Report on Spending Patterns and Capitalization Policy

January 8, 2026

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Executive Summary

The Ontario Energy Board ("OEB") has for more than two decades used multiyear rate plans ("MRPs") to regulate gas and electricity distributors. In these plans, the rates of each utility are escalated for several years by a predetermined attrition relief mechanism that is not linked, like a variance account, to the utility's actual cost during the plan. A utility's revenue is typically rebased to the efficient cost of its services in regularly scheduled proceedings that use a forward-looking test year informed by costs in one or more recent historical reference years. MRPs are a form of performance-based ratemaking ("PBR") that can strengthen utility cost containment incentives and streamline the ratemaking process by various means that may include a reduction in the frequency of rate rebasings.

The OEB is undertaking multi-year work to refine its approach to performance-based regulation (PBR) and assess aspects of its ratemaking approach. One area of investigation is whether the OEB's current approach weakens cost containment incentives and encourages accelerated cost growth in later years of an MRP rate cycle. Another area of interest is whether distributors are and should be increasing capitalization of asset repair and field work expenses.

To explore these issues, the OEB has commissioned a research project with several tasks. Empirical research has looked for discrepancies between the cost growth in the early years and later years of the MRP rate cycles of Ontario energy distributors. Reviews of the ratemaking literature and of experience with MRPs in other jurisdictions have considered whether these plans tend to encourage skewed spending patterns and increased capitalization of operation, maintenance, and administrative ("OM&A") expenses. Ontario distributors and intervenors and regulators in other jurisdictions have been surveyed to gather their views on these matters. Pacific Economics Group Research LLC ("PEG") is the OEB's consultant on this project.

Literature Review

The academic literature on rate regulation suggests that MRPs with regularly scheduled full rebasings of a utility's revenue to the cost of its services can materially weaken its cost containment incentives and encourage strategic tactics to influence future rates. Utility spending patterns tend to be skewed, with more efficiency savings occurring in early plan years than in later plan years when the next rebasing is more imminent. This type of skewed spending pattern is suboptimal for several reasons. Promising efficiency initiatives are not pursued. Bunching of expenditures can create additional inefficiencies. Customer benefits from MRPs can be reduced.

Various remedies have been suggested in the literature for these problems. These remedies include longer plan terms, yardstick competition using statistical cost research, menus of incentivized ratemaking options, and the use of multiple historical reference years in rate rebasings.

Capitalization Policy

Capitalization of utility OM&A expenses has not received widespread attention in the academic literature on accounting or utility ratemaking. Surveys of evolving utility capitalization policies are not readily available. It is known, however, that capitalizations of cloud computing, conservation and demand management ("CDM"), and a broader range of inputs that include asset repair and field work have been issues in some jurisdictions. Appropriate capitalization policies may change over time and merit periodic examination by regulators.

Capitalization policy is limited by accounting standards. The modified international financial reporting standards ("MIFRS") that most Ontario energy distributors use is more restrictive regarding capitalizations than the U.S. generally accepted accounting principles ("GAAP") that some distributors use. Changes in capitalization policies have nonetheless occurred in Ontario and have not always been transparent. Utilities have been afforded some flexibility in the policies that they use.

Jurisdictional Review

We reviewed experience with spending patterns and changing capitalization practices in several jurisdictions where regulators have extensive MRP experience. The jurisdictions we examined were Alberta, Australia, California, Chile, Great Britain, Ireland, and New Zealand.

Regulators in all of these jurisdictions have been concerned about utility spending patterns during MRPs. Several of these regulators have approved efficiency carryover mechanisms ("ECMs") designed to encourage better spending patterns. Some of these regulators have expressed satisfaction with the outcomes of these mechanisms while others have not. Alberta has been an innovator in the use of historical reference years in rebasing proceedings. Australia makes extensive use of statistical benchmarking in ratemaking.

Several regulators have voiced concerns about capitalization policies. An underlying concern is that utilities strike the right balance between opportunities to use OM&A and traditional capital inputs. Another concern is that changes in capitalization policies in the middle of an MRP can bolster utility earnings at the expense of customers. Changes in capitalization policies can complicate statistical cost benchmarking by making apples to apples comparisons more difficult.

SPA Survey

Voluntary surveys of spending pattern and capitalization issues were developed by PEG and sent to Ontario distributors and intervenors and to some regulators in other jurisdictions that have MRP experience. Ten Ontario electricity distributors, six Ontario intervenors, and regulators from three jurisdictions outside Ontario responded. Responding intervenors raised concerns about utility spending patterns and maintained that these patterns are incentivized by MRP provisions. Notwithstanding these concerns, responding intervenors were generally circumspect about spending pattern remedies. Responding distributors were generally not inclined to acknowledge spending pattern problems. Various respondents noted that other conditions can also encourage late plan spending surges, and that patterns can be randomly affected by external business conditions.

Empirical Research

Our statistical research on the spending patterns of Ontario electricity distributors focused on the ten years from 2014 to 2023. Since input prices and operating scale are key external drivers of cost, we tried to control for these business conditions by calculating growth in the real unit costs of each sampled electricity distributor. These metrics were separately calculated for OM&A expenses (which we will call "opex" for short in this report) and gross plant additions (which we will call "capex" for short). We then considered how growth rates in these indexes differed in the years of an MRP rate cycle.

For both opex and capex, we found that the average growth in real unit cost was slower in early plan years than in later plan years, and that more than half of distributors studied exhibited such skewed spending patterns. For example, in the last two years of rate plans for which we have data on complete rate cycles, real unit capex averaged 7.96% annual *growth* whereas in earlier plan years it averaged a 2.22% annual *decline*. The difference in these average growth rates was statistically significant. The difference between average opex growth in early and late plan years was less pronounced and was not highly significant. In plans where opex was skewed, the difference between the annual growth rates of real unit opex in early and late plan years averaged a material 7.20%. However, when we examined the subset of all plans where real unit cost growth was more rapid in later plan years, we found that the average difference in the growth rates between early and late plan years was a sizable 7.5%. Thus, when skewness occurred it was often pronounced.

For capex and opex alike, many plans nonetheless did not result in skewed expenditures. For example, most large distributors did not display the skewed capex pattern. This result could reflect the greater need of large distributors for capex, but it may also reflect the common recourse of these distributors to provisions within custom incentive ratemaking ("Custom IR" or "CIR") ") that supplement the capital revenue provided by rate or revenue cap indexing. These provisions rely on capex forecasts and, in some cases, have included rate adjustments for underspending relative to forecast.

Remedies for Spending Pattern and Capitalization Policy Concerns

Spending Patterns

Our research suggests that a remarkably wide array of remedies can help improve utility spending patterns during MRPs. We discuss the pros and cons of several of these remedies in the report. Our general conclusion is that skewed spending patterns are a problem in Ontario and measures should be taken to discourage them. Although some of these remedies are already used in Ontario, the commonplace skewness of expenditures suggests that some of these remedies may need to be used more adroitly.

Since skewed patterns have not occurred in quite a few plans, including many those for larger distributors, the introduction of complicated and novel mechanisms is probably not warranted solely to reduce spending pattern skewness. Mechanisms that seem more appropriate under these circumstances include the following.

- Increased attention to capex and opex patterns and deviations from distribution system plans in rebasing proceedings. Econometric benchmarking of opex and capex can help with this.
- Increased role for multiple historical test years in rebasing proceedings.
- Consider on an ad-hoc basis special ratemaking treatment for sustained cost reduction initiatives that utilities pursue in later plan years.

Some other reforms, nonetheless, warrant continued consideration in the Advanced PBR initiative because they have other benefits that include an ability to improve general operating efficiency. These include the following.

- Efficiency carryover mechanisms are used in several jurisdictions.
- Expand the role of statistical benchmarking
- Upgrade the OEB's use of incentive-compatible ratemaking options such as the annual incentive ratemaking option that is currently available so that more distributors use such options.

Capitalization of Asset Repair and Field Work Expenses

The merit of capitalizing asset repair and field work expenses is a complicated issue with arguments on both sides. Capitalization of OM&A expenses is one means of improving the balance of incentives to use capital and OM&A inputs efficiently. However, other remedies for this problem are available.

Here are our recommendations concerning the capitalization of asset repair and field work expenses.

- The OEB and stakeholders should sharpen their understanding of desirable capitalization policies for costs of asset repair and field work and consider policy guidelines. Generic proceedings and/or utility rebasing proceedings may both prove useful for this purpose. Continuing flexibility regarding guidelines for individual utilities may have merit. Total expenditure accounting may be explored in other segments of the Advancing PBR initiative.

- Customers should be protected from utility-initiated increases in the capitalization of opex during MRPs. Utilities should be required to notify the regulator when they change capitalization policies during the term of an MRP. Such changes could be prohibited or, more flexibly, customers could be compensated for detrimental short-term effects of the changes, such as paying for opex in one rate plan only to pay again for its capitalized balance in the next plan.

- Changes in capitalization policies can complicate benchmarking. This raises the question of whether standardized capitalization rules should apply to data used in benchmarking. Capitalization policies are an issue worth exploring in the TCB/TFP consultation.

1. Introduction

The Ontario Energy Board has used multi-year rate plans for around twenty years to regulate utilities. In such plans, a utility's rates are rebased to its cost infrequently. Between rebasings, rates are escalated in part using a predetermined attrition relief mechanism that is not linked, like a variance account or American-style formula rate[1], to the utility's actual cost during the plan. These plans are a form of PBR that can strengthen utility cost containment incentives and streamline the ratemaking process[2].

The OEB is now in a multiyear Advancing PBR initiative to reconsider its ratemaking approach. One area of interest is whether the established ratemaking approach encourages diminishing cost efficiency gains in later plan years. Another area of interest is the capitalization of their asset repair and fieldwork expenses.

To explore these issues the OEB has commissioned a research project with several tasks. Reviews of the ratemaking literature and of experience with MRPs in other jurisdictions have examined two related questions: first, whether these plans encourage skewed spending patterns, and second, whether they create incentives for increased capitalization of operating and maintenance expenses. We have also examined whether concerns about these matters have led MRP practitioners to develop policies to address them. Policies used by MRP practitioners in other jurisdictions to address these matters have been examined. Empirical research has looked for patterns in the OM&A expenses and gross plant additions of Ontario distributors. Remedies for skewed spending patterns and capitalization concerns have been considered. PEG has been the OEB's consultant on this project.

This is our draft report on this research. Section 2 details our empirical research on the spending patterns of Ontario electricity distributors. To help interpret these results, we then review discussions in scholarly literature on how MRPs affect utility spending patterns. There follows in Section 4 an introduction to capitalization policy. We next discuss experiences of regulators in other jurisdictions with spending patterns and capitalization issues. Section 6 recounts survey responses of Ontario stakeholders. Section 7 synthesizes the findings of prior sections of the report. Section 8 then considers possible remedies for skewed spending pattern and capitalization concerns. A skewed spending pattern refers to a tendency for distributors to concentrate a disproportionate share of expenditures towards the later years of a rate plan. Such patterns are of concern because they reduce operating efficiency and the benefits of MRPs for customers. The Appendix contains a glossary of terms and further discussions of matters raised in the report.

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[1] An American-style cost of service formula rate causes a utility's revenue to track its actual cost of service closely. This ratemaking approach is used by the FERC for electricity transmission ratemaking and is also used by several state commissions.

[2] Approved MRPs may not produce the maximum incentives that can potentially be achieved by these plans, and there are other sources of performance incentives that include traditional prudence reviews during rebasing proceedings.

2. Empirical Research on Ontario Spending Patterns

2.1 Research Methodology

PEG's methodology for studying spending patterns of Ontario electricity distributors had the following steps.

Identify Distributor Cost Data That Are Useful for Spending Pattern Research

The first step in our empirical research was to identify Ontario electricity distributor cost data that would be useful in spending pattern analysis ("SPA"). Here are some circumstances we took account of and methodological decisions we made in light of them.

Sample Period

In choosing a sample period, the circumstances we considered included the following.

- OEB Staff's statement of work for this project calls for the SPA empirical research to focus on the 2010-2023 period.

- Standardized data on OM&A expenses of Ontario electricity distributors are not available before 2002, when submission of such data was prompted by the OEB's Reporting and Recordkeeping Requirements ("RRR").

- 2001 was the first year of the first-generation incentive rate-setting mechanism ("IRM") for electricity distributors.[3] However, in late 2002 a legislated freeze was imposed (without rebasing) on electricity distributor rates.[4] Rebasing proceedings were next held in 2005 and 2006, and rates were reset in 2006. The freeze did not compensate distributors for price inflation and thereby made rates less compensatory.

- The second generation IRM applied to distributors following the 2006 rebasing until their next rebasing, which could occur for 2008, 2009, or 2010. Many distributors effectively had MRPs with only three years, while some would have MRPs with four-year terms, including the 2006 rebasing year.

- Many Ontario electricity distributors changed their accounting standards in the 2011-2013 period. Most of the changes were from Canadian GAAP to international financial reporting system ("IFRS") accounting. This affected opex capitalization

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[3] Rate unbundling occurred during 2000 and 2001, with the first rate adjustment under the 1st generation IRM occurring in 2002.
[4] *Electricity Pricing, Conservation, and Supply Act, 2002.*

policies of the distributors and, in many cases, resulted in a surge of opex and a drop in capex that may have obscured underlying MRP spending patterns.

- During the 2006-2010 period Ontario electricity distributors deployed first-generation smart meters. This transition affected opex as well as capex. Costs of this transition were accorded deferral account treatment. The deferred opex was chiefly recovered from ratepayers in the 2011-2013 period, and this encouraged a surge in OM&A expenses.

- Before 2013, Ontario electricity distributors did not annually report their gross plant additions data to the OEB in their RRR filings. Data for earlier years would need to be drawn from the utilities' occasional rebasing applications --- a sizable, complex undertaking --- or imputed inexactly from gross plant value data.

- Distributor operating data were not yet available for 2024 at the time we conducted the bulk of our research.

Faced with these circumstances, PEG only included Ontario distributor cost growth from 2014 to 2023 in the calculations.

Sorting the Data

We sorted the data from this sample period into identifiable years of MRP rate cycles where this was practical. Here are some circumstances we considered in developing a sorting strategy.

- Rebasings of Ontario distributors operating under MRPs have typically occurred on a predictable cycle in which the proceeding to consider the rebasing typically takes place in the last year of a plan. The rebasing uses one or more historical reference years and a fully forecasted test year to determine a rate reset that is implemented in the first year of the next plan. Formulaic escalation of normalized costs in historical reference years is uncommon.

- In the second generation IRM, which applied to distributors following the 2006 rebasing until their next rebasing, we noted above that many distributors effectively had MRPs with only three years. Moreover, only estimated plant additions are available.

- During the third generation IRM, which applied to tranches of distributors after rebasings that occurred in 2008, 2009, and 2010, most distributors had MRPs with four-year terms. Opex and capex data of many distributors were affected by changes in accounting standards during these plans and we only have estimates of gross plant additions for some plan years. The next round of widespread rebasings began in 2012 and ended in 2014. A few utilities did not have the typical plan term. Notably, Toronto Hydro had more frequent rebasings. Several smaller distributors (e.g., PUC Distribution and ENWIN) had longer plan terms.

- Since the Renewed Regulatory Framework became operational in 2014 most utilities have had MRPs with five-year terms. However, some distributors have operated under the Annual IR Index ("AIR") option and did not have predetermined plan terms. Some distributors have switched between Custom IR, the 4th generation IRM, and AIR without a rebasing. Some distributors have been permitted to defer their rebasings and many have done so at least once.[5]

- The number of identifiable completed rate cycles is fairly small. This diminishes the statistical significance of research results. We can expand the sample by considering years of incomplete rate cycles.

- Distributors have been permitted to schedule rebased rates to take effect on May 1 or January 1 of a year. To the extent that distributors rebased their rates on May 1, the full spending pattern impact of an MRP may not be properly reflected in data that are reported on a calendar year basis.

Faced with these realities, here is how we sorted the cost data.

- The most common rebasing cycle we considered was five years, and we treated this as the standard cycle. If the year in which new cost-based rates are established is year t-0, we treated this as the *end* of a standard rate cycle that started in year t-4. Thus, the rate cycle for our research purposes differs from the years of an MRP, as illustrated in Figure 1 below. This figure shows how we coped with plans of four, five-, and six-years duration.

- For rate cycles longer than five years that have ended, we used data for all years and treated the earliest years as t-e (e for early) observations.

- With respect to four-year cycles, we treated year t-3 as a year t-3 in a five-year cycle and assumed that there was no observation analogous to year t-4 in a five-year cycle.

- Data for rate cycles less than four years in length were excluded.

- For current rate plans that have an unknown end date we treated all years following the rebasing year as t-e years.[6]

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[5] See, for example, the policy with respect to rebasing deferrals in Ontario Energy Board, "Letter of December 1, 2021 to All Licensed and Rate-Regulated Electricity Distributors, All Intervenors in 2022 Electricity Distribution Cost of Service Proceedings, and All Interested Parties Re: Applications for 2023 Electricity Distribution Rates". Between 2010 and 2021, the Board received 113 requests to defer rate rebasings and approved 110 of those requests.
[6] The exception to this is Chapleau Public Utilities Corporation, which subsequently merged into Hydro One Networks. All years following their most recent rebasing were excluded from the analysis.

Figure 1

Rate Cycle Illustration

Multiyear Rate Plan Years

Plan 1						Plan 2					Plan 3				
1	2	3	4	5	6	1	2	3	4	5	1	2	3	4	1

Rate Cycle Years

	Cycle 1						Cycle 2					Cycle 3			
t	t-e	t-4	t-3	t-2	t-1	t-0	t-4	t-3	t-2	t-1	t-0	t-3	t-2	t-1	t-0

Our approach gleaned cost growth rates for around 45 complete rate cycles during the 2014-2023 period. Our calculations also included cost growth rates where we can identify with reasonable accuracy in the year within a rate cycle but don't have a complete cycle. The combination of these two sets of growth rates is the totality of what we call our "sorted" data.

Several sample expansions are possible should the marginal benefit be deemed to exceed the marginal cost. Our comments on these options appear in brackets.

- 1st generation IRM/rate freeze cycles, which were typically five years ending in 2006 [Dozens of partial cycles could be added.[7] However, these occurred before 2010, spending may have been influenced by the rate freeze, some observations would be lost due to industry consolidation, and we would only have estimates of capex].

- 4-year cycles during the 2nd generation IRM [There were some, but these also involve data before 2010, and we would also have to use estimates of capex].

- 4-year cycles during the 3rd generation IRM that were completed before 2014 [There were a few, but some involved data before 2010, or before good capex data were available, and data were affected by the change in accounting standards]

- Early MRPs of distributors that later amalgamated or were acquired. [This would add several new cycles but entail quite a bit of work].

Acquisitions and Amalgamations

[7] The first growth rates for Ontario opex and capex in the dataset are in 2003. This is 2 years into the first generation IRM.

Many distributors were parties to acquisitions and/or amalgamations during the focus period. The utilities involved sometimes had different rate cycles. Our approach was to ignore acquisitions between parties of unequal size (e.g., acquisitions by HONI) and to exclude from the study data for amalgamating utilities of similar size (e.g., those which merged to form Alectra) for all years preceding the amalgamation and the year in which the amalgamation occurred.

Further Research Complications

Some other circumstances of Ontario electricity distributors during the sample period also complicated the empirical spending pattern research.

- Capex and opex growth are influenced by external business conditions that include, most notably, growth in the operating scale of distributors and the input prices they pay. Multiple dimensions of operating scale (e.g., the number of customers served and the length of distribution lines) can drive the capex and opex growth of electricity distributors. Some external cost drivers (e.g., weather, the pandemic, and construction cost inflation) are volatile.[8]

- A few distributors operated under CIR plans during the sample period. In many approved CIR plans, most or all capital cost underspends have been subject to claw back treatment.[9] Moreover, capex in 4th generation price cap IR has sometimes been afforded supplemental funding from incremental capital modules ("ICMs") and/or advanced capital modules ("ACMs"). Underspends of capital cost funded by ICMs and ACMs were sometimes clawed back. Additionally, some OM&A expenses and capex of Ontario electricity distributors were accorded deferral and variance account treatment for other reasons. All these ratemaking treatments weaken distributor cost containment incentives and can affect MRP spending patterns. The cost data PEG was able to rely on included costs that were addressed by claw back, deferral, and variance accounts as well as those that were not.

- Adverse rebasing decisions could in theory affect spending patterns.

[8] Real capex was found to be more volatile than real opex.
[9] Mechanisms of this kind have sometimes been called capital in service variance accounts ("CIVAs")

Controlling for External Business Conditions

To control for the impact of the most important external business conditions on cost growth, we calculated the annual growth rates in real (inflation-adjusted) cost and real unit cost of sampled distributors from 2014 to 2023.[10] These calculations used methods similar to those that PEG is using in the new cost benchmarking and productivity research for electricity distributors that the OEB has commissioned.

The calculations make use of some basic results of the logic of economic indexes.

- The growth (rate) of any real cost *j* is the difference between growth in the corresponding nominal cost of input j and growth in a corresponding input price index.

$$\text{growth } Cost_j^{\ Real} = \text{growth } Cost_j - \text{growth Input } Price_j \qquad [1]$$

- The growth of any real *unit* cost index *j* ("$UCNDX_j^{Real}$") is the difference between growth in real cost *j* and the growth in a corresponding scale index ($Scale_j$).

$$\text{growth } UCNDX_j^{Real} = \text{growth } Cost_j^{\ Real} - \text{growth } Scale_j. \qquad [2]$$

The growth in each scale index was a weighted average of the growth in multiple scale variables that drive cost growth. The weight placed on the growth in each scale variable was its share in the sum of the corresponding elasticities of cost with respect to these variables.[11] Scale variables may have different cost impacts on capex and opex.

Here are some further details of our opex and capex calculations.

Opex Calculations

- OM&A expenses excluded those for bad debt, CDM, power procurement, and low voltage services to embedded distributors. OM&A expenses for street and sentinel lighting; advertising; and sales and demonstration activities were also excluded from our definition of OM&A expenses.

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[10] The level of real unit cost in a given year *t* is $Unit\ Cost_t^{Real} = \frac{Cost_t / Input\ Prices_t}{Scale_t}$.

[11] For an early discussion of elasticity-weighted scale indexes see Denny, Michael, Melvyn A. Fuss and Leonard Waverman, "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York), 1981, pp. 172-218. The authors of this seminal paper included University of Toronto economists.

- The resultant residual OM&A expenses of each sampled distributor were deflated by an OM&A input price index to produce real OM&A costs.

- Growth of the OM&A input price index was a cost-weighted average of growth in the average weekly earnings of the Ontario industrial aggregate and of the gross domestic product implicit price index for final domestic demand ("$GDPIPI^{FDD}$") in Ontario.

- The annual growth in the OM&A scale index of each distributor was a weighted average of the growth in the number of customers it served and its ratcheted peak demand. The weights were estimated cost elasticity shares drawn from an econometric model of OM&A expenses that we developed for this project. Details of work are provided in the Appendix Section A.2.

- The annual real OM&A unit cost growth of each utility was the difference between the growth of its real OM&A cost and its scale index.

- Logarithmic growth rates were used in all of these calculations and in the analogous calculations for capex discussed below.

Capex Calculations

The values of (gross) plant additions (which we will resume calling capex for short) of each distributor were drawn from RRR data. These additions include those for general plant as well as distribution plant. High voltage capex and customer contributions were included.

The capex of each sampled distributor was deflated. Various inflation measures were considered as the deflator, and we ultimately chose the Handy Whitman Index of Power Distribution Construction Cost in the North Atlantic region of the U.S.

The annual growth (rate) of the capex scale index of each distributor was a weighted average of the growth in the number of customers it served and its ratcheted peak demand. Distribution line length was not included because inconsistency in its reporting has led to fluctuations in reported total line length that are particularly undesirable in the context of this study, which focusses on unit cost growth over a short sample period. The weights were capex elasticity shares drawn from an econometric capex model we developed for this project using Ontario RRR capex data. The annual growth in the real unit capex of each distributor was the difference between the growth of its real capex and the growth of its capex scale index.

Average Growth Rates

For capex and opex alike, we next calculated the corresponding *average* growth rates of cost, real cost, unit cost, and real unit cost in each year of the identified rate cycles. We also calculated the levels of the real unit cost trend indexes and then considered how these levels compared to the average for the cycle. Average results for each rate cycle year were then calculated. Natural logarithms were used in the calculation of the growth rates.

We itemized results for distributors of different sizes. Large distributors were defined as those that had total cost larger than 5% of the industry total in 2023.[12] Medium distributors are defined as those between 0.5% and 5% of total cost while small distributors are those under 0.5% of total cost. We also assessed the spending patterns of distributors that received supplemental capital revenue via CIR.

We are chiefly interested in comparisons of cost growth in early and late years of the business cycle. The theory is that MRPs incentivize cost growth to be more rapid in later years. The early plan years are defined as t-3, t-4, and t-e. The later plan years certainly include years t-1 and t-2. However, we explained above that it is not clear how to treat cost growth in year t-0 (the first year of the next plan). We accordingly computed late plan cost growth averages for years t-2, t-1, and t-0 and for t-2 and t-1 (i.e., excluding year t-0).

2.2 Capex Spending Patterns

Results of our capex pattern empirical research can be found in Tables 1a-1d and Figure 2. Table 1a shows that the average annual growth rates in capex, real capex, unit capex, and real unit capex were all materially slower in years t-3, t-4, and any earlier years of the rate cycle than in years t-1 and t-2. However, the average growth in most of these metrics in year t-0 was materially negative. In the complete cycles, real unit capex averaged a 2.22% annual *decline* in years t-3, t-4, and t-e but averaged 7.96% annual *growth* in years t-2 and t-1 and 2.99% annual growth in years t-2, t-1, and t-0. For the cost growth comparison rate row labeled Difference [A] – [B] in Table 1a, PEG calculated t-tests of the equality of means of the real unit capex growth and the index level relative to the complete cycle average in the early years against the later years reported in Table 1a. These results were statistically significant at levels from 95% to over 99%.

[12] The methods and data used to calculate total cost came from the PEG productivity work for the OEB that is in progress.

