESL should report premature replacement of assets that it installs going forward. However, the prudence of such replacements is difficult to ascertain due to uncertainties about the future of beneficial electrification and DERs.

<u>M1-ED-006</u>

Reference: Report

Interrogatories:

a) Please discuss incentive structures that can be put in place to ensure that Toronto Hydro will continue to be able to meet electricity demand of its customers without delay, including new connections and service upgrades related to electrification.

Response:

The following response was provided by PEG.

a) PEG expressed concern in its plan design report concerning the weak incentives that a multiyear rate plan with revenue decoupling and a high reliance on fixed charges engender to facilitate beneficial electrification. Incentives can be strengthened in several ways.

- Certain costs attributable to beneficial electrification can be afforded variance account treatment.
- Rates to beneficial electrification customers can be designed to recover certain incremental costs of serving them.
- PIMs can address the progress of beneficial electrification.
- THESL can be paid a management fee for efforts to facilitate beneficial electrification.
- Pilot programs can be approved that encourage innovative ways to cost effectively encourage beneficial electrification (e.g., managed charging)
- Encouragement of peak load management by various means will increase the ability of the distribution system to accommodate beneficial electrification.

PEG Responses to Pollution Probe Interrogatories

M1-PP-1

Interrogatories:

Please confirm if PEG is aware of any other utilities or regulators leveraging the following as proposed by Toronto Hydro:

- The new Custom Incentive Rate-Setting ("CIR") framework (in part or whole).
- The proposed attrition relief mechanism ("ARM") (in part or whole)
- The Demand Related Variance Account (DRVA) (in part or whole)

Responses:

The following response was provided by PEG.

CIR 2.0 is probably most similar to ratemaking in New York and Great Britain. In both jurisdictions, the ARM is primarily based on cost forecasts, revenue is decoupled from system use, and there is an extensive use of metrics and PIMs. Britain additionally has uncertainty mechanisms to deal with the unpredictable cost of demand growth.

M1-PP-2

Reference: However, several regulators have balked at using ARMs that rely heavily on cost forecasts and variance accounts. Cited problems include high regulatory cost, utility abuse of information asymmetries to pad cost forecasts, and weakened cost containment incentives. [M1 Evidence Page 6]

Interrogatories:

a) Please identify mitigation measures or controls that have been (or could be) successfully leveraged to resolve the potential risk of ARMs mechanism abuse.

b) Please discuss any interplay between application of Toronto Hydro's proposed ARM and the proposed performance incentive mechanism (PIM), including funding and delivery of the (PIM) scorecard deliverables over the term.

c) Would the recent CIR period under-earnings profile for Toronto Hydro be a relevant factor to consider (vs. a utility that consistently over-earned through the term which may represent a tendency toward abuse)? Please explain.

Responses:

The following responses were provided by PEG.

a) PEG's plan design report explains at some length the alternatives to forecasting for ARM design. These include indexing, historical own-cost trending of capital revenue, and limiting the use of forecasting (with possible variance account trueups) to certain rapidly-growing costs. Energetic and competent reviews of distribution system plans and of cost prudence during rate rebasings are of course also helpful. Statistical benchmarking is useful in prudence reviews.

b) PEG has not been asked by Board Staff to consider the details of the Company's proposed PIM. We challenge in our plan design report, however, the idea of linking the PIM to the X factor.

c) Yes. The Company’s recent underearning experience could indicate a tendency of the CIR 1.0 regulatory system to underfund efficient operation. However, it could also reflect poor cost management and/or the fact that unstable business conditions are more favorable in some plans than in others.

M1-PP-3

Reference: The Company forecasts plant additions in the next five years that are well in excess of its high recent historical norms. [M1 Evidence Page 6]

Interrogatories:

a) Toronto Hydro has outlined its rationale for increased capital spending over the term which includes investments that could decrease costs in the future and enable important component of the energy transition (e.g. DERs). One of the challenges is that OEB approval of the plan and related framework/budgets would not guarantee that those outcomes are delivered over the term since the OEB is not prescriptive on where Toronto Hydro must spend actual capital and O&M over the term. What mechanisms, metrics or other tools could be considered to tangibly link delivery of those specific outcomes with the proposed budget/framework?

b) With the acceleration of the energy transition, electrification and Net Zero by 2040 in Toronto, there is a risk that delaying enabling infrastructure until the next rate term would be too late to take the necessary actions. How are these risks managed or mitigated in the alternate proposal put forward by PEG?

Responses:

The following responses were provided by PEG.

a) PEG believes that a utility should be allowed some freedom during a plan to incur a different mix of costs than it forecasted. However, insofar as the ARM is based on cost forecasts, the OEB should routinely consider how and why incurred and forecasted costs differed and whether goals of programs were met. PEG understands that some of the metrics in THESL's proposed PIM are linked to goals of its business plan.

b) PEG proposes forecast and/or variance account treatment for most of the capital expenditures that would support the energy transition. We have also identified certain transition-related OM&A costs as meriting consideration for forecasting and/or variance account treatment in the event that the OEB decides to stick with an indexed ARM for OM&A revenue. We have more generally identified costs of accommodating DERs and beneficial electrification and demand side management as warranting variance account treatment. PEG also notes that accommodating the energy transition is not just a matter of infrastructure.

PIMs or management fees for peak load management and the quality of service to DER customers therefore make sense. So do pilot programs for innovative peak load management initiatives. Just as there may be a need to bolster infrastructure now in anticipation of beneficial electrification, there may be a need to get started now on peak load management practices that will be needed much more in the future.

M1-PP-4

Reference: Revenue decoupling can reduce the sensitivity of utility earnings to demand-side management, DERs, and demand volatility. [M1 Evidence Page 11]

Interrogatories:

a) Please explain how this could work in the case of Toronto Hydro and how it differs from what was proposed by Toronto Hydro.

b) Please provide your opinion on the mechanism or other tools that the OEB could leverage to maximize Toronto Hydro's focus and related system/customer net benefits of demand-side management and DERs.

Responses:

The following responses were provided by PEG.

a) Revenue decoupling automatically reduces the risk of lost base revenue due to demand-side management (defined to include both conservation and peak load management), DERs, and time-sensitive distribution rates. PEG's concern is that Toronto Hydro is not proposing more progress in these areas that would take advantage of this risk mitigation for desirable activities.

b) These tools include variance account treatment for the costs of DSM and DER accommodation, PIMs and management fees to reward good DSM and DER accommodation, and the use of pilot programs and/or the innovation fund to encourage new activities in these areas.

M1-PP-5

Interrogatories:

The Toronto Hydro demand forecast is Gross, which means that the benefits of things like DERs has not been included and is not tracked over the term. Toronto Hydro is also not incented (or penalized) to maximize these net benefits. Please provide feedback on how this could be addressed through the 2025-2029 term.

Responses:

The following response was provided by PEG.

Please see our response to M1-PP-4.

M1-PP-6

Reference: The most popular focus of new policy PIMs is peak load management (e.g., IL, NC, NY, WA). To date, PIMs for peak load management have rewarded performance on various metrics that include achieved peak load reductions, successful implementation of non-wires alternative projects, and encouraging customer enrollment in time of use rates (this sometimes crosses over with PIMs for the use of AMI). [M1 Evidence, Page 46]

Interrogatories:

a) Please provide copies of the referenced peak load management scorecards and/or metrics which could be considered in the Ontario context.

b) Please explain why peak load management PIMs have become popular for regulators and the benefits that are expected to accrue.

c) Please confirm that the Toronto Hydro PIM scorecard does not include 'peak load management' metrics.

d) Please identify what metrics should be added to the Toronto Hydro scorecard if the OEB wanted 'peak load management' included.

Responses:

The following responses were provided by PEG.

a) Ameren Illinois has two PIMs for peak load management. One is for overall peak load reductions and the other is the share of known customers with EVs that participate in the company's EV managed charging program. Please see Attachment N1-PP-6-1 for additional details of Ameren Illinois' PIMs for peak load management.

   Duke Energy Progress has a PIM for the number of customers enrolled in the company's time-differentiated and dynamic rates. Please see Attachment N1-PP-6-2 for additional details of this PIM.

Consolidated Edison has a PIM for incremental MW reductions that are due to its demand response programs and those of the New York Independent System Operator. Please see Attachment N1-PP-6-3 for additional details of this PIM.

Puget Sound Energy has a PIM for the expected MW reduction in the Company's need for planning reserves for winter coincident peak demand (effective DR capacity). Please see Attachment N1-PP-6-4 for additional details of this PIM.

b) Peak load management is a key to utility cost containment in areas like Toronto that face brisk demand growth and looming capacity constraints. Short-run benefits of peak load management include avoidance of major capacity additions. Longer term, peak load management can limit the capacity additions that must occur due to beneficial electrification. There is legitimate concern that utilities have weak incentives to materially reduce the need for capacity expansion with peak load management.

c) This statement is confirmed. While Toronto Hydro has proposed a metric for flexible system capacity procured through demand response offerings, these are in limited geographic areas. No reward is possible for superior performance. No metric or PIM considers the Company's progress in managing peak load by such means as time-sensitive distribution rates and managed charging of electric vehicles.

d) PEG was not retained to provide specific PIM proposals and has not reviewed the specific circumstances for the Ontario regulatory environment such that they can provide specific metric proposals. However, PEG believes that any of the metrics described in part a) above have merit, though they would likely need to be adapted to best fit Toronto Hydro's specific circumstances.

M1-PP-7

Toronto Hydro has included metrics on the PIM scorecard that are ‘must do’ in order to meet the needs over the term.

Interrogatories:

a) Please confirm that the metrics and targets included in the PIM scorecard submitted by Toronto Hydro do not represent ‘stretch’ objectives.

b) Please confirm that PIM scorecards typically reward achieving ‘stretch’ (i.e. incremental to baseline) objectives.

c) What changes would PEG recommend to the PIM scorecard in order to represent ‘stretch’ objectives?

Responses:

The following responses were provided by PEG.

a) PEG has not been asked by Board Staff to consider the Company’s proposed PIM in detail.

b) PEG’s understanding is that traditional penalty-only PIMs (e.g., reliability and customer service) tend to have targets that are more in line with a recent historical average. Rewards for superior service quality are uncommon. PEG does not have a similar stylized fact about the targets in other kinds of PIMs. PEG notes that PIMs that tie financial incentives to the completion of investment programs or OM&A projects, much less ISO certification are very rare.

c) PEG was not retained to provide specific PIM proposals and has not reviewed the specific circumstances for the Ontario regulatory environment such that they can provide specific proposals on the PIM. We note, however, that THESL is essentially proposing a penalty-only PIM. Some metrics (e.g., emissions reductions) proposed by THESL may have already been given a stretch target. PEG notes that several PIMs, such as ISO compliance and certification, and grid automation readiness can only be stretched by requiring completion at an earlier timeframe than 2029.

PEG Responses to Toronto Hydro-Electric System Limited ("Toronto Hydro")

M1-TH-002

Reference: PEG Framework Report, p. 8 "We also recommend replacing the average weekly earnings of Ontario workers in the revenue cap index inflation measure with Statistics Canada's fixed-weight index ("FWI") of average hourly earnings ("AHE") in Ontario. This is a more accurate measure of labor price inflation. An FWI AHE was recently adopted by the AUC as a component of its inflation factor formula."

Interrogatories

a) Does PEG recommend the OEB transition its sector-wide Inflation Factor to the use of the FWI AHE as opposed to the currently used Average Weekly Earnings? If not, why not?

b) Please provide all facts and analysis performed by PEG, and any related documents, on which PEG relies to conclude that the fixed-weight index ("FWI") of average hourly earnings ("AHE") in Ontario is a more accurate measure of labor price inflation.

