CIR 2.0 for Toronto Hydro-Electric System Limited

2 May 2024

Mark Newton Lowry, Ph.D.
President

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin St., Suite 601
Madison, Wisconsin USA 53703
608.257.1522 608.257.1540 Fax

Table of Contents

1. Introduction and Summary

Introduction

Ontario Energy Board ("OEB" or "the Board") proceeding EB-2023-0195 concerns an application by Toronto Hydro-Electric System Ltd. ("Toronto Hydro" or "THESL" or "the Company") to rebase its rates and establish a new Custom Incentive Rate-Setting ("CIR") framework. This framework involves a multiyear rate plan ("MRP") that would apply over the five years from 2025 to 2029. The proposed plan, which THESL has dubbed "CIR 2.0," has an attrition relief mechanism ("ARM") that differs in important respects from those recently used in Ontario. The looming energy transition is central to the Company's rationale for the changes. Evidence supporting the proposal includes discussions of recent MRP precedents by ScottMadden.

This proposal and supporting evidence merit careful scrutiny in this proceeding for reasons that include the following.

- Toronto Hydro is one of Ontario's largest power distributors. Its service territory is the hub of the provincial and Canadian economy.
- THESL has been a CIR innovator, having previously developed CIR mechanisms that other Ontario utilities have adopted.
- The energy transition is advanced as a prime reason for the proposed new CIR approach.
- The Company's "CIR 1.0" approach has been controversial because it entails weak (capital expenditures ("capex") containment incentives and high regulatory cost.
- ScottMadden shows that other jurisdictions have adopted elements of the approach that THESL proposes. This kind of incentive rate-setting ("IR") survey evidence has been rare in OEB proceedings, and the Board may benefit from some additional information about IR trends.

Pacific Economics Group Research LLC ("PEG") has for many years been North America's leading IR consultancy. We have undertaken several surveys of IR and other alternatives to traditional ratemaking. We are experts on IR plan design and the benchmarking and price and productivity trend research that supports it. In addition to Ontario, we have played a prominent role in IR in several other North American jurisdictions, including Alberta and Québec. OEB Staff retained PEG to provide an independent expert appraisal and commentary on THESL's CIR proposal and ScottMadden's evidence.

The goal is to help the Board choose the right CIR plan for Toronto Hydro and not to change the general approach to CIR in Ontario.

This is our report on this work. Following a brief summary of our findings, Section 2 complements ScottMadden's evidence with discussions of MRP design issues and notable precedents that are especially pertinent to the CIR 2.0 proposal. We call this a "refresher" on MRP design. Section 3 discusses the evolution of the OEB's IR policies and implications for THESL's next plan. Section 4 outlines Toronto Hydro's CIR 2.0 proposal. In Section 5 we consider THESL's case for a new approach to IR. Sections 6 and 7 appraise key aspects of the CIR 2.0 proposal and detail an alternative approach. A brief discussion of PEG's credentials is provided in the Appendix. The views expressed in this report are those of the author.

Summary

ARM Design

- The ARM component of a multiyear rate plan escalates the rates or revenue of a utility between rate rebasings without being linked closely to a utility's actual costs. The externalization is accomplished using predetermined escalation formulas that are based on indexes, forecasts, and/or historical own-cost trending. Variance accounts ("VAs") typically true up some revenue components to actual costs.
- The K-bar approaches to the escalation of capital revenue that are used in Alberta and Massachusetts are salient examples of historical own-cost trending.
- The forecasting approach to ARM design that THESL proposes has been used in Great Britain and New York for decades. 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.
- Many ARMs have been proposed by utilities and approved over the years that are not closely linked to comprehensive cost forecasts.
- Combinations of forecasts, historical own-cost trending, and variance account treatment of rapidly growing costs can enable the continued use of indexing for slower-growing costs. The

easiest way to accomplish this is to index only OM&A revenue, as has effectively been done in Alberta, California, Massachusetts, and Ontario. Indexation of OM&A revenue can be facilitated where necessary by forecasting some rapidly growing OM&A costs. Some forecasts may be subject to variance account adjustments.

- Cost efficiency growth targets and stretch factors can apply to cost forecasts, K-bar mechanisms, and VAs as well as to indexes. Outside of Ontario, for example, efficiency markdowns apply to forecasts in Great Britain and to the K-bar mechanism in Alberta. These offsets may reflect estimates of industry efficiency trends that are gleaned from econometric and/or productivity studies.

The OEB's Evolving IR Policies

- Faced with the high regulatory cost of an approach to CIR that features multiyear forecasts for most capex and a claw back of capital underspends that weakened incentives, the Board seems to have become increasingly disenchanted with hybrid ARMs requiring forecasts of capital costs and outspoken in its request for an alternative ARM design method.
- Cost efficiency (e.g., stretch factor and external productivity) markdowns on revenue requirement proposals has been a major Board focus in CIR proceedings. The OEB's October 13, 2016 *Handbook for Utility Rate Applications* ("*Rate Handbook*") calls for markdowns that are greater than those in fourth-generation generic IR.
- In the last few years, the Board has prioritized generic proceedings on various incentives for targeted utility activities such as the accommodation of distributed energy resources ("DERs") over a reconsideration of ARM design. The *Rate Handbook* was written before some approaches to ARM design were well-established.
- The Board has been open to the evolution of the ARMs used in CIR without a generic proceeding. The approved innovations have included revenue caps and supplemental capital stretch factors. Some innovations have been proposed by distributors and others by Board Staff and intervenors. If THESL can propose major changes to ARM design without a generic proceeding, so too can other parties to the proceeding.

THESL's CIR 2.0 Rationale

- The energy transition is an important goal of policymakers and will complicate power distributor ratemaking. However, THESL's proposal for rapid cost growth in the next five years is not driven primarily by the energy transition. The Company essentially proposes high capex that is largely unrelated to the energy transition before demand growth materially accelerates.
- There is not a trend in ARM design to do away with indexing of OM&A revenue as Toronto Hydro has proposed.
- Recent ARM design precedents don't justify all aspects of the approach that THESL proposes. In particular, many jurisdictions use indexing for OM&A revenue and several use alternatives to forecasting for capital revenue. Several jurisdictions that use alternatives to forecasting are, like THESL, confronting the early stages of an energy transition.

PEG's Alternative CIR 2.0 Proposal

PEG recommends an alternative approach to the next CIR for Toronto Hydro. We are not proposing a generic CIR design that should apply to all distributors.

Some of our proposed provisions would contain the role of forecasting in the determination of the Company's revenue requirement. It should be possible to continue indexing Toronto Hydo's OM&A revenue requirement. If supplemental OM&A revenue is warranted, it can be provided by forecasting (with variance account trueups in some cases) some *rapidly growing* OM&A costs along with VA treatment of some other OM&A costs. We identify some candidates for forecasting treatment.

If a revenue cap index applies to OM&A revenue in the new plan, a customer growth term should be added to the revenue cap index formula. The many precedents for this approach include a multiyear rate plan for Enbridge Gas Distribution.

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.

The bulk of the capital revenue requirement does not have to be escalated using forecasts, as in past THESL plans. Historical own-cost trending is a well-established alternative to capital cost forecasts.

The California and Alberta “K-bar” approaches are both legitimate candidates. Under either of these approaches, Toronto Hydro would be assigned a gross plant addition budget in each year of the new plan that is similar in the dollars of the next plan (and with a cost efficiency markdown) to their average prudent plant additions during the expiring plan.

The Company forecasts plant additions in the next five years that are well in excess of its high recent historical norms. If the Board deems this a problem, it can be finessed using forecasting (with variance account true ups in some cases as warranted) to address some rapidly growing capital costs and then use historic own-cost trending for the residual capital revenue requirement. We identify some candidate capex categories for forecasting treatment.

THESL’s proposed “proactive 0.6% performance factor” is mathematically equivalent to a penalty-only targeted performance incentive mechanism that pays customers the full penalty for bad performance in the form of an up-front X factor supplement. Any upfront penalty payment is not comparable to a stretch factor and should not be linked to the X factor.

PEG has for many years supported revenue decoupling for energy utilities. However, many of the reasons that revenue decoupling is popular in the United States are not applicable in Ontario. Revenue decoupling encourages rate design experimentation such as time-sensitive distribution rates. Ontario distributors have unusually high reliance on fixed charges for small volume customers and traditional demand-based charges for customers with larger loads. In an era of growth in distributed energy resources and beneficial electrification, we believe that time-sensitive distribution rates merit eventual consideration. Decoupling only weather normalized demand variances is consistent with the Board’s desire to shift more operating risk to utilities.

PEG’s proposal renders variance account treatment of all demand-related costs unnecessary.

2. An MRP Refresher Course

Multiyear rate plans are complex regulatory systems with a few essential characteristics and various optional provisions. These plans are frequently used in combination with other forms of IR such as revenue decoupling, targeted performance incentive mechanisms, and targeted incentives for preferred practices. For that reason, MRPs have become synonymous with incentive rate-setting in the minds of many. In the United States, however, some kinds of IR are used independently of MRPs. That is why we prefer to use the MRP term.

In this section, we provide an overview of MRPs before discussing precedents and MRP design issues.

What Are Multiyear Rate Plans?

The Basic Idea

MRPs have the following essential characteristics.

- A moratorium is placed on rate rebasings. Rebasings are typically held every four to five years.
- 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. Rate adjustments may nonetheless be timely in the sense that they provide reasonable compensation for growing cost pressures.
- Some costs that are difficult to address with predetermined formulas may instead be addressed using variance accounts and associated rate riders or deferrals. Costs scheduled *in advance* for VA treatment are sometimes said to be Y factored. Y-factored costs typically include those for energy commodities and frequently also include pension expenses.
- Revenue adjustments are typically also permitted for hard to foresee events that are largely beyond utility control but materially affect utility finances. These events are sometimes said to be Z factored. Events commonly eligible for Z factoring include major storms, changes in

accounting standards, highway construction programs, and changes in taxes and regulatory policies.

The combination of infrequent rate reviews and an ARM makes ratemaking more efficient and strengthens utility cost containment incentives by externalizing the ratemaking process. Benefits of better performance can be shared between the electric company and its customers. Trimming the frequency of rate reviews is especially advantageous in jurisdictions like Ontario and Great Britain that have many companies to regulate and complex ratemaking issues to consider. The complicated issue of rate designs is sometimes reconsidered between MRP proceedings.

A number of other provisions are sometimes added to MRPs. These include the following.

- Concern about strengthened cost containment incentives often prompts regulators to include targeted service quality incentive mechanism plan provisions.
- Many plans have additional performance metrics and performance incentive mechanisms ("PIMs").
- When an MRP features an indexed ARM, provisions are often made to provide supplemental revenue for unusually high capex if this is deemed necessary during the plan.
- Revenue decoupling can reduce the sensitivity of utility earnings to demand-side management, DERs, and demand volatility.
- Some plans feature an earnings sharing mechanism ("ESM") that shares surplus or deficit earnings (or both) with customers when the utility's rate of return on equity ("ROE") varies from the commission-approved target.
- Off-ramp mechanisms may permit reconsideration and possible suspension of a plan under pre-specified outcomes such as extreme ROEs.
- Special incentives to use disfavored inputs are common in MRPs. For example, costs of some disfavored inputs may be tracked and/or capitalized.

In practice, the revenue from an energy utility MRP typically doesn't vary too far from the utility's cost for an extended period. Utilities aren't the only party to regulation that seeks to preserve some cost basis for MRP rates. For example, consumer groups are customarily wary of letting a utility's revenue rise substantially above its cost for lengthy periods.

MRP Precedents

MRPs have been used in North America since the 1980s. They were first applied on a large scale to U.S. railroads and incumbent telecommunications carriers. Companies in these industries faced significant competitive challenges and complex, changing customer needs that complicated cost of service rate-setting ("COSR"). MRPs streamlined regulation and afforded companies in both industries more marketing flexibility and a chance to earn superior returns for superior performance. In the United States, both industries achieved rapid productivity growth under MRPs. The Federal Energy Regulation Commission ("FERC") has used MRPs for many years to regulate oil pipelines.[1]

MRPs have also been used on many occasions to regulate retail services of gas and electric utilities.[2] In the United States, California has used these plans since the 1980s, and MRPs became popular in some northeastern states (e.g., Maine, Massachusetts, and New York) in the 1990s. In addition to MRPs, several states approved extended rate freezes for electric utilities during their transition to retail competition. Rate freezes have also often been part of the ratemaking treatment for utility mergers and acquisitions.

Figure 1a shows American states that have recently used MRPs to regulate retail gas and electric services.[3] The figure also indicates jurisdictions where MRPs were used in the past but expired. These should not be construed as jurisdictions where MRPs were deemed unsatisfactory.

---

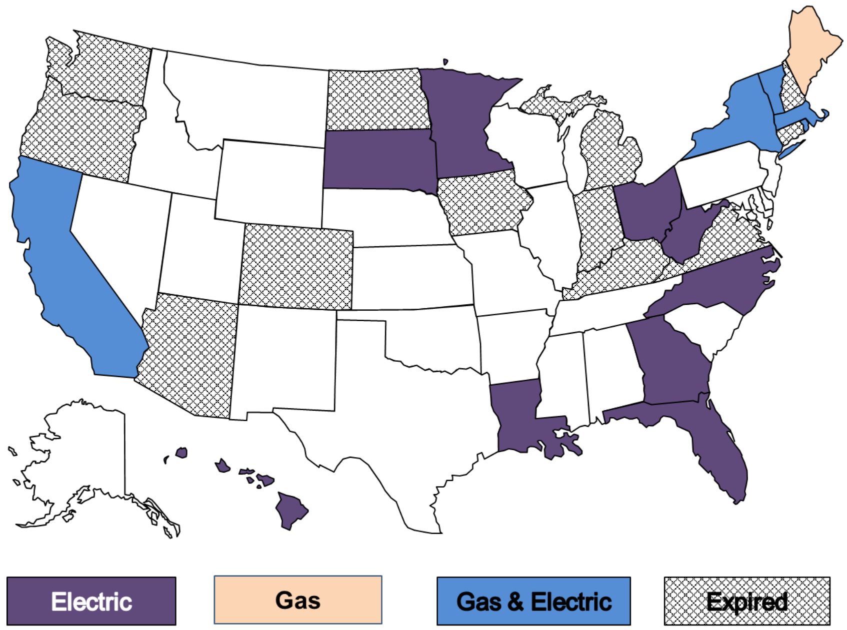
[1] See, for example, Federal Energy Regulatory Commission, Order Establishing Index Level, Five-Year Review of the Oil Pipeline Index, Docket RM15-20-000, December 2015.

[2] MRP precedents for gas and electric utilities have been monitored by the Edison Electric Institution in a series of surveys. See, for example, Lowry, M., Makos, M., and Waschbusch, G., *Alternative Regulation for Emerging Utility Challenges: 2015 Update*, Edison Electric Institute, November 2015.

[3] These maps reflect the status of North American MRPs ca March 2024.

Figure 1a

Recent MRPs for Energy Utilities in American States



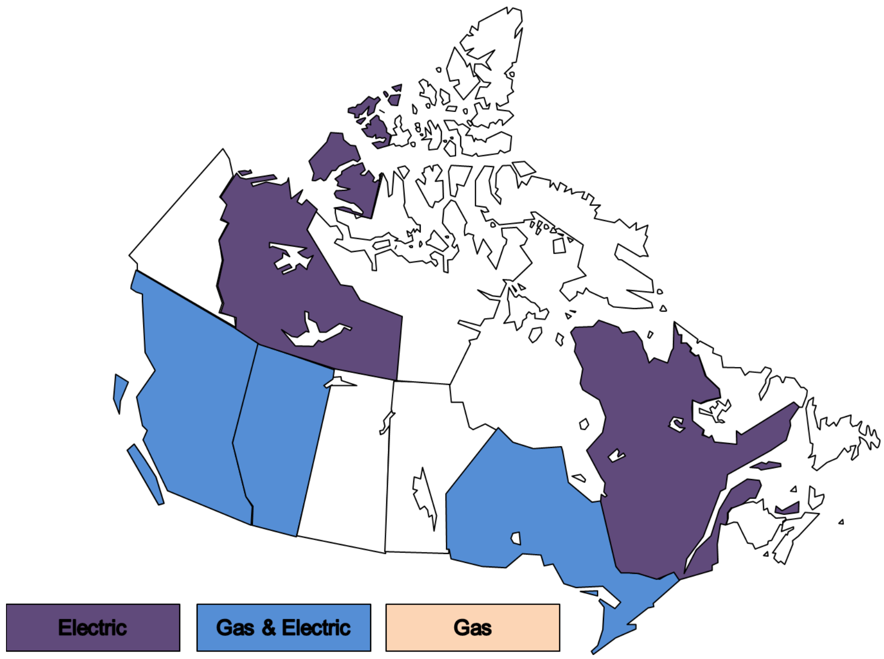
It can be seen that MRPs are now used in numerous states. Energy distributors operate under MRPs in California, Ohio, New York, and New England. MRPs are also used by vertically-integrated electric utilities ("VIEUs") in diverse states that include Florida, Georgia, Louisiana, Minnesota, North Carolina, South Dakota, and West Virginia.

Figure 1b shows that MRPs are even more widely used to regulate energy utilities in Canada. Ontario was an early innovator there. MRPs are also used now in Alberta, British Columbia, and Québec. Overseas, MRPs are the norm in many English-speaking countries (e.g., Australia, Ireland, New Zealand, and the United Kingdom). Great Britain's innovative RIIO approach to MRP design has drawn considerable interest in North America.[4] Countries in continental Europe which regulate energy utilities with MRPs include Austria, Germany, the Netherlands, Norway, Romania, and Sweden.

[4] The term RIIO stands for Revenue = Incentives + Innovation + Outputs.

Figure 1b

Recent MRPs for Energy Utilities in Canadian Provinces



U.S. railroads and telecom utilities exhibited rapid productivity growth under MRPs. There are also many examples of electric companies improving performance when operating under MRPs or lengthy periods without a rebasing.[5]

Implications for Ontario

Ontario is a world-class MRP practitioner, but other jurisdictions (e.g., California, Maine, and New York) were using MRPs before the Board did and use of MRPs has proliferated. The art of ARM design has accordingly advanced since the *Rate Handbook* was written. MRP practice in other jurisdictions should be monitored for ideas that could improve Ontario ARMs as well as other plan provisions.

[5] Examples of improved productivity growth are discussed in a paper on MRPs that PEG recently prepared for Lawrence Berkeley National Laboratory. See Mark N. Lowry, Matt Makos, and Jeff Deason, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities, Ed. L. Schwartz, 2017. Available at: https://eta-publications.lbl.gov/sites/default/files/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf

Attrition Relief Mechanisms

The attrition relief mechanism is a key component of an MRP and typically attracts the most attention in an MRP proceeding. In this section we discuss salient issues in ARM design. We first consider how ARMs are used to cap the growth in rates and revenue. Major approaches to ARM design are then discussed at a high level.

Rate Caps vs. Revenue Caps

ARMs can escalate rates or allowed revenue. Limits on rate growth are sometimes called "price caps." Customers in each basket are insulated from the discounts and other market developments going on with services in other baskets, except as these developments influence shared earnings.

Price caps have been widely used to regulate industries, such as telecommunications, where it is desirable for utilities to market their services aggressively and promote system use. This will generally be so to the extent that utilities have excess capacity and use of their systems does not involve negative externalities. When rates have high usage charges, price caps make utility earnings more sensitive to the kWh and kW of system use and thereby strengthen utility incentives to encourage greater use.

Under *revenue* caps, the escalator permits growth in allowed revenue (aka the revenue requirement). The allowed revenue yielded by a revenue adjustment mechanism must be converted into rates, and this conversion requires assumptions regarding billing determinants. Rate growth typically does not equal allowed revenue growth since the growth rates of allowed revenue and billing determinants differ.