Table 1a

Capex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

All Distributors

Rate Cycle Year	Comments on Rate Cycle Years	Capex Growth		Unit Capex			
		Nominal	Real	Nominal	Real		
		All Observations	All Observations	All Observations	All Observations	Complete Cycles Only	
						Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	4.80%	-1.84%	4.04%	-2.59%	2.19%	99.5%
t-4	4 years before next rebasing	1.90%	-1.61%	0.95%	-2.56%	-6.05%	94.4%
t-3	3 years before next rebasing	3.48%	-2.17%	2.79%	-2.85%	-2.16%	89.6%
t-2	2 years before next rebasing	12.52%	6.04%	11.88%	5.40%	10.42%	102.9%
t-1	Year of rebasing proceeding	14.91%	9.49%	14.22%	8.80%	5.49%	106.6%
t-0	Rebasing year	0.23%	-5.03%	-0.58%	-5.83%	-6.95%	103.4%
	Averages						
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**3.83%**	**-1.88%**	**3.05%**	**-2.66%**	**-2.22%**	**93.69%**
	Later Rate Cycle Years (t-2, t-1) [B]	**13.66%**	**7.68%**	**13.00%**	**7.02%**	**7.96%**	**104.70%**
	Difference [A] - [B]	**-9.83%**	**-9.56%**	**-9.94%**	**-9.67%**	**-10.18%**	**-11.01%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**9.29%**	**3.54%**	**8.58%**	**2.83%**	**2.99%**	**104.27%**
	Difference [A] - [C]	**-5.45%**	**-5.42%**	**-5.52%**	**-5.49%**	**-5.21%**	**-10.58%**

Table 1b

Capex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

Four Largest Distributors

Rate Cycle Year	Comments on Rate Cycle Years	Capex Growth		Unit Capex			
		Nominal	Real	Nominal	Real		
		All	All	All	All	Complete Cycles Only	
		Observations	Observations	Observations	Observations	Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	8.16%	0.44%	7.61%	-0.11%	na	na
t-4	4 years before next rebasing	9.94%	5.62%	9.20%	4.88%	11.83%	100.2%
t-3	3 years before next rebasing	-4.16%	-12.47%	-4.95%	-13.26%	-4.43%	95.4%
t-2	2 years before next rebasing	16.30%	9.38%	15.60%	8.67%	20.96%	119.4%
t-1	Year of rebasing proceeding	-14.29%	-20.14%	-15.26%	-21.11%	-29.90%	87.6%
t-0	Rebasing year	2.97%	-2.14%	2.02%	-3.09%	11.25%	97.3%
	Averages						
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**4.87%**	**-1.98%**	**4.18%**	**-2.66%**	**3.70%**	**97.84%**
	Later Rate Cycle Years (t-2, t-1) [B]	**2.70%**	**-3.74%**	**1.88%**	**-4.56%**	**-4.47%**	**103.51%**
	Difference [A] - [B]	**2.16%**	**1.76%**	**2.30%**	**1.91%**	**8.17%**	**-5.67%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**2.81%**	**-3.10%**	**1.94%**	**-3.98%**	**0.77%**	**101.44%**
	Difference [A] - [C]	**2.05%**	**1.12%**	**2.25%**	**1.32%**	**2.93%**	**-3.60%**

Note: [A] includes all observations for rate cycle years t-3, t-4, and t-e where there are t-e observations available. Otherwise [A] only includes rate cycle years t-4 and t-3.

Table 1c

Capex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

Medium Distributors

Rate Cycle Year	Comments on Rate Cycle Years	Capex Growth		Unit Capex			
		Nominal	Real	Nominal	Real		
		All Observations	All Observations	All Observations	All Observations	Complete Cycles Only	
						Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	2.84%	-4.55%	1.96%	-5.42%	0.41%	97.1%
t-4	4 years before next rebasing	-3.32%	-7.04%	-3.89%	-7.61%	-5.83%	97.1%
t-3	3 years before next rebasing	7.22%	1.10%	6.64%	0.52%	-1.74%	93.6%
t-2	2 years before next rebasing	16.71%	11.12%	16.14%	10.54%	6.66%	102.0%
t-1	Year of rebasing proceeding	5.50%	0.33%	4.90%	-0.27%	0.68%	99.8%
t-0	Rebasing year	13.18%	6.85%	12.31%	5.98%	4.23%	110.2%
	Averages						
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**2.58%**	**-3.77%**	**1.84%**	**-4.51%**	**-2.15%**	**95.91%**
	Later Rate Cycle Years (t-2, t-1) [B]	**10.96%**	**5.58%**	**10.37%**	**4.99%**	**3.67%**	**100.91%**
	Difference [A] - [B]	**-8.38%**	**-9.34%**	**-8.53%**	**-9.50%**	**-5.82%**	**-5.00%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**11.74%**	**6.02%**	**11.05%**	**5.34%**	**3.86%**	**104.00%**
	Difference [A] - [C]	**-9.16%**	**-9.79%**	**-9.21%**	**-9.85%**	**-6.01%**	**-8.09%**

Table 1d

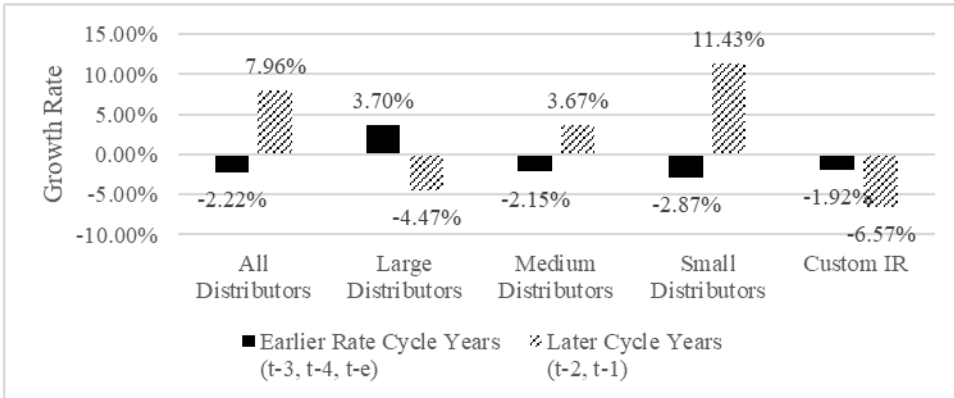
Capex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

Small Distributors

Rate Cycle Year	Comments on Rate Cycle Years	Capex Growth: Nominal All Observations	Capex Growth: Real All Observations	Unit Capex: Nominal All Observations	Unit Capex: Real All Observations	Unit Capex: Real, Complete Cycles Only: Index Growth	Unit Capex: Real, Complete Cycles Only: Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	5.65%	-0.49%	4.95%	-1.19%	4.24%	102.2%
t-4	4 years before next rebasing	3.34%	0.04%	2.16%	-1.14%	-9.17%	91.6%
t-3	3 years before next rebasing	2.73%	-2.41%	2.01%	-3.13%	-2.12%	87.0%
t-2	2 years before next rebasing	10.70%	3.96%	10.05%	3.31%	11.17%	101.5%
t-1	Year of rebasing proceeding	21.48%	15.99%	20.78%	15.29%	11.69%	111.9%
t-0	Rebasing year	-6.18%	-10.96%	-6.93%	-11.71%	-14.48%	100.6%
	Averages						
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**4.37%**	**-0.90%**	**3.57%**	**-1.71%**	**-2.87%**	**91.73%**
	Later Rate Cycle Years (t-2, t-1) [B]	**15.70%**	**9.54%**	**15.03%**	**8.86%**	**11.43%**	**106.73%**
	Difference [A] - [B]	**-11.33%**	**-10.44%**	**-11.46%**	**-10.57%**	**-14.30%**	**-15.00%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**8.98%**	**3.24%**	**8.28%**	**2.54%**	**2.79%**	**104.70%**
	Difference [A] - [C]	**-4.61%**	**-4.14%**	**-4.72%**	**-4.25%**	**-5.66%**	**-12.98%**

Figure 2

Real Unit Capex Growth Patterns by Rate Cycle Year: Complete Cycles Only, 2014-2023[13]



Tables 1b-1d itemize results for large, medium, and small distributors, while Figure 2 presents summary results comparing the real unit capex growth in earlier years to later years of completed rate cycles. It can be seen that the pattern of accelerating capex growth in later plan years was typical of medium-sized and (especially) small distributors but not of the four largest distributors (Alectra, HONI, Hydro Ottawa, and THESL).[14] This may reflect the greater need that larger distributors had for capex but it may also reflect the success of larger distributors in obtaining supplemental capital revenue. Caution should be exercised when examining the results table for large distributors due to the small sample size. Only four distributors with three complete cycles and some extra years of observations were used to tabulate these results.

Table 1e presents the capex patterns of distributors that had approved Custom IR plans. It can be seen that there was no tendency for distributors to spend more in the later cycle years than the earlier cycle years. Only one of the five distributors with approved Custom IR plans exhibited a pattern where late cycle capex growth was more rapid. Custom IR may have significantly influenced the patterns of these distributors.

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[13] Custom IR distributors are not mutually exclusive from large or medium distributors.
[14] Alectra Utilities has been operating under a deferred rebasing that stems from a merger.

Table 1e

Capex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

Custom IR

Rate Cycle Year	Comments on Rate Cycle Years	Capex Growth		Unit Capex			
		Nominal	Real	Nominal	Real		
		All Observations	All Observations	All Observations	All Observations	Complete Cycles	
						Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	-15.79%	-17.50%	-16.29%	-18.00%	-18.00%	126.3%
t-4	4 years before next rebasing	3.58%	-0.65%	2.85%	-1.37%	0.30%	92.4%
t-3	3 years before next rebasing	4.02%	-2.88%	3.26%	-3.64%	5.50%	95.9%
t-2	2 years before next rebasing	24.39%	17.85%	23.78%	17.23%	24.31%	125.9%
t-1	Year of rebasing proceeding	-29.81%	-36.81%	-30.45%	-37.46%	-37.46%	84.8%
t-0	Rebasing year	9.42%	-0.14%	8.67%	-0.90%	-0.90%	85.2%
	Earlier Rate Cycle Years (e.g., t-e, t-4, t-3) [A]	**0.21%**	**-2.76%**	**-0.22%**	**-3.18%**	**-1.92%**	**101.58%**
	Later Rate Cycle Years (e.g., t-2, t-1) [B]	**-2.71%**	**-9.48%**	**-3.34%**	**-10.11%**	**-6.57%**	**105.34%**
	Difference [A] - [B]	**2.91%**	**6.72%**	**3.12%**	**6.93%**	**4.65%**	**-3.75%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**1.34%**	**-6.37%**	**0.66%**	**-7.04%**	**-4.68%**	**98.63%**
	Difference [A] - [C]	**-1.13%**	**3.61%**	**-0.88%**	**3.86%**	**2.76%**	**2.95%**

Figure 3 sheds additional light on the capex results. Note first that 26 of the 45 complete rate cycles exhibited capex surges in later plan years. While this is the majority, capex spending surges did not occur in a sizable 42% of the complete rate cycles.

Figure 3

Relationship Between Distributor Underearning and Capex Patterns*

Complete Cycles Only, 2014-2023

Skewed Spending Pattern?			
Yes		No	
26 (58%)		19 (42%)	
14	12	5	14
Yes	No	Yes	No
Underearning?			

* Underearning for this study is defined as an average earned ROE over plan term below 7%.

Figure 3 also provides details on the relationship between skewed capex and underearning during MRPs. Underearning was defined as a local distribution company ("LDC") averaging an earned ROE over the plan term of less than 7%. A 7% ROE is approximately 200 basis points less than the 8.95% average allowed ROE for the 2014-2023 period. Low ROEs could cause distributors to cut capex and to delay the capex that is undertaken to later plan years.

Inspecting the results, it can be seen that nineteen of forty-five rate cycles met this study's definition of LDC underearning.[15] About half of the complete rate cycles involving skewed capex also involved underearning. The great majority (14) of distributors that underearned had late plan capex surges. Roughly half of the distributors that did *not* experience material underearning also had late plan capex surges. Thus, late plan capex surges were especially prevalent when distributors underearned.

2.3 Opex Spending Patterns

Results of our OM&A spending pattern analysis can be found in Tables 2a-2e and Figure 4. Table 2a shows that the average annual growth rates in opex, real opex, unit opex, and real unit opex growth in years t-3, t-4, and t-e of the rate cycle were somewhat slower than those in later years. In complete cycles, for example, the real unit opex of distributors averaged 1.16% annual *declines* in years t-3, t-4, and t-e, but averaged 0.07% annual *growth* in years t and t-1 and 0.03% annual *growth* in years t-0, t-1, and t-2. Similar results held for all sorted observations.

[15] All but one of the distributors that underearned was municipally owned.

For the cost growth differences row [A-B] in Table 2a, PEG calculated t-tests of the equality of means of the real unit opex growth, and the index level compared to the complete cycle average in the early years against the later years. The opex spending pattern t-tests were statistically suggestive but not highly significant, with estimates between 75% and 89% significance. The less pronounced spending pattern for opex could reflect, in part, differences discussed in Section 7 below in how MRPs affect opex and capex spending patterns. In particular, we discuss there that there is a special reason for capex to be high in year t-1.

Table 2a

Opex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

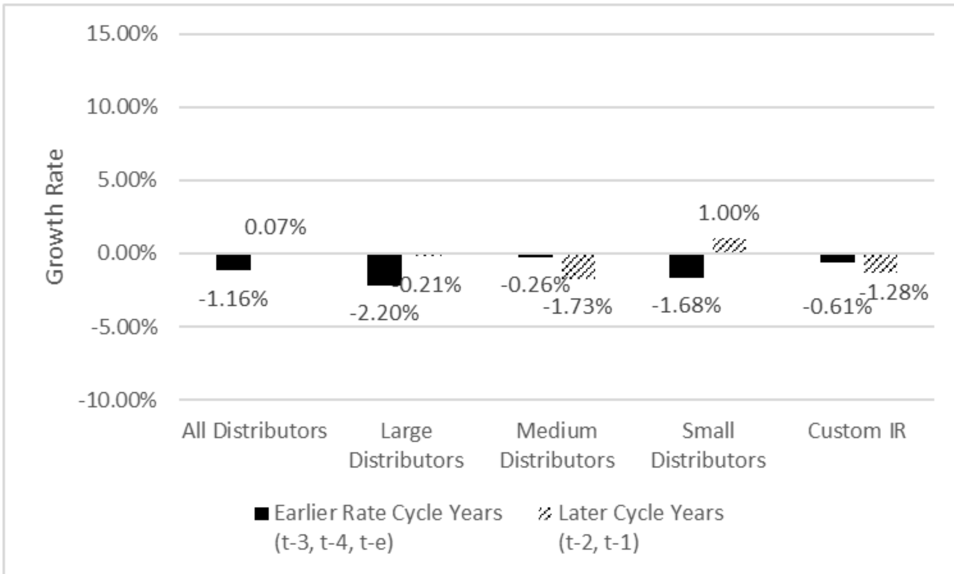
All Distributors

Rate Cycle Year	Comments on Rate Cycle Years	OM&A Cost Growth				OM&A Unit Cost Growth			
		Nominal	Real			Nominal	Real		
		All Observations	All Observations	Complete Cycles		All Observations	All Observations	Complete Cycles Only	
				Growth	Index Level Relative to Complete Cycle Average			Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	2.65%	-0.20%	0.07%	98.8%	2.08%	-0.78%	-0.46%	100.2%
t-4	4 years before next rebasing	2.12%	-0.53%	0.30%	101.6%	1.39%	-1.26%	-0.43%	102.1%
t-3	3 years before next rebasing	2.44%	-0.35%	-1.63%	99.4%	1.91%	-0.87%	-2.13%	100.0%
t-2	2 years before next rebasing	2.71%	-0.24%	-0.63%	98.7%	2.22%	-0.73%	-1.02%	98.7%
t-1	Year of rebasing proceeding	4.08%	1.32%	1.61%	100.3%	3.55%	0.79%	1.15%	99.8%
t-0	Rebasing year	3.22%	0.67%	0.58%	101.1%	2.60%	0.05%	-0.06%	99.8%
	Averages								
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**2.48%**	**-0.31%**	**-0.58%**	**99.91%**	**1.89%**	**-0.91%**	**-1.16%**	**100.71%**
	Later Rate Cycle Years (t-2, t-1) [B]	**3.36%**	**0.50%**	**0.49%**	**99.53%**	**2.85%**	**-0.01%**	**0.07%**	**99.24%**
	Difference [A] - [B]	**-0.87%**	**-0.81%**	**-1.07%**	**0.38%**	**-0.96%**	**-0.90%**	**-1.23%**	**1.47%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**3.31%**	**0.56%**	**0.52%**	**100.05%**	**2.77%**	**0.01%**	**0.03%**	**99.42%**
	Difference [A] - [C]	**-0.83%**	**-0.87%**	**-1.10%**	**-0.14%**	**-0.88%**	**-0.92%**	**-1.19%**	**1.29%**

Figure 4

Unit Opex Growth Patterns by Rate Cycle Year:

Complete Cycles Only, 2014-2023[16]



Tables 2b-2d itemize opex growth results for large, medium, and small distributors. It can be seen that opex growth tended to be more rapid in later plan years for small distributors but was slower for medium-sized distributors.[17] Results for large distributors were mixed.

Table 2e presents results on the opex patterns of distributors that received approval of Custom IR plans. Late plan skewing of opex is not evident in the *averages*. However, three of the five distributors with complete Custom IR plan cycles did exhibit a skewed opex pattern.

Figure 5 sheds additional light on the opex spending patterns. Note first that twenty-five of the forty-five complete rate cycles exhibited opex surges in later plan years. Thus, these surges were about as common for opex than for capex.

Figure 5 also provides details as to the relationship between skewed opex and underearning. Most of the cycles with skewed spending patterns did not involve underearning. Of the 26 cycles that did not involve low ROE, we found that around 58% had late plan opex surges. Of the 19 plan cycles that did involve underearning, around 53% fit the anticipated

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[16] Custom IR distributors are not mutually exclusive from large or medium distributors.
[17] All opex trends of medium-sized distributors were actually more rapid in early plan years.

spending pattern. Thus, late plan opex surges had about the same frequency whether or not distributors were underearning.

The difference between average opex growth in early and late plan years was less pronounced and was not highly significant than for capex. However, when spending patterns *were* skewed, the difference between early and late year growth in real unit opex averaged a material 7.20%.

Table 2b

Opex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

Large Distributors

Rate Cycle Year	Comments on Rate Cycle Years	**OM&A Cost Growth**				**OM&A Unit Cost Growth**			
		Nominal	Real			Nominal	Real		
		All Observations	All Observations	Complete Cycles		All Observations	All Observations	Complete Cycles Only	
				Index Growth	Index Level Relative to Complete Cycle Average			Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	2.27%	-1.17%	na	na	1.85%	-1.59%	na	na
t-4	4 years before next rebasing	3.62%	1.43%	-1.64%	101.1%	3.06%	0.87%	-2.12%	102.4%
t-3	3 years before next rebasing	3.92%	0.33%	-1.69%	99.6%	3.31%	-0.27%	-2.28%	100.2%
t-2	2 years before next rebasing	0.13%	-2.75%	-0.91%	98.6%	-0.41%	-3.29%	-1.46%	98.7%
t-1	Year of rebasing proceeding	6.23%	2.97%	1.77%	100.3%	5.48%	2.22%	1.04%	99.7%
t-0	Rebasing year	2.45%	-0.49%	-0.06%	100.4%	1.72%	-1.22%	-0.72%	99.1%
	Averages								
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**3.21%**	**0.11%**	**-1.67%**	**100.35%**	**2.69%**	**-0.41%**	**-2.20%**	**101.29%**
	Later Rate Cycle Years (t-2, t-1) [B]	**2.84%**	**-0.21%**	**0.43%**	**99.46%**	**2.21%**	**-0.84%**	**-0.21%**	**99.17%**
	Difference [A] - [B]	**0.37%**	**0.33%**	**-2.10%**	**0.89%**	**0.48%**	**0.43%**	**-1.99%**	**2.11%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**2.68%**	**-0.32%**	**0.27%**	**99.77%**	**2.01%**	**-0.99%**	**-0.38%**	**99.14%**
	Difference [A] - [C]	**0.52%**	**0.43%**	**-1.93%**	**0.59%**	**0.67%**	**0.58%**	**-1.82%**	**2.15%**

Note: [A] includes all observations for rate cycle years t-3, t-4, and t-e where there are t-e observations available. Otherwise [A] only includes rate cycle years t-4 and t-3.

Table 2c

Opex Patterns of Ontario Electricity Distributors by Rate Cycle Year 2014-2023:

Medium-Sized Distributors

Rate Cycle Year	Comments on Rate Cycle Years	OM&A Cost Growth				OM&A Unit Cost Growth			
		Nominal	Real			Nominal	Real		
		All Observations	All Observations	Complete Cycles		All Observations	All Observations	Complete Cycles Only	
				Index Growth	Index Level Relative to Complete Cycle Average			Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	4.14%	1.22%	1.79%	100.8%	3.47%	0.55%	1.21%	102.3%
t-4	4 years before next rebasing	1.68%	-0.64%	-0.22%	102.5%	1.25%	-1.08%	-0.70%	103.2%
t-3	3 years before next rebasing	2.27%	-0.80%	-1.00%	100.9%	1.83%	-1.25%	-1.45%	101.0%
t-2	2 years before next rebasing	3.10%	-0.06%	-0.93%	99.9%	2.67%	-0.50%	-1.31%	99.7%
t-1	Year of rebasing proceeding	1.67%	-1.20%	-1.75%	98.2%	1.21%	-1.66%	-2.16%	97.6%
t-0	Rebasing year	2.49%	-0.44%	-0.43%	98.0%	1.82%	-1.11%	-1.00%	96.4%
	Averages								
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**3.21%**	**0.38%**	**0.25%**	**101.32%**	**2.64%**	**-0.19%**	**-0.26%**	**102.16%**
	Later Rate Cycle Years (t-2, t-1) [B]	**2.37%**	**-0.65%**	**-1.34%**	**99.09%**	**1.92%**	**-1.10%**	**-1.73%**	**98.68%**
	Difference [A] - [B]	**0.84%**	**1.02%**	**1.59%**	**2.23%**	**0.72%**	**0.90%**	**1.48%**	**3.47%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**2.41%**	**-0.57%**	**-1.03%**	**98.71%**	**1.88%**	**-1.10%**	**-1.49%**	**97.92%**
	Difference [A] - [C]	**0.80%**	**0.95%**	**1.28%**	**2.61%**	**0.75%**	**0.91%**	**1.23%**	**4.24%**

Table 2d

Opex Patterns of Ontario Electricity Distributors By Rate Cycle Year 2014-2023:

Small Distributors

Rate Cycle Year	Comments on Rate Cycle Years	OM&A Cost Growth				OM&A Unit Cost Growth			
		Nominal	Real			Nominal	Real		
		All Observations	All Observations	Complete Cycles		All Observations	All Observations	Complete Cycles Only	
				Index Growth	Index Level Relative to Complete Cycle Average			Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	1.85%	-0.93%	-1.91%	96.4%	1.31%	-1.46%	-2.39%	98.0%
t-4	4 years before next rebasing	2.13%	-0.76%	0.97%	101.1%	1.22%	-1.67%	0.03%	101.3%
t-3	3 years before next rebasing	2.35%	-0.23%	-1.94%	98.7%	1.79%	-0.78%	-2.45%	99.5%
t-2	2 years before next rebasing	2.82%	-0.06%	-0.45%	98.1%	2.31%	-0.56%	-0.82%	98.1%
t-1	Year of rebasing proceeding	4.90%	2.24%	3.27%	101.4%	4.36%	1.70%	2.82%	101.0%
t-0	Rebasing year	3.67%	1.35%	1.15%	102.7%	3.09%	0.77%	0.49%	101.6%
	Averages								
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**2.04%**	**-0.70%**	**-1.05%**	**98.89%**	**1.42%**	**-1.32%**	**-1.68%**	**99.70%**
	Later Rate Cycle Years (t-2, t-1) [B]	**3.78%**	**1.00%**	**1.41%**	**99.76%**	**3.27%**	**0.49%**	**1.00%**	**99.55%**
	Difference [A] - [B]	**-1.74%**	**-1.71%**	**-2.45%**	**-0.86%**	**-1.84%**	**-1.81%**	**-2.68%**	**0.15%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**3.75%**	**1.11%**	**1.32%**	**100.75%**	**3.21%**	**0.57%**	**0.83%**	**100.22%**
	Difference [A] - [C]	**-1.71%**	**-1.81%**	**-2.37%**	**-1.86%**	**-1.79%**	**-1.89%**	**-2.51%**	**-0.52%**

Table 2e

Opex Patterns of Ontario Electricity Distributors By Rate Cycle Year 2014-2023:

Custom IR

Rate Cycle Year	Comments on Rate Cycle Years	OM&A Cost Growth				OM&A Unit Cost Growth			
		Nominal	Real			Nominal	Real		
		All	All	Complete Cycles		All	All	Complete Cycles	
		Observations	Observations	Index Growth	Index Level Relative to Complete Cycle Average	Observations	Observations	Index Growth	Index Level Relative to Complete Cycle Average
t-e	Any earlier years (e.g., t-5) before next rebasing	4.73%	3.33%	3.33%	102.2%	4.35%	2.95%	2.95%	103.1%
t-4	4 years before next rebasing	2.27%	0.25%	-2.07%	101.1%	1.71%	-0.31%	-2.57%	102.1%
t-3	3 years before next rebasing	3.99%	0.81%	-0.21%	101.0%	3.41%	0.23%	-0.78%	101.4%
t-2	2 years before next rebasing	-0.25%	-3.00%	-3.22%	97.8%	-0.72%	-3.47%	-3.75%	97.6%
t-1	Year of rebasing proceeding	5.60%	1.69%	1.69%	99.4%	5.11%	1.19%	1.19%	98.8%
t-0	Rebasing year	3.96%	-0.05%	-0.05%	99.4%	3.37%	-0.63%	-0.63%	98.2%
	Earlier Cycle Years (e.g., t-3, t-4, t-e) [A]	**3.41%**	**1.02%**	**-1.60%**	**101.3%**	**2.88%**	**0.49%**	**-0.61%**	**102.1%**
	Later Rate Cycle Years (e.g., t-2, t-1) [B]	**2.41%**	**-0.87%**	**-0.99%**	**98.5%**	**1.93%**	**-1.35%**	**-1.28%**	**98.2%**
	Difference [A] - [B]	**1.00%**	**1.89%**	**-0.61%**	**2.79%**	**0.95%**	**1.84%**	**0.67%**	**3.83%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**2.89%**	**-0.61%**	**-0.53%**	**98.86%**	**2.38%**	**-1.13%**	**-1.06%**	**98.22%**
	Difference [A] - [C]	**0.52%**	**1.64%**	**-1.07%**	**2.45%**	**0.50%**	**1.61%**	**0.46%**	**3.84%**

Figure 5

Relationship Between Distributor Opex Underearning and Patterns*

Complete Cycles Only, 2014-2023

Skewed Spending Pattern?			
Yes		No	
25 (56%)		20 (44%)	
10	15	9	11
Yes	No	Yes	No
Underearning?			