Responses:

The following response was provided by PEG.

a) PEG's evidence in this proceeding is intended to aid development of an appropriate CIR framework for Toronto Hydro. However, we do believe that the FWI AHE is an appropriate labor price index to use in the inflation factor formulas of other Ontario utilities.

b) Please see Section 8 of PEG's empirical report. The FWI AHE is a more accurate measure of labor price inflation because it is less sensitive to changes in the mix of workers with low and high salaries. Its accuracy advantage is especially pronounced during and shortly after the conclusion of recessions such as the one that Canada recently experienced. In its recent PBR3 decision, the

Alberta Utilities Commission updated the inflation measure it uses in generic PBR for energy distributors to include the fixed-weighted index of AHE.[1]

[1] Alberta Utilities Commission (2023), Decision 27388-D01-2023, pp. 20-21.

M1-TH-003

Reference: PEG Framework Report, p. 17 “In energy distribution, the number of customers served has been found to be a sensible stand-alone measure of growth in operating scale. When the scale of the utility business is multidimensional, growth in its scale can be measured by a scale index.”

Interrogatory

a) Please provide examples and descriptions of scale indices utilized in other jurisdictions?

Response:

The following response was provided by PEG.

a) The number of customers served is the scale escalator typically used in revenue cap indexes for energy distributors. Customer growth drives many distributor costs and is highly correlated with peak demand, which is another important cost driver. Using peak load as an escalator could weaken incentives for utilities to engage in peak demand management.

   PEG noted on pages 18 and 86 of its framework report the use of a customer escalator in an approved revenue cap index for Enbridge Gas Distribution. Additional precedents for scale escalators in revenue cap indexes are provided in Attachment N1-TH-003.

   PEG is not aware of a plan where a multidimensional output index has been used as a scale escalator in an attrition relief mechanism. However, plans in British Columbia have used different scale variables to escalate different revenue requirement components.

   An example of a scale index that could sensibly be used in ARM design is a weighted average of growth in electric customers and the length of distribution lines. Another example is a weighted average of growth in the numbers of different classes of electric customers.

M1-TH-004

Reference: PEG Framework Report, p.24-25 "In Ontario, ARMs that are based primarily on forecasts have been used on a few occasions to regulate power distributors and Enbridge Gas Distribution."

Interrogatory

a) Please confirm that since the Renewed Regulatory Framework was adopted in October 2012 the OEB approved multi-year ARMs based primarily on forecasts in the following docket numbers.

Applicant	**Docket Number**
Toronto Hydro	EB-2012-0064
Enbridge Gas	EB-2012-0459
Oshawa PUC	EB-2013-0101
Horizon	EB-2014-0002
Toronto Hydro	EB-2014-0116
Hydro Ottawa	EB-2015-0004
Kingston Hydro	EB-2015-0083
Hydro One	EB-2017-0049
Toronto Hydro	EB-2018-0165
Hydro Ottawa	EB-2019-0261
Hydro One	EB-2021-0110

b) Please confirm that the ACM is an attrition relief mechanism that is also based primarily on forecasted capital costs, which are reviewed and approved in the utility's cost of service rebasing

c) Please confirm that since the ACM became available in 2014, the OEB approved forecast-based ACMs in the following docket numbers:

Applicant	**Docket Number**
Wellington North Power	EB-2015-0110
Energy +	EB-2018-0028
Greater Sudbury Hydro	EB-2019-0037
Algoma Power	EB-2019-0019
London Hydro	EB-2023-0037

Response:

The following response was provided by PEG.

a) PEG does not consider ARMs that index OM&A revenue to be *primarily* based on forecasting. This would exclude the following citations on the list, which comprise the majority of the citations and include the four most recent proceedings.

- EB-2012-0064 (ICM application by Toronto Hydro,)
- EB-2014-0116, EB-2018-0165, EB-2017-0049, EB-2021-0110 (Custom IR 1.0 filings, where OM&A expenses were indexed)
- EB-2019-0261 (approved ARM features a capex forecast and a specific OM&A index)

The vast majority of IR plans for power distributors that the Board has approved have not had ARMs based on forecasts of OM&A as well as capital cost.

b) This statement is partially confirmed. PEG notes that even in the most generous application of the ACM where it addresses all capital costs throughout the entirety of the plan term, the ARM would still index OM&A revenue. Further, PEG's review of the ACM precedents listed by Toronto Hydro indicated that in none of the cited instances were all of a distributor's capital costs fully addressed by an ACM. ACMs have been used to date to address high capex in 1 or more years for a few discrete projects (e.g., substation replacement). For example, PEG notes that the Wellington North Power ACM only addressed an unusually high capex level in a single year due to a substation replacement that was scheduled to occur in that year. In all other years, capital cost would be addressed by the index.

c) This statement is confirmed.

M1-TH-005

Reference: PEG Framework Report, p. 50 "PIMs tend to be limited to situations where incentives are conspicuously weak and performance really matters."

Interrogatory:

a) Aside from cost-efficiency which is incentivized by the stretch factor, please identify the financial incentives currently embedded within Ontario's commonly deployed rate frameworks (i.e. Annual IR, Price Cap IR, CIR 1.0) for each of the following areas of performance:

   i. Reliability, as measured via outage duration and frequency;
   ii. Physical and cyber security enhancements;
   iii. Timely connections and service upgrades;
   iv. Customer satisfaction;
   v. Employee safety;
   vi. Continuous improvement in management governance per international standards
   vii. Grid modernization; and,
   viii. The deferral or avoidance of traditional capital investments via non-wires solutions.

Response:

The following response was provided by PEG.

a) i., iii., iv., v., and vi: None of the Board's existing ratemaking frameworks have explicit financial incentives in these areas. However, performance in some of these areas is monitored and there may be consequences for poor performance.

   i., ii., and vii: To the extent that activities in these areas involve capex, distributors under Custom IR have an incentive to propose and undertake them if revenue is reasonably compensatory.

   viii: PEG understands that the Board has invited distributors to propose incentive mechanisms to encourage deployment of 3rd party distributed energy resources as non-wires alternatives. The sanctioned incentives include targeted performance incentive mechanisms, management fees, and variance account treatment of the attendant costs. These incentives are available to distributors operating under any of the Board's current approaches to IR. However, these incentives must be added to the IR frameworks and are not yet "embedded".

PEG understands that the Board plans to explore the addition of targeted financial incentives for various performance areas in an upcoming proceeding.

PEG is not aware of any utility in North America that has financial incentives for the metrics THESL proposes with regard to the areas of performance in ii., vi, and vii.

M1-TH-006

Reference: PEG Framework Report, p. 67 “As CIR evolved to typically feature multiyear forecasts for most capex and a clawback of capital cost savings that weakened incentives, PEG’s perception is that the Board has become increasingly disenchanted with extensive reliance on forecasting in ARM design and outspoken in its request for another ARM design method.”

Interrogatory

a) Please provide all facts and analysis, and any related documents including any correspondence (including emails) and memoranda received from OEB staff or the OEB, on which PEG relies to reach the conclusion that the Board is increasingly disenchanted and outspoken with reliance on forecasting?

Response:

The following response was provided by PEG.

a) PEG’s statement is based on its review of OEB IR documents. Relevant documents are cited in Section 3 of PEG’s plan design evidence. The Board’s frustration with forecasting is hardly unique, as PEG discusses in Section 4.

M1-TH-007

Reference: PEG Framework Report, p. 87 “Ontario distributors have often had variance account treatment of certain costs that result from external events (e.g., changes in government policies) and are hard to predict accurately. In the case of Toronto Hydro, it seems reasonable to accord Y factor treatment for this reason in the new plan to cost categories that include the following.

- externally initiated plant locations and expansions
- Hydro One contributions
- costs occasioned by the Getting Ontario Connected Act”

Interrogatory

Please confirm that Y factor treatment in this context refers to the subjecting of noted costs to a symmetrical Variance Account.

Response:

The following response was provided by PEG.

This statement is confirmed.

M1-TH-008

Reference: PEG Framework Report, p. 85 “Toronto Hydro could be assigned a gross plant additions budget in each year of the new plan that is similar (in the dollars of the next plan) to their average plant additions during the expiring plan less a cost efficiency markdown.”

Interrogatory

a) PEG refers to the “new plan” and the “expiring plan”, please clarify what is meant by the “next plan”.

Response:

The following response was provided by PEG.

a) PEG clarifies that the expiring plan is that for the 2020-2024 period whereas the “new” or “next” plan is for the 2025-2029 period.

M1-TH-009

Reference: PEG Framework Report, p. 86 "Note also that just adjusting the revenue cap index for total customer growth won't fully compensate Toronto Hydro for the costs of high-rise condo connections"

Interrogatory

a) Please confirm that the inclusion of customer growth in the revenue cap index also won't fully compensate Toronto Hydro for the costs of: (i) hyperscale data centers and other large loads (e.g. transit), and (ii) service upgrades to accommodate the increasing load needs of existing customers

Response:

The following response was provided by PEG.

a) The degree to which the customer growth escalator would be compensatory is difficult to ascertain. The following considerations are relevant.

- The econometric research by PEG and Clearspring both revealed that the elasticity of total cost with respect to growth in the total number of customers served was well below 1% during the sample periods of the two studies.
- On the other hand, growth in the total number of customers does not capture the effect on cost growth of service upgrades or of changes in the mix of high and low cost customers. Higher-cost customers include high rise condominiums and large data centers. An elasticity-weighted average of growth in various kinds of customers might better capture the impact of customer growth on power distributor cost. PEG considered this alternative approach but discovered that the overall growth in the number of THESL's non-residential customers was *slower* than the growth in the number of its residential customers.

PEG Responses to School Energy Coalition Interrogatories on CIR 2.0 for Toronto Hydro-Electric System Limited Report

M1-SEC-1

[M1, p.21] PEG states: "Cost trackers can be incentivized mechanistically. For example, a portion of the variance between tracked costs and those already reflected in rates may be deemed ineligible for passthrough."

Interrogatories:

Please provide further details including an example of such an approach that could be used in this application.

Response:

The following response was provided by PEG.

The basic approaches to incentivizing a variance account ("VA") include the following.

1. A "one-way" VA adjusts revenue only for cost underspends
2. Variances must fall outside a dead-band before revenue adjustments can occur. The adjustment can then draw down the entirety of the variance.
3. Variances must exceed a dead-band before revenue adjustments can occur. A portion of the variance commensurate with the deadband (aka the "dead zone") is ineligible for revenue adjustment.
4. A share (e.g., 5-10%) of the variance is ineligible for recovery. Sharing percentages can differ in different ranges of the variances.

These basic approaches can be combined. Here are some examples.

5. One-way VA with sharing of underspends
6. Dead band with sharing
7. Dead zone with sharing

PEG generally supports the incentivization of variance accounts and favors a sharing approach to accomplish this. The rationale for incentivization diminishes to the extent that the cost is volatile and the utility has little control over the cost.

<u>M1-SEC-2</u>

[M1, p.22] PEG states: "The second kind of UM for LREs is a volume driver. This is only available for a limited set of reinforcement projects on the secondary network including flexibility services and low voltage services reinforcements. With a volume driver, "Unit rates" (unit costs) and "volumes" (typically asset quantities) have been established for various kinds of LREs at the outset of the plan term. When actual volumes are known, allowed revenues for eligible cost categories are updated to equal the unit rate x actual required volume. Variances between the allowed and actual unit rates are shared with customers.

Various metrics (e.g., transformer utilization) have been established to flag potential suboptimal investment. If the distributor does not meet the targets for the applicable metrics, it must submit additional information to justify the volumes deployed.20 If the regulator is not satisfied that the expenditure was justified, it may reduce the volumes that are included in rates. There are also caps on the costs addressed by volume drivers."

Interrogatories:

a) Please provide further details regarding the "limited set of reinforcement projects on the secondary network including flexibility services and low voltage services reinforcements" to which this mechanism has be applied to. What capital programs/projects in Toronto Hydro's application would be most similar?

b) Please details regarding how "Variances between the allowed and actual unit rates are shared with customers." If such a mechanism was applied in the current application, how would PEG propose it could work?

c) Please provide further details regarding the "Various metrics (e.g., transformer utilization) have been established to flag potential suboptimal investment". If such metrics were applied in the current application, how would PEG propose it could work?

d) Please provide details regarding "caps on the costs addressed by volume drivers." If such a cap were applied to the current application, how would PEG propose it be set?

e) In the context of the referenced mechanism, or otherwise, please provide PEG's opinion on Toronto Hydro's response to interrogatory 9-SEC-129.