Revenue caps are often paired with revenue decoupling mechanisms, which we discuss further below. However, revenue caps have intuitive appeal with or without decoupling because revenue cap escalators deal with the drivers of *cost* growth, whereas price cap escalators must also reflect the trends in billing determinants.[6] For this and other reasons, revenue caps are sometimes used even in the absence of decoupling. We often assume for expositional simplicity that growth in allowed *revenue* (rather than *rates*) is capped.

[6] If cost is growing by 2%, for example, and billing determinants are growing by 1% on average, rates need rise only 1%.

For rate and revenue caps alike, four approaches to the design of predetermined ARM formulas have been established.

- Indexing
- Forecasting
- Historical own-cost trending
- Hybrids of the above

Costs that are difficult to address with predetermined formulas may be accorded VA treatment. We will discuss these design options in turn.

Indexed ARMs

The Basic Idea

An indexing approach to ARM design is popular in North America and based primarily on industry cost trend research. In these studies, the historical cost trends of sampled utilities are usually decomposed into input price, output, and productivity trends using indexes. This research has revealed over the years that trends in utility input prices and productivity display patterns that can often provide the basis for just and reasonable adjustments to rates or revenue between rate cases. Since prices in competitive markets also reflect industry input price and productivity trends, this approach to ARM design is sometimes portrayed as simulating competitive market conditions. Indexed ARMs for rates are sometimes called price cap indexes while those revenue requirements are called revenue cap indexes.

The following result from cost theory is useful in the design of revenue cap indexes:

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Scale} - \textit{growth Productivity}. \qquad [1]$$

The growth (rate) of cost is the sum of growth in input prices and operating scale less the growth in productivity. Equation [1] provides the basis for the following revenue cap index.

$$Revenue_t = Revenue_{t-1} \cdot [1 + Inflation + growth\ Scale - (X + Stretch)] + Y_t + Z_t. \qquad [2]$$

Here *X*, the “X factor,” typically reflects the historical productivity trend of a group of utilities. Revenue escalation therefore embodies an external productivity growth standard. A **stretch factor** (aka **customer or consumer dividend**) is often added to X to guarantee customers a share of the benefit of the stronger performance incentives expected under the plan. Stretch factors are discussed further in our companion report in this proceeding. The Y factor term indicates that some costs are chosen in advance for variance account treatment. The Z factor term indicates that revenue is subject to adjustment for events that are particularly difficult to foresee accurately.

Inflation, the inflation factor, is the growth in an inflation index. In United States MRPs, the inflation measure in an indexed ARM is often a macroeconomic price index such as the gross domestic product price index ("GDP-PI"). The propensity of the GDP-PI to track industry input prices then becomes an issue.

A stand-alone adjustment can in principle be made to the rate or revenue cap index but in practice the adjustment is made to the X factor. This is a particular concern in the U.S. because GDP-PI growth is slowed by the multifactor productivity ("MFP") growth of the economy, which tends to be brisk. Canadian MRPs are more likely to feature the average of the trends in a macroeconomic inflation measure (e.g., the gross domestic product implicit price index for final domestic demand) and a provincial labor price index. The ability of such inflation measures to track industry input price growth is rarely considered.

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*. For example, an index for a gas distributor could track trends in the length of gas mains as well as the number of customers served.

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. Due to a lack of standardized data for numerous utilities across Canada, most of the productivity studies used in North American MRP proceedings have been based on U.S. data.

Precedents for Indexed ARMs

Indexed ARMs based on industry cost trend research originated in the United States.[7] Development was facilitated there by the availability of standardized, quality operating data over many

[7] Early American papers discussing the use of price and productivity research to design ARMs include Sudit (1979) and Baumol (1982).

years from dozens of companies in several utility industries. This general approach to ARM design was employed in a number of the early MRPs that employed price or (less frequently in those days) revenue cap indexes. The terms Y factor and Z factor were first used in early U.S. telecom MRPs with price cap indexes. First applied in the railroad industry, indexed ARMs have subsequently been used on a large scale to regulate telecommunications utilities and oil pipelines.

California, Maine, and Massachusetts adopted MRPs with indexed ARMs for energy utilities in the 1990s. U.S. energy utilities that have operated under such ARMs include Bangor Hydro Electric, Bangor Gas, Bay State Gas, Berkshire Gas, Blackstone Gas, Boston Gas, California Pacific Electric, Central Maine Power, Eversource Energy, Massachusetts Electric, NSTAR Electric, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, Southern California Gas, Summit Natural Gas of Maine, PacifiCorp (OR), and PacifiCorp (CA). Most of the early plans with indexed ARMs were proposed by utilities and did not entail large adjustments for forecasted capex. Indexed ARMs are currently used in the United States by NSTAR Gas, National Grid (MA), and the three Hawaiian Electric utilities.

ARMs based chiefly on index research have been used to regulate utilities in Canada as well. The Canadian Radio-television and Telecommunications Commission was an early adopter. Indexed ARMs have also been used to regulate western rail freight rates. Indexed ARMs were approved in Alberta for ENMAX and the first generation of PBR plans for electric and gas distributors (“PBR1”). British Columbia used indexed ARMs for FortisBC in the past. Power distributors in New Zealand have also used indexed ARMs in the past.

In Ontario, indexed ARMs were applied to power distributors in the first generation incentive ratemaking mechanism (“1st GIRM”)-, 2nd GIRM, and 3rd GIRM. Enbridge Gas Distribution and Union Gas operated under such ARMs for several years starting in 2008. It is notable that the Enbridge Gas Distribution plan featured a revenue cap index with a customer growth term. Starting in the 2nd GIRM, it is also notable that power distributors could apply for a “smart meter funding adder.”[8] Distributors were permitted to recover metering costs that were prudently incurred between rate reviews. This is an example of singling out a rapidly growing cost for forecasting and/or VA treatment. Current MRPs with this general kind of ARM in Ontario include those for B2M Limited Partnership, the Niagara

[8] See the OEB’s guideline G-2008-002 (“Smart Meter Funding and Cost Recovery”).

Reinforcement Limited Partnership, and Hydro One Sault Ste. Marie. In Québec, an indexed ARM is currently used for power distribution services of Hydro Québec. This plan was "hardwired" in a bill of the Assemblée nationale du Québec with input from the company.

Pros and Cons of Indexed ARMs

Index-based ARMs automatically compensate utilities automatically for key external cost drivers such as inflation and customer growth. This addresses key sources of financial attrition between rate cases without weakening utility cost containment incentives. Controversies over cost forecasts can be contained.

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.

Cost surges can be addressed by variance accounts, but these involve their own complications as we discuss further below. The design of indexed ARMs can involve statistical cost research that is complex and sometimes controversial. This particularly poses a problem in jurisdictions that have little experience with cost trend studies.

Some Comments on Variance Accounts

This is a good place to interject a discussion of variance accounts. A VA is a mechanism for expedited recovery of specific utility costs. It is not an example of a predetermined formula since it is linked to actual cost during a plan. Such mechanisms can be combined with all of the predetermined formulas that we discuss in this section of the report.

VAs are typically used to track certain unrecovered costs that regulators deem prudent. Recovery of these costs is then typically initiated promptly using rate riders. The costs may, alternatively, be treated as a regulatory asset that may earn interest and be considered for inclusion in the revenue requirement in future rebasings. VAs tend to weaken utility cost containment incentives and raise regulatory cost.

There are several reasons why VAs may nonetheless be used in ratemaking.

- The cost to be tracked is large and difficult to address using an *I-X* formula because it has *volatility* that *I-X* doesn't capture. Common examples include purchased power and pension expenses.
- The cost is large and difficult to address using a predetermined *I-X* formula because it has *rapid growth* that *I-X* doesn't capture. An example here might be the replacement capital expenditures of a utility with an unusually large cohort of assets approaching replacement age. Addressing volatile and rapidly growing costs with VAs makes it feasible to address some costs using indexes.
- The cost is sensitive to changes in government policies or other external cost drivers such as severe storms and highway and mass transit construction.
- The cost is one that the commission wants to carefully monitor anyways. A prime example is the cost of new generation units for a VIEU.
- The utility is predisposed to use too little of some inputs and practices because they reduce capex opportunities, are too risky, and/or reduce costs that don't affect utility earnings very much because those costs are external or subject to VA treatment.

<u>Capital Cost VAs</u>

It can be challenging to ascertain the need for high capex in a proceeding considering capital variance accounts, as it is in a forward test year rate case. Capital VAs for energy distributors often address the cost of accelerated system modernization. The need for a particular plan of modernization can be more challenging to appraise than the need for other kinds of capex surges that are commonly tracked, such as those for new generation capacity or emissions control facilities. Distribution modernization plans involve a measure of discretion. The utility might, for example, claim that it is desirable to replace some assets a little before they absolutely must be in order to avoid having too many assets to replace at the same time. The regulatory community does not always have much expertise in evaluating such claims.

Generation plant additions also involve some discretion, but regulators of vertically-integrated electric utilities have years of experience considering both the need for new capacity and the right generation technology. Integrated resource planning and/or a certificate of public convenience and necessity ("CPCN") are often required before the construction or purchase of generation capacity can proceed. There are often competitive alternatives to a utility's proposal to increase generation capacity. Proponents of these alternatives are often aggressive in pressing their cases in these hearings.

A notable problem with VAs is that, if recovery of costs is prompt (or deferred with interest) with little risk of prudence disallowance, they can weaken the incentive to contain these costs. Where the cost containment incentives generated by conventional trackers are a particular concern, methods are available to strengthen incentives.

- Tracked costs can be subject to especially intensive oversight. The reduction in rate cases that MRPs make possible frees up resources to review these costs.
- 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.

In its new generic MRP design for power distributors (RIIO-ED2), the British regulator Ofgem has established "uncertainty mechanisms" ("UMs") to provide supplemental revenue for load-related expenditures ("LREs").[9] There are two separate kinds of uncertainty mechanisms for LREs: reopeners and volume drivers. Increases in most kinds of LREs (including most system reinforcements and customer connections) resulting from unexpectedly rapid demand growth will be addressed through "reopeners".[10] These reopeners are only available in limited windows (e.g., January 2025 and January 2027, unless Ofgem authorizes additional reopener windows).[11] Distributors must present a narrative explaining why the budget should be increased (e.g., more rapid low carbon technology adoption than forecast), present an updated cost forecast, and include engineering justification papers to support the need for increased investment.[12] In a reopener, the distributor must also demonstrate that the increased cost will exceed a common 0.5% of annual average base revenues, after a sharing of cost

[9] Ofgem (2022), Decision – RIIO-ED2 Final Determinations Core Methodology Document, pp. 21-34.

[10] *Ibid.* pp. 21-22.

[11] *Ibid.* p. 21.

[12] Ofgem (2023), Re-opener Guidance and Applications Requirements Document, pp. 44-46.

variances.[13] A portion of these allowances may be subject to clawbacks if the distributor underspends for the wrong reasons.[14]

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.[15] 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.[16] When actual volumes are known, allowed revenues for eligible cost categories are updated to equal the unit rate x actual required volume.[17] Variances between the allowed and actual unit rates are shared with customers.[18] Various metrics (e.g., transformer utilization) have been established to flag potential suboptimal investment.[19] 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.[21] There are also caps on the costs addressed by volume drivers.[22]

Capital Cost VA Precedents

There are numerous precedents for capital cost trackers for gas, electric, and water utilities in the United States. The popularity of such trackers reflects in part the generally conservative approach to utility regulation in American states. Many state regulators use historical test years in rate cases, and many do not use MRPs or revenue decoupling. These policies encourage utilities to file rate cases more

[13] The percentage of cost variances that the distributor could share in or refund varied by distributor but in all cases was around 50%.

[14] Ofgem (2023), Re-opener Guidance and Applications Requirements Document, pp. 49-50.

[15] Ofgem (2022), Decision – RIIO-ED2 Final Determinations Core Methodology Document, pp. 23-24, 31-32.

[16] Ofgem (2022), Decision – RIIO-ED2 Final Determinations Core Methodology Document, p. 24, 32.

[17] Ofgem (2023), RIIO-ED2 LRE Volume Drivers Governance Document, p. 29.

[18] *Ibid*.

[19] Ofgem (2022), Decision – RIIO-ED2 Final Determinations Core Methodology Document, pp. 24-25, 32.

[20] Ofgem (2023), RIIO-ED2 LRE Volume Drivers Governance Document, pp. 29-30.

[21] Ofgem (2023), RIIO-ED2 LRE Volume Drivers Governance Document, p. 30.

[22] Ofgem (2022), Decision – RIIO-ED2 Final Determinations Core Methodology Document, p. 25, 32.

frequently. Capital cost trackers are perceived by regulators as a way to reduce the frequency of rate cases by "chipping away" at the problem of financial attrition instead of undertaking more sweeping changes in the regulatory system.

Capital VAs have also been components of a number of MRPs. MRPs in California and Maine, for example, have had trackers for costs of automated metering infrastructure ("AMI"). MRPs in Alberta, British Columbia, and Ontario permit cost trackers for a broader range of distributor capex, as we discuss further below.

It is also interesting to examine the kinds of capex that are typically made eligible for tracking in the States. On the electric side, trackers for emissions controls, generation capacity, AMI, and accelerated modernization account for the vast majority of trackers approved in recent years. Most capital cost trackers for gas utilities address the cost of accelerated programs for replacing cast iron and bare steel mains. Trackers for water utilities, sometimes called distribution system improvement charges, are also common today for accelerated replacement capex ("repex").

Some capital cost trackers have been incentivized. In California, for example, the AMI trackers of Southern California Edison and San Diego Gas & Electric have involved preapproved multiyear cost forecasts. Each company was permitted to recover 90 percent of prudent overspends of its cost forecast up to a cap, and San Diego Gas & Electric was permitted to keep 10 percent of underspends.[23]

Forecasted ARMs

The Basic Idea

A forecasted ARM is based primarily on a multi-year revenue requirement proposal. These proposals are often called "forecasts" even though the utility's cost is usually expected to be lower if portions of its proposed revenue requirement aren't approved. A revenue cap requires a forecast of the net cost of service. A price cap requires, additionally, a forecast of billing determinant growth. VAs may

---

[23] California Public Utilities Commission (2007), *Application of San Diego Gas & Electric Company (U 902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design*. Decision 07-04-043, Application 05-03-015, April 16.

California Public Utilities Commission (2008), *Southern California Edison Company's (U 338-E) Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism*. Decision 08-04-039, Application 07-07-026, September 18.

once again be used because some costs are difficult to project accurately or for other reasons that we discuss above.

A rate or revenue cap based on forecasts typically increases by a certain predetermined percentage in each year of the plan (e.g., 4% in 2021, 5% in 2022, 3% in 2023, etc.). This is one example of a "stairstep" ARM trajectory. Forecasts are sometimes conditional on an inflation assumption and subject to a true-up when the actual inflation rate becomes known. In Great Britain, for example, revenue requirements based on forecasts are adjusted for actual inflation in a macroeconomic price index.

Familiar accounting methods are typically used when forecasting growth in capital cost. The trend in the cost of older capital is relatively easy to forecast since it depends chiefly on mechanistic depreciation. The more controversial issue, and a major focus of a typical proceeding to approve a forecasted ARM, is the value of gross plant additions during the plan term.

A key decision in the design of a forecasted ARM is the extent of true-ups to actuals. In some forecasted ARMs true-ups are quite limited. These ARMs function much like the revenue requirements that result from multiple forecasted test years. In some jurisdictions, most or all capital cost savings during the plan have been returned to customers. In Great Britain, cost variances have been shared mechanistically between utilities and customers. In principle, some asset categories could be subject to cost true-ups but not others.

Shortcuts are sometimes taken in the preparation of forecasts for ARM design. For example, the forecast of OM&A expenses may be escalated using a formula that takes inflation into account, and possibly also trends in productivity and/or growth in the utility's operating scale.

Precedents for Forecasted ARMs

This approach to ARM design has been used for gas and electric utilities for decades in Great Britain and the state of New York. Ofgem's use of forecasts in ARM design is sometimes called the "building block" approach since the revenue requirement is built up from forecasts of component costs. MRPs in New York usually have a term of three years and are the outcome of settlements that reduce the burden on the commission to approve their reasonableness. Some gas distributors in New York state have operated under revenue *per customer* caps based on forecasts. In Ontario, ARMs that are based primarily on forecasts have been used on a few occasions to regulate power distributors and Enbridge Gas Distribution.

Forecasted ARMs are also currently used in British Columbia (BC Hydro), Georgia, and Minnesota. These ARMs are all vertically-integrated utilities that occasionally make large generation plant additions. In the New York and Minnesota plans there is a claw back of any capital cost underspends. Notably, this ARM design is similar to that proposed by Toronto Hydro for CIR 2.0.

Forecasting Pros and Cons

One important advantage of forecasted ARMs is their ability to be tailored to various cost trajectories. For example, a forecasted ARM can provide timely funding for an expected OM&A and capital cost surge. Forecasted ARMs are also particularly valuable when OM&A and capital expenditures are particularly risky. Unless underspends are returned to customers, the incentive to contain cost is material. Another advantage is that capital cost forecasts can be made using familiar capital cost accounting.

On the downside, a utility's incentive to contain cost is somewhat weaker when it is addressed by a forecasted ARM than when it is addressed by an indexed ARM. For example, a distributor is more likely to undertake a major substation capacity expansion if it is expressly approved in advance. Incentives to contain a forecasted cost are, however, stronger than the incentive to contain a cost that is subject to VA treatment. Another problem with forecasted ARMs is that they frequently are not designed to protect utilities from unforeseen changes in inflation. This was a problem for some New York utilities during the pandemic.

The biggest challenge with forecasted ARMs, however, is the difficulty of establishing a just and reasonable multiyear cost forecast. The efficient future cost of service is usually uncertain and uncertainty increases with the length of the MRP term. Utilities are generally incentivized to overstate required cost growth while consumer advocates are incented to understate it. Given the substantial money at stake, parties are incentivized to argue their positions energetically and controversy can ensue.

Padding a cost forecast reduces the pressure on the utility to achieve cost savings and can legitimize more capex than it really needs. The utility can profit in the short term from spending less than it forecasts. Exaggeration of required revenue may reduce the company's credibility in future proceedings. However, the company can always claim that it "discovered" ways to economize. This problem can also be finessed by spending close to the padded forecast, even if it isn't efficient.

Concern about exaggerated cost forecasts, and the general difficulty of conscientiously reviewing multiyear cost forecasts, raises the cost of processing an MRP application with a forecasted ARM. Moreover, concerns about information asymmetries and an uncertain future are often addressed by shortening the plan term and truing up forecasted costs to actual cost. Both of these approaches weaken cost containment incentives and raise regulatory costs.

Some regulatory communities lack the expertise to appraise multiyear cost forecasts. However, many commissions routinely use forward test years in rate cases and some use multiple years. Some commissions also periodically review multiyear business plans of utilities or consider utility proposals for major plant additions (e.g., in proceedings to approve certificates of public convenience and necessity). These exercises create expertise that is useful in considering forecasted ARMs.

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

Ofgem has also reduced distributor forecasts to reflect its assumptions about expected productivity gains. These reflect its expectations about the annual productivity gains that companies can achieve during the term of the MRP based on the available evidence on productivity trends. For RIIO-ED2, Ofgem assumed that distributors can achieve 1% productivity per year.

Hybrid ARMs 1: Indexing and Forecasting

All ARMs are hybrids in the sense that they use a mix of variance accounts and one or more of the three formulaic approaches to ARM design. The term hybrid is customarily reserved for a design that uses more than one of the three predetermined formula approaches.

Hybrid ARMs are used in situations where no one approach to ARM design is suitable for all costs. Most commonly, an indexed ARM is expected to yield insufficient revenue for a utility but regulators may nonetheless want to limit reliance on cost forecasts and variance accounts. One approach to accomplishing this is to index some parts of the revenue requirement while using some combination of cost forecasts and variance accounts for others.