* Underearning defined as an average earned ROE over plan term below 7%.

2.4 Other Requested Metrics

Table 3 contains results for other metrics requested in the statement of work for this project. The table provides average growth rates by rate cycle year for real and nominal capital and total cost, the ratio of capex to opex, achieved ROE, and the ratio of capex to depreciation expenses. The results are for all sorted observations and not just for complete rate cycles. The capital cost and total cost metrics were computed using the monetary approach to capital cost calculations that is often used in statistical benchmarking and productivity trend research.

Capital Cost and Total Cost

PEG believes that a focus on OM&A and capital expenditures provides the best evidence that MRPs with standard rebasings skew spending patterns because these costs are more controllable by utilities in the short run. Capital cost and total cost both reflect many years of historical capex that are insensitive to which year it is in the rate cycle. Inspecting Table 3, it can nonetheless be seen that both nominal and real capital cost and total cost tended to grow more rapidly on average in later years of rate cycles.

Table 3

Spending Patterns of Ontario Electricity Distributors:

Other Metrics by Rate Cycle Year 2014-2023

(Growth Rates)

Rate Cycle Year	Comments on Rate Cycle Years	Capital Cost		Total Cost		Capex / Opex		Opex / Totex	Capex / Depreciation		Achieved ROE
		Nominal	Real	Nominal	Real	Ratio	Growth	Ratio	Ratio	Growth	Percent
t-e	Any earlier years (e.g., t-5) before next rebasing	1.69%	0.16%	2.08%	0.00%	1.74	1.06%	60.6%	2.56	3.83%	7.97%
t-4	4 years before next rebasing	-0.23%	0.86%	1.03%	0.37%	1.83	0.40%	58.7%	2.61	-0.96%	8.23%
t-3	3 years before next rebasing	1.54%	0.38%	1.93%	0.08%	1.78	-0.80%	60.0%	2.45	-0.23%	7.78%
t-2	Historical reference year for rebasing	4.41%	0.44%	3.36%	0.19%	1.95	6.91%	58.6%	3.06	10.46%	7.19%
t-1	Year of rebasing proceeding	5.13%	1.30%	4.72%	1.54%	1.94	1.37%	56.2%	3.16	9.65%	5.82%
t	Rebasing year	4.07%	1.15%	3.92%	1.13%	1.87	-0.71%	57.9%	2.77	-6.85%	7.18%
	Earlier Rate Cycle Years (t-3, t-4, t-e) [A]	**1.24%**	**0.37%**	**1.81%**	**0.10%**	**1.77**	**0.43%**	**60.0%**	**2.54**	**1.75%**	**7.97%**
	Later Cycle Years (t-2, t-1) [B]	**4.75%**	**0.85%**	**4.01%**	**0.83%**	**1.94**	**4.27%**	**57.46%**	**3.11**	**10.08%**	**6.54%**
	Difference [A] - [B]	**-3.51%**	**-0.48%**	**-2.20%**	**-0.73%**	**(0.17)**	**-3.84%**	**2.58%**	**(0.56)**	**-8.33%**	**1.44%**
	Later Rate Cycle Years (t-2, t-1, t) [C]	**4.53%**	**0.95%**	**3.98%**	**0.93%**	**1.92**	**2.65%**	**57.6%**	**3.00**	**4.57%**	**6.7%**
	Difference [A] - [C]	**-3.29%**	**-0.58%**	**-2.17%**	**-0.83%**	**(0.15)**	**-2.22%**	**2.42%**	**(0.46)**	**-2.82%**	**1.2%**

Capex vs. Opex and Totex

The capex to opex ratio can provide some insight into substitutions between capital and OM&A inputs during MRP rate cycles. It can be seen in Table 3 that the ratio of capex to opex tended to be a little higher in later cycle years and the growth rate of this ratio also tended to be higher. The ratio of opex to total expenses ("totex") shrank a little in later plan years.

Capex vs. Depreciation

Table 3 shows that the ratio of capex to depreciation displayed a similar intertemporal pattern to that of capex to opex. However, this may be more due to the pattern of capex than to any relationship to depreciation.

ROE

Table 3 shows that the reported ROEs of Ontario electricity distributors tended to be modestly higher in early plan years than in later plan years.

2.5 Enbridge Gas Inc.

We also looked for patterns in the OM&A expenses of Enbridge Gas Inc. ("EGI") during its first MRP after the amalgamation of Enbridge Gas Distribution and Union Gas. Useful information for such an assessment can be found in PEG's testimony for OEB Staff in Case EB-2024-0111. In that proceeding, we developed an econometric OM&A cost benchmarking model that we used to compare the company's actual OM&A costs to the model's prediction of these costs.

Table 6 from our report in that proceeding presents econometric benchmarking results for Enbridge for the 2019-2022 period.[18] Each score was calculated as the logarithmic difference between actual and predicted cost.

[18] Lowry, Mark Newton, "Empirical Research for Enbridge Gas IR," in OEB Case EB-2024-0111, Exhibit M3, August 13, 2024, p. 80.

Table 6

Econometric Cost Level Benchmarking Scores

[Actual – Predicted Cost]

Period	Total Cost	Capital Cost	O&M Cost
2019	25.66%	26.74%	11.70%
2020	26.00%	26.29%	14.66%
2021	21.66%	24.72%	1.24%
2022	22.46%	24.09%	3.33%
Annual Averages			
2020-2022	**23.37%**	**25.03%**	**6.41%**

These results shed some light on the spending patterns for EGI. Years 2019, 2020, 2021, and 2022 can be construed as years t-e, t-4, t-3, and t-2 of the rate cycle, respectively. The OM&A cost efficiency growth implied by these results can be found in Table 4 below.

Although the cost performance scores for EGI were consistently below average, the change in these scores is informative. The table shows that EGI achieved notable improvements in capital cost, total cost, and (especially) OM&A expenses in 2021. Because 2021 was year t-3 of the company's rate cycle, this conforms to the spending patterns of many distributors. However, the pattern may also reflect merger savings and effects of the pandemic. The results are consistent with the theory of skewed spending patterns but inconclusive.

Table 4

Inferring EGI's Spending Patterns from Econometric Cost Benchmarking

Calendar Year	**2019**	**2020**	**2021**	**2022**	**Overall Performance Level**
Rate Cycle Year	**t-e**	**t-4**	**t-3**	**t-2**	
Total Cost					
Actual vs. Predicted	25.66%	26.00%	21.66%	22.46%	Below Average
Change in Score		0.34%	-4.34%	0.80%	
Direction of Performance		Slightly Worse	Much Better	Slightly Worse	
Capital Cost					
Actual vs. Predicted	26.74%	26.29%	24.72%	24.09%	Below Average
Change in Score		-0.45%	-1.57%	-0.63%	
Direction of Performance		Slightly Better	Modestly Better	Slightly Better	
OM&A Cost					
Actual vs. Predicted	11.70%	14.66%	1.24%	3.33%	Below Average
Change in Score		2.96%	-13.42%	2.09%	
Direction of Performance		Modestly Worse	Much Better	Modestly Worse	

3. Spending Patterns in White Papers and the Scholarly Ratemaking Literature

3.1 Early Discussions of Utility Incentives

Discussions of how MRPs affect utility spending patterns naturally did not exist before MRPs were a theoretical construct or established ratemaking practice. Ratemaking theorists did, however, discuss how traditional ratemaking practices affect utility performance incentives. Regulatory lag was an important focus. The famous regulatory economist Alfred Kahn stated in his classic 1970 treatise that

> Public utility commissions ought not even to *try* continuously and instantaneously to adjust rate levels in such a way as to hold companies continually to some fixed rate of return; and they probably ought not to try either to hold the rate of return down to the bare cost of capital. The *regulatory lag*-the inevitable delay that regulation imposes in the downward adjustment of rate levels that produce excessive rates of return and in the upward adjustments ordinarily called for if profits are too low is thus to be regarded not as a deplorable imperfection of regulation but as a positive advantage. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites: companies can for a time keep the

higher profits they reap from a superior performance and have to suffer the losses from a poor one.[19]

This commentary is dated only by the implicit assumption that the only alternative to a rebasing is a rate freeze.

Baumol and Klevorick (1970) state that regulatory lag "is potentially of very great significance for economic efficiency in general"[20] and that "regulators have at their disposal an instrument, regulatory lag, of which they have not made much conscious use."[21] These authors noted that, while total net benefits from utility activity may increase with lag due to the stronger performance incentives it provides, utilities may garner a disproportionately large share of benefits.

An absence of regulatory lag is an assumed condition for the well-known Averch-Johnson result that utilities tend to favor capex over opex solutions.[22] This result is intuitively plausible since, if a utility's revenue equals its cost, the only way to boost earnings is to increase investment. It follows that a utility's incentives to favor capex strengthen as a rebasing approaches. The Averch-Johnson literature also implies that it is not necessarily desirable for a utility to minimize its OM&A expenses and that utilities may use too few OM&A inputs.

A notable aside is that Kahn's list of symptoms of utility capex bias includes several that are relevant today. For example, items one and two on his list are "the resistance of many public utility companies to full peak-responsibility pricing which would tend to hold down the expansion of demand at the peak and the consequent justification for capacity" and "a willingness to maintain a large amount of standby capacity."[23] In Ontario, accelerating demand growth from the energy transition and other causes has made rate design and the ratemaking treatment of capacity expansion key issues.

3.2 Early MRP Discussions

A multi-year rate plan is an approach to ratemaking that entails infrequent rebasings of a utility's rates to the cost of its services. Revenue may be escalated during the plan by an attrition relief mechanism ("ARM") that is not linked, like a variance account, to the utility's own cost during the plan. These provisions of MRPs can streamline ratemaking and engender regulatory lag that strengthens utility performance incentives.

[19] Alfred E. Kahn, "The Economics of Regulation: Principles and Institutions," New York: Wiley, 1971, p. 48.
[20] William T Baumol and Alvin K. Klevorick, "Input Choices and Rate of Return Regulation: An Overview of the Discussion," *The Bell Journal of Economics and Management Science*, Autumn 1970, p. 182.
[21] Ibid., p. 185.
[22] Harvey Averch and Leland Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, 1962.
[23] Kahn, op. cit., p. 50.

Starting around 1980, the concept of MRPs and other incentive ratemaking mechanisms for utilities surfaced in the academic literature, and large-scale experiments with MRPs were undertaken. Interest in MRPs was spurred in that decade by complications to traditional cost of service ratemaking ("COSR") that included rapid input price inflation and the emergence of competitive pressures on telecommunications utilities and railroads. MRPs had the potential to address both of these challenges, thereby streamlining ratemaking, as well as the potential to strengthen utility performance incentives. This was also a decade during which industry restructurings and the privatization of public utilities in Great Britain and other countries created an increased need for rate regulation that sparked innovation in ratemaking practices.

In the 1980s there were large-scale experiments with MRPs featuring indexed price caps in the regulation of U.S. railroads and British telecommunications utilities. Indexed price caps began for AT&T in the United States in 1989. Price cap indexes were a form of ARM that used an I–X formula where *I* was measured inflation and *X* was called the X factor. The British approach to indexed price cap design has been called RPI-X, reflecting the use of the Retail Price Index as the inflation measure. The X factor in a British ARM is chosen to help revenue track the expected efficient cost of the utility over the plan period. Cost forecasts are built up from forecasts of component costs, an approach that is sometimes called the "building block" method.

The early incentive ratemaking literature recognized that MRPs can, through a combination of less frequent rate cases and externally based ARMs, strengthen utility performance incentives and streamline ratemaking. However, few contributions to the early literature on MRPs considered the implications of periodic rate rebasings for utility spending patterns. One reason is that some early uses of price caps did not entail regularly scheduled full rebasings of a utility's revenue to its cost. Many of the services to which price caps applied faced growing competition, and rapid productivity growth in some of the industries subject to price caps (e.g., railroads and telcos) reduced the need for rebasings.

Theorists did, however, discuss new ratemaking tools to bolster utility incentives that could potentially influence spending patterns. For example, Laffont and Tirole and other economists explored the implications of asymmetric information for rate regulation.[24] They argued that it is difficult for regulators to gauge the cost containment effort of utilities or the effect of external business conditions on the efficient cost of service. These information asymmetries weaken cost containment incentives of utilities and permit them to extract rents from the ratemaking process. Ratemaking can be improved by offering utilities a well-designed menu of incentive contracts. Jean Tirole later won the Nobel Prize in economics.

Andrei Shleifer was an early proponent of yardstick competition, which uses cost information from other utilities to set rates.[25] Laffont and Tirole stated relatedly that

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[24] Jean-Jacques Laffont and Jean Tirole, *A Theory of Incentives in Procurement and Regulation*, The MIT Press, 1993.
[25] Andrei Shleifer, "A Theory of Yardstick Competition," *Rand Journal of Economics* 16 (3): 319-327, 1985.

> Because informational asymmetries between the regulator and the firm reduce the efficacy of regulation, the regulator ought to use all available information to reduce these asymmetries. One way of learning about the technology parameter is to compare the firm's performance to that of other firms facing a similar technological environment.[26]

Joskow and Schmalensee note that

> Cost norms based on the statistical yardstick notion could be developed by applying econometric techniques to data on hundreds of plants and utilities, along with indices of local wages and raw material prices; such norms could be used as a basis for incentive payments.[27]

The early academic literature on incentive ratemaking also included some skepticism of the extent to which new approaches to ratemaking could drive changes in behavior. Sappington (1980), for example, showed how utilities could game one incentive rate setting mechanism that intrigued academicians. He showed that utilities could try to raise future rates by engaging in pure waste, excessive capitalization, and other strategic tactics.[28]

Interest in using MRPs soon extended to the regulation of utility services that are not subject to much competition or scheduled for decontrol. California energy utilities have typically operated under MRPs since the mid-1980s. The British government was using MRPs in several natural monopoly industries by the early 1990s. In the United States, MRPs were approved in the 1990s for many local telecommunications exchange carriers and for retail services of U.S. energy utilities in states that included Maine, Massachusetts, and New York.

Where MRPs were not part of a transition to competition there was more interest in periodically rebasing the revenue of utilities to their cost. Turner and Sappington recently called this practice "standard rebasing".[29] In Great Britain, rebasing might periodically involve resetting a utility's initial rates (P_0) and the X factor in the RPI – X formula of its next plan to reflect a multi-year forecast of its cost. In North America, it might involve setting a utility's revenue requirement equal to its prudently incurred cost in the first year (if not in later years) of the next plan.

Academicians were soon discussing the likelihood and implications of periodic full rebasings. For example, Brennan (1991) envisioned that in the future, the

[26] Laffont and Tirole, op. cit., p. 84.
[27] Paul Joskow and Richard Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal of Regulation* 4:1-49, 1986.
[28] David Sappington, "Strategic Firm Behavior Under a Dynamic Regulatory Adjustment Process," *The Bell Journal of Economics*, Spring 1980.
[29] Douglas Turner and David Sappington, "Motivating Cost Reduction in Regulated Industries with Rolling Incentive Schemes," Department of Economics, University of Florida, December 2024, p. 21.

legal or political inability of the government to commit over time to permit the regulated firm to either lose money or earn supranormal profits will lead to price caps becoming more like conventional regulation.[30]

and that

> the most a regulator may be able to achieve is an institutionalized "regulatory lag," in which a firm can reduce its costs without fearing imminent price deductions from the regulator, but the regulator will subject the firm to periodic review with action taken on the basis of achieved profit.[31]

Brennan concluded that "the advantages of price caps will be greatest as part of a regulatory regime designed for elimination in the near future," [32] as in a utility industry transitioning to competition.

Theorists increasingly noted that rebasings weakened utility performance incentives. Beesley and Littlechild, for example, noted in a 1989 paper that

> The level of *X* [in a British MRP] must in practice be set and repeatedly adjusted to secure a reasonable rate of return. If not, allocative inefficiencies will arise (from prices being out of line with costs), and there will be political pressures from company or consumers. If the criteria for revising *X* are left unclear, this will increase the cost of capital and/or discourage investment. Clear guidelines must therefore be laid down, or must emerge from precedent for resetting *X*. These guidelines will have to embody explicit feedback from cost reduction to (eventual) price reduction. This will negate the superior incentive effects claimed for *RPI - X*. Specifically, companies may believe that the short-term advantages of increased efficiency and lower costs will be more than offset by a tougher *X* and therefore lower prices in the next period and may even induce an adverse change of *X* within the current period. In this view, *RPI - X* is merely a special form of rate-of-return control, embodying no significant net advantage over the U.S. approach on grounds of economic efficiency.[33]

These authors further noted that "shortening the review period would reduce risk but would also reduce the scope and incentive for cost savings."[34] Sappington commented relatedly in a 2000 paper that MRPs with periodic full rebasings would not create stronger performance

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[30] Timothy Brennan, "Regulating by Capping Prices," M.A. Einhorn (ed.), Price Caps and Incentive Regulation in Telecommunications, Kluwer Academic Publishers, 1991, p. 33.
[31] Ibid., p. 41.
[32] Ibid., p. 41.
[33] M. E. Beesley and S.C. Littlechild, "The Regulation of Privatized Monopolies in the United Kingdom," *RAND Journal of Economics*, Vol 20, No. 3, Autumn 1989, p. 456.
[34] Ibid., p. 463.

incentives than traditional ratemaking if these rebasings occurred at the same frequency as in traditional ratemaking.[35]

> Vickers and Yarrow noted in a 1988 book on British utility ratemaking that Regulatory lag allows the firm to appropriate the benefits of improved cost efficiency until the next review occurs. A longer lag increases the firm's incentives to reduce its costs by innovation or superior organization of factors of production, but it delays the time at which consumers benefit from this greater efficiency. On the other hand, a shorter lag means that consumers benefit sooner, but the incentive to cut costs is reduced.[36]

Joskow and Schmalensee have written of Britain's MRPs that

> In practice the system came to involve regularly scheduled true-up proceedings in which the regulator evaluated whether the utility's earnings were adequate or excessive and adjusted initial prices and X accordingly. Thus RPI-X regulation for electric distribution companies is properly viewed as a form of COSR, albeit an important and interesting form, not an alternative to it. The RPI-X regulatory formula has been much more successful in the regulation of landline telephone regulation where competition has emerged and reliance on the legacy landline networks has declined significantly."[37]

3.3 Spending Pattern Discussions

As MRPs bookended by rebasings proliferated, ratemaking theorists began to discuss the impact of these rebasings on utility spending patterns. Vickers and Yarrow wrote that

> as time passes the firm's calculations will be increasingly affected by the benefit to be gained from influencing the outcome of the next regulatory review. As that time approaches, the firm will have little or no incentive to reduce costs if its future prices are positively related to its current cost level. Indeed, a point would then arise when the immediate gain from cost reduction was so short-lived as to be outweighed by the cost of having to face lower prices for the whole of the period until the following price review. … the firm would come to favor *higher* costs when regulatory review is close at hand.[38]

Experience with utility spending patterns that are consistent with this theory soon accumulated.

Pint (1992) presented a stylized MRP model with an explicit multiyear framework and showed that, while MRPs generally increase cost efficiency, if they are scheduled to end with a

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[35] David Sappington, "Price Regulation and Incentives," *Handbook of Telecommunications Economics*, edited by Martin Cave, Sumit Majumdar, and Ingo Vogelsang, North-Holland, 2002, p. 21.
[36] John Vickers and George Yarrow, "Privatization: An Economic Analysis," The MIT Press, 1988, p. 86.
[37] Paul Joskow and Richard Schmalensee, "Cost of Service Regulation of Electricity Distribution Services in the U.S." Massachusetts Institute of Technology, March 2, 2024, p. 25. Published as Chapter 3 in the *Handbook on Electricity Regulation*, Jan-Michel Glachant, Michael Pollitt, and Paul Joskow, Editors. Edward Elgar Press, 2025.
[38] Vickers and Yarrow, op. cit., p. 87.

rate rebasing that uses a recent historical reference year, utilities will boost their capex in later plan years, reducing customer benefits. She showed that MRPs would be much more favorable to customers if regulators considered utility costs and profits in multiple historical reference years when rebasing rates. We discuss this option further in Section 8 below. Pint concluded that "the timing of regulatory hearings and the use of average rather than [single] test-year costs can have important effects on the regulated price and on capital and effort distortions."[39]

Jamasb, Nillesen, and Pollitt (2004) discussed strategic tactics of utilities, defining them as

> the type of behaviour that aims to increase profits without achieving real efficiency gains, i.e., they defy the incentive purpose of benchmarking, the regulatory objectives of efficient operation, and protection of public interest.[40]

The authors further noted that,

> Some regulation games are associated with the periodic aspect of [rate of return] and incentive-based regulatory reviews through timing of specific types of actions.[41]

An example is

> the form of behaviour that distorts the efficient operation and investment decisions of the firm. For example, the firm might increase its cost base or delay efficiency improvements in periods leading to a new rate case. This type of gaming results in socially inefficient resource allocation and dead-weight loss.[42]

3.4 PEG's Incentive Power Research

Overview

With funding from several utilities and regulatory agencies, PEG has for many years researched the incentive power of alternative systems for setting utility rates. Much of this work was undertaken by Travis Johnson (BS, Massachusetts Institute of Technology and PhD, Stanford Business School) who is now a professor at the University of Texas Business School.

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[39] Ellen M. Pint, "Price Cap versus Regulation in a Stochastic Cost Model," *The Rand Journal of Economics,* Winter 1992, p. 578.
[40] Tooraj Jamasb, Paul Nillesen, and Michael Pollitt, "Strategic behaviour under regulatory benchmarking," *Energy Economics* 26, 2004, p. 826.
[41] Ibid., p. 829.
[42] Ibid., p. 829.

Results of this research were later reported in a U.S. government white paper by Lowry, Makos, and Deason in 2017.[43]

At the core of this research was a mathematical optimization model of the cost management of a company subject to rate regulation. We considered a company facing business conditions resembling those of a medium-sized energy distributor.[44] The model was calibrated when the typical productivity growth rates of energy distributors were more rapid than they are now, but we believe that the differences in the predicted cost efficiency growth of the company that result from different ratemaking systems that we considered remain relevant.

While this research does not report spending pattern results for the individual years of an MRP cycle, it is relevant to this project for several reasons. First, the focus is on medium-sized energy distributors that are commonplace in Ontario electricity distribution. Second, we modelled the incentive impact of many of the remedies for suboptimal spending patterns that have been discussed in the ratemaking literature or tried by regulators. Third, we built into the decision problem various kinds of cost containment opportunities that contribute to spending patterns and that have been considered in spending pattern discussions. Fourth, one of the ratemaking options considered is similar to price cap IR. This provides a good point of comparison to alternative ratemaking systems that add various "bells and whistles."

We assumed in model development that two general categories of cost reduction projects were available. Projects of the first type led to one-off (specifically, one-year) cost reductions. Projects of the second type involved a net cost increase in the first year in exchange for *sustained* reductions in future costs. Projects in this category differed in their payback periods. The payback periods that we specified were one year, three years, and five years, respectively. For projects of each kind, there were diminishing returns to additional cost reduction effort in a given year. In total, we permitted eight kinds of projects, four for opex and four for capex. The company could pass up each kind of project in a given year but could not choose *negative* levels of effort that amount, essentially, to deliberate waste. This is tantamount to assuming that such waste would be recognized by the regulator and disallowed.

The company could increase earnings by reducing costs, but we also assumed that its employees incurred distress and other *unaccountable* costs when pursuing such projects. These costs were assumed to occur up front. We assigned these a value that is about one quarter the size of the *accountable* upfront costs of cost reductions. The company was assumed to choose the cost containment strategy that maximizes the net present value ("NPV") of earnings in a

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[43] Mark Newton Lowry, Matthew Makos, and Jeff Deason, Ed. Lisa Schwartz, "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities," for Lawrence Berkeley National Laboratory, July 2017.

[44] In the first year of the decision problem, we assumed for our featured calculations that total annual cost was around $500 million for a company of average efficiency. Capital accounted for a little more than half of total cost. The annual depreciation rate was a constant 5 percent, the weighted average cost of capital was 7 percent, and the income tax rate was 30 percent. Some assumptions were made in the model to simplify the analysis. There was no inflation or output growth that would cause cost to grow over time. The utility's revenue was the same year after year in the absence of a rate case.

given year less the distress costs to employees of performance improvement given the regulatory system, income tax rate, and available cost reduction opportunities.[45]

Numerical analysis was used to predict the utility's optimal strategy. In this analysis we considered, for each regulatory system and each kind of cost containment initiative, thousands of different possible responses by the company. We chose as the predicted strategy the one yielding the highest value for the utility's objective function.

A summary of results from this incentive power research is found in Table 5. For each of several stylized ratemaking systems, the table shows the NPV of cost reductions from repeated operation of the system over many years. The relative incentive power column compares the NPV of savings to those that would result from a complete externalization of rate adjustments. The columns on the right-hand side of the table report the average annual percentage reduction in the company's total cost that results from the regulatory system. We itemize outcomes for the first plan, the second plan, and the long run, and discuss here only the long run results. Key results of our analysis that are mentioned in the discussion below are highlighted in the table.

We produced runs on the assumption of 10%, 30% and 50% levels of initial operating efficiency. Table 5 presents results for the 30% assumption. These are particularly relevant because PEG's statistical cost benchmarking research over many years has suggested that this is a normal level of short-term operating inefficiency. That is to say that the typical utility has a recent cost performance that is 30% below what some utilities have recently been able to achieve in the short run.