Responses:

The following responses were provided by PEG.

a) Secondary reinforcement activities addressed by the volume driver are projects that manage load-related capacity constraints affecting substations and circuits on the secondary distribution network (i.e. at voltages up to 22kV). These include the reinforcement of pad-mounted and pole-mounted transformers, reinforcement of overhead lines and underground cables, and the use of flexibility services to defer reinforcements. PEG believes that Toronto Hydro has several capex programs and at least one OM&A program that are similar to these activities. These programs include load demand (e.g., feeder cable upgrades and load transfers to improve capacity and asset utilization), non-wires solutions, the load connections segment of the Customer and Generation Connections program, stations expansion, and the flexibility services segment of the OM&A program Asset and Program Management.

   Low voltage service reinforcement activities addressed with volume drivers include projects that are required to increase the capacity of service connections to individual loads at low voltage (e.g., less than 1 kV). This may entail the replacement of overhead pole lines, underground cables, switchgear fuses, and switchgear cut outs. PEG believes that the closest analogue to this program is the segment load connections of the Customer and Generation Connections capex program. However, the load connections segment also includes new load connections, so it is not a perfect match.

b) Variances between allowed and actual unit rates are flowed through the totex incentive mechanism, which addresses most variances between actual and allowed costs. The variance in each unit rate is multiplied by the final actual volumes deemed prudent in order to come up with an amount that flows into the "totex incentive mechanism".[1] The totex incentive mechanism varies amongst British power distributors, but is generally

[1] The term totex incentive mechanism is used by Ofgem to describe its mechanism for sharing totex variances. PEG has placed it in quotes to point out that the mechanism provides a disincentive to contain totex, by reducing the potential profit that the distributor may earn by keeping totex under forecast levels.

close to 50% (e.g., the distributor is allowed to retain 50% of savings on unit rates and is only allowed to recover 50% of unit rates in excess of allowed levels). In Toronto Hydro's current application, this could be addressed via a variance account where the distributor is allowed to keep 50% of unit cost variances multiplied by actual volumes deemed prudent.

c) Five metrics were approved to monitor distributor performance with the secondary reinforcement volume driver. One metric was approved to monitor performance with the low voltage service volume driver. In most cases these metrics have targets. We briefly discuss each metric and target.

- Forecasted transformer utilization for transformers to be reinforced Only 10% of capacity additions may be for transformers that have a utilization level below 100%.
- Change in gross transformer capacity divided by the peak load impact of additional low carbon technologies (e.g., heat pumps and electric vehicles) This value is compared to an industry benchmark and a tolerance of 10% above the industry benchmark is permitted. There are separate metrics for pole mounted and pad mounted transformers.
- Length of low voltage circuits added divided by the peak load impact of additional low carbon technologies This value is compared to an industry benchmark and a tolerance of 10% above the industry benchmark is permitted. There are separate metrics for overhead line and underground circuits.
- Length of high voltage circuits added divided by the peak load impact of additional low carbon technologies. This value is compared to an industry benchmark and a tolerance of 10% above the industry benchmark is permitted. There are separate metrics for overhead line and underground circuits.
- Growth in peak demand and electricity consumption for transformers where low voltage monitoring is possible. Peak demand is based on the peak for individual low voltage substations. There is no target for this metric.
- Transformer utilization rate for transformers where flexibility services were procured. The goal is to limit flexibility service procurement to transformers with

utilization rates above or projected to be above 100%.

- The <u>Low Voltage Service volume driver metric</u> only applies to *proactive* efforts by the distributor (e.g., *reactive* reinforcement efforts are not addressed by this metric). For those activities, the number of properties that are "unlooped" (e.g., ensuring that each electricity meter is connected to the network directly rather than from one house to another) is compared to the number of overhead pole lines, service cables, cut outs (metered), and fuse upgrades. If the number of proactively-reinforced overhead pole lines, service cables, cut outs (metered), and fuse upgrades exceeds the number of properties unlooped by more than 20%, the distributor has failed to pass this metric.

PEG has not considered how an analogous scheme might work in Toronto.

d) For each of the secondary reinforcement and low voltage services volume drivers, the cap is a single value that applies to the entirety of the term of the MRP. There are no annual caps or caps on the individual asset categories that are eligible for volume driver treatment. The cap for the low voltage services volume driver is based on the distributor's forecast of low voltage service upgrade costs from the rate case, while the secondary reinforcement volume driver cap is based on Ofgem's estimate of the difference in the efficient level of secondary reinforcement costs between various scenarios of low carbon technology uptake. PEG has not considered how an analogous scheme might work in Toronto.

e) Toronto Hydro is essentially saying that it seeks VA treatment of demand-related costs for various reasons. Limiting revenue adjustments to just a few of the possible reasons would be unfair to the Company and create accounting complications. The Company skates over how variance-account treatment would weaken the Company's incentive to contain demand-related costs. In fairness, Ofgem limits the use of volume drivers to just a few cost categories and permits reopeners for several other kinds of demand-related costs.

M1-SEC-3

Interrogatory:

[M1, p.26] Please provide details regarding the Ofgem "information quality incentive". If such an incentive were applied to Toronto Hydro, how would PEG propose it could be done?

Response:

The following response was provided by PEG.

Given the time allotted to respond to interrogatories, PEG relied on its existing research on the subject which was discussed in a white paper we prepared for Lawrence Berkeley National Laboratory.[2] This report discussed the information quality incentive ("IQI") as it functioned in the multiyear rate plans that were approved in Ofgem's 5th Distribution Price Control Review.

This IQI rewarded distributors for making conservative cost forecasts and then performing better. This was accomplished with a menu consisting of cost forecast-allowed revenue combinations. It applied to most operation and maintenance ("O&M") expenses and capex. Each utility was asked to forecast its cost and was eventually given an allowed revenue amount based on this forecast. The IQI's input on allowed revenue was in two parts: *ex-ante* allowed revenue and an IQI adjustment factor. By announcing its cost forecast, the utility implicitly chose both its *ex-ante* allowed revenue and an IQI adjustment factor formula.

The *ex-ante* allowed revenue was a weighted average of the regulator's and the utility's cost forecasts. The regulator's forecast received 75 percent weight while the utility's forecast received 25 percent weight. This treatment alone greatly reduced the payoff to the distributor from a high cost forecast. The substantial weight assigned to Ofgem's forecast reflected the sizable outlay it made on engineering and consulting services to develop an independent view of future cost.

The IQI adjustment factor was composed of an incentive rate and an additional income factor. The incentive rate specified sharing, between utilities and customers, of variances between

[2] Lowry, M.N., M. Makos, J. Deason, L.C. Schwartz, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," prepared for Lawrence Berkeley National Lab, July 2017.

the utility's actual expenditures and the allowed revenue for these expenditures that it was granted *ex ante*. The utility's share of these variances increased as the difference between the utility's cost forecast and the regulator's own forecast decreased. The additional income factor, also referred to as an upfront reward or penalty, provided an immediate incentive for the utility to provide a cost forecast that was at or below Ofgem's own forecast.

Together these provisions made the IQI an "incentive compatible" menu. The utility was rewarded when its cost forecast was low and its actual cost was similar to its forecast. The IQI discouraged a strategy of proposing a high forecast and subsequently incurring low costs.

Figure A-1 shows the IQI menu developed for the 2010-2015 plan:

- The first row is a ratio of the utility's cost forecast to the regulator's cost forecast. A ratio of less than 100 means the utility has presented a lower cost forecast than the regulator, while a ratio above 100 means the utility's cost forecast is higher than the regulator's.
- The second row is the utility's share of what it over- or underspends relative to the *ex-ante* allowed revenue. The utility's share of these variances increases when its cost forecast is low. This feature provides greater incentives for the utility to cut costs and provide a forecast that is not inflated.
- The third row is the *ex-ante* revenue the utility is allowed to collect, expressed as a percentage of the regulator's cost forecast. This is much closer to Ofgem's forecast than to the utility's.
- The fourth row is the additional *ex post* income the utility can collect, expressed as a percentage of the regulator's cost forecast. This is a reward for a low cost forecast.

Figure A-1

Utility's cost forecast (% of Ofgem's cost forecast)	95	100	105	110	115	120	125	130	135	140
Utility's share of under/over spending (incentive rate)	0.53	0.5	0.48	0.45	0.43	0.4	0.38	0.35	0.33	0.3
Ex-ante allowed revenue (% of Ofgem's cost forecast)	98.75	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Ex-post additional income (% of Ofgem's cost forecast)	3.09	2.5	1.84	1.13	0.34	-0.5	-1.41	-2.38	-3.41	-4.5
Actual utility expenditure (% of Ofgem's cost forecast)	**IQI Adjustment Factor (% of Ofgem's cost forecast)**									
90	7.69	7.5	7.19	6.75	6.19	5.5	4.69	3.75	2.69	1.5
95	5.06	5	4.81	4.5	4.06	3.5	2.81	2	1.06	0
100	2.44	2.5	2.44	2.25	1.94	1.5	0.94	0.25	-0.56	-1.5
105	-0.19	0	0.06	0	-0.19	-0.5	-0.94	-1.5	-2.19	-3
110	-2.81	-2.5	-2.31	-2.25	-2.31	-2.5	-2.81	-3.25	-3.81	-4.5
115	-5.44	-5	-4.69	-4.5	-4.44	-4.5	-4.69	-5	-5.44	-6
120	-8.06	-7.5	-7.06	-6.75	-6.56	-6.5	-6.56	-6.75	-7.06	-7.5
125	-10.69	-10	-9.44	-9	-8.69	-8.5	-8.44	-8.5	-8.69	-9
130	-13.31	-12.5	-11.81	-11.25	-10.81	-10.5	-10.31	-10.25	-10.31	-10.5
135	-15.94	-15	-14.19	-13.5	-12.94	-12.5	-12.19	-12	-11.94	-12
140	-18.56	-17.5	-16.56	-15.75	-15.06	-14.5	-14.06	-13.75	-13.56	-13.5
145	-21.19	-20	-18.94	-18	-17.19	-16.5	-15.94	-15.5	-15.19	-15

Figure A-1. IQI Matrix for Ofgem's 5th Distribution Price Control Review.[3] IQI Matrix was an incentive compatible menu intended to encourage utilities to make low expenditure forecasts and then outperform them.

Values in the second section of Figure A-1, labeled IQI Adjustment Factor, illustrate possibilities for additional revenue (expressed as a percentage of Ofgem's cost forecast) which the utility was allowed to collect after it reported actual expenditures for the price control period. The amount of additional revenue depended on how the company's forecast

[3] Ofgem (2009), "DPCR5 Final Proposals Incentives and Obligations," Ref. 145/09, p. 111. Presented here with some small changes to be more easily understood.

compared to Ofgem's forecast and to the company's ultimate expenditures. The revenue adjustment was more favorable to the utility to the extent that its expenditures were low relative to its own forecast and Ofgem's forecast. The highest reward was offered for spending less than a utility forecast that was low relative to Ofgem's forecast.

PEG has not considered how an IQI could apply to Toronto Hydro. A notable challenge is the lack of an independent view of what the Company's cost should be in the next five years. PEG does not believe that its econometric benchmarking model is appropriate for this purpose because it is based on long-run capital cost.

M1-SEC-4

Interrogatory:

[M1, p.26] Please explain how the California "Old School" approach would be applied to Toronto Hydro, including all necessary calculations.

Response:

The following response was provided by PEG.

The California Old School approach to ARM design combines indexation of OM&A revenue with historical own cost trending of capital revenue. Capital revenue escalation differs from Alberta's K-bar approach in several important respects.