Hybrid 1 Precedents

This general approach has for many years been used to regulate energy distributors in Australia. OM&A revenue is indexed while capital revenue is based on forecasts. One reason this approach has been used there is that the Australian regulator has been advised by experts that it has not yet accumulated the many years of capital cost data needed to properly measure capital productivity growth. Hybrid 1 ARMs are also used in British Columbia, Massachusetts, and Vermont and are currently being proposed by the FortisBC utilities. In Massachusetts, National Grid is proposing to index its OM&A revenue. Both of these utilities propose to base the X factor on U.S. OM&A productivity trends and to include customer growth in the revenue cap index formula.

Hybrids of indexation and forecasting are widely used by power distributors in Ontario. [24] Under 4th GIRM a utility can request supplemental capital revenue if there was/is a difference between forecasted capital cost and the capital revenue yielded by indexing (less a materiality threshold). The supplemental revenue is later trued up to the actual capital cost. Mechanisms for achieving this in Ontario 4th GIRM include incremental capital modules and advanced capital modules. In 2nd and 3rd GIRM there were also separate funding mechanisms for smart meter costs.

The Renewed Regulatory Framework also provides a Custom IR option and most of Ontario's larger power distributors have used this option. In CIR plans to date, a rate or revenue cap index with a "C factor" has typically been used that ensures that the *growth rate* of capital revenue equals the forecasted/proposed *growth rate* of capital cost. The peculiar focus on growth rates conforms to the OEB's *Rate Handbook*, which states that "The annual rate adjustment must be based on a *custom index* supported by empirical evidence (using third party and/or internal resources) that can be tested."[25] [italics added] This is a variant on the theme of a Hybrid 1 ARM. The fact that the C factor is expressed in growth rate terms is in our view immaterial.

---

[24] Ontario's gas Amalco has also operated under the OEB's 4th GIRM price cap IR.

[25] Ontario Energy Board (2016), Handbook to Utility Rate Applications, p. 25.

Pros and Cons of Hybrid 1 ARMs

Indexation of OM&A revenue provides automatic protection from hyperinflationary episodes and can limit the scope of forecasting controversy in IR proceedings. Good data on OM&A input price trends of utilities are available in the United States.[26] The idea of indexing a utility's OM&A compensation has such appeal that it is also used sometimes to establish OM&A revenue requirements in rate cases.[27]

The forecast approach to capital costs, meanwhile, accommodates diverse capital cost trajectories. The complicated issue of designing index-based ARMs for capital revenue is sidestepped. The traditional approach to capital cost accounting can be used. There can be added advantages to separately addressing revenue for OM&A and capital costs such as a particular desire for a claw back of capex underspends.

On the other hand, we have shown that capital cost forecasts can be complex and controversial. Regulators in several jurisdictions have deemed it necessary to hire engineering and benchmarking consultants to appraise such forecasts.

Consumer advocates are influential in California and have on several occasions convinced the regulator not to set rates using the company's budgeted plant additions beyond the (forward) test year. In several rate case decisions for Southern California Edison ("SCE"), for example, the California Public Utilities Commission rejected Edison's request to adopt a multiyear budget-based forecast for conventional plant additions, stating in one decision that:

> As recognized by SCE, in recent [general rate cases] the Commission has rejected SCE's requests to use budget-based capital addition forecasts in its [post-test-year rate] mechanism. The Commission has previously explained that an attrition rate adjustment "is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [a] rate of return." The Commission has also explained:
>
> > As we repeatedly observed in prior decisions, there is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned. In addition, no party other than SCE provided or analyzed

[26] In Canada, on the other hand, custom indexes of utility material and service prices are unavailable and government labor price indexes do not encompass pensions and benefits.

[27] For example, indexing has been used to escalate at least some portion of test year OM&A expenses in Massachusetts and New York.

> detailed post-TY plant addition forecasts in determining increases. We cannot fault other parties for not recommending detailed PTYR budgets… [it] imposes a significant burden on resources.[28]

Central Maine Power operated under a succession of three MRPs with indexed ARMs starting in 1995. In a 2013 MRP filing, however, it requested approval of a hybrid ARM. While OM&A revenue would be indexed, most capital costs would be fully forecasted. The company could retain the revenue requirements associated with the first 10% of cumulative underspends if it met certain criteria.

The Maine commission took the unusual step of rejecting this proposed mechanism in the middle of the proceeding. The commission's rationale for rejecting the proposed hybrid ARM included concerns about the removal of the incentive to over-capitalize that is provided by indexing, the possibility that Central Maine Power's ("CMP") proposal to share in underspends is actually an incentive to exaggerate capital cost forecasts, and the inability of customers to share in OM&A savings that may result from the proposed capital spending due to the proposed OM&A indexation. The use of a multiyear forecast for setting rates elicited the following comment:

> We are also not persuaded by CMP's arguments that its 6-year capital distribution plan should be fully vetted and blessed by the Commission in this proceeding. Detailed long-term capital planning is an activity that, at least in detail, should be left to management subject to prudency review. In addition, as a practical matter, by requiring that the parties and the Commission pre-approved specific capital programs years in advance, whenever CMP acknowledges that there is uncertainty relating to the timing, cost and even the ultimate need for the projects, the [Capital Expenditure Recovery Mechanism] introduces a level of predictive uncertainty into the ratemaking process that we find to be unacceptable.[29]

Hybrid ARMs 2: Indexing and Historical Own-Cost Trending

The Basic Idea

By own-cost trending we mean basing a utility's rate or revenue growth during an MRP on its past cost trend in some fashion. This approach has been most commonly applied to capital rather than OM&A costs. Suppose, for example, that

---

[28] California Public Utilities Commission (2012), Decision 12-11-051 at 606 quoting D.09-03-025.

[29] Maine Public Utilities Commission (2013), "Order of Partial Dismissal," Docket No. 2013-00168, August 2, p. 7.

- a utility claimed that, due to external business conditions, it would be unable to operate under a comprehensive revenue cap index over the next fifteen years; and that
- its first MRP was based on a hybrid ARM that combined indexing of OM&A revenue with a forecast-based capital revenue stairstep.

In the next two plans, the capital revenue requirement could then be based on the average annual value of plant additions in the first plan. These may be adjusted for inflation and an external cost efficiency growth target.

California "Old School" Approach

California's commission has required MRPs for decades but, as noted above, doesn't like to base the ARM on multiyear forecasts for most costs. Hybrid ARMs have been used in numerous MRPs wherein much of the OM&A revenue requirement is indexed while that for capital is based on a calculation that uses traditional cost of service capital cost accounting but includes the simplifying assumption that gross plant additions in each "out" year of the plan reflect either the company's approved additions for the first year of the plan or an average of the company's recent historical additions.[30] The plant additions in these calculations may be escalated for inflation.

Alberta's K-bar Approach

A K-bar approach to ARM design used by the Alberta Utilities Commission ("AUC") for the generic MRPs of gas and electric power distributors in PBR2 and PBR3 is a variant on the California theme. The AUC was disappointed with the results of PBR1, where extensive use of capital cost VAs by distributors weakened their capex containment incentives and raised regulatory cost. The alternative K-bar approach was originally suggested in the hearing to approve PBR1 by AUC commissioner Moin Yahya, a University of Alberta law school professor who earned a PhD in economics from the University of Toronto. K bar is mathematical notation for a value of capex that is fixed in real terms.

The recently approved PBR3 plan for Alberta energy distributors provides an example of the use of K bar in the context of an approaching energy transition. "Type 1" capex is eligible for forecasting

[30] This approach has been used most recently in California by one of North America's largest electric utilities, Southern California Edison.

with subsequent variance account treatment. In order to qualify as Type 1 capex a project must have a material effect on the distributor's finances, be required by a third party or directly caused by applicable law related to net-zero objectives, and be extraordinary and not previously included in the distribution utility's rate base.[31] Capex that is not deemed to be of Type 1 is "Type 2" capex and is addressed by the K-bar mechanism. This mechanism effectively replaces capital revenue based on indexing by capital revenue based on historical own-cost trending.

Massachusetts K-bar Approach

The ARM design for power distributor services of Eversource Energy in Massachusetts is a variant on the Alberta theme. The capital revenue requirement is calculated using a *rolling average* of the company's recent plant additions. To reduce the chance that the company may have excessive plant additions, a cap on the amount of annual plant additions supported by K bar has been established. This annual cap is 10% above the level of annual plant additions that the company forecasted at the start of the proceeding. The prudence of any plant additions subject to K-bar treatment may be investigated at any time and the company has been placed on notice that the regulator may review its capital spending if it determines that the company over-estimated its plant additions forecast and was underinvesting in capital.

In return for the supplemental capital revenue that K bar provides, Eversource agreed to a zero X factor. This is more of a concession in the United States than in Canada since the gross domestic product price index that is widely used in indexed ARMs in the States tends to understate utility input price inflation and this often results in an X factor adjustment that makes it negative.

K bar Appraisal

A K-bar mechanism can reduce the cost of ARM design and strengthen capex containment incentives when a utility is expected to need sufficiently high capex for a number of years that an indexed ARM is uncompensatory for capital revenue.

However, the incentive impact of K bar weakens if utilities suspect that K bar in future plans reflects their gross plant additions in the latest plan. The productivity growth of California power

[31] The criteria changed slightly between the previous and current PBR plans. No projects qualified as Type 1 capex in the prior plan.

distributors has been unremarkable, although this may also reflect special circumstances such as heightening wildfire risk.[32]

A paper on a study by PEG that was published in *The Electricity Journal* last June revealed that in PBR1 the capital productivity growth of participating energy distributors was just as sluggish as in the prior period of frequent rebasings. In PBR2, replacement of variance account treatment of supplemental capital revenue with a K bar caused material acceleration in the capital productivity growth of Alberta energy distributors.[33]

A special advantage of the K-bar approach is that it automatically takes into account how sustained high capex tends to slow capital cost growth over the years as high recent capex depreciates.

Tracker/Freeze ARMs

If most or all of a utility's rapidly growing costs are accorded forecasting and/or VA treatment, the residual cost, which includes the shrinking return on older plant, may grow more *slowly* than *I-X*. This effect can be magnified by adding the annual cost of capex to the revenue requirement without accounting for how depreciation is shrinking the net value of older plant.

Tracking rapidly growing costs has led several U.S. regulators to approve MRPs with "tracker/freeze" ARMs that use forecasts and/or variance accounts to address some rapidly growing costs (e.g., those for new power generation facilities of VIEUs) and a rate freeze addresses other costs. Funding for costs that are addressed by frozen rates comes from growth in billing determinants and the depreciation of plant. The analogue to a rate freeze for a revenue cap might be a freeze in revenue *per customer*. Revenue for costs that are growing less rapidly would rise at the gradual pace of customer growth.

MRPs with tracker/freeze ARMs have been approved numerous times in the U.S. and some approvals are quite recent. To date, they have been more popular amongst VIEUs than amongst power

[32] Lowry, Mark Newton, Matthew Makos, Jeff Deason, and Lisa C. Schwartz. "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," for Berkeley Lab, July 2017. https://emp.lbl.gov/publications/state-performance-based-regulation

[33] Lowry, Mark Newton, David Hovde, Rebecca Kavan, and Matthew Makos. "Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta," *The Electricity Journal*, Volume 36, Issue 5, June 2023.

distributors. Recently, Appalachian Power, Arizona Public Service, Cleco Power, Florida Power and Light, Kentucky Power, Tampa Electric, Virginia Electric Power, and Wheeling Power have received approval of MRPs with tracker/freeze ARMs.[34] However, in recent years some power distributors (e.g., Cleveland Electric Illuminating, Fitchburg Gas & Electric, Narragansett Electric, Ohio Edison, and Toledo Edison) have also received approval of MRPs with tracker/freeze ARMs.

The North Carolina operations of Duke Energy Progress and Duke Energy Carolinas received approval of MRPs based on a variant of a tracker/freeze ARM. Base rates are adjusted annually only to account for forecasted capital costs and related OM&A expenses of projects that are expected to enter service in that year. These projects had to be reviewed and approved in their most recent rate cases, and the approved amount from the rate case is the amount that is eligible to be added to rates (i.e., there is not a tracker to true up forecasted costs to actuals).

Menu Approaches to ARM Design

The Menu Idea

ARM design can be aided by menus of MRP provisions. The menus typically include a key ARM provision and another plan provision that affects utility finances. Utilities are permitted to choose among the menu options. The menus can be designed so that utilities, by their choices, reveal their views of required cost growth. This can reduce the information asymmetry between utilities and regulators.

Suppose, for example, that a utility is given a choice between various combinations of revenue cap indexes and ESMs. Revenue cap indexes with higher X factors are combined with ESMs that accord a higher share of surplus earnings to utilities. A utility that believes it can achieve slow cost growth is then more likely to choose a plan with a higher X factor.

The menu approach to MRP design has been discussed in the academic regulatory economics literature since the 1980s. Major contributions have been made by Michael Crew, Paul Kleindorfer, and Nobel prize winning economist Jean Tirole.

[34] Several of these utilities, particularly Cleco Power and the Florida utilities, have had multiple generations of MRPs with tracker/freeze ARMs.

<u>Menu Precedents</u>

The OEB's current ratemaking options for power distributors under the RRFE is a good example of the menu approach to ARM design (e.g., distributors may choose to request the Annual IR index, 4thGIRM, or Custom IR). In the United States, the Federal Communications Commission used a menu approach to MRP design in a 1990 price cap plan for interstate access services of incumbent local telecommunications exchange carriers. Under the plan, the target rate of return was set at 11.25%. The company could choose between two X-factor options. The first option set the X-factor at 3.31% and entitled the company to retain all of its earnings until it achieved a 12.25% rate of return. Earnings between 12.25% and 16.25% would be shared equally with consumers, and earnings above 16.25% would go fully to consumers. The second option allowed a company to elect an X-factor of 4.3% and in return retain all of its earnings until it reached a 13.25% rate of return. Equal sharing of earnings would occur between 13.25% and 17.25%, and consumers would receive all earning above 17.25%.

Starting in 2004, Ofgem offered British power distributors an array of menu options in several generic rate plans. The menus consist of combinations of utility cost forecasts and allowed revenue. The first mechanism applied to the capex forecast. It enabled distributors with

> less well justified capex forecasts, as compared with the views of Ofgem's consultants … to spend above the amounts that they had justified to Ofgem but [these distributors] would receive relatively lower returns for underspending. In contrast, those [distributors] that had better justified their forecasts, and were in line with the views of the consultants, would be rewarded with a higher rate of return and a stronger incentive for efficiency.[35]

An Information Quality Incentive ("IQI") of similar design covered most OM&A and capital expenditures in the fifth electricity distribution price control in 2009 and, with modifications, was used in Ofgem's first generation RIIO plan for electricity distributors. An IQI also applied to gas distributors during their first generation RIIO plan.

[35] Ofgem (2007), Regulating Energy Networks for the Future: RPI-X@20 History of Energy Network Regulation, p. 38.

Z Factors

A Z factor adjusts revenue for miscellaneous hard-to-foresee events that impact utility earnings and are not effectively addressed by other ARM provisions. Many MRPs have explicit eligibility requirements for Z-factor events. Here is a typical list of requirements.

Causation: The expense must be clearly outside of the base upon which rates were derived.

Materiality: The event must have a significant impact on the finances of the utility. Materiality can be measured based on individual events or the cumulative impact of multiple events. Some plans have materiality thresholds of both kinds.

Outside of Management Control: The cost must be attributable to some event outside of management's ability to control.

Prudence: The cost must have been prudently incurred.

Eligible events may, in principle, raise or lower earnings. For example, a cut in corporate income taxes could lower earnings.

One of the primary rationales for Z-factor adjustments is the need to adjust revenue for the effect of changes in tax rates, highway relocations, mass transit construction, system undergrounding requirements, and other government initiatives on utility cost. Absent such adjustments, policymakers can adopt new policies that increase the cost of a utility, confident in the knowledge that its earnings, rather than customer bills, will be affected between rate cases.

Z-factors can reduce utility operating risk and encourage more cautious behavior by government agencies, without weakening performance incentives for the majority of costs. Z-factors can thus reduce the possibility that an MRP needs to be reopened, while maintaining most of the benefits of MRPs. Disadvantages of Z factors include the fact that they can materially raise regulatory cost, and the possibility that they may weaken utility incentives to mitigate the impacts of triggering events. It may be easier for the utility to obtain higher revenue from the process than it is for customers to obtain lower revenue. Z factors also raise overcompensation concerns in plans with indexed ARMs.

ARM Design Takeaways

Here are some general takeaways from our discussion of ARM design that are useful in Ontario ratemaking.

- ARMs use predetermined escalation formulas that may be based on indexes, forecasts, or historical own-cost trending. A mix of these approaches is possible, and many hybrid ARM designs have been approved. Some mixes that have never been approved may also be reasonable. Each approach can be used where appropriate to balance the goals of reasonable compensation, strong performance incentives, and streamlined ratemaking.
- The forecasting approach to ARM design is popular in some jurisdictions. The leading practitioners of forecasted ARMs, Great Britain and New York, have been using this approach for decades and not as an improvised response to the energy transition. Several regulators have resisted the use of multiyear forecasts in ARM design. Common complaints include high regulatory cost, uncertainty about the future, and the problem of asymmetric information that leads to palliative plan provisions such as clawbacks of underspends that weaken incentives.
- Many ARMs have been proposed by utilities and approved over the years that are not closely linked to comprehensive cost forecasts.
- There are various ways to reduce reliance on cost forecasts in ARM design.
- Combinations of forecasts, historical own-cost trending, and variance accounts for rapidly growing costs can enable the continued use of indexing for slower-growing costs. The easiest way to accomplish this is to index only OM&A revenue, as has effectively been done in Alberta, California, Massachusetts, and CIR 1.0 as currently practiced by Toronto Hydro. Indexing of OM&A revenue can also be facilitated where necessary by forecasting and/or variance account treatment of some rapidly-growing OM&A costs.
- VA treatment of costs weakens utility incentives to contain them and raises regulatory costs. Variance accounts can nonetheless be useful in ARM design. For example, they can strengthen utility incentives to use inputs that they tend to underuse because they reduce capex opportunities or trim costs that don't affect utility earnings because they are externalities or subject to VA treatment.

- VAs can be incentivized by various means. These include permitting only a partial true up to actual costs.
- Variance accounts are also used in MRPs to address energy commodity expenses and other costs that are difficult to address with ARMs, like severe storms and changes in policies that affect costs.
- While ratemaking is complicated when portions of the revenue requirement are excluded from indexing, it can be worthwhile to accord some costs special oversight anyways.
- The most common hybrid approach to ARM design in the United States entails indexing OM&A revenue and predetermined revenue "stairsteps" for capital revenue. The stairsteps may be based on multiyear capex forecasts, test year capex, or recent historical capex.
- A tracker that recovers a large portion of an electric company's annual capex cost has sometimes permitted companies to operate under a multiyear rate freeze for other non-energy costs. MRPs with such "tracker/freeze" provisions have typically accorded tracker treatment to costs of new or refurbished generating plants.
- Cost efficiency growth targets and stretch factors can apply to cost forecasts, K bars, and VAs as well as to indexes. Outside of Ontario, for example, efficiency markdowns apply to forecasts in Great Britain and to K bar in Alberta. These offsets may reflect estimates of industry efficiency trends gleaned from econometric and/or productivity studies. However, the use of historical own-cost trending may result in a capital revenue requirement that is well below the Company's forecast. In that event, the question arises as to whether any additional productivity offset is warranted.