Research Results

Reference Regulatory Systems

Inspecting first results for reference regulatory systems, it can be seen that no cost reduction initiatives are undertaken under cost plus ratemaking. This reflects the fact that there is no benefit to the utility for undertaking the cost reduction initiatives, all of which involve some kind of cost.

It can next be seen that if rebasings typically occur every three years, as is common in the absence of MRPs, long-run cost savings have an NPV of about $900 million - a major improvement over cost plus ratemaking but less than half of those that are potentially available with strong incentives. Average annual performance gains in the long run rises by about 90 basis points (from 0% to 0.90%).[46] The fact that some cost savings occur under COSR is not surprising since the assumed typical three-year rate case frequency permits some gains to be

[45] Laffont and Tirole assumed similarly on page 38 of their classic text that "the firm cares about income and effort only" and that its utility increases with the former and falls with the latter.
[46] The model was calibrated to produce this result since 0.90% annual TFP growth was the norm at that time.

reaped from one-off and short payback cost reduction opportunities, and no earnings sharing is assumed apart from income taxes.

Let us next consider an MRP with a five-year term and no earnings sharing. This is particularly important in the Ontario context because it is a stylized version of price cap IR when supplemental capital revenue is unavailable. It can be seen that the NPV of cost savings increases by about 47% and average annual performance gains improve by 51 basis points in the long run. Note that a complete externalization of future rates produces performance improvements relative to a five-year rate cycle with no earnings sharing or extra capital revenue that accelerates average annual performance gains in the long run by an additional 1.30% per year.

Table 5[47]

Results From PEG's Incentive Power Model: 30% Initial Inefficiency

	Net Present Value ($m) of Cost Reductions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Reference Ratemaking Options				
Cost plus	0	**0%**	0.00%	0.00%
2 Year Cost of Service	657	**29%**	1.19%	0.66%
3 Year Cost of Service	899	**39%**	1.22%	0.90%
Full Rate Externalization	2299	**100%**	3.93%	2.71%
Impact of Plan Term				
Term = 3 years	899	**39%**	1.22%	0.90%
Term = 5 years	1318	**57%**	1.93%	1.41%
Term = 6 years	1428	**62%**	1.96%	1.58%
Term = 10 years	1664	**72%**	2.35%	2.23%
Impact of Averaging Multiple Historical Reference Years During Rate Rebasings				
3-Year Plans, Averaging				
No averaging	899	**39%**	1.93%	0.90%
Averaging years = 3	1351	**59%**	1.75%	1.36%
5-Year Plans, Averaging				
No averaging	1318	**57%**	1.93%	1.41%
Averaging years = 3	1302	**57%**	1.65%	1.54%
Averaging years = 5	1576	**69%**	2.04%	1.88%
Impact of Earnings Sharing				
3-year plans, ESM				
No Sharing	899	**39%**	1.93%	0.90%
Company Share = 75%	796	**35%**	1.29%	0.74%
Company Share = 50%	761	**33%**	1.14%	0.67%
Company Share = 25%	662	**29%**	1.03%	0.59%
5-year plans, ESM				
No Sharing	1318	**57%**	1.93%	1.41%
Company Share = 75%	1075	**47%**	1.29%	1.17%
Company Share = 50%	966	**42%**	1.14%	1.01%
Company Share = 25%	879	**38%**	1.03%	0.88%

[47] Results discussed in the text are highlighted for reader convenience.

Table 5 (continued)

Results From PEG's Incentive Power Model: 30% Initial Inefficiency

	Net Present Value ($m) of Cost Reductions	Relative Incentive Power	Average Annual Performance Gain*	
			First two rate cycles	Long run
Impact of ECM1 (Previous Revenue as Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	990	**43%**	1.29%	1.07%
Externalized Percentage = 25%	1336	**58%**	1.80%	1.66%
Externalized Percentage = 50%	1799	**78%**	3.41%	2.15%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1469	**64%**	2.07%	1.55%
Externalized Percentage = 25%	1598	**70%**	2.30%	1.76%
Externalized Percentage = 50%	1989	**86%**	3.00%	2.27%
Impact of ECM2 (Fully Exogenous Benchmark)				
3-Year Plans				
Externalized Percentage = 0%	899	**39%**	1.93%	0.90%
Externalized Percentage = 10%	1535	**67%**	2.26%	1.93%
Externalized Percentage = 25%	1824	**79%**	3.68%	2.29%
Externalized Percentage = 50%	2016	**88%**	3.84%	2.54%
5-Year Plans				
Externalized Percentage = 0%	1318	**57%**	1.93%	1.41%
Externalized Percentage = 10%	1621	**70%**	2.34%	1.80%
Externalized Percentage = 25%	1908	**83%**	3.08%	2.31%
Externalized Percentage = 50%	2109	**92%**	3.57%	2.56%
Rate Option Plans				
3-Year Plans, TFP rate option				
No TFP rate option	899	**39%**	1.93%	0.90%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2.5%	899	**39%**	1.93%	0.90%
5-Year Plans, TFP rate option				
No TFP rate option	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 1%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 1.5%	2299	**100%**	3.93%	2.71%
Yearly rate reduction = 2%	1318	**57%**	1.93%	1.41%
Yearly rate reduction = 2.5%	1318	**57%**	1.93%	1.41%

*** = measured by the average year-over-year percent decrease in costs**

Multiple Historical Reference Years

Consider, next, what happens when rate rebasings use multiple historical reference years instead of focusing on one year late in the rate case cycle. Historical reference years are commonly combined with forward-looking test years in rate rebasings and are not synonymous with the historical test years used in many US ratemaking jurisdictions.[48] Cost in the historical reference year can be normalized and then escalated for inflation and growth in operating scale. Utility rates often reflect a single historical test year that, in the context of an MRP, is usually the penultimate year of the plan. Pint was an early proponent of using multiple historical test years in rebasings between MRPs and we discuss below non-traditional uses of historical reference years in Alberta. Application of this approach in Ontario would be straightforward. Table 5 shows that, using five historical reference years in a five-year rate plan rather than a single historical reference year increases the NPV of cost savings by a further 20% (1.576 m/1.318 m). The annual average performance gain accelerates by 47 basis points in the longer run.

Earnings Sharing

Consider next the impact of adding a symmetrical earnings sharing mechanism ("ESM") with no dead band to an MRP. In plans of a given duration, it can be seen that the addition of such an ESM reduces cost savings compared to a plan with no ESM. The lower is the company's share of earnings variances, the lower are its cost savings. In a five-year plan with 50/50 sharing of earnings variances, it can be seen that long-run average annual performance gains fall by 0.40% annually.[49]

ECM with Revenue Requirement Benchmark

We discuss in the next section the use by several regulators of efficiency carryover mechanisms to address spending pattern concerns. ECMs are discussed further in the remedies section of the report (Section 8). Our Berkeley Lab paper considered two kinds of ECMs. In the first, the revenue requirement at the start of each new plan is based 100 x α% on the predetermined revenue requirement for the last year of the previous plan and 100 x (1- α)% on the actual cost in that year. We consider for illustrative purposes alternative values of α ranging from 10% to 50%. A higher value for α means that utility revenue is more externalized and there is a great opportunity to profit from cost containment activities. We capped the value of α at 50% thinking that any higher value would be impractical.

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[48] Precedents for historical test years are discussed in Mark Newton Lowry, Matthew Makos, Gretchen Waschbusch, and Benjamin Cohen, "Innovative Regulatory Tools for Addressing an Increasingly Complex Energy Landscape: 2023 Update," for Edison Electric Institute, February 2024.

[49] However, plans of longer duration that *have* an ESM can deliver more cost savings than plans of shorter duration that *lack* an ESM. For example, a five-year plan with 50/50 sharing produces about 7% greater savings than COSR with a three-year cycle. One reason that this is notable is that a regulator may use MRPs as much to streamline ratemaking as it does to boost utility performance. An MRP with an ESM could permit streamlining with less risk of extreme earnings outcomes.

Table 5 shows that, in the context of a five-year rate plan, assigning α a weight of 25% (rather than 0% if there is no ECM) increases the NPV of cost savings by about 21% (from 1.318 to 1.598 m). The average annual performance gains for a 5-year plan with a 25% weight on the benchmark rise 35 basis points (from 1.41% to 1.76%) in the long run.

ECM With a Fully External Benchmark

PEG also considered an ECM in which the revenue requirement at the start of each new plan is based α% on an exogeneous benchmark for cost (like that yielded by an econometric model) in the last year of the prior plan and (1- α) on the actual cost in that year. An exogenous benchmark could be produced with statistical cost research. This would be a form of yardstick competition that the OEB is well positioned to implement given its experience with statistical cost benchmarking. We once again consider alternative values of α (the "externalized percentage") that range from 10% to 50%.

Table 5 shows that with a five-year MRP rebasing cycle, the effect on cost reductions of a 25% externalization is material (a roughly 45% increase). This is mainly due to the fact that more of the potential cost savings are achieved by the five-year term. The long-run average annual performance gains in this scenario rise 90 basis points. Thus, an ECM based on external benchmarks can "supercharge" the efficiency gains from a five-year plan.

Incentive-Compatible Menus

We also have considered the use of incentive-compatible menus of ratemaking options. This is the approach championed by Laffont and Tirole and the concept behind the Annual IR index that the OEB has used for many years. It gives the utility the option at the end of the plan to start a new plan without rebasing. The revenue requirement for the next plan in this eventuality is established on the basis of a predetermined formula. The formula we considered in our incentive power research is a stretch factor that reduces the revenue requirement established in the preceding rate case. The company can thus avoid a rebasing if it agrees to a starting revenue requirement for the new plan that regulators believe offers value to customers.

Table 5 shows that, with a 5-year plan and stretch factors of 1% and 1.5%, the rate option approach produces the same dramatic cost efficiency savings and accelerated performance growth that would result from full rate externalization.

4. An Introduction to Capitalization Policy

4.1 Introduction

Utility capitalization policies have generally not received widespread attention in academic literature on accounting. A recent paper noted that

> Utilities and financial institutions are often excluded from accounting research studies because of the unique accounting considerations and the effects of regulation on these two industries. In the last 20 years, we find only three articles that specifically examine utilities in the leading accounting academic journals… and none in the last 15 years. Due to the uniqueness of the accounting for utilities and the direct link between accounting and rates charged to utility consumers, we believe that more accounting research is needed in the utility industry.[50]

In research for this report, PEG reached out to the National Association of Regulatory Utility Commissioners (the U.S. analogue to CAMPUT) and the Edison Electric Institute (analogous to the Canadian Electricity Association) for information on utility capitalization policies. Neither entity said that it was engaged in a careful tracking of these policies. This likely reflects the fact that this is not a hot issue in most jurisdictions. To the extent that either entity has recently considered the topic, treatment of expenditures related to cloud computing has been the noteworthy issue.

Capitalization of a broader range of OM&A expenses has nonetheless sparked interest in some energy utility rate proceedings in recent years. The Averch-Johnson result that utilities tend to favor capex over opex solutions has drawn new interest in an era when aging grids and strengthening demand for electricity raise the risk of excessive capex, and there are substitutes for utility capex in the provision of electricity and natural gas services. In the case of electric utilities, these substitutes include energy conservation, peak load management, distributed energy resources, better vegetation management and facility maintenance, cloud computing and, for vertically-integrated electric utilities, the acquisition of power from independent producers. Vendors of substitutes for utility capex are frequent participants in rate proceedings or fund active stakeholder groups.

To encourage more substitution of cost-effective OM&A for capital inputs, some parties to rate proceedings have advocated increased capitalization of OM&A expenses. The focus of such initiatives has been as narrow as the capitalization of cloud computing expenses and as broad as British-style total expenditure accounting.[51] The extent to which OM&A inputs are

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[50] Brockbank, B., Ha, K., Hill, M.S., Thomas, W.B., "The Power of Accounting: Capitalization of Cloud Computing for Utilities," 2024, pp. 6-7.

[51] See, for example, Brockbank, B., Ha, K., Hill, M.S., Thomas, W.B., "The Power of Accounting: Capitalization of Cloud Computing for Utilities," 2024 and Kaja Rebane and Cara Goldenberg, "How to Restructure Utility

cost effective substitutes for capital equipment changes with technology and the real price of labor. While there is no consensus that increased capitalization of OM&A expenses is wrong, there has been controversy over the appropriate scope of such capitalizations (e.g., whether to capitalize overhead expenses) and on whether a utility's capitalization policies should change in the middle of a plan. Issues surrounding the capitalization of asset repair and field work expenses are discussed in Section 8 below.

4.2 Accounting Standards

Capitalization of opex is limited by accounting standards. Two sets of accounting standards are currently common in Canada: IFRS and U.S. GAAP. IFRS has more clearly defined limitations on capitalization than U.S. GAAP. International Accounting Standard ("IAS") 16 addresses property, plant, and equipment accounting for utilities that use IFRS. This standard explicitly precludes the allocation of administrative and general overhead costs to property, plant, and equipment ("PP&E").[52] The reported opex of many Ontario distributors surged around 2017 due to their transition to IFRS accounting.

Price Waterhouse Coopers describes the guidance provided by U.S. GAAP regarding capitalization policies.

> U.S. GAAP does not currently include any specific guidance on capitalization policies for facilities constructed for a reporting entity's own use. In 2001, the Financial Reporting Executive Committee of the AICPA (FinREC) issued a proposed Statement of Position, Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment. FinREC approved this proposed SOP (referred to herein as the proposed PP&E SOP) in 2003 subject to the FASB's clearance; however, it was not approved for issuance by the FASB and therefore never issued in final form. Nevertheless, the proposed PP&E SOP is often referred to for guidance on cost capitalization.[53]

General guidelines for capitalization policies are provided in Accounting Standards Codification ("ASC") 360 for property, plant, and equipment. This guidance outlines when a capital expense may be recognized, the eligible costs, and what to do if an asset is impaired. A major difference between IFRS and U.S. GAAP is that U.S. GAAP allows companies to capitalize administrative and general overhead expenditures.

Incentives: The Four Pillars of Comprehensive Performance-Based Regulation," RMI, July 2024, https://rmi.org/insight/how-to-restructure-utility-incentivesfour-pillars-of-comprehensive-performance-based-regulation/.

[52] IFRS Foundation, IAS 16 Property, Plant and Equipment, p. A1150.

[53] Price Waterhouse Coopers (2024), "Utilities and power companies guide, Chapter 12: Plant – Updated January 2024", pp. 12-2 and 12-3. Accessed from: https://viewpoint.pwc.com/dt/us/en/pwc/accounting_guides/utilities_and_power_/assets/up12.pdf

Neither IFRS nor U.S. GAAP itemize a specific materiality threshold that an expenditure must exceed to qualify as an asset. This amount is typically set by individual entities based on their judgment. For example, the IFRS Foundation states that IAS 16

> does not prescribe the unit of measure for recognition, i.e. what constitutes an item of property, plant and equipment. Thus judgement is required in applying the recognition criteria to an entity's specific circumstances. It may be appropriate to aggregate individually insignificant items, such as moulds, tools and dies, and to apply the criteria to the aggregate value.[54]

4.3 Capitalization Policies in the U.S. and Ontario

United States

The Federal Energy Regulatory Commission ("FERC") regulates interstate services of U.S. utilities that include electricity and natural gas transmitters, while state regulators address utility retail operations, including distributor services. Federal law requires major investor-owned electric utilities to file the FERC Form 1, which provides detailed data on their operations.[55] Submissions are governed by the FERC's instructions for the Form 1, a Uniform Systems of Accounts, and accounting guidance.

The FERC does not provide specific guidance on utility capitalization policies.[56] For example, the FERC does not specify the minimum dollar amount or size of asset which must be exceeded for an expense to be capitalized. However, the FERC does provide examples of costs that are ineligible for capitalization. The FERC's Uniform System of Accounts for electric utilities includes instructions that require utilities to expense costs from "work performed specifically for the purpose of preventing failure, restoring serviceability, or maintaining life of plant." Utilities are required to treat as maintenance expenses costs that are for "replacing or adding minor items of plant which do not constitute a retirement unit."[57]

The FERC periodically audits jurisdictional utilities to ensure that they are providing reports that are consistent with its accounting regulations. These audits include a review of a utility's capitalization policies. For example, in a 2011 audit of American Transmission Systems the FERC noted that the company's policy of capitalizing costs of expanding existing corridors and of removing danger trees due to inadequate right of way clearances during initial construction was inconsistent with the FERC's accounting regulations, which limited

[54] IFRS Foundation, IAS 16 Property, Plant and Equipment, p. A1146.
[55] Larger interstate gas utilities are required to report on their operations in the FERC Form 2.
[56] The extent of capitalization is known to vary between U.S. utilities.
[57] Title 18, Chapter I, Subchapter C, Part 101, Operating Expense Instructions, 2. Maintenance, Subpart C, Item 9. Title 18, Chapter I, Subchapter F, Part 201, Operating Expense Instructions, 2. Maintenance, Subpart C, Item 8.

capitalization of vegetation management expenses solely to the clearances of the right of way during the initial construction of a transmission line.[58]

State regulators, through NARUC, collaborated with the FERC to establish the Uniform System of Accounts for electric utilities. They usually rely on the FERC Form 1 or a similar form customized to their state for the reporting of electric utility operating data. Capitalization policies are filed irregularly with state regulators.

Ontario

The OEB has had to address several issues with capitalization policies over the past fifteen years. Most utilities have changed their accounting standards at least once, and this has often triggered changes to their capitalization policies. Utility amalgamations have also resulted in changes in capitalization policies. Differences in capitalization policies due to varying accounting standards, particularly related to whether capitalization of overheads is appropriate, have come up in several distributor rate proceedings. Changing operating environments have also led to changes in capitalization policies. Each of these issues is discussed below.

Prior to 2012, most Ontario electricity distributors provided their financial statements in accordance with Canadian GAAP. Most of these distributors now use MIFRS accounting while a few (e.g., Hydro One) use U.S. GAAP accounting.[59]

During the transition from Canadian GAAP to MIFRS or U.S. GAAP, the OEB required utilities to maintain records based on both Canadian GAAP and their new accounting standards. These records were to be maintained from the last rebasing under Canadian GAAP until their first rebasing under the new accounting standard. The OEB also authorized the establishment of generic deferral accounts to account for changes in accounting standards in the switch from Canadian GAAP. These accounts addressed changes in rate base resulting from changes in the treatment of property, plant, and equipment between rebasings that were a result of changing accounting standards and capitalization policies. Amounts in these accounts were reviewed at a subsequent annual rate update proceeding or the next rebasing, with approved amounts added to rate base.

Distributors are required to file their capitalization policies in their rebasing proceedings. There is no analogous requirement that utilities file their capitalization policies as they are updated. For various reasons, utilities sometimes change their capitalization policies during MRPs, and they do not always advise of these changes until the next rebasing. Toronto Hydro revised its capitalization policy three times during its 2015-2019 Custom IR plan and twice during its most recently completed plan.[60]

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[58] FERC Docket No. FA11-8-000
[59] Generally, the ability to rely on U.S. GAAP for Canadian companies is limited to those that have registered securities in the United States.
[60] EB-2023-0195, Exhibit 2A, Tab 4, Schedule 1, Appendix A, p. 2.

Capitalization policy issues have also arisen with utility amalgamations.[61] Under IFRS, the acquired utility must adopt the capitalization policy of the acquiring utility. Under U.S. GAAP, changes may take the form of a "harmonization" of capitalization policies, which allows the successor company to adopt aspects of both capitalization policies. As part of an amalgamation, utility management must determine an appropriate capitalization policy for the surviving entity.

Following the approval of the formation of Alectra Utilities ("Alectra"), the company harmonized the capitalization policies of the predecessor companies under the OEBs Mergers, Amalgamations, Acquisitions, and Divestitures ("MAADs") policy, but did not comment on the financial effects of the harmonization to parties in the MAADs proceeding. Harmonized capitalization policies would allow Alectra to capitalize more opex than previously allowed, as discovered in a subsequent Alectra rate update proceeding.[62]

The OEB ultimately decided to establish deferral accounts to refund to customers the benefits from lower revenue requirements due to the harmonization of capitalization policies for most of the Alectra rate zones, with the disposition of amounts in these accounts to be reviewed and refunded to customers in Alectra's next rebasing.[63] A similar deferral account was established as part of the amalgamation of Union Gas and Enbridge Gas Distribution with balances reviewed during Enbridge Gas Inc's ("Enbridge Gas") first rebasing proceeding. [64] [65]

The OEB has also expressed concerns with some impacts related to the greater ability for utilities to capitalize overheads under U.S. GAAP than MIFRS. This would result in higher plant additions and lower OM&A expenses relative to utilities that relied on MIFRS. This issue has arisen in rebasing proceedings for Enbridge Gas and Hydro One Networks over the years. Both utilities have had to propose and defend appropriate rates for the capitalization of overhead costs in rate proceedings. In the most recent rebasing proceeding of Enbridge Gas, the OEB ultimately decided to reduce the company's capitalization of indirect overheads to zero over a multiyear period.

In recent years, the OEB has also adopted policies to encourage utilities to adopt more cost-effective cloud computing options. In a report for the Board, KPMG reported results of a survey of utilities about cloud computing. KPMG found that

[61] In the case of utility acquisitions, IFRS requires the acquired entity to adopt the capitalization policy of the acquirer.
[62] Ontario Energy Board Case EB-2017-0024
[63] Because PowerStream was the acquiring company, its capitalization policies were unaffected and no deferral account was established for those customers.
[64] The proceeding where the deferral account was established was EB-2017-0306/EB-2016-0307 while the rebasing proceeding was EB-2022-0200 (Phase 1).
[65] Some examples of the harmonization of capitalization policies between Enbridge Gas Distribution and Union involved the capitalization of certain programs by Enbridge Gas Distribution that Union Gas expensed. These include costs related to distribution integrity technology, verification of maximum operating pressure program, integrity digs, and distribution records management. In these cases, Enbridge Gas chose to expense these costs.

> The accounting and regulatory treatments of cloud costs currently appear to be impacting the decision making of utilities when choosing between on-premise and cloud solutions: 69% of utilities see that accounting treatment as a key/major consideration in their decision and 74% see regulatory treatment as a key/major consideration.[66]

The OEB ultimately approved the use of deferral accounts to allow utilities to recover incremental cloud computing implementation costs less savings that resulted from the implementation of cloud computing. Some of these costs were allowed to be capitalized (e.g., construction of a new interface software owned by the utility). To address concerns that U.S. GAAP was more generous in providing utilities the ability to capitalize expenditures, utilities that used U.S. GAAP were required to disclose incremental capital costs that would not be eligible for capitalization if the utility operated under MIFRS accounting.

A few Ontario utilities have changed their capitalization policies more frequently than just to account for the change in accounting standards. For example, in Toronto Hydro's most recent rate case filing, its capitalization policy discussion included a history suggesting that it had been revised nine times since 2008.[67] Utilities operating under U.S. GAAP (e.g., Hydro One and Enbridge Gas) must justify the rates at which they capitalize overhead expenses during rebasings.

Here are some additional features of the OEB's regulation of capitalization policies that merit note.

- Review of capitalization policies focuses primarily on whether a utility's capitalization policy conforms to their accounting standards. These reviews generally do not appraise the justifications for capitalizing expenditures (e.g., based on considerations such as asset behavior, service life, or engineering rationale).

- Reviews of capitalization policies and their application tend to be backwards looking (e.g., focused on costs already incurred and whether those costs were recorded properly), while Ontario rebasing proceedings tend to focus on forecasted costs.

- Capitalization policies that are unchanged from prior rebasing applications are generally accepted without further inquiry.

- If changes are made to capitalization policies or if the policy appears to be materially unusual, the OEB (and intervenors) may ask questions, but there is no systematic process or standard review checklist to inform these questions.

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[66] KPMG, "Cloud Computing Cost: Regulatory Options for the Treatment of Cloud Computing Costs," Report Prepared for the Ontario Energy Board. September 30, 2023, p. 30.
[67] Ontario Energy Board Case EB-2023-0195, Exhibit 2A, Tab 4, Schedule 1, Appendix A, p. 2.

- There is no assessment of whether specific expenditures proposed by a utility will be appropriately capitalized, though the OEB does appraise them for prudence and need. In these cases, the classification of expenditures as capital vs. OM&A is left to the utility's interpretation of its accounting policy.

- There is no unified mechanism or review to consider the implications of capitalization choices, particularly the effects on rate base and return on equity.

- Utilities are not required to file updated capitalization policies if they change during the MRP. There is no monitoring function in place to detect mid-term shifts in capitalization policies.

- The minimum value for an expense to be considered for capitalization is not consistent across utilities.

5. MRP Spending Patterns and Capitalization Policies in Other Jurisdictions

In this section we discuss experience with utility spending patterns and capitalization policies in some jurisdictions where MRPs have been used in ratemaking. Some measures that regulators have taken in these jurisdictions to address skewed spending patterns and capitalization concerns are detailed. It is not our intent to provide here comprehensive reviews of ratemaking in these jurisdictions.[68]

Our review primarily covers jurisdictions in the English-speaking world. The discussion is more suggestive than exhaustive of spending pattern experience, as only a few jurisdictions could cost-effectively be considered in this project. We focus in this section on precedents in Alberta, Australia, Great Britain, and New Zealand. Precedents for California, Chile, and Ireland are discussed in the Appendix.

5.1 Great Britain

Great Britain has had one of the world's most extensive experiences with the MRP approach to ratemaking. MRPs were used to regulate British Telecom beginning in 1983 and have been used to regulate British gas utilities since 1986, water utilities since 1989, and electricity distributors since 1990. Having three different sets of regulators grappling with MRP design challenges encouraged innovation. British MRPs have typically featured five-year terms and the design of ARMs has been heavily influenced by multiyear forecasts of OM&A expenses and capital expenditures.

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[68] Further information about ratemaking in some of these jurisdictions can be found in the "Jurisdictional Review of Utility Remuneration Models for The Ontario Energy Board," by Christensen Associates [Nicholas Crowley, Xueting (Sherry) Wang, and Andi Romanovs-Malovrh], September 2024.