1. It does not entail replacement of indexed capital revenue with a capital revenue alternative. Indexing applies only to OM&A revenue and doesn't apply even nominally to capital revenue.
2. While each year's gross plant addition budgets have on many occasions been based on the Company's historical gross plant additions, these budgets have instead sometimes been based on the budget approved for the test year.
3. There is no productivity markdown for plant addition budgets.

To clarify this California "old school" approach to ARM design and other approaches that PEG has discussed, PEG provides a compendium of ARM design formulas below.

PEG cannot undertake all necessary calculations to illustrate this approach because they do not have access to THESL's capital revenue requirement model or its historical and forecasted gross plant additions by customer. They can only provide suggestive calculations using the available data on program capex. Please see our response to M1-SEC-11 for details of these calculations.

PEG also notes that in California indexation of the OM&A revenue requirement usually takes the form of a simple inflation adjustment on the assumption that productivity growth equals growth in operating scale.

Useful Formulas for ARM Design

This compendium details some useful formulas for attrition relief mechanism ("ARMs") that can be used in multiyear rate plan ("MRP") design. To simplify exposition, we assume that the ARM caps growth in the utility's revenue requirement even though some ARMs cap price growth.

Indexed ARMs

Here is one version of the general formula for a substantially comprehensive indexed revenue cap ARM. In each "out" year *t* of the MRP (i.e., in years after the rebasing year), the total revenue requirement (denoted R_t) is determined by the formula

$$R_t = R_{t-1} \cdot [1 + (I - X + N)] + Y_t + Z_t. \qquad [1a]$$

Here

$$I - X + N = \Delta I_t - X + \Delta N_t,$$

where Δ is a growth rate, I_t is the inflation measure, X is the X factor, and N_t is the number of customers served. Y_t is the Y factor and Z_t is the Z factor.

The total revenue requirement is the sum of revenue that is subject to Y factor treatment ("RY_t") after indexing and revenue that is only subject to indexing treatment ("$RNDX_t$")

$$R_t = RY_t + RNDX_t.$$

The Y factor uses one or more variance accounts ("VAs") established in advance to implement an "index runaround" for certain itemized revenue requirement components. Let CY_t be the portion of the corresponding actual cost incurred in year *t* that is deemed prudent by the regulator. Then, effectively, for each cost category *j*

$$Y_{j,t} = CY_{j,t} - RY_{j,t-1} \cdot [1 + (I - X + N)].[4]$$

$$Y_t = SUM_j Y_{j,t}$$

[4] We ignore here and elsewhere in the discussion the fact that true ups to actual cost may occur in the next plan period or at the end of the plan. The value of true ups next period would be discounted in a net present value analysis but this would be roughly offset by the carrying charges that many utilities with VAs receive on unrecovered balances.

$Z_t = RZ_t^{net}$ is a net revenue requirement adjustment for one or more hard-to-foresee external events that materially affect earnings.[5]

The ARM then has the following outcome for revenue attributable to year *t*

$$R_t = RNDX_{t-1} \cdot [1 + (I - X + N)] + CY_t + RZ_t^{net}. \qquad [1b]$$

Forecasted ARMs

Some ARMs have been based primarily on cost forecasts and do not use indexing.[6] In such forecasted ARMs, let costs that are Y factored be denoted CF_t^Y while those that are not are denoted CF_t^{Other}. If $F_0(\ )$ indicates a forecast made in year 0 then

$$R_t = F_0(CF_t^{Other}) + F_0(CF_t^Y) \ + Y_t + Z_t. \qquad [2a]$$

We assume again that

$$Y_{j,t} = CF_{j,t}^Y - F_0(CF_{j,t}^Y)$$

$$Y_t = SUM_j Y_{j,t}.$$

Then, effectively, the revenue requirement attributable to year *t* is

$$R_t = F_0\left(CF_t^{Other}\right) + CF_t^Y \ + RZ_t^{net}. \qquad [2b]$$

Hybrid ARMs 1: Indexing and Forecasts

This approach entails indexing for some revenue requirement components and forecasting for others. Some components of forecasted cost may be trued up to actuals while others may not be. Then

$$R_t = RNDX_{t-1} \cdot [1 + (I - X + N)] + F_0(CF_t^{Other}) + F_0(CF_t^Y) \ + Y_t + Z_t \qquad [3a]$$

where, for each Y-factored cost category *j*, effectively

$$Y_{j,t} = CF_{j,t}^Y - \left[F_0\left(CF_{j,t}^Y\right)\right]$$

$$Y_t = SUM_j Y_{j,t}.$$

Then, effectively, this hybrid approach produces the following revenue requirement

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[5] Eligible adjustments must typically exceed a materiality threshold either individually or cumulatively.

[6] In some of these plans indexing may have provided part of the basis for forecasts.

attributable to year *t*.

$$R_t = RNDX_{t-1} \cdot [1 + (I - X + N)] + F_0\left(CF_t^{Other}\right) + CF_t^Y \ + RZ_t^{net}. \quad [3b]$$

A common use of this kind of hybrid is to index most OM&A revenue while forecasting most or all capital cost.

The CIR approach used by some Ontario utilities is a variant on this theme. There is no customer growth escalator in the revenue index but there is a C factor that ensures that capital revenue requirement growth equals forecasted capital cost growth.

$$R_t = RNDX_{t-1} \cdot [1 + (I - X + C)] + Y_t \ + Z_t. \quad [4a]$$

Ignoring *Y* and *Z* for simplicity,

$$\frac{R_t}{R_{t-1}} - 1 = I - X + C$$

$$= sr_{OM} \cdot (I - X) + sr_k \cdot \Delta CK_t.$$

$$= (1 - sr_k) \cdot (I - X) + sr_k \cdot \Delta CK_t$$

where sr_{OM} and sr_k are the shares of OM&A expenses and capital in the revenue requirement and ΔCK_t is the forecasted growth rate of capital cost. Solving for the C factor we find that

$$C = (1 - sr_k - 1) \cdot (I - X) + sr_k \cdot \Delta CK_t$$

$$= sr_k \cdot [\Delta CK_t - (I - X)]$$

$$= \frac{CK}{C^{tot}} \cdot \frac{CK_t - CK_{t-1}}{CK} - sr_k \cdot (I - X)$$

$$= \frac{CK_t - CK_{t-1}}{C^{tot}} - sr_k \cdot (I - X)$$

In recent Ontario CIR plans, *C* is not bolstered by the X factor or reduced by customer growth but is reduced by a supplemental capital stretch factor (“S”). Thus

$$C = \frac{CK_t - CK_{t-1}}{C^{tot}} - sr_k \cdot (I + S)$$

$$= C_n - sr_k \cdot (I + S). \quad [4b]$$

Here C_n is a term of art that has been used by Toronto Hydro.[7]

Hybrid ARMs 2: Indexing and Historical Own-Cost Trending

Here is a stylized formula for the "old school" California approach to ARM design. In each year *t* let the capital revenue requirement that is escalated using trended historical gross plant additions be denoted $\overline{RK}_t$ while ROM_t is once again the OM&A revenue requirement. We allow for a portion of ROM to be Y factored after initial indexing. Then in each year *t* let

$$R_t = ROM_{t-1} \cdot [1 + (I - X + N)] + \overline{RK}_t + Y_t + Z_t \qquad [5a]$$

$$ROM_t = ROM_t^{NDX} + ROM_t^{Y}$$

$$Y_{j,t} = COM_{j,t}^{Y} - ROM_{j,t}^{Y} \cdot [1 + (I - X + N)]$$

$$Y_t = SUM_j Y_{j,t}.$$

Then effectively

$$R_t = ROM_{t-1}^{NDX} \cdot [1 + (I - X + N)] + \overline{RK}_t + COM_t^{Y} + RZ_t^{net}. \qquad [5b]$$

The Alberta K-bar approach is a variant on this theme. The capital revenue requirement is nominally subject to indexing $\left(RK_{t-1}^{bar}\right)$ and a K-bar term replaces this with a capital revenue requirement escalated using historical gross plant additions ($\overline{RK}$).

$$R_t = \left(ROM_{t-1} + RK_{t-1}^{bar}\right) \cdot [1 + (I - X + N)] + \overline{K} + Y_t + Z_t \qquad [6a]$$

$$ROM_t = ROM_t^{NDX} + ROM_t^{Y}$$

$$\overline{K} = \overline{RK}_t - RK_{t-1}^{bar} \cdot [1 + (I - X + N)]$$

$$Y_{j,t} = COM_{j,t}^{Y} - ROM_{j,t}^{Y} \cdot [1 + (I - X + N)]$$

$$Y_t = SUM_j Y_{j,t}.$$

Then effectively

$$R_t = ROM_{t-1}^{NDX} \cdot [1 + (I - X + N)] + \overline{RK}_t + COM_t^{Y} + RZ_t^{net}. \qquad [6b]$$

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[7] See, for example, EB-2023-0195 Exhibit 1B Tab 2 Schedule 1 p. 5.

Hybrid ARMs 3: Indexing + Forecasting + K Bar

A third logical possibility is a hybrid design that includes indexing, forecasting, and historical own-cost trending. This can make sense where costs grow more rapidly than either indexing or historical own-cost trending can compensate.

Let's allow for the possibility that some revenue requirement components that are initially indexed or forecasted costs are later Y-factored. The general formula for the ARM is then

$$R_t = \left(ROM_{t-1} + RK_{t-1}^{bar}\right) \cdot [1 + (I - X + N)] + \overline{K} + F_0(CF^0 + CF^Y) + Y_t + Z_t \qquad [7a]$$

where RK_t^{bar} is the component of the capital revenue requirement that is nominally subject to indexing, and

$$ROM_t = ROM_t^{NDX} + ROM_t^Y.$$

$$\overline{K}_t = \overline{RK}_t - RK_{t-1}^{Bar} \cdot [1 + (I - X + N)]$$

$$Y_{j,t} = COM_{j,t}^Y - \left\{ROM_{j,t-1}^Y \cdot [1 + (I - X + N)] + F_0(CF_{j,t}^Y)\right\}$$

$$Y_t = SUM_j Y_{j,t}.$$

This kind of hybrid ARM then effectively produces the following result.

$$R_t = ROM_{t-1}^{NDX} \cdot [1 + (I - X + N)] + \overline{RK}_t + F_0(CF_t^0) + COM_t^Y + RZ_t^{net}. \qquad [7b]$$

I-X+N only applies to OM&A revenue that isn't Y factored.

M1-SEC-5

Interrogatories:

[M1, p.32] Please provide a copy of referenced PEG paper in *The Electricity Journal*.

Response:

The following response was provided by PEG.

Please see Attachment N1-SEC-5.

M1-SEC-6

Interrogatory:

[M1, p.33] Please provide further details regarding the Duke Energy ARM, and if such an approach was applied to Toronto Hydro, how would be calculated?

Response:

The following response was provided by PEG.

In the ARMs for Duke's two electric utilities in North Carolina there is no base rate escalation for some costs in the out years of the plan. Adjustments to base rates are limited to changes resulting from discrete and identifiable capital projects that were reviewed and approved in the company's rate case and had entered service in a given year. Costs related to blanket programs were ineligible for this treatment. The costs of these projects, along with any increases in OM&A expenses, were funded indirectly through billing determinant growth and funding provided by the depreciation of plant value. Thus, most costs were not afforded a forecasting treatment.

For example, Duke Energy Progress proposed 17 distribution capital projects (e.g., hazard tree removal, voltage regulation, distribution automation, equipment retrofit, and targeted undergrounding), a cybersecurity project, and a portfolio of battery energy storage projects as part of its proposed MRP.[8] For each program Duke forecasted the level of plant additions during each rate year and presented forecasts of associated OM&A expenses and net operating benefits, if applicable. During the course of the rate case, these projects and associated revenue requirements were reviewed, with the regulator making the decision on which projects (or portions thereof) merited approval. Revenue requirements and rates are adjusted each year based on the level of eligible costs approved from the rate case decision. Some examples of operating benefits from these projects were reduced vegetation management expenses due to an undergrounding program and reduced outages due to

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[8] These projects often include numerous subprojects (e.g., substation and line projects named the various facilities that the company proposed to work on by location or task).