Relaxing the Link Between Revenue and System Use

Regulators are increasingly interested in relaxing the link between a utility's revenue and the kWh and kW of system use by customers. This counts as IR because it reduces incentives that utilities have to boost system utilization (aka "throughput"). Under legacy rate designs, with their high usage charges, utilities generally profit from increased capacity utilization. Even when demand growth taxes capacity there may be profitable investment opportunities, and utilities are largely indifferent to the growth in tracked costs and externalities that demand growth entails. Higher system use is undesirable to the extent that alternatives to higher use such as DERs are less costly. A diminished throughput incentive reduces the disincentive utilities otherwise have to facilitate use of conservation and demand management ("CDM") and DERs. Relaxation of the revenue/usage link can also address any problem of declining average use that the utility is experiencing. The frequency of rate cases can to that extent be reduced, thereby strengthening cost containment incentives and reducing regulatory cost.

Three methods are widely used in North America for relaxing the revenue/usage link: revenue decoupling, lost revenue adjustment mechanisms ("LRAMs"), and high fixed charges. These options are discussed in turn.

Revenue Decoupling

Revenue decoupling adjusts a utility's rates mechanistically to help its *actual* revenue track its *allowed* revenue more closely. Most decoupling systems have two basic components: a revenue decoupling mechanism ("RDM") and a revenue adjustment mechanism. The RDM tracks variances between actual and approved revenue and adjusts rates periodically to reduce them. A rate rider is commonly used to draw down these variances by raising or lowering rates.

Most RDMs account for *all* sources of demand variance and these may be called "full" decoupling mechanisms. Some RDMs are "partial" in the sense that they exclude the revenue impact of certain kinds of demand fluctuations. For example, true ups are sometimes allowed only for differences between allowed revenue and weather-normalized actuals.

The revenue adjustment mechanism escalates allowed base rate revenue to provide relief for cost pressures. The great majority of decoupling systems have some kind of revenue adjustment mechanism since, if allowed revenue is static, the utility will experience financial attrition as its costs rise with increased operating scale and other cost drivers. In a multiyear rate plan, the ARM plays the role of escalating allowed revenue.

American states that have recently utilized revenue decoupling for electric and gas utilities are indicated on the maps below in Figures 3a and 3b, respectively.[36] In the electric utility industry, it can be seen that decoupling is currently used in 18 American jurisdictions. CDM and DERs are aggressively

[36] The maps reflect the status of decoupling circa March 2024.

encouraged by policymakers in many of these jurisdictions. Decoupling is more common in the gas distribution industry and is the most widespread means of relaxing the revenue/usage link there. This reflects the fact that gas distributors often experience declining average use and that this has been due chiefly to external forces.

The popularity of decoupling in the United States reflects numerous potential benefits in the American context. It eliminates the lost-margin disincentive for a wide array of utility initiatives to encourage CDM and DERs, without relying on complicated load impact calculations or rate designs with high fixed charges that could discourage customers from adopting CDM and DERs.[37] For example, it reduces the risk from offering customers time-sensitive usage charges that shift loads away from peak demand periods. The adjustment to an individual customer's charges is not linked to its use of the grid, so the customer's incentive to conserve is unaffected.

[37] Load impact calculations may nonetheless be undertaken to help ascertain the effectiveness of CDM programs.

Figure 3a

Recent Electric Revenue Decoupling Precedents in American States

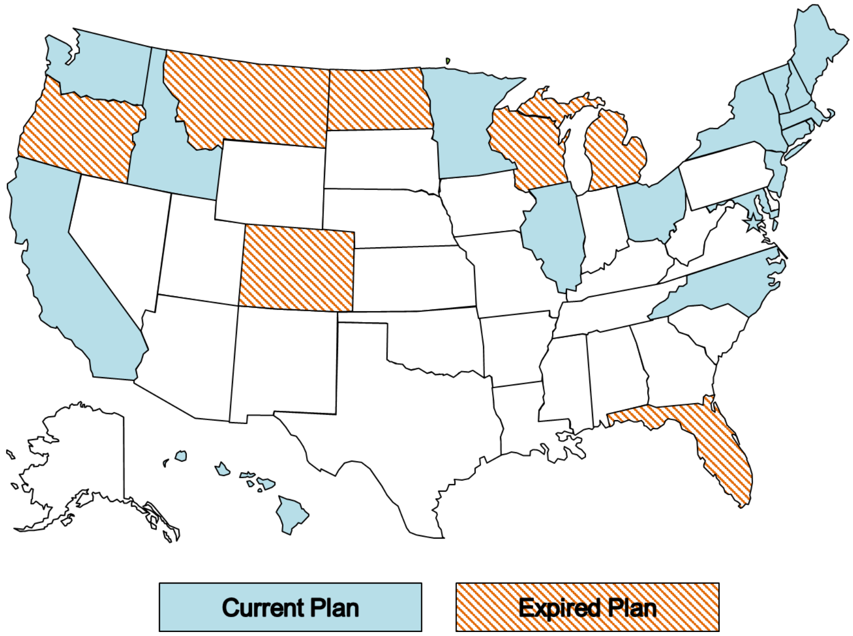
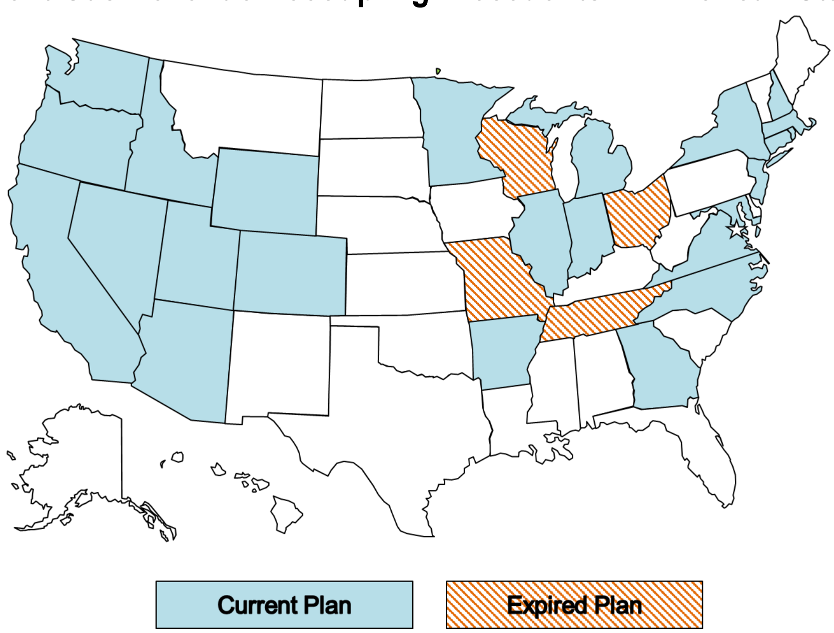


Figure 3b

Recent Gas Revenue Decoupling Precedents in American States



Source: Lowry, Mark Newton, et al., "Innovative Regulatory Tools for Addressing an Increasingly Complex Energy Landscape: 2023 Update," for Edison Electric Institute, February 2024.

Decoupling can also compensate utilities for reduced usage-charge revenue due to CDM promotion by third parties, such as government agencies. Because it encourages a wide range of CDM initiatives and DERs, environmental intervenors are typically strong supporters of decoupling. Rate cases are less frequent to the extent that utilities are experiencing declining average use. Decoupling also reduces controversy over billing determinants in rate cases with future test years.

Revenue decoupling may not be desirable for all services. For example, some customers may have a demand for utility services that is particularly sensitive to the terms of services. Utilities under decoupling may in such cases be insufficiently attentive to retaining the business of these customers. Quite commonly, only revenues from residential and commercial business customers are decoupled. These customers account for a high share of a distributor's base rate revenue, and are often the primary focus of CDM programs.[38] Electric vehicles and heat pumps can produce positive environmental impacts and permit reductions in rates to other customer classes. The incentive to promote beneficial electrification could in principle be accomplished by excluding these loads from decoupling.

LRAMs

LRAMs can explicitly compensate utilities for short-term losses in base rate revenues that they experience due to their CDM programs and DERs. Estimates of load losses are needed to calculate the compensation. The lost revenue is usually collected through a special rate rider.

LRAMs reduce the disincentive for utilities to embrace CDM and DERs. By reducing earnings erosion, they may also reduce the required frequency of rate cases. On the other hand, LRAMs generally do not compensate utilities for the effects of important external forces, like the CDM initiatives of public agencies, which slow load growth. Moreover, estimates of load savings from utility CDM programs can be complex and are sometimes controversial. The scope of CDM initiatives addressed by LRAMs is therefore frequently limited to those for which load impacts are easier to measure. If the utility has high usage charges, it remains at risk for revenue fluctuations, due to variation in volumes and peak load, which may result from changes in weather, local economic activity, and other volatile drivers of system use.

[38] In a multiyear rate plan, service classes excluded from decoupling can be subject to price caps.

High Fixed Charges

Fixed/variable pricing is an approach to rate design that relies heavily on fixed charges (charges that do not vary with a customer's actual sales/delivery volumes or peak demands) to compensate utilities for fixed costs of service. Between rate cases, base revenue tends to grow at the gradual pace of customer growth. A *straight* fixed/variable ("SFV") rate design recovers substantially *all* (e.g., distribution) base revenue through fixed charges.

Increasing the share of fixed cost collected through fixed charges relaxes the revenue/usage link with low administrative cost since this approach requires neither decoupling true ups nor load impact calculations. This is a major selling point in jurisdictions with numerous utilities to regulate. The throughput disincentive for the utility to embrace CDM and DERs is reduced. When residential and commercial average use is declining, base revenue will grow more rapidly with fixed charges so that rate reviews tend to be less frequent even if the decline is largely driven by external forces.

However, high fixed charges also reduce an electric company's ability to use usage charges as a tool for encouraging efficient CDM and DERs. For example, they do not encourage customers with electric vehicles to charge at night. There is growing interest in time-sensitive distribution charges in the United States.[39] When average use is growing, high fixed charges slow revenue growth and in the absence of an MRP encourage more frequent rate cases.

Performance Metrics and PIMs

The Basic Idea

Performance metrics (called "outputs" in Britain) quantify aspects of utility operations which matter to customers and the public. The use of metrics in regulation can alert utility managers to key concerns, target areas of poor (or poorly incentivized) performance, and reduce the cost of oversight on balance. A **performance metric system** is a system for routinely monitoring select metrics and using them in performance appraisals. Scorecards (sometimes called dashboards) summarizing performance

[39] Juan Pablo Carvallo and Lisa Schwartz (2023), "The use of price-based demand response as a resource in electricity system planning," Lawrence Berkeley National Laboratory Technical Brief, November.

results using metrics are often tabulated and posted on a publicly available website, allowing regulators and stakeholders to quickly review electric company performance in a number of areas.

Metrics that are closely linked to the welfare of customers and the public include those that address the cost of service and service quality. A familiar example of such metrics is the system average interruption frequency index ("SAIFI"), which measures an aspect of service reliability. There is also an interest in metrics that are closely associated with variables of ultimate interest. An example is the number of customers taking service with time-sensitive rates.

In a performance metric system, target (aka "benchmark") values are usually established for some metrics. Performance can then be measured by comparing a utility's values for these metrics to the targets. This is typically done by taking the differences or ratios between the actual and target values. Performance appraisals can focus on the *level* of a metric or on its *trend*.

Quantitative performance appraisals using metrics are sometimes used in ratemaking. A performance incentive mechanism or ("PIM") can, for example, link revenue mechanistically to the outcomes of performance appraisals based on metrics. These revenue adjustments can be made in rate cases and/or between rate cases. The following simple mechanism for a hypothetical utility called Canada Power is one example of how a PIM can be designed:

$$\textit{Revenue Adjustment}^{Canada} = \$ \times (SAIFI^{Canada} - SAIFI^{Target}).$$

Here, SAIFI is the performance metric. The SAIFI value attained by Canada is compared to a target. The term "$" is the award/penalty rate per unit of deviation from the target. If Canada meets the target, then $SAIFI^{Canada}$ equals $SAIFI^{Target}$ and the revenue adjustment is zero. If Canada performs better than the benchmark, the company may increase its revenue. By the same token, if Canada underperforms it must decrease its revenue.

Targets that provide a realistic stretch goal for the utility and properly reflect circumstances that it cannot control can be difficult to establish. For example, the SAIFI of a utility depends on the extent of system undergrounding, forestation, and the prevalence of severe storms. Improved reliability can be costly. The full set of business conditions that "drive" a metric and their relative importance is often unclear.

Consideration of conditions that influence the *level* of a metric can be sidestepped by making the *trend* in its value the focus of the performance appraisal. A PIM could, for example, focus on the change in a utility's SAIFI from its recent average historical value, and not address whether historical reliability was appropriate. A focus on trends is thus especially convenient when there is not much reason for the target to change over time.

Popular PIMs

Service Quality

Service quality is one of the most common areas of utility operations where PIMs are employed in utility regulation. Service quality PIMs can strengthen incentives to maintain or improve quality and simulate the connection between revenue and product quality that firms in competitive markets experience. Service quality PIMs for electric utilities have traditionally fallen into two general categories: reliability and customer service.[40]

Reliability PIMs based on metrics like systemwide SAIDI, SAIFI, and CAIDI are common in MRPs (e.g., HI, IL, MA, MN, NC, NY). PIMs for reliability at more granular levels have also been approved (e.g., worst circuit performance for Massachusetts power distributors and reliability in disadvantaged communities in Illinois). PIMs for customer service are also quite common in MRPs (e.g., HI, MA, MN, NY, and WA) and often feature multiple metrics (e.g., customer satisfaction, customer complaint rates, appointments kept, and speed with which utility representatives answer customer phone calls).

Performance on reliability and customer service quality metrics is often assessed through a comparison of a company's current year performance to its recent historical performance. Because of a lack of standardization in service quality data and the effort required to process available data, benchmarking a company's performance on service quality PIMs is challenging and has rarely if ever provided the basis for PIMs.

[40] See Kaufmann, L., Getachew, L., Rich, J., and Makos, M., *System Reliability Regulation: A Jurisdictional Survey*, report prepared for the Ontario Energy Board and filed in OEB Case EB-2010-0249, May 2010, for a survey of reliability PIMs.

See Kaufmann, L., *Service Quality Regulation for Detroit Edison: A Critical Assessment*, Michigan PSC Case No. U-15244, report prepared for Detroit Edison and Michigan Public Service Commission Staff, March 2007, for a survey of customer service PIMs.

Conservation

Conservation PIMs tie the revenue of a utility to indications of success in their conservation programs. Sensible performance metrics for such PIMs include the peak MW or total MWh of load. The success of a utility conservation program depends partly on kWh of load savings achieved and partly on program cost per kWh saved. Some conservation PIMs have a "shared savings" format that can guard against excessive program cost. Net benefits of programs are calculated, and these are shared mechanistically between utilities and their customers.

PIMs can strengthen incentives for utilities to embrace CDM. Revenue decoupling, LRAMs, and SFV pricing can remove the throughput disincentive to resist CDM whereas CDM PIMs can provide a *positive* incentive.

However, CDM PIMs also have some disadvantages. As with LRAMs, the calculation of load savings from CDM and their cost impact is generally costly and can be controversial. Independent verification of savings has sometimes been required. PIMs for CDM therefore typically exclude many kinds of CDM programs (e.g., customer information programs and time-sensitive distribution rates). In this situation, utilities are incentivized to focus on programs addressed by the PIMs and may neglect programs that aren't addressed.

The American Council for an Energy-Efficient Economy ("ACEEE") reports that targeted incentives for CDM are quite common in the United States.[41] In their 2022 State Energy Efficiency Scorecard, ACEEE found that 28 states had some form of performance incentives for electric CDM programs.[42] Among states that had implemented PIMs, all but seven had also adopted decoupling or LRAMs. The incentives surveyed encompassed management fees as well as PIMs.[43] Among CDM PIMs, those focused on energy efficiency programs are the most common, and some states have decades of experience with them. Some PIMs also incorporate demand response programs.

[41] Sagarika Subramanian, et al., 2022 State Energy Efficiency Scorecard, ACEEE Report (Dec. 2022), https://www.aceee.org/research-report/u2206.

[42] *Ibid.* at 49-50.

[43] Management fees reward the electric company for spending on specific programs, sometimes by providing them a share of expenditures. See the discussion on targeted incentives for underused practices below for further discussion of this general approach to PBR.

Cost

Regulators in several countries use statistical cost benchmarking in rate setting. The use of benchmarking to set the stretch factor terms of ARMs is discussed in our companion empirical report.

New Uses for PIMs

Interest in using performance metrics in utility regulation has been growing in the U.S., spurred in part by the elaborate performance metric system in Britain's RIIO approach to energy utility regulation. Outputs is the British term for metrics. RIIO includes numerous PIMs and many additional metrics. Some of the PIMs are quite innovative.

Regulators in several North American jurisdictions (e.g., Colorado, Connecticut, Hawaii, Minnesota, New York, Washington, Wisconsin, and Ontario) have held generic proceedings to consider greater use of metrics and PIMs. The Renewing the Energy Vision ("REV") proceeding in New York has given rise to several new kinds of PIMs in that state's regulatory systems.[44] Hawaii has been another PIM innovator.

Metric systems are evolving to meet new industry challenges. Metrics that address special concerns of policymakers are sometimes called policy metrics. These metrics are sometimes used to construct PIMs. The new policy PIMs are usually asymmetrical and often reward-only.

Some policy PIMs address concerns by regulators and many stakeholders that utilities make greater use of peak load management to contain growth-related capex and facilitate greater reliance on intermittent renewable resources. In the mainland United States, management of systemwide peaks can also reduce the share of regional transmission costs that are assigned to a utility.

Conservation PIMs are an example of policy PIMs that encourage realization of policy goals. Newfangled policy PIMs have been approved in several jurisdictions (e.g., NY).

- 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

[44] Some of the new New York PIMs are called "earnings adjustment mechanisms".

projects, and encouraging customer enrollment in time of use rates (this sometimes crosses over with PIMs for the use of AMI).

- PIMs for electric vehicles are used in several jurisdictions that have revenue decoupling (e.g., IL and NY). As electric vehicle demand may increase the system peak, some jurisdictions have developed PIMs to minimize the impact of new EV load on system peak (e.g., by encouraging utilities to sign up EV customers for time of use rates).
- In an age when many utilities are investing in AMI and other smart grid facilities, policymakers want to know if these facilities work well and are properly utilized. AMI benefits include reductions in consumption on inactive meters, unaccounted-for energy use, and lower meter reading costs.
- Utility emission PIMs focus on the emissions resulting from the utility's management of the system. Metrics for this performance area include reductions in emissions due to fewer truck rolls, carbon dioxide emissions by business function, line losses, sulfur hexafluoride emissions, and the number of utility vehicles that are electric.
- Other areas addressed by approved policy PIMs include the use and usefulness of AMI (e.g., change in stolen electricity and the number of customers authorizing sharing of energy usage data with 3rd parties), the utilization of distributed energy resources (e.g., solar and storage), use of CDM and other third-party services, and electrification of space heating.

Most *reliability* PIMs in the States are penalty-only while most *policy* PIMs are award-only.

PIM Pros and Cons

Performance metric systems have notable pros and cons as additions to utility regulation.

<u>Pros</u>

- PIMs can strengthen financial incentives to perform well in targeted areas that matter to regulators, customers, and the general public. Even in the absence of explicit financial incentives, utilities that try to perform well in targeted areas can garner valuable goodwill from regulators and the public.

- PIMs can evolve incrementally and gradually as new performance concerns arise and older concerns recede.
- PIMs can reduce the need for prudence oversight. For example, reliability PIMs can reduce the need for formal reliability reviews.
- Other means of strengthening incentives and/or reducing regulatory cost may be less feasible. For example, incentivization of energy cost trackers can be difficult because these costs are volatile. A PIM for energy conservation programs is an alternative.

Cons

One disadvantage of PIMs is that performance is often difficult to measure accurately. Some utility activities are hard to quantify. An example is utility efforts to encourage development of markets for CDM products and services. Some performance metrics (e.g., reliability, sales volumes, and peak loads) are sensitive to external business conditions, and these conditions are sometimes volatile. The utility is not then fully responsible for the values of performance metrics. Standardized data on metrics and business conditions that affect them are often unavailable for numerous utilities. The impact of external business conditions on performance metrics may be unclear and/or complicated. These problems can make it difficult to base performance targets for many metrics on operating data from other utilities.