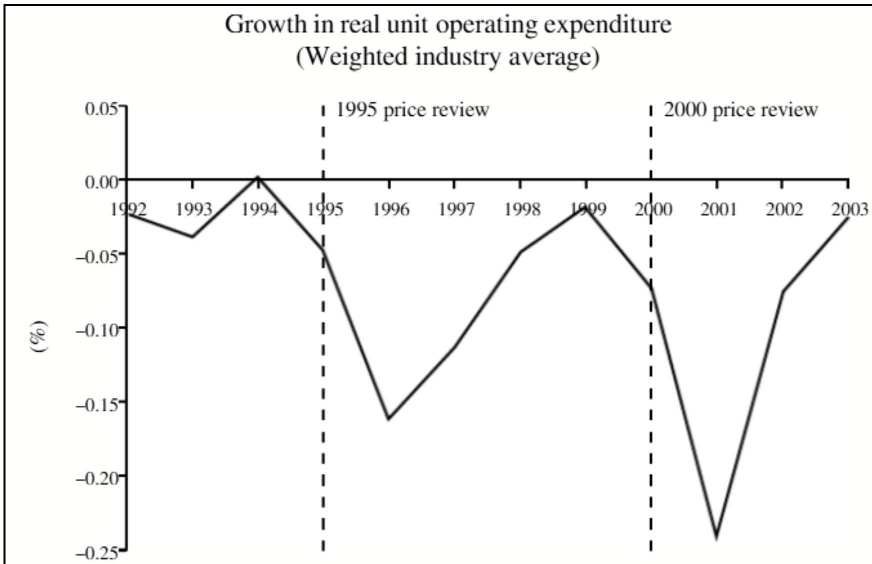
Suboptimal Spending Patterns

In a 2006 chapter of an edited volume, Burns, Jenkins, and Weyman-Jones discuss opex patterns of British electricity distributors subject to MRPs in the 1990s. During earlier MRPs, these distributors were allowed to keep all opex savings between rebasings. The authors' discussion of distributor spending patterns under this ratemaking system merits quotation at some length.

> At each periodic review (1994, 1999 and 2004) the electricity regulator (Ofgem) used data for the penultimate year of the regulatory period as the starting point for determining required operating expenditure in the next period. Adjustments were made to a company's own actual cost data to ensure consistency with other companies in the sector and to ensure that efficiency was improved over the period. But the opening level of allowed operating expenditure at the start of the next regulatory period was closely correlated with the level at the end of the previous period (i.e. the year for which data were available 1992/93, 1998/99 and 2003/04 respectively).
>
> Companies knew that the regulator would base future price caps on historical expenditure levels and a classic ratchet effect problem may have arisen. While, as discussed above, companies had an incentive to make savings during the regulatory period - particularly the early years - they were also faced with an opposite incentive to retain high costs towards the end of the period to signal to the regulator that higher costs were required in the next period. This could be done by hiding cost savings, delaying them to the start of the next period, or transferring them to other input choices (e.g. classifying operating expenditure savings as capital expenditure savings).
>
> The impact can be seen, again, in figure 8.3, where we see that real unit operating costs increased, or at least did not fall as significantly as in other years, towards the end of each regulatory period. The regulator's use of historic information at each review may have therefore provided companies with a distorted incentive that resulted in them revealing biased information about their efficient cost levels. Companies had an incentive to game the regulatory process which may have outweighed, particularly in the last years of the regulatory period, the regulator's objective of encouraging the company to reveal the efficient level of costs.[69]

[69] Phil Burns, Cloda Jenkins and Thomas Weyman-Jones, "Information revelation and incentives," Chapter 8 in the *International Handbook on Economic Regulation*, edited by Michael Crew and David Parker, Edward Elgar Publishing, Inc. 2006, pp. 179-180.

Figure 8.3



Note: Real unit operating expenditure is calculated as turnover minus operating profits minus depreciation, exceptionals, MWCA and loss on disposals.

Source: Companies' annual regulatory accounts and authors' calculations.

Figure 8.3 Annual growth in real unit operating expenditure of electricity distribution network operators in England and Wales

The calculations we made for Ontario electricity distributors and discussed in Section 2 were similar.

Efficiency Carryover Mechanisms

The British Water Services Regulation Authority ("Ofwat" or "the Authority") had a similar experience and pioneered the addition of ECMs to MRPs in hopes of improving spending patterns and efficiency gains. The mechanisms they developed ensured that if utilities achieved incremental efficiency gains in any year of an MRP, they would be able to keep a share of these gains for five years. This would encourage incremental efficiency gains and discourage losses in later plan years. Efficiency gains in these years would raise the revenue requirement in the first few years of the subsequent plan. Customers still benefited insofar as they received *most* of the benefits of the efficiency gains in the early years of the next plan (instead of *all* of the benefits, as in a conventional rebasing) and received all of the benefits in later plan years. Cost efficiencies were measured as the achievement of costs that were lower than the corresponding revenue requirements.

This type of ECM is sometimes called a "rolling" incentive mechanism because the revenue adjustments change from year to year as time advances from the end of the expired plan. Rolling incentive mechanisms were later adopted for some MRPs by Great Britain's energy utility regulator (Ofgem). ECMs of this kind are discussed further in the remedies section of the report (Section 8).

Rolling incentive mechanism did not appear to alter spending patterns for British electricity distributors during the 4th and 5th distribution price control reviews.[70] Ofgem noted

> that the [distributors] have back-loaded expenditure in both the [4th and 5th distribution price control reviews]. One potential explanation for this is that following a price control review, [distributors] pause to reassess and revise their business strategy and renegotiate contracts. A number of the [distributors] have indicated that they restructured in the early stages of the price controls and reviewed and retendered work programmes. Some of the work from earlier years of the price control was deferred to later in the period.[71]

Some distributors nonetheless managed to earn rewards through the rolling incentive mechanisms.

Longer Plan Term

Ofgem launched an RPI-X@20 initiative in 2008 to reconsider its approach to ratemaking. It was concerned that changes to the industry that were underway or expected to occur would not be adequately addressed by the existing regulatory system. These changes included decarbonization; enhanced need for reliability and resiliency; stakeholder concerns about the complexity of the ratemaking system; and affordability. This initiative ultimately resulted in a new approach to ratemaking that Ofgem calls Revenue = Incentives + Innovation + Outputs ("RIIO").

The length of MRP terms was one plan provision reconsidered. Ofgem stated that its standard five-year plan terms were

> geared towards encouraging network companies to adopt delivery approaches and business strategies that minimise costs in the short term, without necessarily providing value for money over the long term.[72]

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[70] In the 4th distribution price control review, the rolling incentive mechanism applied only to capex. As totex accounting was adopted for the 5th distribution price control review, the rolling incentive mechanism applied to the capitalized portion of totex during that MRP.
[71] Ofgem, "Electricity Distribution Company performance 2010 to 2015, Performance Report", 2015, p. 21.
[72] Ofgem, "Regulating energy networks for the future: RPI-X@20 Current thinking working paper: The length of the price control period," 2010, p. 3.

Making matters worse was that

> at a more practical level, the existing price control review processes run for around two years. Holding reviews of this nature for two out of every five years may distract companies' management teams from finding the best ways to run their networks.[73]

Utility management could spend nearly half of an MRP term considering, pleading for, and negotiating features of the next plan. Ofgem struggled with determining what the appropriate length of an MRP should be.

> The length needs to be sufficiently longer than five years to make the change worthwhile. But to go beyond doubling the length seems too radical a step, especially in light of the other changes to the regulatory framework that we envisage….
> Any finite price control period will mean that some decisions have important implications that stretch beyond the end of the current price control period. A price control set for eight or ten years could provide substantial benefits over a five-year control, but would not, in itself, ensure that network companies focus on a sufficiently long period of time.[74]

Ofgem ultimately decided to extend the length of MRPs for regulated utilities from five to eight years for the first generation of RIIO MRPs.

However, Ofgem reversed itself when designing MRPs for the second generation RIIO, stating that

> The uncertainty surrounding network activity in the future makes it difficult to predict the allowances necessary for a range of different activities. We think that this risk is too high to justify retaining the current arrangements of setting price controls for eight years, with a limited scope for a mid-period review to recalibrate elements….
>
> In RIIO-1, we have already observed that things have turned out differently from the assumptions made at the time of setting the price control. Some cost allowances were set too high in hindsight, and some performance targets were set too low. This forecast risk is inherent in ex ante regulation. However, extending the price control to eight years with only a limited scope for an [mid period review], limits our ability to reset certain cost allowances and output targets.
>
> The uncertainty surrounding network activity in the future, even within the next 5-10 years, means it is extremely difficult to predict the allowances necessary for a range of different activities. Forecasts could be wrong to a significant degree and this could harm consumers, or investors. Our experience with RIIO-1 suggests that it may not be possible to anticipate all of the areas where this will arise.[75]

[73] Ofgem, 2010, op. cit., p. 4.
[74] Ofgem, 2010, op. cit., pp. 7-8.
[75] Ofgem, Decision RIIO-2 Framework, op. cit., p. 18.

Most parties to the proceeding agreed with this assessment. Ofgem noted that

> Respondents overwhelmingly supported the proposal to shorten the length of the price control to five years. This was seen to be a sensible precaution at a time of high uncertainty.[76]

Ofgem has not proposed a longer term for the 3rd generation RIIO plans. For gas utilities and power transmission, Ofgem has explicitly endorsed the continuation of MRPs with 5-year terms.[77]

Totex Accounting

Ofwat, as part of a wide-ranging review of its ratemaking policies in 2011, considered whether there was a bias in utility spending in favor of capex. The Authority believed that capex bias could affect the choice of solutions and how that solution is addressed in the utility's accounting. Ofwat defined bias in capitalization *policy* as "a company choosing an optimal solution, but where the costs are categorized differently."[78] It believed that changing cost classifications would not cause operational problems, but would

> indicate that the companies have more to gain by classifying a solution as capex rather than opex by increasing the return they receive from customers through their regulated revenue. An example of this form of bias could involve classifying opex as maintenance or enhancement expenditure.
>
> A company's ability to do this (and hence to increase its revenue) is limited in two ways.
>
> - It has to comply with regulatory accounting guidelines.
> - As part of our regulatory challenge, for the purposes of price setting we reserve the right to reallocate expenditure that has been misallocated because of capitalization policies.[79]

Ofwat undertook several analyses to determine whether there was capex bias and found some evidence of a bias in capitalization policies. Ofwat also believed that the opex rolling incentive mechanism was "increasing the likelihood of a capex bias."[80]

Ofgem has also considered the impact of its MRPs on utility incentives to consider opex and capex solutions. It stated that

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[76] Ofgem, Decision RIIO-2 Framework, op. cit., p. 18.
[77] Ofgem, Decision – Future Systems and Network Regulation Core Document, 2023, p. 11.
[78] Ofwat, "Capex bias in the water and sewerage sectors in England and Wales – substance, perception, or myth? A discussion paper," 2011, p. 19.
[79] Ofwat, op. cit., p. 19.
[80] Ofwat, op. cit., p. 23.

> Current regulatory arrangements may provide [distribution network operators ("DNOs")] with a skewed incentive to solve network performance or constraint problems through further investment in transformers and cables, rather than maintaining existing assets to prolong their life or seeking to reduce or manage load, even when the latter solution is cheaper. This is because, relative to the arrangements for network investment, the DNO can currently keep a much higher proportion of underspend against the regulatory operating cost allowance, and is not able to pass onto customers any of the overspend.
>
> The same incentive arrangements mean that DNOs may invest in high cost "fix and forget" assets that do not require much in the way of maintenance even where there are alternative solutions with lower whole life costs or which bring other benefits. These arrangements also provide DNOs with an incentive to reclassify costs from operating expenditure to network investment where the associated incentives are lower. A significant amount of our time in running the annual cost reporting process is spent on policing the boundaries between these categories…
>
> In some circumstances there may be greater value in delaying investment and extending asset lives until there is greater certainty of the future demands on the networks. This may be more expensive in the short term but could result lower long term charges to customers as there may be fewer stranded assets. As well as having an eye to the total costs customers will need to pay to fund DNO investments, we are concerned to make sure there is no regulatory barrier to DNOs adopting network management arrangements that are compatible with tackling climate change. Some network problems could be addressed by the DNO contracting with [distributed generation] (this could, for example, help the DNO to reduce losses on the network, or address local network constraints) or with large customers for [demand side management].[81]

To address these concerns, Ofgem opted to completely overhaul utility capitalization policies. Utilities would capitalize a fixed percentage of *total* expenditures rather than the common practice of capitalizing much higher percentages of certain capital-related expenditures (e.g., those on equipment).

Ofgem subsequently extended totex accounting to its RIIO-style MRPs. Expenditures eligible for capitalization and the percentage of total expenditures that are to be capitalized are approved by Ofgem based on financial modelling that appraised utility cash flows, profitability, and indebtedness.[82] These percentages are established at the outset of the plan, often vary by distributor, and have changed over time. Generally, utilities are allowed to capitalize 60-85% of eligible totex.[83]

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[81] Ofgem, Electricity Distribution Price Control Review – Final Proposals, 2009, p. 27.
[82] The capitalization rates Ofgem approved in the first plans featuring totex accounting were informed by the share of totex that was capitalized in previous plans.
[83] The definition of eligible totex has varied between plans but has generally expanded over time.

5.2 Australia

Overview of Australian Ratemaking

Regulation of energy utility rates in Australia expanded in the mid-1990s following the restructuring and partial privatization of its gas and electric utility industries. MRPs have since been widely used. Transmission and distribution utilities are called network service providers ("NSPs"). NSP rates were initially regulated by state agencies. At least one of these (Victoria's) experimented with ECMs to encourage efficiency gains in later plan years.

The Australian Energy Regulator ("AER") was established in 2005 and soon had oversight over rates for most NSPs, guided by rules formulated by the Australian Energy Market Commission. The AER's multiyear rate plans typically have 5-year terms, with start dates staggered such that plans of only a few utilities are reconsidered each year. AER-approved plans typically have hybrid ARMs in which revenues for opex and capex are handled differently.

Opex revenue is typically established using a "base-step-trend" method.[84] For most opex, a utility's revenue is based on its corresponding cost in a historical reference year (typically year 3 or 4 of the prior MRP) as escalated using a "rate of change" formula that is driven by expected growth in input prices, operating scale, and productivity. Opex from the historical reference year is appraised for efficiency. Opex that is not reflected in the historical reference year (e.g., increased cost due to changes in regulatory obligations) or that doesn't fit the opex trend formula is addressed by step changes that are forecasted separately. Capex for the MRP term is forecasted, though the forecasts are informed by recent historical capex, input price trends, and expected productivity growth.

ECM for Opex

A few years after its establishment, the AER in 2008 approved ECMs for opex revenue of electricity distributors ("DNSPs") that it called efficiency benefit sharing schemes ("EBSS"). [85] The AER stated the following concern about its initial MRPs.

> A DNSP that is able to reduce expenditure near the beginning of the regulatory control period is able to retain the benefits of the reduction longer than if it were to reduce expenditure closer to the end of the regulatory control period. Consequently, the power of the incentive reduces as the regulatory control period progresses. Furthermore, if forecast expenditure allowances are specifically set with reference to a previous year, the incentive for a DNSP to reduce expenditure in that year is likely to be reduced.[86]

The EBSS applies only to the portion of OM&A expenses that is addressed by the base

[84] In Australian regulation the term opex is interchangeable with OM&A expenses.
[85] An EBSS had been established for power transmitters in the prior year.
[86] Australian Energy Regulator, Electricity distribution network service providers, Efficiency Benefit Sharing Scheme, Final Decision, June 2008, p. 3.

and trend parts of the base-step-trend methodology.

The scheme allows NSPs to retain *incremental* efficiency gains or losses for 6 years (e.g., the year in which the efficiency gain was first achieved plus 5 years). For the first year of the term, incremental efficiency gains or losses are calculated as the difference between actual and allowed OM&A expenses, with some adjustments. For subsequent years of the plan, incremental efficiency gains or losses are calculated based on the *change* in the difference between actual and allowed OM&A expenses. Thus, the possible reward for efficiency gains in early plan years can be eroded or even reversed by efficiency losses in later plan years. The incremental efficiency gain or loss in the final year of the plan must initially be estimated, as actual data are not available. This is later trued up to actuals.

Better Regulation Initiative

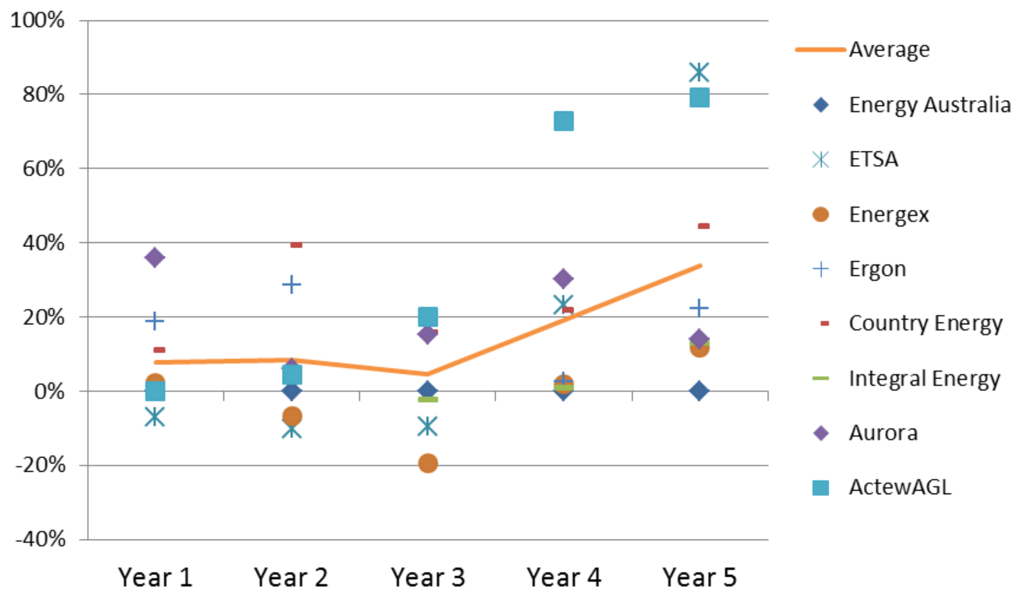
About five years later and pursuant to changes in NSP ratemaking rules, the AER launched a Better Regulation initiative. In a 2013 consultation paper on the development of new expenditure incentive guidelines for electricity NSPs, the AER noted regarding the EBSS that

> where opex incentive schemes have been in place for a whole regulatory control period there is no systematic empirical evidence that illustrates opex of NSPs is excessively high in year 4 compared to earlier years in the regulatory control period.[87]

The AER also noted in this paper that "there is some evidence that the capex profile of NSPs has been skewed towards more capex in later years of the control period" and provided the following figure depicting electricity NSP capex as evidence.[88]

[87] Australian Energy Regulator, Better Regulation, Expenditure incentives guidelines for electricity network service providers, Issues paper, March 2013, p. 26.
[88] Ibid., p. 11.

Capital Overspends Over the Regulatory Control Period



Source: Productivity Commission, 2012, Electricity Network Regulatory Frameworks, Draft Report, Canberra, p. 194.

Notes: The vertical axis shows overspending as a proportion of the capex allowance (that is, (actual capex – forecast capex) / forecast capex). Cost pass throughs have been considered as part of forecast capex. Victorian networks have been excluded since a capex efficiency carryover mechanism applied at the time.

The AER discussed the need for stronger capex containment incentives, stating that

> if the capex and opex incentives are not balanced then NSPs may have an incentive to install new assets rather than maintain existing assets or vice versa. For example, if the opex incentive were greater than the capex incentive a NSP would have an incentive to replace an existing asset rather than maintain it since the reward from reducing its maintenance expenditure could be greater than the penalty from the additional capex. This could lead to inefficient investment decisions. Similarly, imbalanced incentives could distort the use of non-network alternatives since these are typically operating expenses.[89]

Bunching capex in a few years of the MRP term could involve inherent inefficiencies.

> Unnecessary peaks and troughs in a NSP's investment programs can result in higher costs than a more stable work program. For example, if a large number of projects are undertaken during the final years of the regulatory control period, NSPs may rely more

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[89] AER, Better Regulation, op. cit., p. 30.

on external contractors for projects that could have been undertaken more efficiently by in house staff. NSPs may also enter into less cost-effective contracts with external contractors if they are contracting at shorter notice and for a smaller scope of work rather than if they were offering a steady stream of work.[90]

The AER further noted that

> NSPs have some ability to substitute between opex and capex. While this can be efficient in certain circumstances, a NSP's decision may be distorted by differences in the incentive schemes for capex and opex. This could encourage perverse outcomes. In particular, if the incentives for capex are lower, a NSP might choose to undertake capex rather than opex. In addition, NSPs might reclassify expenditure (usually from opex to capex) during a regulatory control period in order to earn higher returns. Ideally, the power of the incentives for capex and opex would be similar so as not to distort business decisions about whether to undertake capex or opex[91]

and that

> If a NSP reclassifies its opex as capex it would be compensated:
>
> - once, in its opex allowance as determined at the determination; and
> - again, by earning a return on and of capital once the amount is included in the [regulatory asset base] as capex.[92]

In addition to discussing ECMs, the AER acknowledged in this paper that there were other ways to strengthen opex and capex containment incentives. These included increased reliance on statistical cost benchmarking in rate setting. The AER was developing an opex benchmarking program and commented that

> The incentives for efficient opex change once benchmarking is used to determine opex allowances. Benchmarking breaks the link between a NSP's performance in one regulatory control period and its opex allowance in the next regulatory control period. If a NSP's opex allowance was based solely on external benchmarks, the NSP would have a very strong incentive to beat the allowance.[93]

With respect to capitalization policy the AER stated that

> To determine whether the capitalisation requirement is satisfied the AER must know:

[90] AER, Better Regulation, op. cit., p. 11.
[91] AER, Better Regulation, op. cit., p. 2.
[92] AER, Better Regulation, op. cit., p. 36.
[93] AER, Better Regulation, op. cit., p. 8.

- when a NSP changes its capitalisation policy during a regulatory period
- whether any opex has been reclassified as capex because of those changes.

> To this end, the guidelines could include a requirement on NSPs to notify the AER of any changes to capitalisation policies during the relevant period. The AER could use this information to assess whether any capex had previously been classified as opex. If the AER found instances of this (i.e. if an expenditure item was funded through an opex allowance but was subsequently classified as capex) the expenditure would not enter the [rate base].[94]

and that

> the issues paper for the expenditure forecast assessment guidelines suggests that all NSPs adopt a standard capitalisation policy.[95]

ECM for Capex

The Better Regulation initiative also resulted in the establishment of an ECM for capex. The AER called this mechanism the capital expenditure sharing scheme ("CESS"). The CESS allows electricity distributors to share, over the next MRP term, a portion of the net present value of overspends and underspends resulting from variances between actual and approved levels of capex.[96]

The AER was concerned that, even were a CESS established, deferrals of capex may be undertaken in ways that reduce customer benefits from MRPs.

> In some circumstances, without an adjustment to the CESS, consumers may not share in the benefits where capex is deferred from one regulatory control period to the next regulatory control period. For instance, if a NSP's capex forecast for the next regulatory control period materially increases because capex was deferred in the current regulatory control period, a NSP's reward from deferring capex through the CESS, will likely exceed the benefit to consumers from the deferral.[97]

To address this issue, the AER decided to reduce CESS payments to NSPs in situations where they seemed to defer capex in an expiring MRP by a material amount from one plan to the next plan, and the total approved forecasted capex in the next plan was materially higher than it would have been if capex had not been deferred.

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[94] AER, Better Regulation, op. cit., p. 45.
[95] AER, Better Regulation, op. cit., p. 45.
[96] The NSP's share of total efficiency gains or losses was initially set at 30%.
[97] Australian Energy Regulator, "Better Regulation: Capital Expenditure Incentive Guideline," 2013, p. 9.

Ex-Post Reviews of Capex

The AER decided that, in future MRP proceedings, they would review NSP capex from the prior plan more carefully to ensure that it was efficient and prudent. The resultant reviews are multi-stage processes that can lead to the exclusion of capex from rate base. The level of scrutiny by the AER escalates the greater the NSP has overspent its capex allowance. Capex may be excluded from the NSP's rate base if it was not prudently incurred or resulted from a change in a NSP's capitalization policy.

Capitalization Policy

If a NSP is subject to both a CESS and an EBSS with the same incentive power, there is no incentive for the NSP to prefer to capitalize a cost over expensing it. In these situations, the AER will not need to consider if the NSP had changed its capitalization policy during the plan term. If the incentives are not balanced, however, the AER would consider whether the NSP had changed its capitalization policy during the plan term and whether OM&A expenses had been reclassified as capex due to these changes.

This reasoning led to a requirement that NSPs provide details of any changes to their capitalization policies during the previous MRP and of the OM&A expenses that had been capitalized due to those policy changes. If opex is capitalized because of a change to its capitalization policy and the AER determines that the incentives to capitalize are greater than the incentive to expense the cost, the expenditure may be treated by the AER as opex.[98] NSPs were also required to identify the effects of changes to their capitalization policies on historical expenditure data as part of MRP proceedings. Standardized capitalization policies amongst NSPs were not, however, mandated.

Statistical Benchmarking

An increased emphasis on statistical cost research was another outcome of the AER's Better Regulation initiative.[99] The AER began to commission annual cost benchmarking reports for transmission and distribution NSPs. These reports included calculations of NSP unit cost and productivity trends and levels and econometric benchmarking of certain O&M expenses. Benchmarking results began to play a larger role in the development of the AER's positions on appropriate levels of NSP cost. If the AER believes that a NSP's historical opex was efficient, it is accepted. If not, the AER has the option to make an adjustment to O&M revenue in MRPs going forward to ensure that it reflects efficient cost.

The reasonableness of early efforts by the AER to cut the O&M revenue proposals of NSPs to reflect the results of its benchmarking studies without a phase in ended up in the courts.

[98] This would be unlikely to occur if the NSP has an approved CESS and EBSS.
[99] The discussion on benchmarking only applies to power NSPs, as benchmarking is not as prominent in gas NSP regulation.

The AER's freedom to use benchmarking to scale back NSP revenue requirements was ultimately scaled back.