Duke Energy Carolinas and Duke Energy Progress are vertically integrated electric utilities. As a result their ARMs also included capital projects for generation and transmission which are not discussed here.

expected reliability improvements.

This ARM design approach could be applied to Toronto Hydro by using price caps and approving plant additions for each year of the plan for discrete and identifiable projects that THESL proposed. Plant additions from capex programs or segments that were not discrete projects (e.g., customer connections and reactive capital) would not be eligible. To the extent that Toronto Hydro could identify any associated OM&A expenses and OM&A benefits, these would also be incorporated into the revenue requirement for each year of the plan. Each year, rates would be updated to account for the revenue requirements of eligible plant that entered service and any associated OM&A impacts. There would be no adjustment to rates for inflation, productivity, or stretch factors.

M1-SEC-7

Interrogatory:

[M1, p.77-78] PEG states: "It should also be noted that the major changes to the rate framework that THESL proposes include the abandonment of indexing for OM&A revenue and variance account treatment of demand-related costs. Neither of these approaches are typical of utilities undergoing an energy transition." Please explain the basis for PEG's view that the changes Toronto Hydro proposes to the rate framework are not typical of a utility undergoing an energy transition.

Response:

The following response was provided by PEG.

Amongst the multiyear rate plans that PEG has surveyed in jurisdictions that are arguably on the forefront of the energy transition, only those in Minnesota, New York and Great Britain use primarily-forecasted ARMs while only Great Britain has an uncertainty mechanism for most demand-related costs. Jurisdictions confronting an energy transition where substantially different ARM designs are used include California, Hawaii, Massachusetts, Vermont, and Australia.

The strawman proposal of Connecticut's regulator for a new ARM design for MRPs of power distributors in the state entails a large role for indexing.[9]

[9] Connecticut Public Utilities Regulatory Authority, Docket 21-05-15RE01, "Straw Proposal," November 16. 2023.

M1-SEC-8

Interrogatory:

[M1, p.79] PEG discusses the Hawaiian Electric Company approved “Exceptional Project Recovery Mechanisms”. Please provide further details regarding the mechanism.

Response:

The following response was provided by PEG.

Appendix A to Hawaii Public Utilities Commission Decision and Order Number 37507 provides extensive details on the Exceptional Project Recovery Mechanism. This is provided as Attachment N1-SEC-8 to this response.

M1-SEC-9

Interrogatory:

[M1, p.81] As compared to its approved rate framework, does PEG believe Toronto Hydro's proposed rate framework increases or decreases risk?

Response:

The following response was provided by PEG.

Several provisions in the Company's proposed CIR 2.0 would reduce risk relative to its current rate framework.

- OM&A revenue would be escalated by an inflation-adjusted forecast that takes account of an anticipated labor cost surge.
- Most or all demand-related cost would be accorded VA treatment.
- Most commercial and industrial revenue would be subject to decoupling.

There would no longer be a clawback of capital cost underspends. However, this is a reduction in risk that benefits the Company since there may, for example, be unusually favorable weather during the plan that doesn't occasion storm-related capex.

M1-SEC-10

Interrogatory:

[M1, p.83] Please explain in greater detail the referenced "double counting" issue, including by providing an illustrative example.

Response:

The following response was provided by PEG.

PEG has discussed the double counting issue at some length in recent CIR proceedings. A good example in the present context would be that THESL wants to replace indexing with cost forecasting as the escalator for OM&A revenue. This is rationalized in part by an anticipated surge in labor costs due to a need to hire workers with more technical skills. This kind of hiring has likely slowed the productivity growth of power distributors in past and future productivity studies that are used to set the base productivity trend.

M1-SEC-11

Interrogatory:

[M1, p.87-93] PEG has provided a Straw Man alternative proposal for OM&A and capital revenue, please provide a step-by-step instruction, including all formulas, rules and criteria, required to implement the proposal for Toronto Hydro.

Response:

The following response was provided by PEG.

PEG's strawman alternative proposal is a Hybrid 3 ARM that mixes indexing, forecasts, and a K-bar treatment of some capital revenue. We assume that 2025 will be the rebasing year, so our proposals for OM&A and capital revenue escalation would be operative for the four years from 2026 to 2029.

OM&A Revenue

The practitioner must first determine which components of the OM&A revenue requirement (if any) would not be escalated by the revenue cap index. All of these excluded components may be escalated based on cost forecasts, and some of these components may subsequently be accorded some kind of one-way or two-way variance account treatment. The residual portion of the revenue requirement would be subject to revenue cap index escalation. PEG nominated some OM&A cost categories for possible forecasting in Table 1 of its plan design report.

PEG believes that there may be some OM&A program segments that are tied to the energy transition (e.g., smart grid deployment, DERs, electric vehicles, and heat pumps) but were not sufficiently itemized for forecasting and/or variance account treatment. PEG believes that if these segments can be sufficiently itemized to isolate the energy transition related items, these segments should also be eligible for forecasting and/or variance account treatment. PEG defers to the parties in this proceeding to determine which of those cost categories should be forecasted and not subsequently trued up and which should have variance account treatment.

For reader convenience, PEG has pasted in its OM&A tables at the end of this response as Table N1-SEC-11a and N1-SEC-11b.

Capital Revenue

The practitioner must first determine which components of the capital revenue requirement would not be subject to a K-bar treatment. All of these excluded components may be escalated based on cost forecasts, and some may subsequently be accorded some kind of one way or two way variance account treatment. PEG is aware that there may be some capex program segments that they have not proposed for forecast or variance account treatment that encompass part of the energy transition (e.g., related to smart grid deployment, DERs, electric vehicles, or heat pumps). PEG believes that those capex program segments, to the extent that the energy transition capex can be itemized should also be eligible for forecasting or variance account treatment. PEG defers to the parties in this proceeding to determine which of those categories should be forecasted and not subsequently trued up and which should have variance account treatment, though PEG believes that capex programs that would increase system capacity should not be afforded variance account treatment. This will increase Toronto Hydro's incentive to pursue non-wires alternatives.

PEG notes that it has decided to treat the capex category: Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets as a forecast and/or tracked category. Much of the capex being addressed here is from programs PEG has nominated for forecast and/or tracking treatment. To the extent that some of the capex in this category is not from a category that would be addressed by a forecast or variance account, an adjustment would need to be made.

The residual portion of the capital revenue requirement would be subject to a K-bar treatment that is similar though not identical to that in Alberta. In each of the five years ending in 2024 the values of THESL's gross plant additions by program that are subject to K-bar treatment would be escalated to 2025 using the revenue cap index formula approved in this proceeding and then averaged. The average values would then be escalated to 2029 using the same formula. The resulting gross plant addition budgets for 2026-2029 would then feed into THESL's revenue requirement model along with the forecasts for the gross plant additions of other programs. This step would require THESL's cooperation. THESL's modelling would take into account plant retirements, depreciation, and plant value.

The gross plant additions data needed to calculate budgets are unavailable, but we tried to do something similar with available capex data in tables N1-SEC-11 (c) and (d) (shown below and included as Attachments N1-SEC-11c and N1-SEC-11d). Table N1-SEC-11(c) details a straw man revenue cap index. Table N1-SEC-11(d) uses this index to escalate the recent historical capex of projects that would be accorded K-bar treatment.

Please note that the K-Bar calculations for PBR3 in Alberta were facilitated by the fact that there was a one-year gap between the PBR2 and PBR3 plans. This made it possible to work with the actual gross plant addition data for the five years of the prior plan. For the calculations in the attached tables we were compelled to work with forecasted capex data for 2024.

PEG would be open to some variations on the Alberta theme. For example, historical gross plant additions could be escalated by an asset price index.

Table N1-SEC-11(a)