It can also be difficult to correctly *value* performance and establish appropriate award/penalty rates for PIMs. The value of changes in performance (e.g., improved service quality and reductions in carbon emissions) is sometimes unclear. Even if it were known, the share of benefits that utilities should receive may be unclear. Customer interests are disserved if awards exceed those needed to incentivize good behavior. The appropriate PIM may have a nonlinear form, so that award rates rise or fall with measured performance. Concern about overpayment for performance has prompted many consumer advocates to oppose PIMs with awards.

Here are some other problems encountered with PIMs.

- Utilities tend to resist PIMs involving penalties and to propose lenient targets, while consumer groups tend to resist PIMs involving awards and to propose aggressive targets.

- Regulators may have difficulty committing long term to a PIM. "Ratcheting" targets over time to reflect a utility's improving performance can weaken incentives for improvement.
- When there are multiple PIMs, the incentives they generate may overlap. Assigning proper weights to individual PIMs can be a difficult and controversial task.

These disadvantages of PIMs have consequences.

- The design and operation of PIMs can invite controversy and strategic behavior by parties to regulation. For example, utilities and other parties to regulation have sometimes disagreed on the load impact of CDM programs that are addressed by PIMs.[45] Awards and penalties have sometimes been disputed when metrics have been influenced by external business conditions.
- The incremental regulatory cost of adding several metrics and PIMs to a regulatory system can be non-negligible. The PIMs in an MRP can grow so large and complex as to constitute an undue administrative burden.
- PIMs can increase utility risk without an appropriate rate of return adjustment. There can also be a risk to customers from poor PIM design.
- Targets, penalties, and rewards may be too high or too low.
- PIMs may focus on more quantifiable performance dimensions and neglect dimensions that are less quantifiable but nonetheless worthwhile. For example, the CDM PIMs may focus on utility programs rather than market transformation initiatives. Amongst possible CDM programs, utilities may focus on initiatives where savings are easier to measure. For example, they might prefer direct load control (i.e., dispatchable) programs to time of use pricing.
- A focus on *summary* metrics can, on the other hand, encourage utilities to focus too much on what's easy while neglecting more difficult initiatives that are also desirable. For example, they may focus on achieving good reliability on urban circuits and neglect rural circuits that serve few customers.

[45] Gold, R., "Penalties in Utility Incentive Mechanisms: A Necessary 'Stick' to Encourage Utility Energy Efficiency?" *The Electricity Journal*, November 2014, p. 89.

Performance Metric Systems in Practice

Approved performance metric systems reflect these considerations.

- PIMs tend to be limited to situations where incentives are conspicuously weak and performance really matters. In searching for incentive "holes," the full range of structural, command and control, and IR provisions of the regulatory system should be considered.
- The need for PIMs tends to be greater to the extent that the regulatory system otherwise has weak incentive power. For example, the need for CDM PIMs is greater in the absence of revenue decoupling, LRAM, or SFV pricing. The need for PIMs to encourage low carbon electrification is greater to the extent that utility benefits of such programs are reduced by decoupling or SFV pricing.
- PIMs also tend to be used where they are relatively easy to develop and administer.
- Many metrics in a performance metric system will have targets but no PIMs. Some metrics will have neither targets nor PIMs.
- Complex calculations are often eschewed in PIM design. For example, the award and penalty rates of service quality PIMs rarely reflect sophisticated calculations of the costs or benefits of changes in quality. California's Public Utilities Commission abandoned the complicated shared savings approach to the calculation of awards for CDM programs. For several years afterwards, utilities instead received a share of CDM expenses as a management fee.
- Some PIMs have dead bands or adjustments like Z factors to reduce the impact on awards and penalties of volatile external business conditions. For example, many reliability metrics exclude major event days because these days are typically the result of unusually severe weather or other extraordinary events.
- Awards and penalties are often small, and rewards may be arbitrarily capped.

The most common areas for PIMs to date have been reliability, customer service quality, and energy conservation. Interest in using performance metrics has been growing in the U.S., inspired in part by the elaborate performance metric systems in Great Britain's RIIO approach to ratemaking.

Targeted Incentives for Underused Practices

"Underused" practices is the term we use for inputs and practices that utilities often use in suboptimally small amounts. Examples include inputs that reduce capex on balance or that reduce costs that utilities are less motivated to contain because they are tracked or external to the company's finances. Inputs may also be disfavored because their use is unusually risky. An example would be equipment embodying a promising new technology which is nonetheless costly or not fully proven. Targeted incentives can "nudge" companies to make greater use of these inputs and practices.

Utilities can be encouraged to make greater use of disfavored inputs by various means that include the following.

- Costs of underused practices can be accorded variance account treatment.
- OM&A expenses for underused practices may be capitalized.
- A return on equity ("ROE") premium can be added to any capitalized costs.
- A utility may be paid a "management fee" to use the inputs (an example is a payment equal to a share of the expenditures on the inputs).[46]
- Commissions can express approval of underused practices by such means as policy statements, defined pilot programs and innovation funds, and marketing flexibility provisions. These approaches are sometimes grouped together under the heading "regulatory sandbox." Many pilots entail supplemental funding and/or cost trackers.

Salient Precedents

Many utility costs have been tracked based in part on the view that the inputs are disfavored because they reduce capex and/or costs that are tracked or externalities. For example, tracking of utility CDM program costs is commonplace, and these expenses are capitalized in several jurisdictions (including BC and Delaware).

[46] ROE premia and expenditure share awards may be linked to performance metrics and targets.

Lost revenue adjustment mechanisms are another widely used mechanism for encouraging specific underused practices (in this case CDM programs and accommodation of DGS) even though we have chosen to discuss them at length in another section instead of here.

MRPs often include target incentives for disfavored inputs. Reasons include the fact that energy expenses are usually tracked and stronger cost containment incentives discourage some underused practices that aren't tracked. MRPs are sometimes touted for encouraging innovation but, in practice, utilities often worry that innovative practices might be adversely treated by regulators in the next rate case. MRPs in Australia, Britain, and the U.S. have had provisions for pilot programs.

Conservation and demand management expenses are usually tracked and are sometimes capitalized or accorded management fees. Incremental costs of DER accommodation, beneficial electrification, and/or mitigation of harmful generation emissions have been afforded VA treatment in several MRPs.

Pilot programs have also been included in MRPs and can be approved when the MRP is authorized or instead "pop up" in the middle of a plan. Pilot programs can make sense during an MRP by offsetting the effect of stronger cost containment incentives and reducing electric company concern about an adverse decision at the end of the plan regarding a promising but risky practice. The term of an MRP can be too short for the company to break even on some promising initiatives, and regulators might approve a rate design pilot in lieu of a Phase 2 rate design proceeding.

Ofgem uses a total expenditure ("totex") approach to the determination of annual revenue requirements in which a common percentage of certain kinds of OM&A expenses and capex is capitalized instead of the COSR approach of capitalizing all capex and a small percentage of OM&A expenses that are related to overheads. The share of totex that is capitalized is typically similar to the share under COSR. Totex may exclude certain costs that the regulator believes should be addressed separately. Capitalized totex is then added to the rate base. This general approach has thus far been used only in combination with multiyear rate plans but may in principle be used in their absence.

Support for these various incentives often comes from parties that would benefit from greater utility use of the targeted inputs and practices. These parties include vendors of smart grid equipment and independent power producers and demand response providers that compete with electric company capex.

Measures to encourage underused practices can result in their overuse, and careful prudence oversight can be used to guard against this outcome. A CDM shared savings PIM can guard against inefficient programs by taking account of program costs as well as benefits. ROE premiums and management fees may be linked to performance metrics and targets.

3. Incentive Ratemaking in Ontario

In this section we present a high-level review of OEB incentive ratemaking policies that have a notable bearing on THESL's CIR 2.0 application. Statements of particular relevance are bold faced.

The Early Years

The rates of Toronto Hydro and other Ontario power distributors were for many years regulated by Ontario Hydro. The OEB approved its first-generation generic incentive regulation mechanism ("1st GIRM") for provincial power distributors for an initial 2000-2002 term. This mechanism was a multiyear rate plan featuring a price cap index and an ESM. The Board subsequently delayed implementation of 1st GIRM to 2001 and removed the ESM. The 1st GIRM later extended to March 2005 to afford distributors more time to "explore the incentives for improvements and savings provided by the current PBR regime." However, Bill 210, enacted in December 2002, froze existing distributor rates until May 2006 unless approval was otherwise granted by the Minister of Energy. Rates were adjusted in May 2006 pending the outcome of rebasings that were filed in 2005. Between 1999 and 2006, it follows that Ontario power distributors operated without a rate case or ESM. During these years, distributors had strong incentives to contain costs and some may have responded by deferring some capex.

The second-generation IRM used 2006 rates as a starting point. The Board introduced staggered terms allowing approximately 1/3 of distributors to rebase rates each year between 2008 and 2010.[47] Utilities would thus have up to 3 years on a new price cap index.

The third generation IRM ("3rd GIRM") also featured a price cap index and its term was initially fixed at four years.[48] Toronto Hydro nonetheless obtained rebasings of its rates for 2008, 2010, and 2011. In its 2008 rebasing proceeding, the Company initially requested approval of an MRP based entirely on cost forecasts. This was rejected by the Board on several grounds.

> In the Board's opinion, the Applicant's proposal does not meet a number of the key elements of its multi-year rate setting plan. First, multi-year regulation seeks to balance ratepayer and shareholder interests through the imposition of **explicit productivity goals**. This means that the multi-year plan should encourage productivity improvements within the Utility, and should ultimately share those gains with the ratepayers. In the Board's plan, this is accomplished

---

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

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

> through the use of an offsetting productivity factor (the X-factor), which provides a sharing of the benefit of efficiency gains to ratepayers immediately. The Board simply could not see any discernable productivity driver within the Applicant's proposal. That is not to say that the Applicant is not concerned about productivity, but simply that there is no transparent reflection in its multi-year rate plan that addresses the issue. The Applicant's plan contains steady increases in spending in each of the three years, but there is **no explicit or measurable incentive to productivity**, nor any mechanism which would capture such gains in any year over the period.
>
> Second, multi-year regulation should provide for a timely review of the extent to which the company is performing to its forecasts. Under the Applicant's proposal there appears to be no check as to the accuracy of its forecasts until the year following the last year of its program; namely, 2011. While this is not problematic under the Board's plan where rates based on one year's forecast are subject to a formulaic adjustment which includes the productivity incentive, here the Applicant has based its proposal on forecasts, each dependent in some measure on the previous year's forecast, with the result that **each additional year's forecast is subject to increasing uncertainty**.
>
> Third, as the Board noted in the Hydro One Networks Inc. case, a time of rapidly increased spending, whether such spending is by way of capital expenditure or current expense, is not a time where regulatory oversight should be diminished.[49] [**emphasis added**]

In this proceeding, the Board ultimately approved rates for two forward test years (2008 and 2009) on the basis of cost forecasts. The issue of whether THESL should be required to operate under 3rd GIRM was discussed in several subsequent applications. In a 2011 rate case decision, the Board stated that Toronto Hydro had made a "choice to approach the Board's ratemaking processes in a manner that is contrary to the Board's rate setting policies."[50] The Board continued:

> In order to justify its approach, THESL posits that two separate frameworks exist and that it has been operating within one of them, that being a cost of service framework. THESL argues that it would be inappropriate for the Board to now treat it as though it were operating within the other framework, that being an IRM framework.
>
> THESL also argues that based on this rate making construct, that there is a distinction between a cost of service application and a rebasing application. THESL submits it would do things differently in a rebasing application and that it did not anticipate that there was an expectation that its 2011 application would be treated as a rebasing application.
>
> The Board's rate setting policies are not composed of the two separate frameworks that THESL describes. As stated above, the Board has clearly articulated the mechanics of the multi-year rate setting plan and its expectations of distributors. **The Board believes that THESL's**

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

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

> **submissions mischaracterize the Board's rate setting policies and the Board does not accept the construct as described by THESL as a Board sanctioned framework**. **[emphasis added]**
>
> THESL has pointed to situations in which the Board's multi-year rate setting plan has not been strictly adhered to in support of its position that its view of the framework is one that the Board should accept. While the Board accepts that there have been deviations from the Board's stated multi-year rate setting plan, including the acceptance of THESL's non-conforming applications in the past, the Board considers the April 20, 2010 letter to be a clear and explicit statement of the Board's expectations of distributors on a going forward basis… The Board is not persuaded by THESL's submissions that the Board's stated rate setting policies did not apply to it.[51]

A THESL application for an MRP based on forecasts for the 2012-2014 period was dismissed at the preliminary issue stage. In making this decision the Board disagreed with Toronto Hydro's contention that it could not conduct its business as it had planned for under COSR.

> But IRM is not intended to result in a status quo approach. The expectation is for changes in the way a distributor conducts business – not to do less – but to find efficiencies and drive productivity improvements.[52]

The company's evidence as to its productivity improvements was not compelling.[53] Instead, THESL's rates for those years were set according to the provisions of 3rd GIRM.

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

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

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

[52] Ontario Energy Board (2012), *Decision With Reasons and Order on the Preliminary Issue*, January 5, p. 17.

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

would **unduly complicate the application**, **reporting, and monitoring requirements** for 2nd Generation IRM because it would require special consideration to be implemented effectively.[54]

Supplemental funding for capital in the 2nd GIRM was limited to a funding adder related to smart meters.[55] A true up between revenues received through this adder and actual revenue requirements resulting from smart meter implementation would occur at a later time. Recovery of a distributor's actual smart metering costs was not permitted until the costs had been reviewed for prudence.

3rd GIRM contained a special provision for capital called the Incremental Capital Module ("ICM"). The Board described the ICM in its decision as "reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capabilities underpinned by existing rates."[56] The OEB set a high bar for approval as amounts were required to exceed a formulaic materiality threshold, meet three need criteria, and be prudent. The materiality threshold was determined formulaically and was intended to be a level of plant additions materially higher than that funded by the price cap index, depreciation, and growth in billing determinants. Smart meter riders also continued during the 3rd GIRM.

Renewed Regulatory Framework

The Renewed Regulatory Framework ("RRF") that is currently used in power distributor ratemaking resulted from initiatives the OEB began in 2010 to review their policies on ratemaking, distribution system planning, and performance measurement. At an early stage of the RRF proceeding, the Board stated that the goal of the RRF is

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

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

[56] Ontario Energy Board, *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, p. 31. Filed September 17, 2008 in EB-2007-0673. The OEB subsequently amended the ICM eligibility criteria to remove the requirement of unusual circumstances.

> to support cost-effective modernization of the network while at the same time controlling rate and/or bill impacts on consumers.[57]

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

> Regulatory frameworks should be sustainable. And, in practice, a framework should be predictable and understood by stakeholders, and **capable of being implemented through efficient & effective regulatory processes**.[58]

Three kinds of multiyear rate plans are available to distributors under the RRF: a fourth-generation of generic IR (now called "Price Cap IR" or 4th GIRM), the Annual IR index, and Custom IR. Each distributor can request its preferred ratemaking approach.[59] All distributors are required to report annually on a wide range of performance metrics and results are summarized on company-specific scorecards that are posed on the Board's website. Reliability, customer service quality, and some other metrics have targets. Distributors are also required to periodically file distribution system plans ("DSPs") and most do so with their rebasing.

An Advanced Capital Module ("ACM") was developed during the term of 4th GIRM to address concerns that distributors were strategically bunching capex around the year of the rebasing and not in accordance with a prudent asset management program. ACMs are generally very similar to ICMs, the key difference being that ACMs can only be requested at rebasing, while ICMs are now only available for capex that was unforeseen at rebasing or for distribution system plan capex that was significantly higher than forecasted. In its decision to implement an ACM option, the Board reduced the dead zone for ACMs and ICMs alike and added a means test to prevent capital module requests from distributors that are overearning by more than 300 basis points.

Under CIR, a distributor-specific rate trend is determined by the Board that is

---

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

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

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

> informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts.[60]

The OEB acknowledged that "The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant."[61]

The Board's *Handbook for Utility Rate Applications* ("Rate Handbook") provides the following guidelines for utilities requesting CIR.[62]

> **The annual rate adjustment must be based on a *custom index* supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; *explicit financial incentives* for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, *must be incorporated through a custom index or an explicit revenue reduction over the term of the plan* (not built into the cost forecast).**
>
> **The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.** An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.
>
> **It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications**. **Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be *higher*, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.**[63] [**Emphasis added**]

---

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

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

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

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

Subsequent CIR Decisions

Hydro One Distribution (2015)

In the early days of CIR the Board approved a few plans that featured forecasted ARMs. However, in 2013 when Hydro One requested a 5-year Custom IR plan based on five forward test years, , the Board approved only three years and noted the following.

> Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation. All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service.
>
> Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies. **Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation….**
>
> **The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are *external to the company*.** The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.
>
> **The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year, that is in a form indicating trending and that is transparent.**[64] [emphasis added]

Toronto Hydro (2015)

In 2015, the OEB approved a CIR for Toronto Hydro[65] that included many of the provisions of subsequent CIR plans. The approved plan had a nearly 5-year term and a hybrid ARM achieved by

---

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

[65] OEB, *Decision and Order*, EB-2014-0116, December 29, 2015

adding a custom capital ("C") factor to a price cap index formula. The C factor ensured that capital revenue growth equaled the approved forecast for capital cost growth less a stretch factor linked to benchmarking and a supplemental stretch for capital. A symmetrical ESM addressed non-capital related earnings variances outside of a 100-basis point dead band. A variance account refunded the entirety of any capital cost underspends to customers. The OEB cut Toronto Hydro's proposed capex budget by 10% annually for the Custom IR term without specifying which proposed components were disallowed.

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

> Custom IR is described in the [Renewed Regulatory Framework for Electricity (RRFE)] as a suitable choice for distributors with large or highly variable capital requirements. . . **The custom option in the policy allows for proposals that are tailored to a distributor's needs as well as for innovative proposals intended to align customer and distributor interests**.[66] [Emphasis added]

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

> [a] **Custom IR, unlike other rate setting options in the RRFE, does not include a predetermined formulaic approach to annual rate adjustments, it does not automatically trigger a financial incentive for distributors to strive for continuous improvement**. **The OEB expects that Custom IR applications will include features that create these incentives in the context of the distributor's particular business environment.**[67]

The Board also commented on the challenge of processing THESL's application, which included multiyear capital cost forecasts.

> **The record in this case is one of the largest that the OEB has ever seen. It is important to strike a balance between the amount of evidence necessary to evaluate the Application and the goal of striving for regulatory efficiency. It is important to note that it is not the OEB's role, nor the intervenors, to manage the utility or substitute their judgment in place of the applicant's management. That is the job of the utility. The OEB has established a renewed regulatory framework for electricity . . . which places a greater emphasis on outcomes and less of an emphasis on a review of individual line items in an application**.[68]

---

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

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

[68] *Ibid*., p. 2.

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

Hydro One Distribution (2019)

The OEB approved its first CIR plan for Hydro One Distribution in EB-2017-0049. This contained a revenue cap index formula with a C factor and a clawback of capital cost underspending. This decision also suggests a wariness on the part of the Board with respect to multiyear capex forecasts and the related C factor. The Board disallowed $300 million (about 8.4%) of Hydro One Distribution's capex forecast.