Benchmarking is also considered in the AER's appraisal of NSP capex forecasts, both for the forecast period and to appraise the efficiency of capex previously incurred. Econometrics plays a smaller role in this performance area.

Recent Reconsideration of ECMs

The EBSS and CESS were reconsidered by the AER in recent years as part of its Review of Incentive Schemes for Networks. After each distributor had operated under two full MRPs with the EBSS in place, the AER found no evidence of the distributors escalating their opex in the historical reference year for rebasings.

> [T]here is no clear pattern that the networks have increased, or decreased, their operating expenditure in any particular year, compared with the other years in the regulatory period. This gives us further confidence that the EBSS is working to provide a constant incentive to reduce operating expenditure as intended.[100]

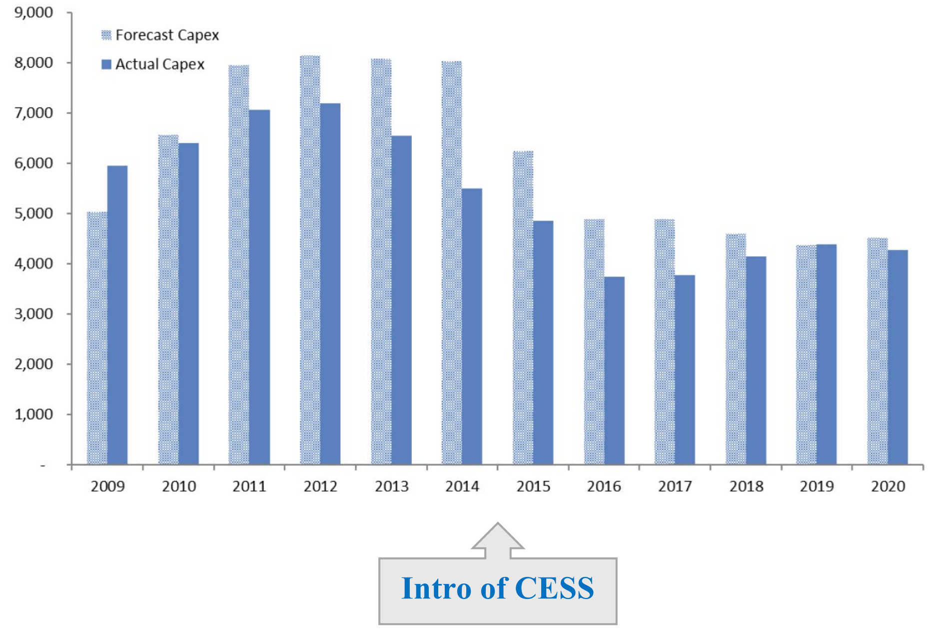
The AER did not make any substantive changes to the EBSS as a result of this review.

The AER also found that capex generally declined after the Better Regulation reforms that included the introduction of CESS in 2015 as shown in Figure 18 of its report. The AER discussed the potential causes of the decline in both the forecasted and actual capex that had occurred.

> There are likely many reasons for the overall decline in capital expenditure, including changes in the external environment (e.g. reductions in demand, and changes in regulatory obligations), as well as networks making more efficient investments.[101]
> We recognise that it is not straightforward to identify whether expenditure underspending is due solely to efficiency gains, or changes in circumstances or happenstance. This is a key concern raised by consumer groups.[102]

[100] Australian Energy Regulator (2021), "Review of incentive schemes for networks discussion paper," p. 54.
[101] Australian Energy Regulator (2021), op. cit., p. 54.
[102] Australian Energy Regulator (2021), op. cit., p. 55.

Figure 18 Forecast and actual capital expenditure – all electricity distribution



The AER did have concerns with the underlying performance of the CESS as shown in the data. One issue with the CESS was that it did not appear to unskew distributors' capex patterns.

> [A]ll electricity distribution networks underspent their capital expenditure allowances in the first 3 to 4 years of their regulatory period, sometimes materially. However, a majority of electricity distribution networks spent closer to, or above, their allowances in the last year or 2 of their regulatory period. In some instances, networks have significantly overspent their allowance in last year of the regulatory period.
> These observed patterns of electricity distribution networks spending higher capital expenditure in the final year of the recent regulatory period is observed historically. However, it is not what we would expect with the financial incentives generated by the CESS. The CESS was expected to lead to smoother spending patterns. This has not yet occurred.

The AER also noticed that there was an increasing gap between the distributors' initial capex proposals and the AER's final decisions, suggesting that there may be an issue with distributors presenting exaggerated capex forecasts. Finally, the AER noted a potential issue with some distributors underspending the capex forecast in one MRP and then proposing a significant increase in capex in the subsequent plan.

> For example, we observe that 9 of the 13 distribution networks underspent their capital expenditure allowances by more than 10 per cent in the recent regulatory period. Of these, 7 distribution networks proposed forecast capital expenditure was more than 10 per

> cent above its actual capital expenditure for the next regulatory period. This includes 2 distribution networks that had proposed forecast capital expenditure 40 per cent higher than actual capital expenditure.[103]

These issues led the AER to question whether the decrease in capex was actually the result of efficiency gains.

> The observed pattern of underspending and over-forecasting is one example of a trend that raises a concern as to whether these CESS rewards were commensurate with efficiency gains. While lower capital expenditure will lead to less added to the [regulatory asset base], these efficiencies are not necessarily being reflected in network proposals for future capital expenditure forecasts. This creates an increased regulatory cost of examining expenditure proposals and determining reasonable forecasts of efficient expenditure.[104]

Because of concerns about the trends it had identified with capex forecasts and spending patterns, the AER made several modifications to the CESS.[105] A NSP now receives 30% of the net present value from all capex underspends up to 10% of the approved capex allowance and a lesser 20% of the net present value of any capex underspends beyond 10% of the approved allowance.[106] NSPs would continue to absorb 30% of any capex overspends.

Complications of Capitalization Policies for Benchmarking

In its decision to increase the role of benchmarking, the AER discussed how differences in the capitalization policies of distributors complicated its benchmarking program. This issue looms particularly large in Australia because statistical benchmarking plays an important role in ratemaking and the principle focus of this benchmarking is opex. The AER stated that

> As with cost allocation policies, these decisions of a NSP to classify costs in a certain way potentially detract from benchmarking comparisons…. However, the more material issue for benchmarking is how capitalisation policies differ across NSPs at any time, and the extent to which the differences affect robust comparisons of direct costs…. [W]e will require full visibility of the impact of different capitalisation policies at the detailed level across all cost categories. We will seek visibility on instances where NSPs capitalise or expense particular activities in our overheads reporting templates. . .

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[103] Australian Energy Regulator (2021), op. cit., p. 57.
[104] Australian Energy Regulator (2021), op. cit., p. 57.
[105] The AER is currently reviewing whether further changes to the CESS are necessary due to a recently implemented rule that established separate targeted reviews of projects addressed by Integrated System Plans and non-integrated system plan projects.
[106] Part of the AER's rationale for a 30% sharing of capital expenditure variances in the CESS was to equalize the incentives between the CESS and EBSS, minimizing the incentives for utilities to game the ECMs by shifting the classification of expenditures.

> if a NSP changes its capitalisation policy, we will require it to identify how such a change affects any historical data on which we rely.[107]

In 2021, the AER initiated a proceeding to consider how it should assess how differences in capitalization policies and practices between utilities should be accounted for in its benchmarking of NSP cost. At the outset of this proceeding, the AER was able to highlight several NSPs that had changed their capitalization policies and practices in ways that made a material impact on the AER's benchmarking research. In several cases, a big change was to decrease capitalization of corporate overheads.[108]

The AER ultimately decided to continue to require electricity distributors to report OM&A and capex based on their cost allocation and capitalization policies as of 2022 and to require distributors to report opex and capex based on 100% of corporate overheads being assigned to opex. To ensure a consistent data series back to the sample period start date, the distributors were required to report their data using this methodology back to 2009 and to estimate these values for the 2006-08 period. [109]

5.3 New Zealand

Electric utility rates in New Zealand have for many years been regulated by the Commerce Commission ("CC") using MRPs.[110] Early plans featured indexed ARMs and 5-year plan terms. However, recent generations of MRPs have featured ARMs similar to those in Australian MRPs. Utilities have the option to select a standard MRP or to propose one that is customized to their needs. Regulation of customer-owned distributors is more light-handed.

Since 2015, MRPs for New Zealand electricity distributors have included ECMs with a design that they call an incremental rolling incentive scheme ("IRIS").[111] Separate ECMs apply to opex and capex.[112] These mechanisms are designed to address both utility incentives to time their expenses and to engage in capex/opex bias. The CC provided the following rationale for balanced incentives between the opex and capex ECMs.

> Reducing the difference between the marginal incentive to control operating expenditure relative to capital expenditure is important because the difference affects the trade-off between different options for meeting demand. For example, large differences in the

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[107] Australian Energy Regulator, "Better Regulation: Explanatory Statement, Expenditure Forecast Assessment Guideline," 2013, p. 208.
[108] New Zealand Commerce Commission, "Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision," December 13, 2023, p. 16.
[109] More consistent data would improve comparability and the accuracy and fairness of benchmarking of the benchmarking process. Distributors which capitalize more of their OM&A costs may look better in total cost benchmarking studies, since capitalized costs are depreciated over a long period of time (e.g., 30 years).
[110] Electricity distributors that are customer-owned are exempt from the CC's price and quality regulation.
[111] The CC has not added an IRIS to the standard gas utilities' MRPs.
[112] The IRIS for OM&A expenses was explicitly inspired by the EBSS approved by the Australian Energy Regulator.

> incentive strength may mean that capital intensive solutions (such as expanding substation capacity) would be preferred over more economical operational solutions (such as contracting for demand-side response).[113]

These ECMs have tended to be symmetrical. Distributors are generally granted 30-35% of their estimated efficiency gains and losses on each IRIS. The CC explained its preference for symmetrical ECMs as follows.

> The marginal incentive is not constant under an asymmetric scheme because the reward from saving an additional dollar depends on whether the supplier spends more or less than the expenditure baseline. Under a symmetric scheme, the reward from saving an additional dollar is always the same.
>
> Therefore, a symmetric approach is the only way to ensure that the marginal incentive is 'time consistent', i.e., where the incentive to control expenditure remains constant throughout the regulatory period. Any form of asymmetry in the IRIS will result in deviations away from a time consistent incentive.[114]

Utility spending patterns have been a key concern that prompted adoption of these mechanisms. For example, during an initiative to reconsider its ECMs, the CC stated the following in a presentation with the heading "Refresher on incentive regulation – What's the problem?"

- Sharing [efficiency] gains each reset creates another issue – in the absence of other mechanisms, the incentive to find efficiency gains varies over time
- The natural incentive to save money is greater at the start of the regulatory period than it is at the end of the period.
    - Therefore, the incentive to control expenditure is not constant over time
- Why is this important?
    - Creates a focus on optimizing the timing of expenditure rather than making expenditure savings
    - This is not in the long-term interests of consumers – suppliers should be incentivized to make efficiency savings as soon as they are identified[115]

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[113] New Zealand Commerce Commission, "Final reasons paper incremental rolling incentive scheme, 2014, p. X3.
[114] Ibid.
[115] Stephen Hudson and Ben Harris, "Expenditure incentives and the Incremental Rolling Incentive Scheme (IRIS), 2020 reset of the DPP for EDBs," Commerce Commission New Zealand, 5 November 2018, p. 84.

Frontier Economics, in a 2015 report on IRIS for Transpower, New Zealand's transmission utility, stated that

> The declining power of incentives under a simple form of building block incentive regulation can encourage network businesses to engage in perverse and inefficient behaviours. In particular, businesses can find it worthwhile to defer making savings available towards the end of [an MRP] to the start of the following [MRP]. Further, if the regulator uses a 'base year approach' to setting the business's opex allowance for the next [MRP] – in which forecast opex for the succeeding [MRP] is set based on the actual opex in a specific 'base' year in the current [MRP] (typically the penultimate year) – the business can have an incentive to bring opex forward from the final year(s) of the [MRP] into the base year to boost its opex allowance at relatively little cost in terms of the present value of the brought-forward expenditure.[116]

A 2023 generic proceeding about the framework of MRPs for New Zealand electric and gas utilities led the CC to indicate a preference for its existing ECMs over totex accounting. The CC stated that its existing tools to mitigate capex bias better address the overarching objectives of its regulatory framework than totex.[117] These objectives include:

- Providing balanced incentives for opex and capex;
- Provide consistent incentive rates to make efficiency savings over time;
- The ability to tailor incentive rates and the extent to which efficiency gains are shared with customers; and
- Removal of incentives to inflate costs in some key years.

The CC believed that totex accounting would only address some of these objectives and that totex did not address all sources of capex bias.

> For example, it does not address the potentially greater performance uncertainty of procuring from a third party, which may lead a business to prefer capex to opex solutions.[118]

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[116] Frontier Economics, "Application of symmetric IRIS," A report prepared for Transpower, March 2015, p. 4.
[117] New Zealand Commerce Commission, "Financing and incentivising efficient expenditure during the energy transition topic paper, Part 4 Input Methodologies Review 2023 – Final decision," December 13, 2023, p. 16.
[118] New Zealand Commerce Commission, "Electricity distributors' expenditure incentives under the current Part 4 approach and under a totex approach: Staff working paper to inform 7 November 2022 workshop 'Forecasting and incentivising efficient expenditure for EDBs,'" p. 11.

5.4 Alberta

The Alberta Utilities Commission ("AUC") is a leading North American MRP practitioner. Following experimental early plans for an electricity distributor (ENMAX) and a gas distributor (Northwestern Utilities, now ATCO Gas), the AUC has approved three generations of generic MRPs that apply to multiple Alberta gas and electricity distributors. These generations are called PBR1, PBR2, and PBR3. All plans have featured five-year terms, indexed ARMs, and the availability of supplemental capital revenue.

Innovative Rebasings

Provisions for the next rebasing were indeterminate at the outset of all three plans.[119] Moreover, the two rebasings that have thus far occurred between plans have not been based on full cost of service forecasts. PBR1 started in 2013 and ended in 2017.[120] In 2016, a proceeding was held that determined the outlines of PBR2, including, unusually, what approach to take to establish going-in rates. In this proceeding, most distributors advocated a traditional full rebasing using a fully forecasted test year, while one distributor (EPCOR) and the intervenors did not. EPCOR proposed setting OM&A revenues for 2017 based on an average of the OM&A expenses during the middle 3 years of the PBR plan.[121] The AUC stated the following in deciding against a fully-forecasted rebasing.

> In reaching its determinations regarding the alternative approaches proposed by the parties for rebasing and establishing the going-in rates for the next generation PBR plans, in order to promote the objectives of PBR, the Commission considered the relative merits of the various approaches to rebasing offered by the parties...
>
> In the Commission's view, achieving these objectives [e.g., reducing regulatory burden, minimizing perverse incentives of rate base rate of return applications and enhancing the incentive property incentives of the PBR plan] requires balancing of the features of both proposed general approaches to rebasing, as each has its merits and disadvantages. EPCOR and the interveners pointed out that setting going-in rates in a [COSR] proceeding based on forecast costs may create incentives to over-forecast, with the result that customers do not share in the benefits of productivity gains achieved by the distribution utilities in the current generation PBR plans. In testimony, Dr. Weisman, an expert witness for EPCOR, supported this view as reflected in the following extract:

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[119] For PBR2, the decision to rebase at all was part of the decision outlining the terms of the PBR2 plan, which was released in year 4 of the PBR1 plan term. A decision on the form of rebasing for PBR3 was made in year 4 of the PBR2 plan term.

[120] One of the distributors, ENMAX, was not subject to the terms of PBR1 until 2015. Their rebasing utilized only the data for the first two years of their three-year PBR1 plan term rather than the descriptions provided in this section for PBR1.

[121] At least one intervenor witness supported a rebasing based simply on adjusting the distributors' 2017 revenue requirement to remove any earnings above the allowed rate of return on equity.

> Forecasts are by their very nature, and the issue of information asymmetries comes up here, are always a source of angst for commissions and regulators. And to the extent they can be avoided, they should. Just because of that information asymmetry, which may be a problem in some cases but not a problem in others, but it also -- the forecast component, in my mind, also renders it a bit less certain that the gains from PBR 1, the first generation PBR, are actually going to be passed on to consumers at the time of rebasing.

Additionally, the interveners stated in argument that because of information asymmetry, testing cost forecasts would require the same level of detail as in a traditional COS proceeding. As such, regulatory burden is unlikely to be reduced under this approach to rebasing.[122]

In the subsequent proceeding to implement the rebasing, the AUC discussed the rebasing process it ultimately chose.

> In [our PBR2 decision], the Commission determined that it would not employ the utilities' forecast costs in order to set going-in rates. Rather, the Commission determined that it would set going-in rates on the basis of a notional 2017 revenue requirement that represents the costs that each utility, operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017. The notional 2017 revenue requirement is developed using actual costs experienced during the previous years of the preceding PBR term for each distribution utility, with any necessary adjustments to reflect individual distribution-utility anomalies.[123]

For electricity distributors, rates for the first year of the PBR2 term were set based on a notional revenue requirement for 2017 — the final year of PBR1 instead of the first year of the next - escalated by an I-X formula plus the growth in billing determinants (e.g., the number of customers, volumes sold, and demand).[124]

Another unusual feature of this rebasing was that each distributor's notional revenue requirements for OM&A expenses were based on its *lowest* cost year over the first four years of PBR1, as adjusted to account for I-X and the growth in billing determinants. Distributors could propose corrections to these lowest-cost year data to account for anomalies. Anomalies were often used to justify proposals to increase OM&A expenses in the rebasing proceeding. Ultimately, the commission rejected all of the proposed anomalies, positive or negative.

The rate base for the notional 2017 test year was calculated from the actual closing rate base from the penultimate year of PBR1 with an adjustment to reflect an estimate of plant

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[122] Alberta Utilities Commission, Decision 20414-D01-2016, 2016, p. 10.
[123] Alberta Utilities Commission, Decision 22394-D01-2018, 2018, pp. 7-8.
[124] As the gas distributors had attrition relief mechanisms that took the form of revenue per customer caps, the only billing determinant considered for the gas distributors was the number of customers.

additions in the final year of PBR1. This estimate was the sum of the approved additions funded by the supplemental revenue provisions of PBR1 and additions that were funded by I-X.[125] The plant additions funded by I-X for the final year of the plan were estimated using the average plant additions funded by I-X during the first four years of PBR1 adjusted to 2017 dollars using I-X and billing determinant growth.

It is also noteworthy that supplemental capital revenue in subsequent MRPs was based on a K-bar term that effectively replaced capital revenue based on an I-X formula with revenue based on the distributor's average plant additions during PBR1 as escalated for inflation and output and productivity growth. This further diminished the role of forecasting in the determination of revenue requirements.

Spending Pattern Concerns

In 2021, which was year four of PBR2, a proceeding was held to determine methods for the year five rebasing proceeding. Rebased rates would take effect in 2023. These rebasings were based primarily on a single forward test year. For each cost category, distributors had the option to use a mechanistic or non-mechanistic approach and they had the burden of justifying that their proposed costs were just and reasonable. Justifications of cost forecasts had to include explanations of how the forecast fit in with trends in the Alberta economy and comparisons between their forecast of costs and recent historical performance with explanations of why these differed.[126] Mechanistic cost adjustments were based on the average value of the cost during the first 3 years of PBR2 as escalated for I-X and the growth in billing determinants. Non-mechanistically escalated costs were forecasted by the utility. Distributors chose to escalate many costs using the mechanistic approach.

In the 2022 rebasing proceedings, two utilities were singled out by the AUC and intervenors for potentially gaming some of their proposed expenses. For example, ATCO Electric proposed an increase in their overhead line expenses for the rebasing year. However, the commission was persuaded that the company was seeking funding for overhead line maintenance that had been deferred during the expiring PBR term. ATCO Electric had restructured its overhead line program during PBR2 and had reduced the number of employees by nearly 50%. The company then noticed that its internal metrics suggested that it may no longer be compliant with the commission's reliability standards and requested an increase in funding during the rebasing. The AUC commented that

> The Commission accepts that initiatives undertaken in PBR to reduce costs can have unintended consequences and some trial and error may be required to "right-size" workforce requirements as described by ATCO Electric. However, the Commission also

[125] Plant additions funded by I-X can be calculated by subtracting the plant additions that received supplemental funding from a distributor's total plant additions.
[126] These comparisons often focused on the average actual data for the 2018-2020 period, but the AUC also wanted to consider distributor forecasts in light of the lowest value from the PBR1 term and the average value for the PBR1 term.

> recognizes that ATCO Electric receives a financial benefit from any cost reductions achieved during the PBR term. ATCO Electric's shareholders received the benefit of the reduction in expenditures due to the cost cutting initiatives in the overhead line expenses [OM&A] account, while still complying with the performance metrics set out in Rule 002.
>
> It is not reasonable that customers should now be required to pay to restore service levels which ATCO Electric indicates were unsustainably eroded during the PBR term and for which customers derived no financial benefit until this rebasing, particularly where ATCO Electric continues to comply with legally imposed service standards.[127]

The Commission ultimately required ATCO Electric to absorb 50% of its proposed cost increase for this expense category.

Similarly, in its rebasing proceeding, FortisAlberta ("Fortis") proposed a new capital program to replace end-of-life conductors, along with associated poles and hardware that were aged and in poor condition in high-risk fire areas. This program and funding for the related capex were rejected, as the commission did not believe that the proposed program was materially different from the company's present practices. Further,

> In response to a Commission IR, Fortis informed the Commission that it identified the backlog in 2018 and initiated the conductor management program to address end of life replacements at that time. It is unclear to the Commission why, with the presence of that program, Fortis still requires an analogous "new" program to address the same core issue. The criteria that guides the "targeted replacement" of conductors in the [high-risk fire areas] should also inform the order and pace of asset replacement in the existing Fortis end of life program. It is also unclear to the Commission why this new program is being undertaken in 2023 rather than having been initiated much earlier given that Fortis has been aware of the underlying issue for years….
>
> In making this decision, the Commission notes that Fortis indicated "the current backlog has not created an imminent operational risk of ignition events" and that Fortis "has no evidence that its [end of life] conductor replacement approach has contributed to an increased risk of wildfire ignition due to conductor breakage.[128]

The AUC has subsequently had to address concerns that at least two distributors may have engaged in strategic capex tactics during PBR2. In the last two years of that plan, ATCO Electric and ATCO Gas overearned by sufficient margins to trigger a request by intervenors to reopen PBR2. The overearnings were primarily the result of capex underspends.[129] When asked

[127] Alberta Utilities Commission Decision, 26615-D01-2022, p. 46.
[128] Alberta Utilities Commission, Decision 26615-D01-2022, p. 59.
[129] A comparison of ATCO Gas' forecast capital additions to actuals for 2022 showed that the company underspent the most in the areas of system growth, system sustainment, and infrastructure renewal. Similarly, ATCO Electric's

to provide evidence that these underspends were the result of efficiency gains, the distributors were unable to provide detailed explanations of efficiencies that had been achieved. This led to concerns that the capex underspends were the result of strategic deferrals rather than efficiency gains. The AUC concluded that

> The magnitude of the savings that were neither quantified nor attributed to particular projects, programs or initiatives by the ATCO Utilities has led the Commission to conclude that the savings cannot be attributed to utility-driven efficiency gains resulting from the incentives intended under PBR. The Commission's view is that much of the ATCO Utilities' unquantified and unexplained savings were the result of factors other than efficiencies, including those asserted by the interveners, such as the ATCO Utilities opting to not pursue certain capital projects …, and realizing cost savings as a result of COVID-related externalities including supply chain disruptions that prevented the ATCO Utilities from executing certain required projects. These decisions are made by each of the ATCO Utilities in response to their PBR2 plans and are therefore operational, rather than structural in nature.
>
> The Commission therefore finds that the PBR2 plans of ATCO Electric and ATCO Gas did not operate as intended in each of 2021 and 2022. The result is rates that were not just and reasonable in those years because customers were required to pay rates (including the rates of return achieved by the ATCO Utilities that exceeded the approved return and the threshold for the reopener) without receiving the benefit of more efficient utility service. In other words, the operation of the plans was inconsistent with the bargain that is inherent in PBR, and customers paid more than what was reasonably required for the provision of safe and reliable utility service. The Commission finds that this constitutes a problem with the operation of each of ATCO Electric's and ATCO Gas's PBR2 plans.[130]

A proceeding to consider the appropriate remedy for these overearnings was recently completed and entailed refunds to customers of ATCO Gas and ATCO Electric. ATCO is appealing the decision to reopen the plan.

Capitalization Issues

Proceedings were held during PBR1 to establish supplemental capital revenue. In one of these proceedings, EPCOR requested permission to capitalize a portion of short-term incentive pay related to capitalized expenses. This request was rejected, even though the AUC believed that the proposed capitalization of short-term incentive pay "appears to be consistent with acceptable accounting practices under IFRS."[131] The AUC rejected this proposal on the grounds that EPCOR would be paid twice for these costs.

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capital underspends were largest in metering (e.g., AMI deployment); environment, safety, and reliability; grid modernization; and externally-driven system modifications.

[130] Alberta Utilities Commission Decision 28300-D01-2024, p. 28.

[131] Alberta Utilities Commission, Decision 20407-D01-2016, p. 43.

> The double-counting will occur because the I-X mechanism already provides funding to account for this type of cost, as EPCOR's going-in rates incorporated the full amount of [short term incentive pay] costs which were classified as an O&M expense in 2012.[132]

This decision also saw the AUC reverse a decision in a previous proceeding on supplemental capital revenue that authorized EPCOR to capitalize the costs associated with inspection of new meters and service connections, as those costs had also been classified as OM&A expenses in the prior rebasing proceeding. In its decision on the rebasing between PBR1 and PBR2, however, the AUC allowed EPCOR to capitalize both of these costs, stating that

> The Commission is … satisfied that EPCOR's proposed method of implementing these accounting changes as part of the rebasing, whereby EPCOR removed the newly capitalized portion of costs from the O&M part of its notional 2017 revenue requirement, will not result in a double-counting of these costs.[133]

6. SPA Survey Responses

Voluntary surveys of spending pattern and capitalization issues were developed by PEG and sent to Ontario distributors and intervenors. We also sent surveys to some regulators in other jurisdictions that have experience with multiyear rate plans. Ten Ontario electricity distributors, six Ontario intervenors, and regulators from three commissions in other jurisdictions responded.