Excluding Certain OM&A Cost Categories from Indexing

	Expiring Plan (Nominal $)					New Plan Proposed					
Programs	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	AAGR 2026-2029
Distribution Operations											
Preventative and Predictive Overhead Line Maintenance	$ 5.8	$ 6.2	$ 5.7	$ 7.3	$ 7.9	$ 9.1	$ 9.2	$ 9.6	$ 9.5	$ 9.4	0.81%
Preventative and Predictive Underground Line Maintenance	$ 5.1	$ 4.4	$ 5.7	$ 6.2	$ 6.1	$ 6.8	$ 7.0	$ 6.7	$ 7.1	$ 7.0	0.72%
Preventative and Predictive Station Maintenance	$ 5.9	$ 6.4	$ 5.5	$ 5.8	$ 7.0	$ 8.0	$ 7.6	$ 7.7	$ 8.6	$ 8.8	2.38%
Corrective Maintenance	$ 23.1	$ 26.5	$ 23.5	$ 25.7	$ 25.6	$ 29.5	$ 30.7	$ 31.0	$ 32.0	$ 33.6	3.25%
Emergency Response	$ 22.1	$ 23.0	$ 22.0	$ 19.8	$ 23.1	$ 25.9	$ 26.4	$ 27.2	$ 27.9	$ 28.6	2.48%
Disaster Preparedness Management Program	$ 6.0	$ 5.5	$ 4.9	$ 0.9	$ 1.8	$ 1.9	$ 1.9	$ 2.0	$ 2.1	$ 2.2	3.67%
Control Centre Operations	$ 7.6	$ 6.0	$ 6.5	$ 6.5	$ 7.9	$ 8.3	$ 9.0	$ 9.5	$ 10.0	$ 10.5	5.88%
Customer Operations	$ 9.3	$ 7.5	$ 9.0	$ 11.1	$ 11.3	$ 12.7	$ 13.1	$ 13.7	$ 14.1	$ 14.6	3.49%
Asset and Program Management	$ 13.4	$ 11.9	$ 13.1	$ 11.8	$ 14.0	$ 14.2	$ 15.8	$ 16.6	$ 17.9	$ 18.7	6.88%
System Planning	$ 5.6	$ 6.1	$ 7.5	$ 6.0	$ 8.1	$ 8.4	$ 9.1	$ 9.5	$ 10.0	$ 10.3	5.10%
Flexibility Services (e.g., Non-wires solutions)	$ 0.4	$ 0.2	$ 0.2	$ 0.6	$ 0.8	$ 0.2	$ 0.9	$ 1.1	$ 1.6	$ 1.9	56.28%
Indexed costs	$ 7.4	$ 5.6	$ 5.4	$ 5.2	$ 5.1	$ 5.6	$ 5.8	$ 6.0	$ 6.3	$ 6.5	3.73%
Work Program Execution	$ 11.0	$ 14.2	$ 17.3	$ 14.4	$ 15.2	$ 16.0	$ 16.8	$ 17.9	$ 18.5	$ 19.4	4.82%
Internal Work Execution	$ 10.0	$ 12.7	$ 16.2	$ 13.9	$ 13.8	$ 14.5	$ 15.2	$ 16.2	$ 16.7	$ 17.6	4.84%
Indexed Costs	$ 1.0	$ 1.5	$ 1.1	$ 0.5	$ 1.4	$ 1.5	$ 1.6	$ 1.7	$ 1.8	$ 1.8	4.56%
Fleet and Equipment Services	$ 9.3	$ 8.5	$ 7.8	$ 8.6	$ 9.1	$ 9.3	$ 9.6	$ 9.8	$ 10.0	$ 10.3	2.55%
Supply Chain Services	$ 15.8	$ 12.9	$ 13.8	$ 16.5	$ 18.8	$ 21.5	$ 23.5	$ 24.9	$ 25.5	$ 27.1	5.79%
Sub-Total	**$ 134.4**	**$ 133.0**	**$ 134.8**	**$ 134.6**	**$ 147.8**	**$ 163.2**	**$ 170.6**	**$ 176.6**	**$ 183.2**	**$ 190.2**	**3.83%**
Facilities Management											
Facilities Maintenance Services	$ 16.6	$ 18.4	$ 17.4	$ 19.0	$ 19.6	$ 19.4	$ 19.8	$ 20.1	$ 20.6	$ 21.0	1.98%
Rentals & Leases	$ 0.4	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.6	$ 0.6	4.56%
Utilities & Communications	$ 2.3	$ 2.2	$ 2.1	$ 1.8	$ 2.4	$ 2.5	$ 2.5	$ 2.6	$ 2.6	$ 2.7	1.92%
Property Taxes	$ 5.0	$ 4.9	$ 5.0	$ 5.1	$ 5.4	$ 5.5	$ 5.6	$ 5.7	$ 5.8	$ 6.0	2.18%
Sub-Total	**$ 24.3**	**$ 26.0**	**$ 25.0**	**$ 26.4**	**$ 27.9**	**$ 27.9**	**$ 28.4**	**$ 28.9**	**$ 29.6**	**$ 30.3**	**2.06%**
Customer Care											
Billing, Remittance and Meter Data Management	$ 19.4	$ 18.9	$ 19.4	$ 20.7	$ 23.1	$ 23.7	$ 25.0	$ 25.4	$ 26.2	$ 27.0	3.26%
Collections	$ 24.9	$ 9.0	$ 7.8	$ 9.1	$ 10.2	$ 10.2	$ 10.9	$ 11.0	$ 11.3	$ 11.6	3.22%
Customer Relationship Management	$ 11.4	$ 11.4	$ 12.1	$ 13.6	$ 15.1	$ 14.7	$ 15.7	$ 16.1	$ 16.9	$ 17.5	4.36%
Sub-Total	**$ 55.7**	**$ 39.3**	**$ 39.3**	**$ 43.4**	**$ 48.4**	**$ 48.6**	**$ 51.6**	**$ 52.5**	**$ 54.4**	**$ 56.1**	**3.59%**
Human Resources, Environment and Safety											
Environment, Health & Safety	$ 2.4	$ 2.3	$ 2.4	$ 2.7	$ 3.1	$ 3.3	$ 3.4	$ 3.6	$ 3.8	$ 3.9	4.18%
Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations	$ 5.9	$ 6.3	$ 5.9	$ 7.2	$ 9.4	$ 10.0	$ 10.4	$ 10.8	$ 11.3	$ 11.8	4.14%
Talent Management, Change Leadership & Sustainability	$ 7.2	$ 9.0	$ 8.4	$ 8.2	$ 8.8	$ 9.3	$ 9.4	$ 9.8	$ 10.2	$ 10.6	3.27%
Sub-Total	**$ 15.5**	**$ 17.6**	**$ 16.7**	**$ 18.1**	**$ 21.3**	**$ 22.6**	**$ 23.2**	**$ 24.2**	**$ 25.3**	**$ 26.3**	**3.79%**
Finance											
Controllership	$ 6.5	$ 6.9	$ 6.9	$ 7.9	$ 8.8	$ 9.4	$ 10.1	$ 10.5	$ 11.0	$ 11.4	4.82%
Financial Services	$ 6.7	$ 7.7	$ 8.4	$ 8.8	$ 9.7	$ 10.5	$ 11.4	$ 12.2	$ 13.3	$ 14.4	7.90%
External Reporting	$ 3.2	$ 3.3	$ 3.1	$ 3.6	$ 4.4	$ 4.5	$ 4.7	$ 4.9	$ 5.1	$ 5.3	4.09%
Sub-Total	**$ 16.4**	**$ 17.9**	**$ 18.4**	**$ 20.3**	**$ 22.9**	**$ 24.4**	**$ 26.2**	**$ 27.6**	**$ 29.4**	**$ 31.1**	**6.07%**
Information Technology											
Security & Enterprise Architecture	$ 3.7	$ 4.5	$ 6.1	$ 6.3	$ 7.3	$ 7.6	$ 7.9	$ 8.4	$ 8.8	$ 9.3	5.05%
IT Operations	$ 36.9	$ 38.4	$ 39.9	$ 42.6	$ 44.8	$ 46.0	$ 47.5	$ 49.1	$ 50.8	$ 52.2	3.16%
Project Execution	$ 4.7	$ 4.9	$ 5.0	$ 4.7	$ 3.2	$ 7.4	$ 8.0	$ 8.8	$ 9.7	$ 11.1	10.14%
IT Governance	$ 2.7	$ 2.8	$ 2.5	$ 2.3	$ 2.3	$ 2.3	$ 2.4	$ 2.4	$ 2.4	$ 2.5	2.08%
Sub-Total	**$ 48.0**	**$ 50.6**	**$ 53.5**	**$ 55.9**	**$ 57.6**	**$ 63.3**	**$ 65.8**	**$ 68.7**	**$ 71.7**	**$ 75.1**	**4.27%**
Legal and Regulatory											
Legal Services	$ 6.1	$ 5.7	$ 5.8	$ 7.0	$ 9.2	$ 9.8	$ 10.3	$ 10.7	$ 11.2	$ 11.6	4.22%
Regulatory Affairs	$ 3.8	$ 4.4	$ 4.1	$ 5.3	$ 6.4	$ 7.0	$ 7.1	$ 7.5	$ 7.9	$ 8.1	3.65%
OEB Fees	$ 3.4	$ 3.2	$ 3.6	$ 4.0	$ 4.4	$ 4.5	$ 4.6	$ 4.6	$ 4.7	$ 4.8	1.61%
Regulatory Applications (Custom IR)	$ 1.6	$ 1.6	$ 1.6	$ 1.6	$ 1.6	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	0.00%
Communications & Public Affairs	$ 3.6	$ 4.1	$ 4.1	$ 4.7	$ 6.4	$ 6.6	$ 6.9	$ 7.1	$ 7.3	$ 7.6	3.53%
Sub-Total	**$ 18.5**	**$ 19.0**	**$ 19.2**	**$ 22.6**	**$ 28.0**	**$ 29.9**	**$ 30.9**	**$ 32.0**	**$ 33.2**	**$ 34.2**	**3.36%**
Charitable Donations and LEAP											
Rate Recoverable	$ 1.0	$ 1.0	$ 1.0	$ 1.0	$ 1.4	$ 1.5	$ 1.6	$ 1.7	$ 1.8	$ 1.9	5.91%
Sub-Total	**$ 1.0**	**$ 1.0**	**$ 1.0**	**$ 1.0**	**$ 1.4**	**$ 1.5**	**$ 1.6**	**$ 1.7**	**$ 1.8**	**$ 1.9**	**5.91%**
Common Costs and Adjustments											
Ongoing or Recurring	$ (0.2)	$ (0.3)	$ (1.0)	$ 0.3	$ (0.9)	$ (0.9)	$ (0.9)	$ (0.8)	$ (0.8)	$ (0.8)	-2.94%
Sub-Total	**$ (0.2)**	**$ (0.3)**	**$ (1.0)**	**$ 0.3**	**$ (0.9)**	**$ (0.9)**	**$ (0.9)**	**$ (0.8)**	**$ (0.8)**	**$ (0.8)**	**-2.94%**
Allocations and Recoveries											
On-cost recovery	$ (13.2)	$ (12.9)	$ (14.2)	$ (16.2)	$ (19.1)	$ (21.7)	$ (23.7)	$ (25.1)	$ (25.7)	$ (27.3)	5.74%
Fleet Recovery Offset	$ (9.6)	$ (9.8)	$ (9.4)	$ (9.6)	$ (10.7)	$ (11.0)	$ (11.3)	$ (11.5)	$ (11.8)	$ (12.2)	2.59%
IT and Occupancy Charges	$ (0.8)	$ (0.8)	$ (0.6)	$ (0.8)	$ (0.8)	$ (0.9)	$ (0.9)	$ (0.9)	$ (0.9)	$ (0.9)	0.00%
Shared Services	$ (1.0)	$ (2.3)	$ (1.5)	$ (1.3)	$ (2.9)	$ (3.4)	$ (3.0)	$ (3.2)	$ (3.4)	$ (3.8)	2.78%
Other Allocated Costs	$ (0.9)	$ (0.8)	$ (0.8)	$ (0.5)	$ (0.4)	$ (0.5)	$ (0.5)	$ (0.5)	$ (0.5)	$ (0.6)	4.56%
Sub-Total	**$ (25.5)**	**$ (26.6)**	**$ (26.5)**	**$ (28.4)**	**$ (33.9)**	**$ (37.5)**	**$ (39.4)**	**$ (41.2)**	**$ (42.3)**	**$ (44.8)**	**4.45%**
Total	**$ 288.1**	**$ 277.5**	**$ 280.4**	**$ 294.2**	**$ 320.5**	**$ 343.0**	**$ 358.0**	**$ 370.2**	**$ 385.5**	**$ 399.6**	**3.82%**
	$ 288.1	$ 277.5	$ 280.4	$ 294.2	$ 320.5	$ 343.0	$ 358.0	$ 370.2	$ 385.5	$ 399.6	
Annual % growth (logarithmic)		**-3.7%**	**1.0%**	**4.8%**	**8.6%**	**6.8%**	**4.3%**	**3.4%**	**4.0%**	**3.6%**	
PEG Proposed Non-indexed OM&A	**$ 43.4**	**$ 45.8**	**$ 53.6**	**$ 51.6**	**$ 56.2**	**$ 61.1**	**$ 65.8**	**$ 69.6**	**$ 73.7**	**$ 78.2**	**6.17%**
PEG Proposed Indexed OM&A	**$ 244.7**	**$ 231.7**	**$ 226.8**	**$ 242.6**	**$ 264.3**	**$ 281.9**	**$ 292.2**	**$ 300.6**	**$ 311.8**	**$ 321.4**	**3.28%**

Source: Exhibit 4, Tab 1, Schedule 4, Dated 1 December 2023 and 4-SEC-89

Highlighted cells show the costs PEG believes are worthy of being excluded from the index.

Table N1-SEC-11(b)

Comparison of Toronto Hydro's Proposed OM&A Revenue Requirement to Indexed Alternatives

Indexing Only

	2025	2026	2027	2028	2029	Cumulative	AAGR
Hypothetical fully indexed OM&A revenue [A]	343,000,000	350,909,220	358,852,062	367,025,254	375,195,516	1,451,982,052	**2.24%**
I (PEG's forecasted O&M price Inflation)	1.97%	1.99%	2.06%	2.06%	2.07%		2.02%
X (THESL Proposal)	0.15%	0.15%	0.15%	0.15%	0.15%		0.15%
G (Customer Growth)	0.46%	0.40%	0.34%	0.29%	0.32%		0.37%
OM&A Escalation (I-X+G)	2.28%	2.24%	2.25%	2.20%	2.24%		**2.24%**
THESL Forecasted/Proposed OM&A Expense [B]	343,000,000	358,000,000	370,200,000	385,500,000	399,600,000	1,513,300,000	**3.82%**
annual growth rate		4.3%	3.4%	4.0%	3.6%		**3.82%**
Difference [C=B-A]	**-**	**(7,090,780)**	**(11,347,938)**	**(18,474,746)**	**(24,404,484)**	**(61,317,948)**	
% Difference (C/B) (%)	**0.00%**	**-1.98%**	**-3.07%**	**-4.79%**	**-6.11%**	**-4.05%**	

Indexing Plus PEG Proposed Non-Indexed OM&A Expense

	2025	2026	2027	2028	2029	Cumulative	AAGR
OM&A revenue subject to forecasting and/or VAs [D]	61,100,000	65,800,000	69,600,000	73,700,000	78,200,000		**6.17%**
Residual OM&A revenue subject to indexing [E=B-D] (2025 only)	281,900,000	288,400,318	294,928,269	301,645,537	308,360,397		**2.24%**
Total OM&A revenue a la PEG [F=D+E]	343,000,000	354,200,318	364,528,269	375,345,537	386,560,397	1,480,634,520	**2.99%**
Difference from forecasted/proposed cost [G=B-F]	**-**	**(3,799,682)**	**(5,671,731)**	**(10,154,463)**	**(13,039,603)**	**(32,665,480)**	
% Difference [G/B]	**0.00%**	**-1.06%**	**-1.53%**	**-2.63%**	**-3.26%**	**-2.16%**	

Notes

In EB 2018-0165, the OEB cut Toronto Hydro's OM&A budget for the rebasing year by $6 million out of a total proposed OM&A forecast of $278.2 million (around 2.2% for the base year).