The OEB also adopted an additional 0.15% stretch factor that applied solely to the C-factor beyond the 0.45% stretch factor that applied to the entire revenue requirement and was based on econometric benchmarking research. This decision was made in part due to the OEB's concern that forecasted capex was causing rate base to grow more rapidly than inflation and in part to "incent further productivity improvements throughout the term, and to provide customers the benefit from these additional improvements upfront."[69] The OEB was also influenced by Hydro One Distribution's prior capital overspending and comments by OEB Staff's expert witness that the C Factor led to perverse incentives for companies to spend excessive amounts on capital to contain OM&A expenses.[70]

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

> Under the Custom IR option, it is open to a utility to propose options as long as all requirements of the Custom IR framework have been met. It is, by its own definition, a custom approach to rate-setting. The OEB finds that Hydro One's proposed RCI is an acceptable approach for adjusting rates to incent productivity and efficiency improvements.[71]

Toronto Hydro (2019)

In 2019 the OEB approved another CIR plan for THESL that applied to the 2020-2024 period. This plan was broadly similar to the Company's prior plan. The ARM took the form of a custom price cap

---

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

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

[71] *Ibid.,* p. 24.

index with an *I-X+C* formula, where I was the Board-calculated inflation factor; X was the sum of a 0% productivity trend and a 0.60% stretch factor based on benchmarking evidence; and C reflected the amount of the capital-related revenue requirement that was not addressed by the index reduced by both the X factor and an additional stretch factor on capital of 0.3%. Other features of the plan include an asymmetrical ESM for overearnings, a refund of capital underspends, and a symmetrical variance account for externally-driven capital.

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

In its decision, the Board expressed concerns about Toronto Hydro's approach to Custom IR.

> The RRF objectives of customer-focused outcomes and continuous improvement were not particularly well serviced under Toronto Hydro's 2015-2019 Custom IR framework. Toronto Hydro made significant investments in its system resulting in increases to rates and declining cost performance. **The OEB will be making several changes to Toronto Hydro's Custom IR proposal to increase compliance with the objectives set out in the Renewed Regulatory Framework….**
>
> The OEB does not agree that the proposed Custom IR framework provides the benefits to ratepayers suggested by Toronto Hydro compared to a standard IRM application….
>
> **The OEB notes that the Custom IR approach taken has required extensive evidence and time to consider the details provided. Toronto Hydro is encouraged to consider an alternative approach in the future that might be more efficient in establishing the revenue requirement for the base year and following years as well as meeting OEB RRF objectives, and improving the balance of risk between customers and the utility. Toronto Hydro should not assume that future panels will continue to accept Toronto Hydro's current proposed Custom IR framework**.[72] (emphasis added)

The Board also discussed the need to add a supplemental stretch factor to Toronto Hydro's C Factor.

> The OEB accepts a C-factor but requires an incremental stretch factor on capital of 0.3% be applied. It is a fundamental component of the OEB's RRF that utilities must demonstrate ongoing continuous improvement in their productivity and cost performance while delivering on

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

> system reliability and quality objectives. In addition, the OEB notes that pacing and prioritization is an important aspect of an efficient capital plan.[73]

In its 2020 decision approving a second-generation Custom IR plan for Hydro Ottawa, the Board expressed a similar concern about Hydro Ottawa coming in repeatedly with requests for Custom IR plans. In particular, the Board stated that "any future Custom IR application needs to be justified and the OEB needs to be satisfied that other rate-setting options have been considered."[74]

Recent Board IR Pronouncements

New Incentive Framework

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

In its Strategic Blueprint decision, the OEB appraised the performance of the Renewed Regulatory Framework stating the following.

> Our expectation has been that the [Renewed Regulatory Framework] would drive:
>
> - Stronger customer engagement by utilities
> - More robust system planning and regional planning
> - A stronger focus by utilities on long-term value for consumers.[75]

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

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

---

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

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

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

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

1. The OEB will allow distributors operating under Custom IR to request supplemental funding during the course of the Custom IR plan term for capital investments that would enable DER adoption by consumers for their own purposes.

2. The OEB expects distributors to modify planning and operations to prepare for DER impacts on their systems, to integrate these resources cost-effectively, and to maintain reliable service. Distributors are also expected to consider DER solutions as non-wire alternatives ("NWAs") when assessing options for meeting system needs.

3. The OEB has outlined options for utilities to propose incentives for deploying 3rd party DERs as non-wires alternatives. Distributors will be allowed to apply for deferral accounts for qualifying projects that occur between rebasings (qualifying projects proposed at rebasings will need to be incorporated into expected spending). For projects where an incentive is requested, it may take one of three forms: a shared savings mechanism, a traditional PIM (e.g., fixed incentive payment for exceeding a target) or a management fee. The OEB has issued a report on filing requirements for potential DER incentives.

Innovation Sandbox

In 2019 an "Innovation Sandbox" grew out of a report to the OEB chair from the Advisory Committee on Innovation. One of the recommendations from this report was to "provide a means by which both utilities and unregulated entities are encouraged to discuss specific regulatory obstacles with the OEB, in order to allow near-term deployment of innovations while longer term regulatory reforms are implemented."[76] The regulatory sandbox is an opportunity outside of rebasings for "innovators" (not necessarily just distributors) to propose pilot projects. Supplemental funding is not always provided.

PIMs

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

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

> Review the elements used in its incentive rate-setting mechanisms and examine distributor spending patterns to identify where changes or incremental incentives are warranted….
>
> This work will become part of a broader planned initiative to review the elements that together comprise the incentive rate-setting mechanisms under the Renewed Regulatory Framework for Electricity. This includes, but is not limited to, the review of productivity and stretch factors employed in adjusting rates in years two through five of a utility's rate plan.[77]

The Board also noted that it would like to develop a performance incentives regime for power distributors, stating:

> In our current framework, a relatively small percentage of distributors' revenues is determined as a function of their measured performance (within a range of 0.6 per cent of expected annual revenues, implemented through the stretch factor adjustment to a distributor's rates under incentive rate-setting options such as the Price Cap).
>
> We believe there is an opportunity to go further, with a durable framework for performance incentives that comprises a larger share of revenue for distributors. Through the design of complementary incentive mechanisms, the OEB can enable a transition from reputational incentives (i.e., the distributor scorecard) toward the greater use of financial incentives that result in increments (or decrements) to a distributor's revenues based on results. However, in pondering this transition, there are important caveats. Good incentives crucially depend on good data. Setting and calibrating incentives can be challenging, and require considerable deliberation and consultation. Also required is a firm understanding of how performance-based incentives interact or overlap with other elements of rate-setting, such as the cost of capital and the fact that earning is based on the value of capital investments in-service.
>
> The design of incentives themselves is crucial. How quickly the value of an incentive increases or decreases (based on results achieved) can alter its power, and can sometimes lead to unintended consequences. Other considerations include: how much more revenue overall should be at risk as a result of outcomes achieved; the type of data required; and the development of reporting and measurement processes that underpin and generate confidence in the overall performance framework. Consideration must also be given to the areas of the distribution business that are suitable for measurement, beyond unit costs and reliability. Areas such as customer service, resilience, or managing peak loads on the system in ways that defer distribution system needs could all be worthwhile domains for performance incentives.[78]

The Minister of Energy, in his letter of direction to the Board, endorsed these proposals.

Implications

This review of the Board's IR policies has several implications for this ratemaking proceeding.

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

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

- The regulatory cost of processing proposals for forecasted ARMs and then administering them does not seem to have been a top concern of the Board in its RRF decisions or the *Rate Handbook*. The Board did, however, state on p. 19 of its RRFE decision that "The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant." 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. In addition to noting its concern about regulatory cost, the Board has on several occasions made statements implying that a forecasted ARM yields weaker performance incentives than an indexed ARM.
- The Board's mentions of a "custom index" in ARM design likely encouraged the peculiar C factor approach that has been used in several CIR plans.
- An external cost efficiency "markdown" on revenue requirement proposals has been a major Board focus. This markdown is supposed to be higher than that in 4th GIRM and the Board disregards its own guidelines when it chooses a 0% productivity growth target.
- The Board's guidance that CIR be informed by cost forecasts and statistical cost research does not imply that these are the *only* legitimate bases for approved ARMs. Even if a K-bar mechanism was used to escalate capital revenue, distributors would file distribution system plans and would be free to file supplemental forecasts.
- CIR and the Ontario approach to IR generally were developed before some IR mechanisms used today were well-established. These mechanisms include targeted incentives for underused practices and K-bar approaches to ARM design like those used in Alberta and Massachusetts. In the last few years the Board has prioritized development in generic proceedings of various targeted incentives that affect remuneration over a reconsideration of ARM design.
- The Board has only provided general guidelines for CIR and has been open to its evolution within utility-specific rate-setting proceedings. The approved innovations have included revenue caps and supplemental capital stretch factors. Some innovations have been proposed by distributors and others by Board staff and intervenors. THESL is proposing important changes to CIR in this

proceeding. It is unreasonable for THESL to propose major changes in CIR while maintaining that major changes proposed by other parties can only be considered in a generic IR proceeding.

4. THESL's CIR 2.0 Proposal

THESL's proposed new CIR framework entails a multiyear rate plan that would operate for the five years from 2025 to 2029. The 2025 revenue requirement would be established by a conventional rebasing using a fully-forecasted test year. Allowed revenue for the remaining four years of the plan would then be escalated by a Custom *Revenue* Cap Index ("CRCI"). Revenue would be converted to rates in a manner that anticipates the growth in billing determinants.

The proposed CRCI formula, effectively, is

$$Revenue_t = Revenue_{t-1} \cdot (1 + I_t - X + RGF_t) + Y_t + Z_t$$

Here I_n would be a time-variant Inflation Factor. This would be determined using the Board's existing Input Price Index methodology. Inflation would be a weighted average of the growth rates of two Statistics Canada inflation indexes: Canada's gross domestic product implicit price index for final domestic demand ("$\text{GDPIPIFDD}^{\text{Canada}}$") and the Average Weekly Earnings for Workers in Ontario ("$\text{AWE}^{\text{Ontario}}$").

The X factor (aka "productivity factor") in the CRCI formula would have 3 components.

- A 0% base efficiency growth factor is consistent with the Board's 4th GIRM decision and recent CIR decisions.[79]
- The 0.15% Stretch Factor is indicated by Clearspring's total cost benchmarking report in this proceeding and the schedule of benchmarking results and stretch factors set forth in Exhibit 1B, Tab 3, Schedule 3, Appendix A.
- A 0.60% *proactive performance incentive mechanism factor* would be added to the X factor.

RGF, the proposed Revenue Growth Factor, is the annual growth rate in the Company's proposed net total real cost. The revenue requirement would thus effectively be based on THESL's

---

[79] OEB, EB-2010-0379, *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013 and as corrected on December 4, 2013.

multiyear net cost real forecast, updated for inflation, net of an X factor. A symmetrical Demand-Related Variance Account ("DRVA") would have two components.

- A deferral account would record the difference between forecasted and weather-normalized actual billing determinants.
- The difference between forecasted and actual demand-related costs (OM&A as well as capital) would also be deferred. These costs would include those programs of customer connections; customer operations; stations expansions; non-wires solutions; generation protection monitoring and control; externally initiated plant relocations and expansions; and the Company's load demand program.

A Performance Incentive Mechanism would use metrics and targets to gauge THESL's performance. There would be 12 targets drawn from 4 performance areas. The mechanism is effectively "penalty only". Performance would be measured on a five-year basis and no revenue adjustment would occur until the end of the plan. The proposed targets for the metrics are conditional on the Board's approval of THESL's proposed revenue requirement. The Company therefore proposes that targets be finalized in a Phase 2 after the revenue requirement has been established.

Several of the Company's other costs would be addressed by OEB-created deferral and variance accounts ("DRVAs"). These would include the costs of cloud computing implementation and the Getting Ontario Connected Act. Additional costs that would be addressed by deferral and variance accounts include pensions and other post-employment benefits, any CDM programs, Green Button initiative implementation, and energy storage. Toronto Hydro has proposed discontinuing the Capital Related Revenue Requirement variance account, which in its current plan returns capital underspends to customers.

The Company could request Z factor treatment if qualifying events occurred, based on the OEB's existing Z factor policy set out in the Report of the Board on 3rd Generation Incentive Regulation. Z-factor claims in Ontario may address OM&A and/or capital costs of qualifying events. There is a materiality threshold of CD 1 million in revenue requirement for each qualifying event and a requirement that the Z factor cost had a significant influence on the operation of the distributor. There is, however, no dead zone if cost exceeds the threshold. Events that could trigger a Z factor claim include severe storms and costs that are government-mandated or outside of management's control for other reasons. Distributors must notify the OEB that a Z factor event had occurred within 6 months of the event. Claimed Z-factor costs will be reviewed for prudence before recovery is permitted.

The Company proposes to apply the ESM formula approved by the OEB in EB-2018-0165 to the entirety of its cost. This mechanism would share with customers 50% of any earnings which exceed the target rate of return on equity ("ROE") by more than 100 basis points in any year. PIM rewards would not be considered in the calculation of earnings.

THESL has also proposed to continue applying the OEB's generic policy with respect to off ramps that is outlined in the *Rate Handbook*. An off-ramp would be triggered if the Company's actual achieved ROE on a regulated basis varied from the OEB-approved ROE by more than 300 basis points (i.e., ± 300 b.p.) in a single year. If an off-ramp is triggered, a regulatory review may be initiated. This review would be prospective in nature and could result in modifications to the plan, the plan continuing without change, or the termination of the plan.

An Innovation Fund with a value of CD 16 million during the term of the CIR plan would be available to support the design and execution of innovative pilot projects during the plan period. Toronto Hydro expressed a desire to focus on projects that would either explore distribution capabilities that are connected to adapting to the OEB's expectations for DER integration (e.g., evolving and enhancing load forecasting and making enabling investments such as system monitoring and data analytics) or would deploy inventive solutions (e.g., use of a new technology or new ways of using existing technology).[80] The programs would be identified and chosen by THESL, though Toronto Hydro would engage with external stakeholders to gain additional perspective on potential pilots.[81] The funds would be collected through a rate rider and variances between revenues collected and actual costs incurred would be tracked symmetrically.

[80] Curiously, Toronto Hydro considered developing skills and knowledge, and acquiring talent to be a possible exploration of a distribution capability.

[81] The examples of external stakeholders included the OEB, IESO, energy services companies, clean technology vendors, government agencies (e.g., Natural Resource Canada), and other regulated entities.

5. THESL's Rationale for CIR 2.0

THESL portrays its proposal for major changes in CIR as an appropriate response to special circumstances that include the energy transition and rapid growth in the City of Toronto. It also argues that there are precedents for its proposal in MRPs approved in other jurisdictions. We address each of these contentions in turn.

General Commentary

Toronto Hydro provides an extensive discussion in its filing of the business challenges that it faces. The impression is conveyed that application of an I-X escalation formula is impractical even to OM&A revenue. In the Company's view, this recommends a "custom rate funding solution" that uses cost forecasts rather than a "standard IRM funding paradigm for OM&A as well as capital revenue."[82] While the Company's business conditions are clearly challenging, the Board and intervenors must be mindful of the incentive the Company has to accentuate cost challenges while understating cost advantages in a rate application. We provide our perspective here on some of the Company's contentions.

Some of THESL's statements are hyperbolic. Here are some examples.

<u>THESL Contention</u>: The Company's proposed OM&A expenses during the next plan would be about 27% above those expected during the current plan.[83]

<u>PEG Response</u>: The 27% calculation is bolstered by the rapid price inflation that occurred during the expiring plan. The forward test year used in the rebasing will incorporate actual and expected inflation from 2020 through 2025. Inflation is expected to be slower during the new plan and, in any event, the plan includes inflation protection.

<u>THESL Contention</u>: Labor cost growth is forecasted to be particularly rapid. The Company requires 11% growth in FTEs during the plan.

---

[82] Exhibit 4 Tab 1 Schedule 1 p. 10.

[83] Exhibit 1B Tab 1 Schedule 3, p. 10 (as updated April 2, 2024).

PEG Response: The biggest single jump in labor cost would occur in 2025. Over the 4 out years of the plan FTEs would grow by around 6.3%, averaging 1.6% annually.

THESL Contention: The Company forecasts its cost to grow much more rapidly than I-X revenue.

PEG Response: The counterfactual "I-X" formula does not include a customer growth term (e.g., percent growth of customers). We have shown that many revenue cap indexes have had a customer growth term, including one approved by the Board for Enbridge Gas Distribution. A possible reason that they aren't concerned about whether the straw man index formula includes a customer growth escalator is that they propose variance account treatment for the costs of demand growth. The Company's calculations may also not consider all of the costs that may be accorded variance account treatment. These may, for example, include incremental costs of accommodating DERs.

THESL Contention: The Company is experiencing rapid demand growth.

PEG Response: PEG acknowledges that the city of Toronto has recently experienced a remarkable condo boom. However, THESL's portrayal of Toronto's growth is exaggerated.

- From 2017 to 2022 the population growth of Toronto's metropolitan area ranked 12th on a *percentage* basis (which is what matters) amongst larger North American metro areas.[84] Several smaller metro areas (e.g., Kelowna BC, Sarasota, FL and Boise, ID) grew much more rapidly.
- THESL forecasts its customer growth in the next five years to average only 0.3% per annum. This is well below the industry norm.

THESL Contention: Future demand for electricity is expected to roughly double over the next two decades.

PEG Response: The Company forecasts a decline in its coincidental peak demand in the next five years.

Energy Transition

Transition to a low-carbon economy is a key goal of Ontario and Canadian federal government policymakers. This transition would entail the electrification of important economic activities such as

[84] Wendell Cox (2023), "Comparing Canadian and U.S. Metropolitan Areas," August 27. Accessed from: https://www.newgeography.com/content/007921-comparing-canadian-and-us-metropolitan-areas

transportation and space heating that today rely chiefly on fossil fuels for energy. Electrification would substantially increase electricity demand. The transition would also likely entail increased reliance on intermittent renewable sources of power supply such as wind and solar energy. Distributed solar power generation and storage would proliferate. Most end users are expected to continue relying exclusively on power delivered by distributors and many prosumers would also want system access. The pace of the energy transition and even its ultimate achievement is uncertain, relying as they do in a democracy like Canada's on voter as well as customer preferences.

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

- Power distributors play a key role in the energy economy and their role would increase in the energy transition. They would eventually need to expand capacity substantially while maintaining or improving reliability and accomplishing these goals at reasonable cost. Cost effective accommodation of growing demand and increased reliance on intermittent renewables would likely require investments in smart grid facilities as well as delivery capacity.
- Investments needed to support the energy transition cost effectively are difficult to predict accurately. This increases the operating risk of power distributors. Multiyear rate plans add to the risk but are nonetheless desirable to the extent that they strengthen utility performance incentives and streamline regulation.
- Increasing the role of cost forecasting in ARM design is one possible way to make multiyear rate plans work better during the energy transition. Many jurisdictions in the early stages of the energy transition already used forecasted ARMs. British Columbia's commission recently paused the implementation of an indexed ARM for BC Hydro based in part on the perceived challenges of the energy transition, stating the following.

> The Panel acknowledges the increasing cost uncertainty that BC Hydro is facing as a result of the energy transition that was not present to the same extent at the time the PBR Report Decision was issued in December 2021. The Panel is persuaded by the evidence provided by BC Hydro in this proceeding of legislative and mandate changes since December 2021 that increase cost uncertainty and cast doubt on whether PBR would be an effective regulatory regime for BC Hydro at this time. This is because the increased cost uncertainty will likely result in more costs that would need to be forecast outside of the PBR formula, as those costs are driven by external factors that are outside of BC Hydro's control. Therefore, given the increased uncertainty that BC Hydro is facing and changes in circumstances since 2021, the Panel is not convinced that the adoption

> of what would be a new and untested regulatory regime for BC Hydro is warranted at this time.
>
> The Panel cautions that this determination should not be construed as a commentary on or rejection of PBR as a regulatory incentive mechanism, nor as criticism of the BCUC's PBR Report Decision which was based on facts and circumstances that existed more than two years ago. As parties are aware, PBR has been successfully implemented and endorsed by the FortisBC utilities for decades in British Columbia, to the mutual benefit of both their ratepayers and shareholders. There may well come a time when BC Hydro will want or be driven to embrace a similar incentive regime, whether due to the need for greater cost containment or other reasons.[85]

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

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

THESL proposes rapid growth in its capital cost during the new plan due to high capital spending. Net capital expenditures are forecasted to be 38% higher in nominal terms and 22% in real terms. Although "a more dynamic growth-oriented context" is emphasized in their rationale, system service capex accounts for only 8% of proposed capex.[86] Half of the capex is for system renewal and another 27% is for system access.