This section of the report details the survey responses. We first discuss the comments of Ontario stakeholders on spending pattern issues before turning to comments on capitalization policy. Discussions with regulators in other jurisdictions are detailed in Appendix Section A.4.

6.1 Spending Patterns of Ontario Distributors Identified Spending Patterns

General Patterns

Most intervenors who responded to the survey noted that it is common for the opex and capex of Ontario electricity distributors to grow more rapidly in later years of multiyear rate plans. Their observations on this matter were generally consistent with the empirical research that we detailed in Section 2. One intervenor noted that "the trend is prevalent in some utilities more than others." Another intervenor noted that

> Increasing OM&A expenses at the end of a term, particularly in the base year (the year before the rebasing test year), is endemic. Ratepayer groups often refer to this as the "[bridge] year bump" or "[bridge] year stuffing." A distributor may show flat or

[132] Alberta Utilities Commission, Decision 20407-D01-2016, p. 43.
[133] Alberta Utilities Commission, Decision 22394-D01-2018, 2018, pp. 90-91.

reasonable OM&A growth for several years, followed by a significant increase in the [bridge] year or the year prior.

Another intervenor noted a tendency for capex to be high in the bridge year.

The tendency of cost growth to accelerate is not necessarily the same for the two cost categories. One intervenor noted succinctly that "Opex always increases whereas Capex mainly does."

Several intervenors noted that a distributor's capex in later plan years often exceeds that contained in its distribution system plan ("DSP") or OEB-approved capex envelope. For example, one intervenor stated that "actual capex in later years of a plan and total capex overall (especially for larger utilities) can deviate and occasionally significantly from the level of spending provided in the [DSP] that underpins the rate plan." Another intervenor stated that "capital spending for some utilities seems to consistently exceed the OEB approved envelope. Those utilities assume that they will get to add the excess Capital to rate base at Rebasing and this has often been done (perpetuating the issue)."

Spending patterns may vary by type of capex, and one respondent suggested that this should be examined. One intervenor suggested that the ability to time capex may be less for system access capex.[134] Two intervenors noted that capex surges often do not coincide with opex slowdowns.

[134] A failure to connect would violate the distributors' obligation to serve and could erode reliability.

Spending Pattern Precedents

Intervenors noted that it is impractical for them to document numerous cases of late-plan spending surges. Nonetheless, intervenors provided the following examples as illustrative cases[135].

- Festival Hydro EB-2024 0023
- Greater Sudbury EB-2024-0026
- Hydro One EB-2021-0110
- Hydro Ottawa EB-2024-0115
- THESL EB-2023-0195

One intervenor noted that the OEB approved a "significantly reduced budget relative to [the Sudbury] proposal for the test year."

Causes of Distributor Spending Patterns

Numerous comments were ventured regarding the causes of spending patterns.

Incentives Driven by Multiyear Rate Plans

One intervenor and several distributors stated that utility spending patterns are not an issue. One distributor stated that it "doesn't believe distributors deliberately stop making effort to control costs in later years of the plan."

However, all but one responding intervenor maintained that OEB ratemaking practices create incentives for cost surges in later plan years. One stated that "this is the single largest reason for late plan surges in costs." There was general agreement that spending pattern incentives differed for capex and opex. We discuss incentives for each in turn.

Opex

For opex, one intervenor noted that, under various kinds of ARMs[136] used in Ontario,

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[135] PEG did not verify the skewness of spending patterns for all five of these distributors but did examine those of the three distributors that operated under CIR. We found that, in the years leading up to the multiyear rate plans established or under consideration in the cited proceedings, Hydro One exhibited skewed opex and capex, Toronto Hydro exhibited skewed opex, and Hydro Ottawa exhibited skewed capex. Skewed capex was built into Hydro Ottawa's approved capital cost forecast but not that of Hydro One. The opex revenue of all three companies was indexed. We reported in Section 2 above that capex skewing was generally less pronounced in the completed plans of CIR distributors while the opex skewing of these distributors was similar to that for the full sample.

[136] ARMs were noted above to be mechanisms that escalate utility revenue during MRPs. In Ontario, distributors have a choice between price caps (with and without supplemental capital revenue in the form of advanced and incremental capital modules) and custom ARM designs that are typically hybrids where OM&A revenue is indexed and capital revenue is based on cost forecasts.

on the OM&A side, there is a clear incentive to spend less than OEB-approved in the early years (as all else being equal, the shareholder can pocket that revenue) and then ramp up in the later years largely to "build the case" for increased OM&A budget approval for the next 5-year term.

Another intervenor maintained that higher opex in later plan years "is almost always a strategic decision to support the test year request, based on the recognition that the OEB is unlikely to reduce test year amounts below the base year or historical actuals."

Capex

Several intervenors noted that capex spending patterns are influenced by the design of the ARM. One intervenor noted that distributors operating under price cap IR with no ACM or ICMs had stronger incentives to boost capex in the last year of an expiring plan or the first year of the next plan. Capex surges should, therefore, be more pronounced for distributors operating under price cap IR without capital revenue supplements.

Some capital investments (e.g., substation upgrades, transformer replacements, and system automation) are inherently lumpy, and these encourage strategic timing. Under price cap IR, one intervenor noted that

> lumpy investments (i.e., larger than average projects) will either be front ended (i.e., year one) or back ended (i.e., year 5) to ensure near immediate cost recovery. You often see major assets be planned for service in the rebasing year (which allows 50% cost recovery over the IR term due to half year rule – though some utilities use a monthly average approach to in-service additions, which could result in higher cost recovery in the year the asset goes into service) or towards the end of an IR term as this allows for entry into opening rate base in the next test year (with minimal time elapsing between the in-service date and cost recovery beginning). With no [capital module] requests/approvals, there would be no flattening of this incentive/pattern.

Another intervenor noted that lumpy plant additions tend to be a bigger challenge for smaller utilities.

The benefit of back-ended capex extends to smaller plant additions as well. One intervenor stated that "assets that are placed in service by the end of the [bridge] year are included in the opening test year rate base. This means they are incorporated into base rates at full value over the next rate term."

One intervenor noted that the amounts the utility is seeking with respect to Opex and Capex in the Test Year are generally reduced through the settlement process or the OEB. There may be an incentive for utilities to elevate spending in the Bridge Year and front-end load their capex in the test year.

Several intervenors noted that when capex exceeds that detailed in the distributor's DSP it is eventually added to the rate base with very little review and analysis by the parties.

One, for example, stated that

> The OEB rarely disallows past capital spending once incurred. The OEB is more willing to reduce forecast capital than it is to make disallowances on past spending. Utilities know that if they spend the money before the test year, the amounts will be included in rate base, even if existing rates during the rate term did not support the investment. Over the life of the asset, the reduced return is not seen as significant, so the long-term financial benefit justifies the spending.

Another intervenor stated that "there is very little, if any, rigorous analysis by parties (and specifically by OEB Staff) as to variations between DSP proposals and actual spending" and, more generally, that "it is very difficult to argue imprudent spending after the fact." Still another intervenor stated that "in most cases this increased level of spending is eventually added to rate base with very little review and analysis by the parties."

Another intervenor averred that for price cap IR the incentive is stronger for capex surges than for opex surges. Another agreed but noted that "experience suggests for many small/medium size utilities they often value opex dollars more."

Supplemental capital revenue provided by ICMs, ACMs, and CIR can reduce the tendency of distributors to time their plant additions because these mechanisms can provide nearly full funding for capex in any plan year, and many mechanisms have entailed a claw back of underspends.[137] A distributor stated that "[its] use of a CIR framework has enabled relatively smooth spending and funding profiles over its 5-year rate cycles."

However, these ratemaking treatments also weaken capex containment incentives. One intervenor noted, for example, that the ICM approach

> undermines the purpose of PBR and significantly weakens the utility's incentive for overall cost containment during the IR term. Now the utility is incentivized to generate "discrete" projects that can pass the ICM threshold and be approved for cost recovery… The availability (and thus the prevalence of ICM applications) has massively increased over the years (as the OEB continues to reduce the barriers to ICM funding).

Spending Pattern Impact of Other OEB Ratemaking Practices

Respondents also noted how other OEB ratemaking practices affect distributor spending patterns.

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[137] The last two approved Custom IR frameworks (Hydro One JRAP 2022–2026 and Toronto Hydro 2025–2029) do not have asymmetrical capital variance accounts.

Distribution System Planning

Intervenors generally acknowledged that DSPs encourage more stable spending patterns. One explained that "although the DSP is not approved by the OEB it informs the Test Year capex and provides the roadmap and forecast that underpins the capital spending for the 5-year term. There is an expectation this 'is the plan'." Another intervenor stated that

> Prudent distribution system planning (and the filing of the DSP in rebasing applications) is designed to alleviate the problem of front-ending or back-ending investments as it gives the OEB insight into the overall capital plan (and the OEB, while not approving the DSP, can use it to order changes to the pace of projects (i.e., moving projects out of the test year into later years of the plan). We suggest that it has some limited moderating effect on the timing of in-service. However, it does not overcome the strong incentive that distributors have to front-end or back-end investments.

A distributor commented that "generally speaking, the preparation of a DSP is a long, complex process that evaluates many different inputs. As a result, DSPs are not ordinarily updated during multiyear plans." An intervenor noted relatedly that "distributors are increasingly on extended or deferred rebasing terms (longer than the standard five years). By the base year, the original DSP has usually expired, and many of the planning assumptions have changed."

Deferral and Variance Accounts ("DVAs")

Some responding distributors stated that DVAs don't affect spending patterns. One stated that

> DVAs serve as effective tools for managing risk and addressing cost variances. In our experience, they have not contributed to any material increases in reported costs during the latter years of a rate plan. True-ups and related entries are performed in accordance with OEB timelines and do not distort annual spending trends.

However, an intervenor suggested that *reported* spending patterns may be affected by some DVAs since

> from a cost recovery perspective… DVAs will result in higher costs in the test year as the OEB approves recovery of the balances from the past 5 years to be recovered in a single year (or sometimes over a couple years if the balances are significant). However, we are not 100% sure if that is how these amounts are reported to the OEB (in the RRR data) – particularly with respect to capital projects.

Another intervenor noted regarding DVAs that

> There is potentially an impact on DVAs in the data, as the costs of expenditures would not be included in the trial balance USoA accounts, but rather in the respective DVAs.

> For ongoing costs, this would likely appear at rebasing as a jump in spending, since the costs are now 'moved' from the DVAs to base rates. PEG should include all Group 2 1508 DVA accounts and sub-accounts in the cost analysis, although I recognize that the account balances generally do not distinguish between capital and OM&A-related costs unless separate sub-accounts are maintained.

Regulatory Cost

Several respondents noted that regulatory costs tend to be higher in later years of an MRP term as LDCs prepare and then file rebasing applications. One distributor commented that applications "can take upwards of 2 years to complete." Another noted that

> Regulatory compliance activities, including engineering assessments, stakeholder engagement, cost allocation reviews, customer engagement, tend to increase in the final year of the MRP as part of rate rebasing preparation. These activities are necessary for a comprehensive application and result in a natural increase in regulatory-related costs during the last plan year.

The spending pattern impact of rebasing proceedings depends on the distributor's mix of internal vs. external (e.g., consultant and legal) resources. An intervenor noted that a surge in such expenses may loom particularly large for smaller distributors. However, another intervenor noted that

> while this may appear in the USoA account data, it has no impact on rate-setting. Utilities are permitted to amortize the application costs, regardless of the year in which they are incurred, over the term leading up to the next rebasing period. In the case of Price Cap IR utilities, they almost always do so.

A distributor acknowledged that "its rate application related costs are amortized over each 5-year period."

Other Drivers of Late-Plan Cost Surges

Project Delays

Some intervenors noted that project delays can lead to late-plan spending surges. Two distributors suggested that final approval of budgets may await the rebasing decision, which is typically not issued until the last plan year. However, some distributors stated that they don't have budget approval delays.

Another distributor noted that "evolving priorities (e.g., DER integration, cybersecurity, electrification trends, etc.) can delay implementation timelines, resulting in a higher concentration of spending toward the later years of a rate plan." An intervenor noted relatedly that

> It is common for projects to be delayed. Utilities often want to complete outstanding work before the end of the term to demonstrate to the OEB and intervenors that they are capable of executing their plans. This can lead to a rush of activity at the end of the plan period.

A distributor noted that

> Customer access projects that individually utilize over 100% of the capital budget result in the deferral of other system renewal, system service and general plant projects. These other projects in the DSP must be deferred to the later years in addition to the projects scheduled for those later years.

Exhaustion of Low Hanging Fruit

One intervenor observed that opportunities to cut costs may diminish in later plan years. This makes some sense since distributors would rationally attack the promising cost containment initiatives first and the remaining prospects could very well be less promising.

Coping with Attrition and Operating Risk

Several distributors stated that financial pressures can cause utilities to defer capex to later plan years or to the next plan. These pressures can result from diverse causes that include a rate plan that provides inadequate funding. For example, the price cap index may rise more slowly than actual input price inflation, or the Z factor may not provide sufficient compensation for hard-to-predict cost shocks. In the last few years, the COVID pandemic posed various cost challenges for distributors. One responding distributor stated that

> Especially in the last few years, inflation on Utility-specific assets has grown at a significantly higher rate than the general inflation rate used in both the PEG models and the IRM rates. Distributors are having to make decisions in the later parts of the DSP to either reduce the volume of work completed to meet the spending forecasts or to significantly overspend on reported values. If the first option is chosen, distributors will need to ask for an increase in spending in the next plan to complete the work required to maintain their system.

Another distributor portrayed the timing of expenditures as a prudent response to operating risk, stating that

> To effectively manage some of our financial challenges, we need to strategically time CAPEX spending to align with revenue adequacy, at least to the extent that it helps to mitigate the risk of long-term sustainability. A combination of factors has led to significantly higher capital replacement costs compared to the past. Funding these increasing expenditures has required a re-evaluation of how internal resources are being deployed.

> Compounding this challenge is regulatory uncertainty, which hampers long-term planning. Current . . . OEB cost recovery mechanisms can constrain early investments in a rate plan. This often leads us to consider back-loading investments, where capital spending is deferred to later years in the plan to align with more favourable cost recovery timing. As a result, there would be a tendency for material surges in capital expenditures and rate rebasing applications in the latter years of a rate plan - a pattern that we recognize, introduces volatility and planning inefficiencies.

This distributor concluded that "spending increases mid-late plan often reflect a utility's efforts to manage financial risks responsibly while balancing growth and operational demands." Another distributor noted that "the incentive to defer spending may arise when utilities feel they lack sufficient mid-term flexibility or if cost recovery risks increase due to perceived disallowances in future applications."

A corollary to this view is that containing opex in early plan years can reduce the risk of unaffordably high costs in later years. A distributor stated in this vein that "to maintain financial balance, controlling and constraining OPEX expenditures early/mid plan is usually a consideration."

Other Expenditure Drivers

Respondents also mentioned miscellaneous other cost drivers that would not necessarily lead to a particular spending pattern. For example, cost is sensitive to various external pressures that include input price inflation, availability of materials and labor, severe storms, growth in network access requirements, accommodation of road widening and rail projects, unplanned asset failures, and changing government policies. These pressures can cause cost to surge in any year of a rate plan. One distributor averred that external cost pressures would not disproportionately affect late-plan costs.

Here are some other expenditure drivers that respondents mentioned.

- Changes in planning procedures such as changes in how asset health is calculated or how risk is evaluated
- Shifts in leadership and strategic direction
- Changes in asset management practices
- Changes in distributor budget strategies such as moving from bottom-up to top-down practices
- Unforeseen cost overruns by third party contractors

Defensibility of Spending Patterns

Some intervenors suggested that, while late plan cost surges could be warranted for any utility under special circumstances, it should not be an industry pattern. One intervenor stated that an industry-wide pattern "is highlighting strategic behavior by the utilities to maximize profits under the OEB's rate-setting framework."

Consequences of Spending Patterns

Several consequences are noted from spending surges in later plan years. These include the following.

- Distributors spend too much in the bridge year.
- Capex is deferred until the next plan so that customers pay twice.

Suggestions to Improve OEB Ratemaking

Respondents stating that spending patterns are not a problem generally did not believe that remedies are warranted. Respondents that did express concerns about spending patterns were nonetheless generally circumspect about the changes to OEB ratemaking practices that are warranted to improve these patterns. Proposed reforms were modest. For example, one intervenor stated that "The rate-setting framework requires a new mechanism to flag the issue of capital spending over a rate term that unreasonably exceeds the amounts forecasted by the utility in the DSP."

Another intervenor stated relatedly that "A [heightened] review should occur if the Capital envelope is overspent and the reasons why." A third suggested that the OEB be notified in advance if capex is going to markedly exceed that detailed in the DSP "so that there is a deterrent to 'wayward' spending."

Another intervenor stated that

> any structural fix [to spending pattern concerns] is likely to result in greater costs being borne by customers in the well-intentioned attempt to fix the incentive problems (e.g. efficiency carryover mechanism). The best thing the PEG/OEB Staff can do is to highlight the issue for commissioners so that they are more likely to recognize the problem when approving test year budgets.

Another respondent questioned the benefits to ratepayers of a smoothed-out spending pattern and stated that

> Changing the rate setting framework such as the use of the single reference year or putting in place more requirements (incentives/disincentives) to monitor spending patterns would pose more regulatory burden and would deprive distributors of the flexibility they need to manage resources within the approved budget and make spending decisions that they deem appropriate.

An intervenor raised the issue of whether shorter plan terms might be warranted if capex forecasts over five years cannot be made with reasonable accuracy.

One distributor seeks more financial flexibility to respond to extraordinary and unforeseen cost drivers within the plan term. Another stated relatedly that "for us to effectively manage infrastructure and plan for the future, it requires regulatory predictability and a cost recovery framework that supports steady, proactive investment that is recoverable."

This distributor called for a Return on Equity DVA [which appears to be tantamount to a comprehensive variance account, which Americans call a (cost of service) formula rate] for utilities that are demonstrably good cost performers. It maintained that "this would promote consistent infrastructure investment," and presumably reduce the need to resort to late-period cost surges as a coping mechanism.

Some distributors cautioned that policies to improve spending patterns be considered in the context of recent changes in OEB policies. These changes include cost benchmarking updates, a reduction in the regulated cost of capital, the development of penalty-only PIMs, encouragement of non-wire alternatives, and the general reliance on electricity distributors to play a key role in the energy transition.

One intervenor was concerned that there be strong incentives for cost containment in the OEB's rate-setting framework. It suggested three changes to the rate-setting framework.

1. Reconsider the availability of Custom IR option.
2. Reduce the eligibility/availability of ICM/ACM (i.e., limit eligibility to "unusual," discrete and non-discretionary capital spending).
3. Explore totex-type rate setting.

Suggestions for PEG's Analysis

One intervenor recommended that the SPA be expanded to

- compare spending patterns of sampled distributors that have used various kinds of ARMs (e.g., price cap vs. Custom IR);
- compare how a utility's spending pattern changed when it moved to a different kind of ARM; and
- compare actual costs to approved costs by ARM type.

A distributor "requests that PEG's analysis be shared with the industry for review and comment to ensure that the consultation is transparent and provides meaningful opportunities for stakeholders to understand and provide input."

6.2 Capitalization Policy

Intervenors were generally less voluble regarding capitalization policies. Some stated that they were unable to provide much information or perspective on capitalization issues but acknowledged that these were important. Several intervenors were unaware of any rising trend in the capitalization of repair and field work expenses. One commented that

> We are not aware of this being an issue, but that is primarily due to the fact that such changes are not easily visible to intervenors. A utility may make changes to the interpretation of an existing capitalization policy (for example, adopting a more aggressive interpretation of the existing approved policy), and this would not be apparent or visible to intervenors in a rate proceeding. To be clear, we are not suggesting that this is occurring just a reason why we do not have specific examples.
> Another intervenor opined that

> With decreased forecasted use of natural gas into the future, there has been a pivot to a request for variance accounts for Capital integrity projects…. This was a trend for Enbridge but given the risk for stranded Capital in the future, the OEB has been actively working to ensure that OM&A is not Capitalised. The risks are lower for electricity, but they still exist. Accounting rules do not allow Capitalization of OM&A unless there is special regulatory approval. It is unclear if the OEB was aware that so much was being Capitalised that was not directly related to the Capital assets.

A third intervenor stated that

> Capitalization policy in the electric LDC sector has, in our experience, been relatively stable and largely uncontroversial. What one does occasionally observe are opex increases being masked by a larger than past capital plan (i.e. new hires attributable to an increasing capital programs). Also…utilities (usually smaller) which use outside contractors for a large proportion of their capital work have a different proportion of OM&A capitalized.

Responding distributors generally claimed that their capitalization policies were not controversial. Several distributors stated that they do not capitalize asset repair and field work expenses. One stated that

> [our] capitalization policy follows IFRS standards. Asset repairs and field work expenses, which consist of day-to-day servicing costs, are deemed repair and maintenance and such costs are expensed. Major asset repairs such as significant refurbishments are capitalized when the refurbishment meets the capitalization criteria and the remaining book value of the replaced part is derecognized.

Another stated that "our current approach remains aligned with IFRS and regulatory guidance, where routine maintenance and minor repairs are expensed as OPEX, while CAPEX is limited to work that meets materiality thresholds and IFRS capitalization criteria." A third distributor stated that "only expenditures meeting established thresholds for betterment and asset life extension are capitalized."

One distributor stated that it does not capitalize costs for what it generally considers to be asset repair, i.e., costs to keep assets in normal operating condition but do not improve the value of the asset, nor prolong its life appreciably. The company did acknowledge, however, that it has changed its field work capitalization policy over time.

Another distributor provided a helpful explanation of its capitalization policy, stating that

> [it] applies capitalization in accordance with International Financial Reporting Standards (IFRS), specifically IAS 16 – Property, Plant and Equipment, which requires that expenditures be capitalized when they are directly attributable to bringing an asset to the location and condition necessary for it to operate as intended, or when they extend the asset's useful life, enhance its output capacity, or improve service potential. Fieldwork expenses are capitalized only when the activity meets these recognition criteria. For example, distribution system upgrades—such as reconductoring, voltage conversion, or transformer upsizing—typically result in increased future economic benefits and therefore meet the capitalization threshold under IFRS. Where work is classified as a repair or maintenance activity that does not enhance future service potential, it is recorded as an OM&A expense.

This distributor also acknowledged changing its capitalization policy, stating that

> Over the past 15 years, [it] has periodically refined internal practices to ensure alignment with evolving guidance, requirements and interpretations of capitalization eligibility, particularly as they relate to indirect costs and field operations.

Another distributor was open to changing its capitalization of asset and field work expenses, stating that

> it may be appropriate to review the cost classification to ensure cost causation is accurately reflected. If the nature of the work clearly meets IFRS capitalization standards, there could be a valid rationale to reconsider its classification.

Recommended Capitalization Policies

A distributor noted that some kinds of asset field work (e.g., painting pad-mounted transformers) can affect asset service lives. An intervenor opined that expenses related to the adoption of new and improved technologies/assets that help extend service life and withstand weather conditions expected to be more severe and more frequent are justifiable [candidates for capitalization].

This intervenor also averred that the OEB, distributors, and other stakeholders should provide further clarity, and "as exhaustively as possible" identify circumstances in which expenses may be capitalized. An additional benefit from this review would be to adapt capitalization policies to reflect changes in technology that impact asset repairs and maintenance. Capitalization policies should reflect the expectation for distributors to replace aging assets with newer assets that are better equipped to withstand severe weather events.

Changing Capitalization Policy in the Middle of the Plan

One intervenor doesn't believe it is reasonable for a utility to change its capitalization policy during an MRP. It stated that "The right approach would be for the OEB, distributors and other stakeholders to improve the current capitalization policy by providing further clarity and, as exhaustively as possible, identifying circumstances in which a distributor could capitalize these expenses."

Another intervenor stated that distributors that change their capitalization policy in the middle of a plan should "present (or be prepared to present) the test year with both the preexisting and new policy for consideration by the OEB." A distributor suggested

- Enhanced guidance on the treatment of refurbishment and modernization activities, particularly for aging infrastructure

- Mechanisms to review capitalization trends as part of DSP or asset management plan reviews

- Explore standardization of capitalization practices across LDCs for consistency, possibly through periodic benchmarking or audit frameworks

Confidentiality

Responding stakeholders were generally opposed to sharing their responses with the public. However, most respondents said that their comments could be shared with the OEB. Several respondents emphasized that their comments were to be used for the purpose of this proceeding only.

7. Summing Up the SPA Analysis

It makes sense to sum up at this point in the report what our reviews of the ratemaking literature and experience in other jurisdictions, the comments of SPA survey respondents, and our empirical research for this project have revealed about utility spending patterns. We also try to fill in some holes in the evolving theory regarding these phenomena.

7.1 Theory

Compared to traditional ratemaking, MRPs can strengthen utility cost containment incentives and streamline the ratemaking process. However, ways must be found for utilities to afford the cost of its base rate inputs. In these rebasings, proceedings determine the reasonable chance to recover the cost of providing their services and to share plan benefits fairly with customers. A standard means of achieving these goals has been the occasional but regularly scheduled rebasings of a utility's base revenue requirement. Appropriate revenue adjustments are typically expected to occur in the last year of the plan. When forward test years are used in rebasing proceedings they are often combined with historical reference years in the later years of the plan. Quite commonly, a single historical reference year is used that is the penultimate year of the plan. Standard rebasings can substantially weaken utility performance incentives and raise regulatory cost. These problems are exacerbated the more frequently these rebasings occur.

MRPs with standard rebasings can also incentivize skewed utility spending patterns during the years of a rate cycle. These patterns are as much a symptom of the general weakness of cost containment incentives as they are a separate problem. Generally speaking, MRPs with standard rebasings tend to weaken utility performance incentives near the end of each plan.[138] This occurs for reasons that include the following.

- Higher costs in later plan years encourage higher rates in the next plan. For example, brisk cost growth in later plan years supports the impression that cost pressures are intensifying, thereby strengthening the utility's case for higher revenue in the next plan. The benefits of higher revenue for the utility include higher earnings, reduced risk, and less pressure on utility personnel to improve performance. When plans have indexed ARMs, as in Ontario, the case is strengthened for utilities to receive more favorable index formulas (e.g., lower X factors) and supplemental revenue (e.g., for capital) in the next plan.