In EB-2014-0116, the OEB cut Toronto Hydro's proposed OM&A budget by $23.5 million out of a total proposed OM&A budget of $269.5 million (around 9% for the base year).

Table N1-SEC-11(c)

Calculating a Hypothetical Revenue Cap Index for Toronto Hydro

	GDPIPI FDD		FWI AHE Ontario		Inflation Factor	X Factor			Customer Growth	Revenue Cap Index
	Inflation	Weight	Inflation	Weight		Base Productivity Growth Target	Stretch Factor	Total		
Year	[A]	[B]	[C]	[D]	[E] = [A*B] + [C*D]	[F]	[G]	[H] = [F + G]	[I]	[J] = [E - H + I]
2018	1.56%	70%	2.29%	30%	1.78%	0.1%	0.6%	0.7%	0.31%	1.39%
2019	1.90%	70%	2.79%	30%	2.17%	0.1%	0.6%	0.7%	0.91%	2.38%
2020	1.79%	70%	3.28%	30%	2.24%	0.1%	0.6%	0.7%	0.51%	2.05%
2021	3.75%	70%	2.75%	30%	3.45%	0.1%	0.6%	0.7%	0.62%	3.37%
2022	6.24%	70%	4.05%	30%	5.58%	0.1%	0.6%	0.7%	0.56%	5.45%
2023	3.75%	70%	3.00%	30%	3.52%	0.1%	0.6%	0.7%	0.35%	3.17%
2024	*2.03%*	70%	*2.69%*	30%	*2.23%*	*0.1%*	*0.6%*	*0.7%*	*0.42%*	*1.95%*
2025	*1.39%*	70%	*2.30%*	30%	*1.66%*	*0.1%*	*0.6%*	*0.7%*	*0.46%*	*1.42%*
2026	*1.48%*	70%	*2.26%*	30%	*1.71%*	*0.1%*	*0.6%*	*0.7%*	*0.40%*	*1.42%*
2027	*1.70%*	70%	*2.25%*	30%	*1.87%*	*0.1%*	*0.6%*	*0.7%*	*0.34%*	*1.51%*
2028	*1.70%*	70%	*2.25%*	30%	*1.87%*	*0.1%*	*0.6%*	*0.7%*	*0.29%*	*1.45%*
2029	*1.70%*	70%	*2.25%*	30%	*1.87%*	*0.1%*	*0.6%*	*0.7%*	*0.32%*	*1.49%*

Notes

Data after 2023 are forecasted, as indicated by italics

Forecasted growth of the GDPIPI FDD after 2023 is based on the forecasted change in the GDP-IPI at Market Prices from the Conference Board of Canada as of January 23, 2023 as provided in Clearspring's working papers.

Forecasted growth in the FWI AHE after 2023 is based on the forecasted change in the AWE from the Conference Board of Canada as of January 23, 2023 as provided in Clearspring's working papers.

The inflation factor is a weighted average of the growth in GDPIPI and the FWI AHE. Standard OEB weights were assumed.

All growth rates are calculated logarithmically.

Table N1-SEC-11(d)

Illustrative Establishment of Capex Budgets for K-bar Calculations

Capex Projects	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	Average	2025	2026	2027	2028	2029	2025	2026	2027	2028	2029	Averages 2026-2029 K-Bar Capex Budget	Averages 2026-2029 THESL Proposed Capex	Averages 2026-2029 Capex Shortfall
	Revenue Cap Index Growth Rate					Revenue Cap Index Growth Rate						Revenue Cap Index Growth Rate												
	2.05%	3.37%	5.45%	3.17%	1.95%	2.05%	3.37%	5.45%	3.17%	1.95%		1.42%	1.42%	1.51%	1.45%	1.49%								
	Expiring Plan Capex (Nominal $)					Expiring Plan Capex (2024$)						New Plan Capex (K-bar Budget)					New Plan Capex (THESL Proposal)							
System Access																						[A]	[B]	[A/B]
Customer and Generation Connections (net of contributions)	35.7	92.8	75.9	86.8	78.2	40.9	102.9	79.9	88.4	78.2	78.0		80.3	81.5	82.7	83.9	84.5	89.9	95.3	100.7	106.0	82.1	98.0	0.84
Externally-Initiated Plant Relocations & Expansion[1] (net of contributions)	8.7	9.3	12.9	16.0	13.0												22.6	16.7	11.9	12.1	12.6			
Generation Protection, Monitoring and Control (e.g., monitoring and control systems for renewable DER facilities greater than 50 kW)[1]	0.8	0.8	0.1	0.2	7.8												5.9	6.1	6.3	6.5	10.3			
Load Demand[1]	24.0	29.9	30.8	26.7	23.2												43.5	46.4	38.1	42.7	46.4			
Metering[1]	11.2	8.1	8.4	8.0	44.6												63.7	69.9	72.4	34.7	7.4			
Subtotal: System Access Total Expenditures	225.2	240.7	244.3	278.2	314.2												384.1	379.8	364.7	343.8	337.5			
Subtotal: System Access Capital Contributions	144.8	100.3	115.9	140.4	147.5												164.0	150.7	140.7	147.2	154.9			
Subtotal: System Access Net Expenditures	**80.4**	**140.3**	**128.4**	**137.7**	**166.7**												**220.1**	**229.1**	**224.0**	**196.6**	**182.7**			
System Renewal																								
Area Conversions (e.g., rear lot and box	35.6	39.5	33.8	41.5	58.9	40.9	43.8	35.5	42.3	58.9	44.3		45.5	46.2	46.9	47.6	64.4	61.1	33.6	39.0	38.6	46.6	43.1	1.08
Network System Renewal	15.0	22.1	32.1	25.6	25.3	17.2	24.5	33.8	26.1	25.3	25.4		26.1	26.5	26.9	27.3	13.7	14.8	30.5	31.2	33.2	26.7	27.4	0.97
Reactive and Corrective Capital	63.1	54.5	59.7	67.8	61.9	72.3	60.5	62.8	69.1	61.9	65.3		67.2	68.2	69.2	70.2	61.6	64.8	64.8	67.3	69.7	68.7	66.6	1.03
Stations Renewal	30.2	33.6	27.4	21.9	40.6												56.4	56.7	58.8	58.6	52.3			
Tracked portion - Control & Monitoring (e.g., interstation control wiring upgrades from copper to fiber)[1]	4.7	3.1	5.1	6.9	8.1												11.9	12.1	13.5	13.1	14.2			
Non-tracked portion	25.5	30.5	22.3	15.0	32.5	29.2	33.8	23.5	15.3	32.5	26.9		27.6	28.0	28.4	28.9	44.5	44.6	45.3	45.5	38.1	28.2	43.4	0.65
Underground Renewal - Downtown	7.1	8.5	20.2	27.6	16.8	8.1	9.5	21.2	28.1	16.8	16.7		17.2	17.5	17.7	18.0	20.5	26.0	32.3	41.3	45.0	17.6	36.1	0.49
Underground Renewal - Horseshoe	73.5	50.9	64.4	71.8	102.5	84.3	56.4	67.8	73.2	102.5	76.8		79.0	80.2	81.4	82.6	92.6	82.3	93.8	101.1	105.9	80.8	95.8	0.84
Overhead Infrastructure Relocation	0.7	0.2	0.2	0.0	0.2	0.8	0.2	0.2	0.0	0.2	0.3		0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.3	0.0	
PILC Piece Outs & Leakers	-0.1	0.0	0.0	-0.1	0.0	-0.1	0.0	0.0	-0.1	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	
Underground Legacy Infrastructure	0.3	-0.1	0.6	0.0	0.0	0.4	-0.1	0.6	0.0	0.0	0.2		0.2	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.2	0.0	
Overhead System Renewal	36.1	38.2	38.2	49.3	60.9	41.4	42.4	40.2	50.3	60.9	47.0		48.4	49.1	49.8	50.6	50.5	60.8	77.4	85.2	84.5	49.5	77.0	0.64
Subtotal: System Renewal Total Expenditures	261.7	247.3	276.6	305.4	367.0												359.7	366.5	391.3	423.7	429.1			
Subtotal: System Renewal Capital Contributions	0.2	0.0	0.1	1.2	0.0												0.0	0.0	0.0	0.0	0.0			
Subtotal: System Renewal Net Expenditures	**261.5**	**247.3**	**276.5**	**304.2**	**367.0**												**359.7**	**366.5**	**391.3**	**423.7**	**429.1**			
System Service																								
Network Condition Monitoring and Control	8.1	12.5	13.0	13.6	6.8	9.3	13.9	13.6	13.9	6.8	11.5		11.8	12.0	12.2	12.4	4.2	0.2	0.4	0.6	0.6	12.1	0.5	26.17
Overhead Momentary Reduction	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.1		0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	
Stations Expansion[1]	18.2	50.3	47.5	10.4	16.1												11.0	7.9	22.2	40.7	40.2			
System Enhancements (e.g., installation of sensors, remotely operable feeder ties)[1]	5.1	5.1	6.7	3.6	6.3												19.6	23.3	35.9	33.0	39.4			
Design Enhancement	0.2	0.0	0.0	0.0	0.0	0.2	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	0.0	0.0	0.0	
Non-Wires Solutions (e.g., storage)[1]	1.7	0.1	-0.1	0.0	0.6												3.6	3.6	7.5	3.8	4.0			
Subtotal: System Service Total Expenditures	33.4	68.0	67.1	27.7	29.8												38.3	35.0	66.0	78.1	84.3			
Subtotal: System Service Capital Contributions	0.7	-0.4	-0.2	0.0	0.0												0.0	0.0	0.0	0.0	0.0			
Subtotal: System Service Net Expenditures	**32.8**	**68.4**	**67.2**	**27.7**	**29.8**												**38.3**	**35.0**	**66.0**	**78.1**	**84.3**			
General Plant																								
Facilities Management and Security	10.6	15.6	21.4	22.0	15.7	12.2	17.3	22.5	22.4	15.7	18.0		18.5	18.8	19.1	19.4	29.6	29.8	29.1	29.3	27.7	18.9	29.0	0.65
Enterprise Data Centre	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	0.0	0.0	5.4	16.5	22.5	20.6	7.0	0.0	16.7	0.00
Fleet and Equipment	6.5	2.3	15.5	3.9	8.6	7.5	2.5	16.3	4.0	8.6	7.8		8.0	8.1	8.2	8.4	9.2	9.9	8.8	7.9	7.8	8.2	8.6	0.95
IT/OT Systems	37.4	44.7	58.0	61.2	55.9												59.7	62.9	64.5	58.2	56.0			
Tracked portion - Communications infrastructure (e.g., replacing radio SCADA endpoints on poles with cellular SCADA endpoints)[1]	3.6	3.0	0.7	2.3	1.8												3.7	2.5	0.9	6.8	1.0			
Non-tracked portion	33.8	41.7	57.3	58.9	54.1	38.7	46.3	60.2	60.0	54.1	51.9		53.4	54.2	54.9	55.8	56.0	60.4	63.6	51.4	55.0	54.6	57.6	0.95
Control Operations Reinforcement	1.6	9.9	18.1	6.4	4.2	1.8	10.9	19.1	6.5	4.2	8.5		8.7	8.9	9.0	9.1	0.0	0.0	0.0	0.0	0.0	8.9	0.0	
Subtotal: General Plant Total Expenditures	56.1	72.4	112.9	93.5	84.4												103.9	119.1	124.9	116.1	98.6			
Subtotal: General Plant Capital Contributions	0.0	0.0	0.0	0.3	0.0												0.0	0.0	0.0	0.0	0.0			
Subtotal: General Plant Net Expenditures	**56.1**	**72.4**	**112.9**	**93.2**	**84.4**												**103.9**	**119.1**	**124.9**	**116.1**	**98.6**			
AFUDC	2.9	4.7	6.8	7.4	6.6	3.3	5.2	7.2	7.5	6.6	6.0		6.2	6.2	6.3	6.4	6.5	7.3	8.4	9.2	10.2	6.3	8.8	0.72
Miscellaneous	14.6	0.1	6.0	35.9	1.3	16.7	0.1	6.3	36.6	1.3	12.2		12.6	12.7	12.9	13.1	0.0	0.0	0.0	0.0	0.0	12.8	0.0	
Other Total Expenditures	17.5	4.8	12.8	43.2	7.9												6.5	7.3	8.4	9.2	10.2			
Miscellaneous Capital Contributions	0.1	0.2	0.0	0.0	0.0												0.0	0.0	0.0	0.0	0.0			
Other Total	17.4	4.6	12.8	43.2	7.9												6.5	7.3	8.4	9.2	10.2			
Total Net Capex	**448.1**	**533.2**	**597.9**	**606.1**	**655.9**												**728.5**	**757.1**	**814.5**	**823.7**	**804.8**			
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets	-0.8	-0.8	-0.1	-0.2	-7.9												-8.9	-9.6	-17.3	-14.7	-18.5			
Total	**447.4**	**532.4**	**597.8**	**605.9**	**648.0**												**719.7**	**747.5**	**797.2**	**809.0**	**786.3**			
Forecasted and/or Tracked Capex: PEG Candidates[1]	**77.2**	**109.0**	**112.1**	**73.9**	**113.6**												**176.5**	**178.9**	**191.3**	**178.6**	**157.0**			
% Forecasted and/or Tracked	17.3%	20.5%	18.8%	12.2%	17.5%												24.5%	23.9%	24.0%	22.1%	20.0%			
K-Bar Capex: PEG Candidates	**370.2**	**423.4**	**485.7**	**532.0**	**534.4**	**425.5**	**470.0**	**510.6**	**543.7**	**534.5**	**496.9**		**511.0**	**518.7**	**526.3**	**534.1**	**543.2**	**568.6**	**605.9**	**630.4**	**629.3**	**522.5**	**608.5**	**0.86**