ScottMadden Jurisdictional Scan

The Company engaged ScottMadden to survey MRP precedents and comment on the implications for THESL's plan. In this section we consider how various contentions of ScottMadden and the Company square with the discussion of multiyear rate plan design and salient precedents that we provided in Section 2 of this report. We begin by noting areas of agreement and then turn to areas of concern.

---

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

[86] Exhibit 2B Section E4, p. 15.

Areas of Agreement

ScottMadden makes several statements about electric utility ratemaking that we agree with. These include the following.

- There are numerous precedents for multiyear rate plans with ARMs that are based primarily on cost forecasts, like the one that THESL proposes. Great Britain and New York are prominent practitioners.
- In plans where indexing is used in ARM design, it has in most recent plans either been used in combination with supplemental capital revenue or not applied to capital revenue.
- Variance accounts for capital cost are widely used in the US.
- Costs of accomplishing public policy goals (e.g., accommodation of EVs and DERs) are increasingly accorded variance account treatment.
- Inspired by innovations in British and New York regulation, there has been increasing interest in PIMs and a growing number of MRPs have included complicated PIMs.

Areas of Concern

Biased Scope and Emphasis

One area of concern with ScottMadden's jurisdictional plan is its biased scope and emphasis. Precedents that support the Company's proposal are highlighted while precedents that don't are either not mentioned in the direct evidence or not emphasized. Most notably, ScottMadden included the PBR1 plans for energy distributors in Alberta that provided supplemented capital revenue using forecasts and variance accounts while ignoring the PBR2 plan and the recently approved PBR3 plan, both of which used the K-bar method rather than forecasting to supplement capital revenue.[87] ScottMadden also largely ignored the popular tracker/freeze approach to ARM design, failing to note for example that Duke Energy has no explicit escalator for OM&A revenue in its Carolina plans.[88]

---

[87] See, for example, ScottMadden's response to 1B-SEC-19.

[88] In 1B-SEC-19, ScottMadden reported that Duke Energy's ARM in North Carolina was "Commission-authorized 'step-ups' in revenue requirements for incremental capital spending projects and associated O&M for each year of the plan." Per North Carolina Utilities Commission's Rule R1-17B, there is no explicit provision for OM&A revenue

Misleading Statements

We also find a number of misleading statements about plan design precedents in the evidence of THESL and ScottMadden. Based on our more balanced and comprehensive discussion of MRP design in Section 2 we provide here some qualifications to THESL and ScottMadden's characterization of industry precedents.

- THESL introduces ScottMadden's evidence with the statement that the Company's proposed framework "is informed by enhanced performance-based regulation ("PBR") approaches employed in other leading jurisdictions that are undergoing an energy transition."[89] This statement suggests that the proposed plan is similar to those of utilities in leading jurisdictions that are undergoing the energy transition. However, many utilities in this situation (e.g., those in California and Massachusetts) have markedly different plan provisions.

- ScottMadden states that the goal of its testimony is to describe "how the Company's proposed *changes* to the Rate Framework are generally consistent with how other electric utilities *have responded* to developments in the energy industry [italics added]."[90] However, in response to 1B-Staff-19, ScottMadden stated that "[it] did not evaluate industry trends. Instead, ScottMadden evaluated Toronto Hydro's proposed custom IR plan for its relative consistency with other electric utility ratemaking frameworks and practices that support a clean energy transition." In other words, it sought examples of ratemaking frameworks with features similar to those proposed by THESL, which are asserted to be preferable for an energy transition.

  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

escalation that is not related to capital spending projects placed into service during the plan term. Indirect funding for OM&A revenue escalation is potentially available from multiple sources: the revenue per customer decoupling mechanism that applies to residential customers, increased revenues from EV demand of residential customers (these were excluded from the revenue decoupling mechanism), and increased revenues from all other customer classes.

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

[90] Exhibit 1B Tab 2 Schedule 1 Appendix A, p. 2.

demand-related costs. Neither of these approaches are typical of utilities undergoing an energy transition.

- There is not a trend in ARM design to do away with indexing as Toronto Hydro has proposed.
    - New York and Great Britain are using forecasted ARMs to address contemporary challenges that include the energy transition. However, both have been using forecasted ARMs for years.
    - Indexed ARMs are especially challenging to design for the vertically integrated electric utilities ("VIEUs") that account for a lot of the recent growth in the use of MRPs in North America. Several of the plans that ScottMadden surveyed were for VIEUs (e.g., Xcel Energy Minnesota).
    - In North America there is strong continuing interest in using indexing in ARM design. ARMs based primarily on indexing are currently used by Hydro Québec Distribution and many Ontario power distributors. Connecticut's regulator has expressed a keen interest in using this approach for power distribution.[91] Hybrid ARMs that index OM&A revenue continue to be used in Australia, California, Massachusetts, and Ontario. Utilities in British Columbia and Massachusetts are currently proposing indexed ARMs for OM&A revenue. Recent legislation in Indiana requires the regulator there to consider MRPs with indexed ARMs.
- Forecasting and variance accounts aren't the only alternative to indexed ARMs for capital revenue. A salient alternative is the historical own-cost trending approaches to ARM design that are used for capital revenue in Alberta, California, and Massachusetts.
- In response to 1B-Staff-38, ScottMadden implies that a forecasted revenue requirement for OM&A and a DRVA expenditures sub-account for all demand-related costs are "consistent with OEB convention." This is a stretch, as the Commission has expressed many reservations about forecasted ARMs and has rarely approved a comprehensive revenue requirement forecast.

---

[91] Connecticut Public Utilities Regulatory Authority (2023), Straw Proposal in Docket No. 21-05-15RE01, November 16, pp. 7-9.

- ScottMadden states on p. 18 of their report that "The performance-based regulation framework in Hawaii ensures that the financial integrity of utility aligns with consumer interests." PEG was a witness for the Hawaiian Electric Company in this proceeding. Based on our experience, we can say that the HECO plans are not that favorable to the companies. Most notably, the inflation-only revenue requirement escalators use the slow-growing GDP-PI as the inflation measure and lack a customer growth term. The Commission disregarded statistical evidence from two parties that the X factor should be negative. A stated rationale for the zero X factor was that the companies had access to supplemental funding through the tracker.[92] Furthermore, the Hawaiian Electric companies have had difficulty securing supplemental revenue under their Exceptional Project Recovery Mechanisms.
- ScottMadden provides misleading commentary about Maine regulation on p. 21 of its report. A major reason why Maine commission staff wanted to abandon multiyear rate plans for CMP is that it wasn't comfortable with the alternative MRP plan designs that the company proposed. One of these featured a forecasted capital revenue requirement. Staff was also unhappy with the supplemental revenue provided by cost trackers in the previous plan.
- Variance accounts are *increasingly* used in MRPs to fund costs associated with policy directives but not for routine costs such as those for replacement capex.
- The widespread use of variance accounts (aka cost trackers) in the United States reflects circumstances there that differ from Ontario's. Most American utilities don't have multiyear rate plans, and, as ScottMadden confirms in response to 1B-Staff-22 iv, nearly half don't have forward test year rate cases. Under these circumstances, cost trackers can materially reduce the frequency of general rate cases without requiring sweeping changes in ratemaking systems.
- Stairstep ARMs aren't always based on cost forecasts. For example, California has been a leading North American MRP practitioner since the 1980s and frequently uses stairstep ARMs for capital revenue. However, the California Commission eschews the use of multiyear forecasts to set capex budgets.

[92] ScottMadden noted in response to 1B-Staff-23 that it did not evaluate the reasonableness of HECO's revenue cap index.

- In Great Britain, Ofgem's "building block" approach to ARM design places heavy weight on its *own* independent view of required future costs.
- Most multiyear rate plans in New York are the outcome of settlements and feature only three-year plan terms.

In summary, recent precedents in ARM design don't justify all aspects of the approach that THESL proposes. In particular, many jurisdictions use indexing for OM&A revenue and alternatives to forecasting for a large share of capital revenue. Several jurisdictions that use these alternative provisions are, like Ontario, bracing for an energy transition. There is no evidence yet that the THESL approach will be preferred as a response to the energy transition.

6. PEG's Critique of the CIR 2.0 Proposal

Attrition Relief Mechanism

Overview

THESL has for many years advocated extensive use of cost forecasting and variance accounts in the design of ARMs for multiyear rate plans. As we have discussed, they championed the C factor term in ARM formulas that replaces capital revenue growth based on price and productivity indexing with growth based on cost forecasts. This has greatly complicated CIR by basing capital revenue chiefly on multiyear capital cost forecasts.

As we discussed in Section 2, a forecasted ARM weakens cost containment incentives relative to an indexed ARM and can also jeopardize customer benefits from IR due to the problem of information asymmetry. The utility is incentivized to include a comfortable cushion in its cost forecast. In prior Custom IR proceedings, this concern has been addressed with a clawback of any capital cost savings. This further weakened capex containment incentives. The approach to CIR that THESL pioneered and other large utilities then adopted thus undermined the *main potential benefits* of multiyear rate plans: stronger performance incentives and streamlined ratemaking. As noted in Section 3, the OEB has asked THESL to contain its use of forecasting and variance accounts and go in another direction.

THESL now proposes to base its OM&A as well as its capital revenue requirements on multiyear forecasts. For most costs, there would be no clawback of underspends in the new proposal. Relative to its current plan, this would strengthen the Company's incentive to contain most capex. Imbalanced incentives for containment of capex and OM&A expenses would be eliminated. However, removing clawbacks for most capital cost also increases concern about information asymmetries and forecasting uncertainty. This concern is important enough to some parties that this proceeding could ultimately result in the continuation of the clawbacks for any capital cost savings and even their extension to any OM&A savings. Although THESL doesn't propose clawbacks it does propose variance account treatment of many costs.

Expanded Role for Forecasting

The most controversial feature of the proposed ARM is the abandonment of indexing for OM&A revenue in favor of forecasting. We challenge this proposal on several grounds.

- In considering a proposal to abandon indexing of OM&A revenue the question arises as to whether other utilities are experiencing OM&A cost challenges. There is insufficient evidence that the average OM&A productivity trend of U.S. power distributors is close to zero or negative. Witnesses for FortisBC and National Grid have recently reported materially positive OM&A productivity trends. Econometric research in this proceeding has yielded a similar result.
- There are alternatives to forecasting all OM&A expenses such as forecasting and/or variance account treatment for some rapidly growing costs. The more rapidly-growing costs that are treated in this way, the more residual OM&A revenue requirement components should be amenable to indexation. Some OM&A costs (e.g., those for flexibility services and the accommodation of DERs) would likely receive VA treatment for other reasons.

Forecasting Treatment of Capital Revenue

We also have concerns about continued forecasting of the capital revenue requirement. The salient alternative to capital cost forecasting is the historical own-cost trending such as the approaches used in Alberta, California, and Massachusetts.

Ongoing Concerns About Forecasting

We also have ongoing concerns about undue reliance on forecasting that PEG has enunciated in prior CIR proceedings. These concerns are reduced by the increasingly lengthy period during which capex requirements are likely to be high due to energy transition. However, they are heightened by THESL's proposal to base OM&A revenue on forecasting.

- THESL is incentivized to "bunch" its costs in ways that support its proposal to base ARMs on OM&A and capital cost forecasts. If, for example, the Company could somehow manage to time its expenditures so that indexing was compensatory for OM&A costs, it would obtain less revenue.
- Another problem with the proposal is that, while customers must fully compensate THESL for the bulk of its expected revenue shortfalls when cost growth is *rapid* for reasons beyond its control, the Company would be under no obligation to return any surplus revenue if in the future it chose to operate under indexing and its cost growth was unusually *slow* for reasons beyond its control. Slow cost growth may very well occur in the future for reasons other than

good cost management. For example, depreciation of recent and prospective surge capex which has provided the rationale for Custom IR will tend to slow future capital cost growth and thereby accelerate productivity growth. Over multiple plans, the revenue escalation between rate cases may therefore not guarantee customers the full benefit of the industry's productivity trend, even if it is achievable.

- A related problem is that most of the cost addressed by the RGF and Z factor would be similar in kind to that incurred by the utilities in past and future cost efficiency studies that are used to calibrate THESL's X factors. The Company can then be compensated twice for the same cost: once via the RGF and then again by low X factors in past, present, and future IRMs.
- This "double counting" issue has been debated in several IR proceedings and no consensus has been established regarding its remedy. Some regulators have eschewed X factor adjustments for double counting and based X factors on unadjusted productivity trends. However, the Hawaii Public Utilities Commission ruled, in a recent IR proceeding, that X factors in revenue cap indexes for the three Hawaiian Electric companies should be set at zero, despite evidence that they should be materially negative, due in part to the fact that their major plant additions will be eligible for cost tracking.[93]

Variance Accounts

Toronto Hydro also proposes several variance accounts, including a Demand-Related Variance Account ("DRVA") for most demand-related costs. Some of the proposed VA applications are more conventional, and the OEB has in the last few years opened the door to some new uses of VAs, as discussed in Section 3. These include VAs for OM&A costs related to flexibility services and DER integration. The Board also indicated that incremental capital modules can be used for DER-related investments. Finally, the Board has approved a deferral account for cloud computing and a variance account for increased costs due to the Getting Ontario Connected Act.

We acknowledge that some demand-related costs are especially risky in an era of uncertain demand growth. However, the DRVA would weaken incentives to contain demand-related costs even

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

though some of these costs (e.g., those for substation capacity) are expected to be major drivers of cost growth. Furthermore, many of the demand-related costs that the Company proposes for VA treatment are conventional and not particularly sensitive to the energy transition.

ScottMadden legitimizes the DRVA by pointing to the uncertainty mechanisms in the RIIO-ED2 generic ratemaking system for British power distributors. However, the proposed DRVA would entail weaker performance incentives since no supplemental revenue would be based on a unit rate x volume formula.

Regulatory Cost

Given THESL's weak incentive to contain demand-related costs, the inherent unfairness to customers of asymmetrically funding revenue shortfalls, and the Company's incentive to exaggerate cost requirements and bunch costs, stakeholders and the Board must be especially vigilant about the Company's cost proposal.[94] This raises regulatory cost. The need for the OEB to approve multiyear revenue requirements greatly complicates CIR proceedings and is one of the reasons why the Board now requires and must review complicated T&D system plans - a major expansion of its workload and that of stakeholders. Despite the extra regulatory cost, OEB Staff and stakeholders will inevitably struggle to effectively challenge the Company's cost proposal.

Alternative Approaches to ARM Design

The preceding discussion has implications for the design of ARMs for Toronto Hydro and other Ontario utilities in the early stages of an energy transition that is expected to accelerate demand growth and may also increase reliance on intermittent renewable generation resources. Let's start by assuming that the utility does need some form of CIR because its revenue requirement is rising quite a bit more rapidly than the escalation that indexing by itself affords. Toronto Hydro is forecasting rapid cost growth in the next five years. Most of this is to accelerate replacement of aging and/or obsolete assets, address customer growth, and install and operate additional smart grid facilities. In effect, Toronto Hydro proposes rapid revenue requirement growth to *make progress on other goals in this plan before large capacity additions are needed*. The service territory is also in the early stages of an energy transition that will ultimately entail more distributed energy resources ("DERs") and beneficial electrification.

[94] Proposed programs that raise capex and reduce OM&A expenses merit especially close examination.

These conditions on balance would typically slow productivity growth in the short run whereas the recent cost efficiency trend of U.S. power distributors has been positive. A comprehensive indexed ARM will therefore not be practical for THESL in its next plan.

However, our analysis above suggests that there are preferable alternatives to both the established CIR approach to ratemaking in Ontario and to Toronto Hydro's proposed CIR 2.0 approach.

- PEG is skeptical of THESL's claimed need to abandon indexing of OM&A revenue. An index may be somewhat uncompensatory in this plant but overcompensatory in prior and future plans.
- If the Board decides that an indexed OM&A revenue requirement does need supplementation in order to be reasonably compensatory this can be accomplished without basing OM&A revenue *entirely* on a cost forecast, as Toronto Hydro proposes. The salient alternative is to permit forecasting (and for some costs, variance account treatment) for some *rapidly growing* OM&A costs. Some other costs might merit VA treatment for other reasons we have discussed.
- The bulk of the capital revenue requirement does not have to be based on forecasts, as in past THESL plans. We have shown that historical own-cost trending is a well-established alternative to forecasting for capital revenue. The California and Alberta K-bar approaches are both legitimate candidates. Under either of these approaches, 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. The K-bar approach is arguably closer than California's approach to the notion of CIR that the Board discussed in its *Rates Handbook* and CIR decisions. It can also be converted to a new kind of C factor if desired.
- A cautionary note about historical own-cost trending in the context of THESL is that the Company forecasts plant additions in the next five years that are well in excess of its high recent historical norms. To the extent that the Board believes that the rapid proposed cost growth is feasible and is not merely a manifestation of the asymmetric information problem and zeal for capex, the situation can be finessed using forecasting and/or variance accounts to address some rapidly growing capital costs and then use historic own-cost trending for the residual capital revenue requirement using either the old school California or Alberta K-bar approach. Either of these approaches should yield considerably more revenue than indexing of capital revenue

would. The OEB may prefer careful prudence oversight anyways of some rapidly growing costs (e.g., transfer and substation capacity capex) that are accorded forecasting and/or variance account treatment.

These steps would materially reduce the role of forecasting in the determination of Toronto Hydro's revenue requirement.

If the Board doesn't wish to go down our recommended path some other ratemaking treatments of capital merit consideration.

a) Continue the forecast-based C factor approach used in recent CIR plans. A supplemental stretch factor should then apply to the calculation of the C factor as in recent Board decisions.

b) The capital revenue requirement could be forecasted but the proposed capex envelope could be reduced by a material amount, as in some past Custom IR decisions.

Here are some other pertinent comments about ARM design for THESL.

- If a revenue cap index applies to OM&A revenue in the new plan, a customer growth term should be added to the revenue cap index formula, as in a prior MRP of Enbridge Gas Distribution. This won't provide much attrition relief, however, since the Company's expected growth in the total number of customers served is sluggish. 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.
- We also recommend replacing the average weekly earnings of Ontario workers in the inflation measure with the FWI of average hourly earnings. This is a more accurate measure of labor price inflation because it is less subject to aggregation bias when the mix of employed workers changes. The FWI AHE was recently adopted by Alberta's commission as a component of its inflation factor formula for energy distributors. We discuss this further in our empirical report.
- Given the expected acceleration of demand growth, it is desirable for utilities to have stronger incentives to contain capacity additions than to contain the cost of NWAs such as flexibility services. One way to create a constructive incentive disparity would be to address the cost of capacity additions via a cost forecast that doesn't have a variance account true up in this plan

but to have variance account treatment of flexibility services. Demand response initiatives can also be encouraged by well-designed PIMs, management fees, and/or pilot programs.

- 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

  The energy transition may expand the scope of costs that should qualify for forecasting and or variance account treatment. We have noted, for example, that costs of DERs and flexibility services are now eligible for Y factor treatment in Ontario. Forecasting and/or Y factor treatment would also be reasonable for incremental costs of accommodating electric vehicles and the cost of new meters and miscellaneous smart grid facilities needed to manage DERs and growing demand.

- We believe that the DRVA expenditure variance subaccount would be rendered unnecessary by our other proposed plan provisions, which include the addition of a customer growth term to the revenue cap index.