[1] Shaded rows indicate capex projects PEG currently considers candidates for forecasting and/or in some cases variance account treatment.

Source of capex data: EB-2023-0195, Exhibit 2B, Section E4, Appendix B, p.1, April 2, 2024

M1-SEC-12

Interrogatory:

[M1, p.90] With respect to customer growth:

a) Please confirm that PEG's customer growth term is equal to the percentage annual increase in the number of customers.

b) If confirmed, please provide any analysis that shows that 1% increase in customer growth has or should equal 1% increase in OM&A spending.

Response:

The following response was provided by PEG.

a) This statement is confirmed.

b) PEG reported in Table 7 of its empirical report in this proceeding that, at sample mean values of the variables, their econometric estimate of the elasticity of OM&A expenses with respect to growth in the total number of customers served was 0.550%. The elasticity of these expenses with respect to growth in 10-year rolling-average peak demand was 0.376% and customer and peak demand growth are highly correlated. Growth in the total number of customers is an imperfect measure of the OM&A cost impact of demand growth because it doesn't take account of change in the mix of customers or possible impacts of beneficial electrification.

M1-SEC-13

[M1, p.87-93] SEC understands PEG's Straw Man alternative proposal for capital revenue to be based on Alberta's K-Bar treatment.

Interrogatory:

a) Please confirm that the K-Bar calculation in Alberta is based on net plant additions (i.e. in-service additions) and not capital expenditures.

b) Please confirm that in the K-Bar calculation in Alberta, each of the historic 5-year net plant additions are escalated to the initial test year by using the AUC approved I-X formula for each year, plus a growth factor. The net additions for each subsequent year during the rate plan are similarly escalated by an approved/forecast approved I-X formula for each year, plus a growth factor.

c) If part (a) and (b) are generally correct, please provide a revised version of Table 2, and all supporting calculations.

Response:

The following responses were provided by PEG.

a) This statement is confirmed.

b) This description is generally correct. In Alberta, there is also an adjustment to account for changes in the weighted average cost of capital.

c) THESL's Distribution System Plan provides forecasts of capex for individual programs. However, THESL has not provided the requisite *gross plant additions* for each year by program. THESL did provide plant additions data by asset type (e.g., land, substations, meters, and line transformers) in their fixed asset continuity schedules, but this is not comparable to Table 2 (or the capex programs THESL described in its Distribution System Plan). PEG is accordingly unable to undertake these calculations. However, it presented an upgraded strawman proposal in response to M1-SEC-11.

PEG Responses to VECC

M1–VECC-1

Reference: PEG CIR 2.0 M2, page 19

However, index-based ARMs are typically based on long-run productivity trends and thus may not appropriately compensate utilities for necessary cost surges. The capital cost of utilities is typically less volatile than OM&A expenses, but capex surges are sometimes needed by VIEUs and utility distribution companies alike. Moreover, capital cost tends to stay high for many years after capex surges whereas OM&A expenses may be unusually high one year and unusually low the next. Thus, if the ARM does not fund a capex surge, the utility can materially underearn for several years.

Interrogatories

a) What evidence are these statements relying upon? Specifically, when "capital surges" presumably it is high, when it is not "surging" presumably it is back to trend (or at a new trend). Similarly, we are unaware of OM&A expenses for electricity distributors in Ontario fluctuating in the sense of going up and then dramatically down again. Rather our experience is that OM&A expenses consistently trend upward overtime. Please clarify the point trying to be made at this reference.

b) The Ontario Energy Board has now had a number of rebased MRPs to consider and a number of multi-year distribution system plans (DSP)s that accompanied them. Has PEG studied electricity distribution capital spending in Ontario see if there are any discernable patterns related to the rate setting mechanism employed? For example, our antidotal observation, based on involvement in numerous rebasing proceedings, is there is a phenomenon of "step" or upward trend changes in capital spending beginning in the cost of service bridge year and continuing in the test year of the new rate plan. Is this phenomenon what is meant by "capital surging" in the above reference?

c) A pattern of capital spending "step change" is observable in Toronto Hydro's current application. This might indicate that there are issues with capital investment that are not related to asset attrition (in the sense of replacing depreciating assets) but with other factors including the "gold platting" of capital investment. How do the various ARMs mechanisms discussed in the evidence fend against utility gold platting (i.e. reduce the incentive to overbuild assets)?

Responses:

The following responses were provided by PEG.

a) Please note the following.

- The OM&A expenses of a power distributor naturally tend to rise due to inflation and customer growth but can fluctuate around trend due to weather, wildfires, and other unstable business conditions. After a year when outlays to manage severe storms are especially high, these expenses will typically fall materially and reflect a normal level of maintenance but could fall further if unstable business conditions such as weather are unusually favorable.
- Similarly, a power distributor's capex naturally tends to rise due to inflation and demand growth but can fluctuate around trend due to unstable business conditions such as weather and wildfires and needs for replacement capex ("repex") and capacity expansions. Following a surge, capex may fall to a normal level but could fall even further if unstable business conditions are favorable (e.g., there are no severe storms or wildfires) and/or there is an unusually small need for replacement capex and capacity expansions. The difference in these cost patterns is that a surge in capex has a lasting effect on cost while a surge in OM&A expenses does not.
- The point that PEG is trying to make is that there are reasons why capex surges are taken more seriously in ratemaking than OM&A cost surges.

b) PEG has not examined the typical pattern of capex in Ontario over the years of the plan term. However, we are aware that high capex often occurs in the latter years of a multiyear rate plan (e.g., the historical reference year for the next plan and any bridge years thereafter) and/or is proposed for the first year of the next plan. High capex in the latter years of a plan may reflect weak cost containment incentives and a desire to have customers absorb a larger share of the high annual cost of new assets. A high capex proposal in the first year of the next plan may also reflect a desire to have customers absorb a larger share of the high cost of new assets, and may additionally reflect a strategy of exploring information asymmetries.

Please note, however, that whereas both kinds of deferrals may simply be opportunistic they could also reflect a coping strategy in the event that revenue hasn't been sufficient to cover the efficient cost of service.

In any event, this is not the kind of capex surge that PEG was referring to in the cited paragraph. In that paragraph, we were focused on those that might result from unstable business conditions. Please also note that some kinds of capex surges (e.g., construction or replacement of a costly substation) loom larger for a smaller utility than for a larger utility like Toronto Hydro (that has numerous substations).

c) Generally speaking, capex containment incentives are strengthened to the extent that capital revenue growth is decoupled from a utility's own capital cost growth and alternatives to capex are encouraged. The various ways to encourage alternatives to capex include effective prudence reviews and distribution system plan oversight and incentive mechanisms such as peak load management PIMs and management fees, totex accounting, pilot programs for capex substitution, and variance account treatment of the costs of capex alternatives.

<u>M1–VECC-2</u>

Reference: PEG CIR 2.0 M2, pages 9, 91

"The California and Alberta K-bar approaches are both legitimate candidates."

Interrogatories

a) It is unclear to us precisely how a "K-bar" mechanism would work in Toronto Hydro's case. Can PEG provide relevant extracts from either of the above noted proceedings which might better illustrate its specific application?

b) It is unclear to us the criteria by which PEG chose its K-Bar candidates in Table 2. Please elucidate and specifically address whether it is specific categories of investments or simply whether the proposed spending on an investment is a significant outlier as compared to past spending.

Responses:

The following responses were provided by PEG.

a) The C factor in THESL's current CIR plan effectively replaces the growth rate of capital revenue based on indexing with a growth rate based on forecasted/proposed capital cost growth. An Alberta-style K-bar mechanism is different from this in two key respects. First, the alternative basis for capital revenue growth is the Company's recent historical plant additions, with adjustments for input price, the X factor (e.g., productivity plus stretch), and customer growth. Second, the K-bar replaces the *level* of capital revenue based on indexing with a *level* that is based on historical gross plant additions.

   A variant on the K-bar theme would be to base an alternative C factor (let's call it "C2") on the difference between a) revenue growth based on gross plant addition budgets that are based on THESL's recent additions and b) capital revenue growth based on indexing.

A relevant account of the Alberta K-bar approach comes from Appendix 7 from the Alberta Utilities Commission decision outlining the third generation PBR plans for Alberta distributors.[1] This appendix can be found in Attachment N1-VECC-2 .

PEG's response to M1-SEC-4 and M1-SEC-11 provide additional information that may be helpful in understanding the K-bar approach and its application to Toronto Hydro.

b) In constructing this table, K bar was considered the default approach for capex. In order to be considered for forecasting (with possible subsequent one-way or two-way variance account treatment), capex had to meet at least one of the following criteria: be rapidly growing (e.g., have a value less than 0.5 in the Table 2 shortfall column) but not be tied simply to traditional asset replacement, be tied to the energy transition (including smart grid development), or be outside the control of Toronto Hydro. The following categories were identified using these criteria as being especially likely to be excluded from K-bar treatment.

- Externally-initiated plant relocations and expansion: outside the control of Toronto Hydro
- Generation Protection, Monitoring and Control: energy transition, rapidly growing
- Load Demand: energy transition (e.g., several of the primary drivers of THESL's anticipated load growth, which this program addresses, are tied to the energy transition)
- Metering: Rapidly growing, energy transition
- Control & Monitoring Segment of Stations Renewal: rapidly growing, energy transition

[1] AUC Proceeding 27388, Decision 27388-D01-2023, Appendix 7, October 4, 2023.

- Stations Expansion: outside the control of Toronto Hydro (particularly Hydro One Contributions), energy transition
- System Enhancements: rapidly growing, energy transition
- Non-wires solutions: rapidly growing, energy transition
- Communications infrastructure segment of IT/OT system: energy transition

Please see our response to M1-SEC-11 for an updated table.