- Costs of inputs and practices that utilities tend to underuse may also warrant other inducements such as PIMs, management fees, or pilot programs.

- 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.

Straw Man Alternative Proposal for OM&A Revenue

The attached Table 1a shows that Toronto Hydro's proposed OM&A revenue requirement would average **3.82%** annual growth in the four out years of its proposed CIR plan (2026 to 2029). During these same four years, a revenue cap index is forecasted to average **2.24%** annual growth. Using

Table 1a

Excluding Certain OM&A Cost Categories from Indexing

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
	Expiring Plan (Nominal $)					New Plan Proposed					
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.

the detailed OM&A cost forecast that THESL provided on pp. 2-4 of Exhibit 4 Tab 1 Schedule 1 and in its response to 4-SEC-89, we considered to what degree this disparity could be narrowed by singling out some cost categories for forecasting treatment, with some of these costs possibly subject to VA trueups. Either of these treatments would afford the Company more rapid revenue growth than indexing alone.

The cost categories in this table are not ideal for undertaking this exercise. However, we singled out some categories with rapid proposed cost growth that is driven by external conditions to receive rapid revenue requirement growth. In Table 1a these categories are highlighted in yellow. It can be seen that the proposed total cost of these categories would average 6.17% growth. The residual costs that would be addressed by the revenue cap index would average a considerably slower 3.28% annual growth.

Table 1b shows that the revenue requirement provided by the combination of forecasting and/or variance accounts and indexing would average 2.99% annual growth in the four out years of the plan. Over the four out years of the plan revenue would fall short of the Company's proposed revenue requirement by 2.16%. The OEB has in prior rebasings approved much larger cost OM&A cost disallowances.

Some other components of the OM&A revenue requirement (e.g., pensions) would likely also be addressed by VAs, and most OM&A revenue would be subject to inflation and customer growth adjustments. The Company already has high fixed charges for small-volume customers and may also have revenue decoupling. All of these features would reduce the Company's operating risk.

Table 1b

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).

Straw Man Alternative Proposal for Capital Revenue

Suppose that Toronto Hydro's capital revenue requirement depends on a mix of cost forecasts, some with VA adjustments and K-bar treatment. In its EB-2023-0195 direct evidence, the Company has disaggregated its proposed and recent historical capex in ways that support this new hybrid approach. Table 2 below illustrates how some kinds of capex could be subject to forecasting and/or variance account treatment, while other kinds could be accorded K-bar treatment. The allocation in this table is just a straw man to stimulate thinking. We recommend limiting the use of variance account treatment.

Table 2

Itemized Toronto Hydro Capex Data Could be Used in K Bar Construction

Projects	Expiring Plan (Nominal $)					Expiring Plan (2027$)[2]					New Plan Proposed					Averages		
	2020	2021	2022	2023	2024	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Old Plan (2027$) [A]	New Plan [B]	Shortfall [A/B]
System Access																		
Customer and Generation Connections	106.4	134.3	138.8	158.7	150.1	133.1	159.5	155.1	172.0	158.8	167.4	178.9	190.0	201.2	212.3	155.7	190.0	0.82
Externally-Initiated Plant Relocations & Expansion[1] (net of contributions)	8.7	9.3	12.9	16.0	13.0	10.9	11.0	14.4	17.3	13.8	22.6	16.7	11.9	12.1	12.6	13.5	15.2	0.89
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	1.0	1.0	0.2	0.2	8.3	5.9	6.1	6.3	6.5	10.3	2.1	7.0	0.30
Load Demand	24.0	29.9	30.8	26.7	23.2	30.1	35.6	34.4	29.0	24.5	43.5	46.4	38.1	42.7	46.4	30.7	43.4	0.71
Metering[1]	11.2	8.1	8.4	8.0	44.6	14.0	9.6	9.4	8.7	47.2	63.7	69.9	72.4	34.7	7.4	17.8	49.6	0.36
Subtotal: System Access Total Expenditures	225.2	240.7	244.3	278.2	314.2	281.8	286.0	272.9	301.5	332.6	384.1	379.8	364.7	343.8	337.5	295.0	362.0	0.81
Subtotal: System Access Capital Contributions	144.8	100.3	115.9	140.4	147.5	181.2	119.2	129.5	152.2	156.1	164.0	150.7	140.7	147.2	154.9	147.6	151.5	0.97
Subtotal: System Access Net Expenditures	**80.4**	**140.3**	**128.4**	**137.7**	**166.7**	**100.6**	**166.8**	**143.4**	**149.2**	**176.5**	**220.1**	**229.1**	**224.0**	**196.6**	**182.7**	**147.3**	**210.5**	**0.70**
System Renewal																		
Area Conversions (e.g., rear lot and box	35.6	39.5	33.8	41.5	58.9	44.6	47.0	37.7	45.0	62.3	64.4	61.1	33.6	39.0	38.6	47.3	47.3	1.00
Network System Renewal	15.0	22.1	32.1	25.6	25.3	18.8	26.3	35.9	27.7	26.8	13.7	14.8	30.5	31.2	33.2	27.1	24.7	1.10
Reactive and Corrective Capital	63.1	54.5	59.7	67.8	61.9	78.9	64.8	66.7	73.5	65.5	61.6	64.8	64.8	67.3	69.7	69.9	65.6	1.07
Stations Renewal	30.2	33.6	27.4	21.9	40.6	37.7	39.9	30.7	23.7	43.0	56.4	56.7	58.8	58.6	52.3	35.0	56.5	0.62
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	5.9	3.7	5.7	7.5	8.6	11.9	12.1	13.5	13.1	14.2	6.3	13.0	0.48
Non-tracked portion	25.5	30.5	22.3	15.0	32.5	31.8	36.2	25.0	16.3	34.4	44.5	44.6	45.3	45.5	38.1	28.7	43.6	0.66
Underground Renewal - Downtown	7.1	8.5	20.2	27.6	16.8	8.9	10.1	22.5	29.9	17.8	20.5	26.0	32.3	41.3	45.0	17.8	33.0	0.54
Underground Renewal - Horseshoe	73.5	50.9	64.4	71.8	102.5	92.0	60.4	72.0	77.8	108.5	92.6	82.3	93.8	101.1	105.9	82.1	95.1	0.86
Overhead Infrastructure Relocation	0.7	0.2	0.2	0.0	0.2	0.9	0.2	0.2	0.0	0.2	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	
Underground Legacy Infrastructure	0.3	-0.1	0.6	0.0	0.0	0.4	-0.2	0.7	0.0	0.0	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	45.2	45.4	42.7	53.4	64.5	50.5	60.8	77.4	85.2	84.5	50.2	71.7	0.70
Subtotal: System Renewal Total Expenditures	261.7	247.3	276.6	305.4	367.0	327.4	293.9	309.0	331.0	388.5	359.7	366.5	391.3	423.7	429.1	329.9	394.1	0.84
Subtotal: System Renewal Capital Contributions	0.2	0.0	0.1	1.2	0.0	0.2	0.0	0.1	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	
Subtotal: System Renewal Net Expenditures	**261.5**	**247.3**	**276.5**	**304.2**	**367.0**	**327.1**	**293.9**	**308.9**	**329.7**	**388.5**	**359.7**	**366.5**	**391.3**	**423.7**	**429.1**	**329.6**	**394.1**	**0.84**
System Service																		
Network Condition Monitoring and Control	8.1	12.5	13.0	13.6	6.8	10.2	14.9	14.5	14.7	7.2	4.2	0.2	0.4	0.6	0.6	12.3	1.2	10.18
Overhead Momentary Reduction	0.2	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	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	22.7	59.7	53.0	11.3	17.0	11.0	7.9	22.2	40.7	40.2	32.8	24.4	1.34
System Enhancements (e.g., installation of sensors, remotely operable feeder ties)[1]	5.1	5.1	6.7	3.6	6.3	6.4	6.1	7.5	3.9	6.7	19.6	23.3	35.9	33.0	39.4	6.1	30.2	0.20
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	
Non-Wires Solutions (e.g., storage)[1]	1.7	0.1	-0.1	0.0	0.6	2.1	0.1	-0.1	0.0	0.6	3.6	3.6	7.5	3.8	4.0	0.5	4.5	0.12
Subtotal: System Service Total Expenditures	33.4	68.0	67.1	27.7	29.8	41.8	80.9	74.9	30.0	31.5	38.3	35.0	66.0	78.1	84.3	51.8	60.3	0.86
Subtotal: System Service Capital Contributions	0.7	-0.4	-0.2	0.0	0.0	0.8	-0.5	-0.2	0.0	0.0	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**	**41.0**	**81.3**	**75.1**	**30.0**	**31.5**	**38.3**	**35.0**	**66.0**	**78.1**	**84.3**	**51.8**	**60.3**	**0.86**
General Plant																		
Facilities Management and Security	10.6	15.6	21.4	22.0	15.7	13.3	18.5	23.9	23.8	16.6	29.6	29.8	29.1	29.3	27.7	19.2	29.1	0.66
Enterprise Data Centre	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	14.4	
Fleet and Equipment	6.5	2.3	15.5	3.9	8.6	8.2	2.7	17.3	4.2	9.1	9.2	9.9	8.8	7.9	7.8	8.3	8.7	0.95
IT/OT Systems	37.4	44.7	58.0	61.2	55.9	46.8	53.1	64.8	66.3	59.2	59.7	62.9	64.5	58.2	56.0	58.0	60.3	0.96
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	4.5	3.6	0.8	2.5	1.9	3.7	2.5	0.9	6.8	1.0	2.6	3.0	0.89
Non-tracked portion	33.8	41.7	57.3	58.9	54.1	42.3	49.6	64.0	63.8	57.3	56.0	60.4	63.6	51.4	55.0	55.4	57.3	0.97
Control Operations Reinforcement	1.6	9.9	18.1	6.4	4.2	1.9	11.7	20.2	6.9	4.4	0.0	0.0	0.0	0.0	0.0	9.1	0.0	
Subtotal: General Plant Total Expenditures	56.1	72.4	112.9	93.5	84.4	70.2	86.1	126.1	101.3	89.3	103.9	119.1	124.9	116.1	98.6	94.6	112.5	0.84
Subtotal: General Plant Capital Contributions	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	
Subtotal: General Plant Net Expenditures	**56.1**	**72.4**	**112.9**	**93.2**	**84.4**	**70.2**	**86.1**	**126.1**	**101.0**	**89.3**	**103.9**	**119.1**	**124.9**	**116.1**	**98.6**	**94.5**	**112.5**	**0.84**
AFUDC	2.9	4.7	6.8	7.4	6.6	3.7	5.6	7.6	8.0	7.0	6.5	7.3	8.4	9.2	10.2	6.4	8.3	0.77
Miscellaneous	14.6	0.1	6.0	35.9	1.3	18.2	0.2	6.7	38.9	1.4	0.0	0.0	0.0	0.0	0.0	13.1	0.0	
Other Total Expenditures	17.5	4.8	12.8	43.2	7.9	21.9	5.7	14.3	46.8	8.4	6.5	7.3	8.4	9.2	10.2	19.4	8.3	2.33
Miscellaneous Capital Contributions	0.1	0.2	0.0	0.0	0.0	0.1	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	
Other Total	17.4	4.6	12.8	43.2	7.9	21.8	5.5	14.3	46.8	8.4	6.5	7.3	8.4	9.2	10.2	19.3	8.3	2.33
Total Net Capex	**448.1**	**533.2**	**597.9**	**606.1**	**655.9**	**560.7**	**633.5**	**667.8**	**656.9**	**694.3**	**728.5**	**757.1**	**814.5**	**823.7**	**804.8**	**642.7**	**785.7**	**0.82**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets	-0.8	-0.8	-0.1	-0.2	-7.9	-0.9	-0.9	-0.1	-0.2	-8.4	-8.9	-9.6	-17.3	-14.7	-18.5	-2.1	-13.8	0.15
Total	**447.4**	**532.4**	**597.8**	**605.9**	**648.0**	**559.7**	**632.6**	**667.7**	**656.7**	**685.9**	**719.7**	**747.5**	**797.2**	**809.0**	**786.3**	**640.5**	**771.9**	**0.83**
Forecasted or VA Capex: PEG Candidates[1]	**78.0**	**109.7**	**112.2**	**74.1**	**121.5**	**97.5**	**130.4**	**125.3**	**80.3**	**128.6**	**185.4**	**188.5**	**208.7**	**193.3**	**175.5**	**112.4**	**190.3**	**0.59**
% Tracked or Forecasted	17.4%	20.6%	18.8%	12.2%	18.7%	17.4%	20.6%	18.8%	12.2%	18.7%	25.8%	25.2%	26.2%	23.9%	22.3%			
K-Bar Capex: PEG Candidates	**369.4**	**422.7**	**485.6**	**531.8**	**526.5**	**462.2**	**502.2**	**542.4**	**576.4**	**557.3**	**534.3**	**559.0**	**588.5**	**615.7**	**610.8**	**528.1**	**581.7**	**0.91**

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

[2] Capex escalated to 2027 dollars using Clearspring's asset price index.

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

Capex categories nominated for forecasting or variance account treatment are highlighted in yellow in the table. All historical capex is escalated to 2027 dollars (the midpoint of the next plan term) using the asset price index that Clearspring Energy Advisors and PEG agreed to in their joint report in the recent Hydro One IR proceeding. The growth rate of this index is a 50/50 weighted average of the growth in the Handy Whitman Index of power distributor construction costs in the North Atlantic (e.g., Northeastern) U.S. and of Statistics Canada's implicit price deflator for non-residential capital.

At the bottom of the table we report the total value of capex that would hypothetically be accorded forecasting and in some cases variance account treatment on the one hand and K-bar treatment on the other. In the right-hand columns it can be seen that the kinds of capex we nominate for forecasting and/or variance account treatment are forecasted to be much higher in the new plan than in the expiring plan. Assume that the Company would receive a budget equal to its forecasts. The inflation-adjusted historical average capex deemed prudent that we nominate for K-bar treatment is less than the Company's proposed capex by 17%.

7. Other Provisions of CIR 2.0

Revenue Cap

THESL proposes a *revenue* cap whereas in the prior two plans it had a *price* cap. We have no objection to using revenue caps rather than price caps. We showed in Section 2 that revenue caps are increasingly common in MRPs and often combined with revenue decoupling.

Revenue Decoupling

PEG has for many years supported revenue decoupling for energy utilities. We recommended decoupling for all Ontario distributors in a prior project for OEB Staff. The Board instead took the alternative (and unusual) path of choosing a high reliance on fixed charges in the distribution rate designs of small-volume customers. The large number of distributors that the Board has to regulate may be one reason for this decision.

Many of the reasons that revenue decoupling is used in the States are not applicable in Ontario. For example, distributors already have multiyear rate plans to protect them from any problem of declining average use. The IESO undertakes most energy conservation. Ontario has a relatively clean generation fleet and carbon taxes. Distributors have high fixed charges for small volume customers and traditional demand-based charges for customers with larger loads.

However, in an era of DERs and brisk demand growth that is expected to require capacity expansions eventually, we believe that time-sensitive distribution rates are more appropriate than high fixed charges. There is a real risk of excessive capacity expansion resembling the excessive expansion of generation capacity that the U.S. experienced in the 1970 and 80s. Decoupling could make Toronto Hydro more open to time-sensitive distribution rates going forward. Nonetheless, there seems to be little interest in tackling time-sensitive rate designs in Ontario in the next five years.

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.

THESL proposes decoupling only weather-normalized revenue variances. This reduces customer risk but also complicates ratemaking. Most revenue decoupling mechanisms for electric utilities in North America don't exclude weather variances. A decoupling with respect to weather variances as well as other demand drivers is one way that decoupling reduces the risk of time sensitive rates. However, we have seen that new rate designs that expose THESL to more risk of demand variances are unlikely during the plan.

PIMs

THESL already maintains an Electricity Distributor Scorecard and has Electricity Service Quality Requirements ("ESQR"). The proposed PIM should be scrutinized with respect to the metrics, targets, and award/penalty rates. Here are some key provisions of the proposal with PEG Commentary.

- The proposed PIM is linked to a "proactive 0.6% performance factor" that is added to the X factor in the revenue cap formula and has an estimated value of $65 million. This is mathematically equivalent to a penalty-only PIM that pays customers the *full* penalty for bad performance in the form of an up-front X factor supplement. The Company can earn all of this back if its performance achieves the targets during the plan. An advantage for customers is that the various policy PIMs are penalty-only, whereas in many plans some are positive. On the downside, this approach sows confusion since, for example, the slowdown in rate growth is only a compensation for poor performance. We propose not tying the PIM to the X factor.

  Rewards would only be calculated at the end of the plan on the basis of all five years of results. Thus, there would be no rate recovery associated with the any PIM rewards during the years of the plan. This is a reasonable ratemaking treatment for metrics that are inherently volatile due, for example, to their sensitivity to volatile external business conditions. Rate churn and regulatory cost are reduced. Recovery of sums in variance accounts is often deferred in Ontario. On the other hand, the reward to be paid at the start of the next plan would be an unwelcome addition to the rate increase that will be due, whatever the PIM outcome, for rebasing.

- Quite a few of the targets are contingent on the Company receiving its proposed revenue requirement. Given the contingency of targets to funding received, the Company proposes final targets would be determined after the revenue requirements for the project are established.

This is unusual but not an unreasonable proposition in PEG's view if the matter isn't addressed in settlement.

Z Factor

THESL proposes to continue the OEB's standard Z factor approach. We noted in Section 2 that Z factors make revenue adjustments for changes in external business conditions that are difficult to foresee accurately and have a material impact on earnings. It is easier to identify a difficult-to-foresee external cost challenge (e.g., a severe storm) than it is to identify many difficult-to-foresee external developments that reduce cost (e.g., a string of years with no severe storm). Z factors also weaken cost containment incentives in the target areas. These are arguments for disallowing a share of otherwise eligible costs.

Appendix: PEG Credentials

Pacific Economics Group Research LLC is an economic consulting firm based in Madison, Wisconsin USA. We are the leading North American consultancy on IR plan design and statistical research on the performance and input price trends of gas and electric utilities. Our personnel have over seventy years of experience in these fields. Work for a mix of utilities, regulators, government agencies, and consumer and environmental groups has given us a reputation for objectivity and dedication to good research methods. Our practice is international in scope. In addition to our numerous projects in Ontario we have done several projects in each of the other three populous Canadian provinces.

Mark Newton Lowry, the senior author and principal investigator for this project, is the President of PEG. He has over thirty years of experience as an industry economist, most of which have been spent addressing energy utility issues. He has prepared IR plan design, productivity, and benchmarking research and testimony in more than 50 proceedings. Dr. Lowry speaks frequently on utility ratemaking and has authored dozens of professional publications. He recently coauthored two influential white papers on IR for Lawrence Berkeley National Laboratory. His most recent publication is a report on a survey of IR and other alternatives to traditional ratemaking that he prepared for the Edison Electric Institute. In the last few years, he has played a prominent role in IR proceedings in Alberta, British Columbia, Québec, Hawaii, Massachusetts, Minnesota, North Carolina, and Washington state as well as Ontario. He holds a PhD in applied economics from the University of Wisconsin. Native to northeast Ohio, he lives near Madison.

References

Lowry, Mark Newton, Matthew Makos, Gretchen Waschbusch, and Benjamin Cohen (2024). "Innovative Regulatory Tools for Addressing an Increasingly Complex Energy Landscape: 2023 Update," for Edison Electric Institute, February.

Lowry, Mark Newton, David Hovde, Rebecca Kavan, and Matthew Makos (2023). "Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta," *The Electricity Journal*, Volume 36, Issue 5.

Lowry, Mark Newton and Matthew Makos (2021). "Revenue Decoupling at 40, Venerable PBR Tool Goes National," *Public Utilities Fortnightly*, April.

Lowry, Mark Newton, Matthew Makos, and Jeff Deason (2017). "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," Ed. Schwartz, Lisa C. LBNL-2001039.