- Plant additions give rise to a stream of annual capital costs (e.g., depreciation expenses, return on the depreciated rate base, and taxes) that typically last for many years. The annual capital cost is highest in the early years of an asset's service life because the rate base is less depreciated. Regulators are often reluctant to disallow costs of capex that has actually occurred. If the test year for the rebasing is forward looking, revenue in the rebasing year reflects capex in the last years of the expiring

[138] These kinds of tactics may also occur under traditional ratemaking. A notable difference is that utilities do not typically receive as much automatic revenue growth in that context.

plan. In Ontario, a portion of the capex in a given year is not eligible for inclusion in the rate base until the following year. For all of these reasons, shifting capex to later years of an MRP bolsters utility earnings and increases the share of the high initial annual capital cost that customers pay for. The incentive is particularly strong to bunch capex in the last year of the expiring plan.

- Capex pattern incentives are also affected by other MRP provisions that include mechanisms to provide supplemental capital revenue. In Ontario, supplemental capital revenue is usually based on capex forecasts. Spending close to forecasts in early plan years may bolster the utility's credibility with regulators and access to continued revenue supplements. Incentives to contain capex are further weakened when there is a provision for returning the cost of capex underspends to customers.

- Spending pattern incentives also depend on specifics of the rebasing process such as the number of historical reference years that are used, the extent to which test years are forward looking, and the extent to which the revenue requirement is based on forecasts rather than a mechanistic escalation of normalized costs for the historical reference year. Multiple historical reference years discourage the bunching of cost in one or two reference years. Forecasts permit the utility to "spin" the issue of why cost in the next plan will be so much higher than in early years of the prior plan.

- Some cost efficiency initiatives entail up-front costs to achieve sustained benefits. In later plan years, the payback period for many of these initiatives may be too long to warrant their pursuit.

Late plan cost surges can bolster utility earnings, but they can also reduce losses. Losses can occur for various reasons. For example, a plan may not compensate a utility for the efficient cost of its services, or the utility may not be efficient. A utility's efforts to reduce losses when it is underearning could obviously include greater cost containment, but they could also include shifting necessary capex to later plan years. Utilities that use this coping strategy are effectively shifting some of their problems to customers.

While MRPs with standard rebasings seem to encourage more cost growth in the later years of a plan, the expectation for the first year of the next plan is less clear. The following considerations suggest that cost growth should tend to be slow in that year.

- Sustained cost savings that start in the first year of an MRP will benefit utilities the longest.

- We just noted that utilities have a particularly strong incentive to surge capex in the last year of a rate plan. This creates a high base for computing the capex growth rate in the first year of the next plan.

- In Ontario, the rate base for the first plan year will not reflect the full amount of plant that is added in that year. This encourages some shifting of capex from that year to the bridge year.

- Regulators often push back on utility forecasts of cost in the rebasing year.

- Utilities may fear that deferring a cost from an expiring plan to the first year of the next plan may prompt accusations of paying them twice for the same task.

Other considerations suggest that cost growth will tend to be brisk in the rebasing year.

- Given the substitutability of opex for capex in certain areas, and a utility's general tendency to favor capex solutions, it's possible for a utility to spend too *few* OM&A inputs instead of too *many*. We noted in Section 5 above efforts by British regulators to encourage opex substitutes for capex using totex accounting. Insofar as capex containment incentives are stronger in early years of a rate cycle than in later years, the utility has stronger incentive to use more capex-substituting OM&A inputs at the start of an MRP.

- Insofar as it makes more sense to undertake sustained cost reductions in early plan years, the first year would be a good one to incur any upfront costs that are required to make these reductions. For example, labor force downsizings might entail severance payments.

- A utility may wish to bolster their forecasting credibility by having a rebasing year cost that is similar to its forecast.

Our analysis suggests that MRPs can have different effects on capex and opex patterns. Capex is more likely to surge in the last year of an MRP and to grow more slowly in the first year of the next plan. Supplemental capital revenue should influence the pattern of capex more than it influences the pattern of opex.

The incentives created by an MRP rate cycle tend to encourage the following kinds of utility behavior.

- Defer costs to later plan years or the next plan.

- Deferment on one-off opportunities to contain cost in later plan years.

- When forecasting cost for the next plan, do not assume that opportunities for cost deferrals and one-off cost reductions will be similar to (much less greater than) those in the expiring plan.

- Defer wholly new initiatives requiring sizable funding (e.g., construction of a new substation) until the start of the next plan.

- Repackage old expenditure initiatives that had been deferred as components of new initiatives.

- Increase capitalization of OM&A expenses during a plan (as this can also shift costs to the next plan).

The resultant spending patterns incentivized by MRPs with standard rebasings tend to be suboptimal for several reasons.

- Promising efficiency initiatives are not pursued.

- Bunching deferable expenditures can add to inefficiencies.

- Customer benefits from MRPs are reduced. For example, customers may not share in the annual capital cost savings realized by deferring capex until later plan years. At the extreme, capex may be deferred until the next plan, thereby requiring customers to “pay twice” for the high early annual costs of capex.

While theory suggests that MRPs encourage strategic tactics that lead to suboptimal utility spending patterns, it is important to recognize that such patterns may also occur for other reasons. We have already mentioned that some kinds of efficiency initiatives may be uneconomic for the utility in later plan years. Here are some other circumstances that tend to encourage late-plan spending surges.

- The quality of opportunities for cost savings may diminish in later plan years.

- External cost pressures may intensify in later plan years. For example, the number of electric vehicles in the service territory that require recharging may be growing rapidly.

- Regulatory cost tends to rise in later plan years due to rebasing proceedings in those years.

- Operation of deferral and variance accounts may cause a cost surge in the rebasing year.

Other circumstances have impacts on spending patterns that sometimes cause later year cost surges even though they have no inherent tendency to do so. These circumstances include the following.

- Severe storms and wildfires

- Changes in planning, asset management, and budgeting practices
- Shifts in leadership and strategic direction

7.2 Real-World Manifestations of Skewed Spending Incentives

A tendency of utility spending to be skewed to later years of an MRP rate cycle has been documented in several studies by regulators and academic scholars. Several plan provisions that have been approved by regulators are rationalized, in whole or in part, by spending pattern concerns. Ontario intervenors responding to the SPA survey voiced a belief that such patterns are common and are influenced by the incentives that MRPs provide.

Our statistical cost research on spending patterns of Ontario electricity distributors did find evidence that the cost growth is skewed to later plan years. The patterns were more pronounced for capex than for opex, and only the capex patterns were found to be statistically significant. Patterns frequently occurred for underearning utilities. Moreover, a sizable minority of distributors did not display the skewed patterns. The capex spending pattern was not typical of the larger distributors that serve most customers. This may reflect a greater need by larger distributors for capex, but it may also reflect their common recourse to supplemental capital revenue, which has often entailed capital cost forecasts and a claw back of underspends that can weaken capex containment incentives.

7.3 Qualifications

Our focus on spending patterns in this paper is not intended to suggest that this is the only or even the biggest problem in Ontario ratemaking. One problem that, in PEG's experience, merits attention is provisions for supplemental capital revenue that weaken capex containment incentives.

Even if spending pattern problems are not rectified, the ability of MRPs to streamline ratemaking can still make these plans a reasonable choice for regulators that face particularly daunting ratemaking challenges. Examples of these challenges include the following.

- The number of jurisdictional utilities is large.
- The overall scale of utility operations in the jurisdiction is large (e.g., there are four hundred distribution substations to oversee, not forty).
- There are numerous important and complex ratemaking issues to consider.

The OEB regulates numerous utilities serving an important regional economy and faces many complicated ratemaking issues due in part to the energy transition. The outsized need for regulatory efficiency together with desire for better utility performance makes MRPs arethus a sensible choice for Ontario electricity distributors. However, it may be possible to increase their benefits and share these benefits more fairly with customers.

8. Remedies for Spending Pattern and Capitalization Concerns

8.1 Spending Pattern Remedies

Introduction

Sections 3-7 of this paper established that MRPs with standard rebasings can weaken utility incentives to contain cost growth in later plan years. The result can be cost surges in these years that diminish efficiency gains from MRPs and reduce the share of benefits from these plans that customers receive. A pattern of late plan cost surges has been noted by ratemaking theorists, Ontario intervenors, and regulators in other jurisdictions. While skewed spending can also result from other factors, several regulators have been sufficiently concerned about spending patterns to have approved mechanisms designed to remedy them. Some of these are quite complicated.

The empirical research detailed in Section 2 of this report has identified a tendency for the cost growth of Ontario electricity distributors to accelerate in later years of an MRP rate cycle. While both capex and opex exhibit this pattern, it is more pronounced and statistically significant for opex. A sizable minority of plans do not display the skewed pattern. The larger utilities that serve most Ontario customers have not tended to display capex spending surges. These findings suggest that adding complicated new mechanisms to Ontario ratemaking with the sole intent of unskewing spending patterns may not be warranted. However, some of these remedies may also address other concerns, such as sluggish performance improvement.

This section of the report considers remedies for skewed spending patterns. A remarkable variety of remedies for skewed spending patterns have been tried by regulators or discussed in the scholarly ratemaking literature. These remedies have included the following.

- Examine a utility's spending pattern in the last plan more carefully when considering its appropriate revenue requirement for the next plan.

- Consider on an ad hoc basis special ratemaking treatment for sustained cost reduction initiatives that utilities pursue in later plan years. The utility could propose such a treatment during a plan or request it in the next rebasing. For example, a utility could propose in the penultimate year of the plan a labor force downsizing in the last year provided that they are compensated for downsizing costs.

- Extend the duration of plans.

- Use multiple historical reference years in rebasings.

- Efficiency carryover mechanisms

- Reduce the extent to which rate resets between plans reflect the utility's cost in the later years of prior plan through approaches like the following.
    - Yardstick Ratemaking
    - Modify the existing Menus of Ratemaking Options
- Add an earnings-sharing mechanism to the plan.
- Reconsider capitalization rules for OM&A expenses.

We discuss pros and cons of these options below and comment on their suitability for implementation in Ontario.

Some of these remedies are already used in Ontario ratemaking. Since skewed spending patterns (e.g., lower investments in early plan years than in later plan years) nonetheless exist, attention should be paid to using these remedies more intensively and/or adroitly. Since many plans have not resulted in skewed spending patterns and several large distributors have not recently displayed skewed capex patterns to our knowledge, complicated new mechanisms may not be warranted solely to discourage skewness. However, some of the mechanisms we discuss may nonetheless merit continued appraisal in the OEB's Advancing PBR initiative due to the full range of benefits that they provide.

Increased Focus on Spending Patterns

The Basic Idea

Increase the attention paid to spending patterns in the expiring plan when considering the revenue requirement for the next plan.

Recommendation

The option makes sense for Ontario. Rate rebasings typically occur every five to eight years (which is to say that rebasings are going to occur anyways with some regularity). In addition to looking for skewness, the issue of divergence from distribution system plans can receive increased emphasis and these matters can loom larger in OEB decisions.

Giving more attention to skewed spending patterns in rebasing proceedings can help to discourage these patterns as well as to identify patterns that do occur. Econometric opex and capex benchmarking models can be developed to identify questionable cost surges. We used results from an econometric cost benchmarking model to explore the opex pattern of Enbridge in Section 2 above.

Use Multiple Historical Reference Years in Rate Rebasings.

The Basic Idea

We noted above that, even when rebasings use forward-looking test years, they frequently also consider costs in historical reference years. To the extent that these reference years are few in number and occur only towards the end of the MRP, they encourage a bunching of costs in these years. Revenue requirements for opex, capex, or both can instead reflect the cost that the utility incurs in most or all years of the expiring plan, including the early years when cost containment incentives are stronger.

Consideration should also be paid to combine normalized costs in multiple historical reference years with a mechanistic escalation for input price inflation and growth in operating scale and productivity. Australia's "base-step-trend" approach to escalating opex is a good example. The Australian approach affords the utility some flexibility in establishing the future revenue requirement, while still relying extensively on mechanistic escalation that reduces the role of cost forecasts. In Alberta, distributors are expected to report historical costs escalated mechanistically even if they propose to use forecasted costs to set the opex requirement. The K-bar terms of attrition relief mechanisms effectively result in capital revenue for *all* years of the next plan being based on the average gross plant additions of the utility in multiple years of the expiring plan, as suitably escalated for external business conditions.[139]

Pro

This is another approach that could improve spending patterns without resorting to novel ratemaking mechanisms. In Ontario, multiple historical reference years have been considered in many Ontario proceedings, but the focus is often on later years. Mechanistic escalation of these costs is rarely used, and this increases the role for utility cost forecasts that exploit asymmetric information.

The use of multiple historical reference years is supported by ratemaking theorists, PEG's incentive power model, and Alberta experience. Variants on Alberta's K-bar approach to the establishment of capex budgets have been used in California and Massachusetts.

Con

Ontario rebasings are usually not based on a mechanistic escalation of normalized costs in historical reference years, so this would be a novel measure. Normalizing cost in multiple

[139] The K-bar approach was used in the second generation of generic MRPs for Alberta energy distributors. Distributors have challenged its use in third generation PBR in Alberta courts. This reflects in part the decision of the AUC to base capex budgets in PBR3 on average capex in the PBR2 plan. During this plan, distributors had stronger capex containment incentives than they did in the PBR1 plan.

historical reference years can be time-consuming and controversial. Some stakeholders will question the reasonableness of escalating normalized costs in these years mechanistically.

Recommendation

More consideration of distributor costs in multiple historical reference years makes sense, particularly when there is evidence that costs were skewed to later years of the prior plan. Consideration should also be paid to expanded use of the mechanistic escalation of normalized costs in (multiple) historical reference years. Ontario regulatory community can "get its feet wet" by comparing the results of such calculations to utility cost forecasts in more proceedings.

Yardstick Competition

The Basic Idea

Yardstick competition entails the use of statistical research on the cost of other utilities to set utility rates. This can be done in several ways.

The utility's revenue requirement ("RR") can depend in part on results of statistical benchmarking using data on the cost and external business conditions of numerous utilities. One possible approach is a formula like

$$RR^{Adjustment} = \text{b x } (Cost^{Benchmark} - Cost^{Actual\ or\ Proposed}) \qquad [3]$$

where $RR^{Adjustment}$ is the revenue requirement adjustment, $Cost^{Benchmark}$ is an external cost benchmark based on statistical cost research, and b is a fraction in the interval [0,1].

The revenue adjustment can be made directly to the RR, as in formula [3], or indirectly by linking the stretch factor term of an ARM formula to benchmarking results. A formula like [3] cannot be used with the kind of total cost benchmarking models that the OEB has used since 2013 since these feature a monetary approach to measuring capital cost that is incompatible with cost-of-service accounting. However, it could be used with econometric models of opex or capex.

The ARM can, alternatively or in addition, reflect the unit cost trend of a utility peer group, as in the familiar price cap index formula

$$growth\ Rates = I - X + Y + Z$$

where I is price inflation and X reflects the estimated industry productivity trend and a stretch factor. The Y factor and Z factor terms in the formula adjust rates for certain hard-to-index costs.

Yardstick Pro

The regulatory community of Ontario has extensive experience with yardstick competition. The OEB uses rate and revenue cap index formulas with X factor terms that reflect industry productivity trends and results of statistical cost benchmarking. This research has been facilitated by the availability in Ontario and the United States of standardized and highly itemized operating data for many energy utilities over many years.

Statistical benchmarking is used today by regulators in many jurisdictions. Several of these jurisdictions are on the forefront of the energy transition, such as Australia, British Columbia, Great Britain, and Massachusetts. Australia's regulators have credited benchmarking with having a major impact on opex efficiency.

Total cost benchmarking in Ontario already strengthens the incentive for late plan cost containment. It does this in part by linking a utility's revenue growth to an appraisal of its recent historical and forecasted test year performance and in part just by using an external cost benchmark in the determination of revenue.[140] By lowering costs in later plan years, the utility has a better chance of entering the new plan with costs that are either below the benchmark or less far above it. The incentive impact of benchmarking could be increased by increasing its role in the determination of utility revenue requirements. For example, the sensitivity of revenue to benchmarking results could be increased.

The OEB could also consider new uses of benchmarking, including itemized benchmarking of OM&A expenses and capex. Regulators in other countries (e.g., Australia) focus on opex and/or capex and totex benchmarking, although this is partly due to the inadequacy of data needed for benchmarking of annual capital cost and total cost that is practicable in Ontario and the United States.

Yardstick Con

The statistical research required for yardstick competition can be complicated and controversial. Methodological controversies between dueling expert witnesses have arisen over cost research methods in several OEB proceedings. The issues debated have included alternative capital cost specifications and econometric estimation procedures.

Some countries lack the data needed for good research on utility cost performance and input price and productivity trends. Data problems encountered in these countries include inadequate standardization and itemization of utility cost data, not enough utilities or years of good data, and poor quality data on input prices and other cost drivers. Data from multiple jurisdictions is an alternative to reliance on one jurisdiction's data but has its own limitations. For example, data may be less standardized, and the scope of utility operations may vary more in a multi-jurisdictional study.

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[140] In other words, performance incentives are strengthened just by using an external benchmark.

By international standards, Ontario and the U.S. have good data on the operations of energy distributors. However, Ontario data are unsuitable by themselves for benchmarking the cost of some of the province's largest utilities. For example, Hydro One serves an unusually large rural area while Toronto Hydro must contend with unusually extensive urban congestion. These utilities already file benchmarking evidence from multijurisdictional samples in their rebasings proceedings.

Recommendation

An increased role for statistical benchmarking in Ontario merits consideration and will be discussed in the Ongoing TCB/TFP initiative. However, it would likely be pursued for the numerous benefits that it can provide and not just to unskew distributor expenditure patterns.

Longer Plan Term

The Basic Idea

The term of the plan can be extended (e.g., from five years to seven). The OEB already permits individual distributors to defer their rebasings for several years. Consideration could be paid to increasing plan terms for all distributors.

Longer Term Pro

- Extending the terms of MRPs can strengthen utility cost containment incentives. Longer plan terms can also streamline ratemaking. There will be more years to benefit from initiatives to achieve sustained cost reductions. Rebasing initiatives can preoccupy utility management in two of every six or seven years instead of two of every five.

- The extensive experience of Ontario's regulatory community with MRP design should help it design longer plans that reasonably anticipate future cost pressures.

Longer Term Con

- PEG's incentive power research suggests that the incremental cost efficiency gains from this approach are reduced when plans are already five years long, as they are in Ontario. The incremental benefits of this approach are greater when the terms of MRPs are initially on the short side (e.g., the change is from three- to five-year terms).

- Fashioning an ARM that is just and reasonable for a term exceeding five years is a challenge, and brisk demand growth due in part to the energy transition goals of the federal and Ontario governments add materially to this challenge. Longer plan terms will encourage calls for greater use of cost forecasting and cost variance accounts that weaken utility cost containment incentives and complicate the design of MRPs.

- The problem of weak performance incentives in later plan years persists when the terms of MRPs are extended. Skewed spending can still materially reduce the potential benefits to customers of MRPs.

- We noted in Section 5 that the British regulator recently tried eight-year MRPs but has since returned to five-year plans.

Recommendation

Longer plan terms for all Ontario electricity distributors may not make sense in this period of rapid change. However, longer terms might merit consideration in EGI's regulation. The OEB's practice of extending plan terms for individual distributors should continue.

Efficiency Carryover Mechanisms

The Basic Idea

Any mechanism that permits a utility to keep a portion of efficiency gains and/or losses that they achieve in one plan after it expires can reasonably be called an ECM. However, the ECM term is typically reserved for mechanisms that do this *expressly* by estimating efficiency gains and losses during one plan and then reserving a portion of them for the utility in the next plan.

An ECM thus defined requires an estimate of a utility's lasting efficiency gains (and/or losses) during a plan and a mechanism for sharing them with the utility after the plan expires. The estimate of efficiency gains (and/or losses) often uses the predetermined revenue requirements in the years of the expiring plan as benchmarks that are compared to the utility's actual cost in those years. Awards and penalties are sensitive to cost efficiency in later plan years when weak cost containment incentives are otherwise suspected.

Suppose, for example, that a utility's revenue requirement in the first year of its next plan (RR_t) is based on a mechanistic escalation of its normalized cost in the penultimate year of its expiring plan. The escalation is specifically assumed to use an I – X + G index formula like those that have been approved for some Ontario revenue cap indexes. In this formula, *G* is the growth in operating scale.[141]

In the absence of the ECM, the revenue requirement might be determined by the following formula:

[141] A real-world formula might also include a Y factor and a Z factor where the Y factor represents revenue adjustments for variance accounts.

$$RR_t = Cost^{Normalized}_{t-2} \text{ x } (1 + I_{t-1} - X + G_{t-1}) \text{ x } (1 + I_t - X + G_t).$$

Suppose next that cost efficiency in the historical reference year (*t-2*) is measured as ($Cost^{Benchmark}_{t-2}$ - $Cost^{Normalized}_{t-2}$) where the benchmark might be the predetermined revenue requirement for that year or an econometric benchmark. The addition of an ECM could then result in the revenue requirement in year t being based on the following formula.

$$RR_t = [Cost^{Actual}_{t-2} + \overbrace{b \text{ x } (Cost^{Benchmark}_{t-2} - Cost^{Normalized}_{t-2})}^{\text{efficiency carryover mechanism}}] \text{ x } (1 + I_{t-1} - X + G_{t-1}) \text{ x } (1 + I_t - X + G_t)$$

$$= [(1- b) \text{ x } Cost^{Normalized}_{t-2} + b \text{ x } Cost^{Benchmark}_{t-2}] \text{ x } (1 + I_{t-1} - X + G_{t-1}) \text{ x } (1 + I_t - X + G_t).$$

The parameter *b* in this formula would be a fraction in the interval [0,1]. Note that this is a symmetrical mechanism that would reward the utility for having a low cost in the historical reference year but also penalize it for having a high cost in that year.

Many variations on this simple ECM are possible. For example, we noted in Section 5 that rolling incentive schemes have been used as ECMs in Australia, Great Britain, and New Zealand.[142] Table 6 below provides a stylized example.[143] The basic idea is that the utility gets to keep for five years any incremental efficiency gains beneficial to customers that it achieves. A reward is only made if it achieves efficiency gains that carry over into rates in the next plan. The predetermined opex revenue requirement in the expiring plan is the benchmark.

Inspecting the table, it can be seen that in the hypothetical example, the utility achieves a big efficiency gain in the first year. If this gain is sustained, the utility will benefit from it for five years. There is no need for a post-plan award and customers receive all of these benefits in the initial rates for the next plan. The utility does not achieve any incremental (i.e., further) efficiency gains again until year 3 of the plan. The utility benefits from this further saving for the last three years of the plan and the ECM permits the customer to keep the benefit for two additional years after the plan expires. The following year, cost efficiency diminishes a bit, and this reduces the after-plan benefits. The utility would not receive any post-plan award if its efficiency deteriorated in later plan years to the point that no lasting incremental efficiency gain was achieved in the last four years of the plan.

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[142] The Appendix includes a discussion of a rolling incentive scheme that was approved in Ireland.
[143] Frontier Economics, "Developing Network Monopoly Price Controls: Workstream B, Balancing incentives, A final report prepared for Ofgem," March 2003, p. 40.

Benchmarks based on statistical cost research could be used to establish cost benchmarks instead of the expiring plans' revenue requirements. PEG's incentive power research suggests that benchmarks based on statistical research have more incentive power than benchmarks based on the predetermined revenue requirement of the expiring plan. Using Ontario data, PEG is developing credible econometric capex and opex models in the TCBTFP project that could, with some enhancements, be used in ECM designs.

Table 6

A Stylized Example of the Calculation of Operating Expenditure Incentive Payments, with Underperformance

Plan 1					
	1996	**1997**	**1998**	**1999**	**2000**
Allowed Opex	100	99	98	97	96
Actual Opex	94	93	89	89	88
Efficiency gain	6	6	9	8	8
Incremental gain	6	0	3	-1	0
Plan 2					
	2001	**2002**	**2003**	**2004**	**2005**
Incentive allowance	0+3-1=2	3-1=2	-1	0	0
Actual Incentive allowance	2	1	0	0	0

ECM Pro

- Several regulators have approved rolling incentive ECMs to deal with skewed expenditures, and some of these regulators have expressed satisfaction with these mechanisms.

- Our incentive power research shows that the impact of ECMs on cost efficiency can be material and that the complications and risk of a longer plan term can be avoided. The addition of an ECM could preserve incentive power should the OEB be interested in shorter (e.g., four-year) plan terms.

- By strengthening cost containment incentives in later plan years, ECMs can make it easier to rely on a combination of the costs incurred in these years and simple escalation formulas like *I–X+G* to reset revenue requirements in rebasings. With such mechanisms, there is less scope for cost forecasts in rebasings that raise regulatory costs and exploit information asymmetries.

- The OEB is better situated than many regulators to base revenue requirements on indexing and to make cost-efficiency calculations based on statistical benchmarking.

ECM Con

- The popular rolling incentive form of ECM is used in the context of mechanized escalation of normalized historical reference year costs in rate rebasings. This approach to rebasing is not currently used in Ontario. Rolling incentive ECMs make less sense to the extent that the utility can argue for and receive more revenue than a mechanistic escalation of cost in the historical reference year would allow.

- ECM formulas can be complicated. This concern is amplified by the fact that in Ontario, our empirical research has suggested that capex ECMs might be warranted for medium and small-sized distributors but not for the largest distributors. In New Zealand, we noted in Section 5 that ECMs don't apply to customer-owned distributors, many of which are small.

- ECMs that focus only on OM&A expenses or capex may lead to inefficient cost shifts. For example, an ECM focused on OM&A expenses may encourage a utility to prefer capex solutions or to change its capitalization policy to ensure that a larger share of OM&A expenses can be capitalized. The need to balance incentives for containment of two costs further complicates ECM design.

- The adequacy of a utility's approved revenue requirement in the expiring plan as a benchmark for its cost is often questionable. This is especially so if the revenue requirement is based on cost forecasts, since in that case the utility benefits from asymmetric information. This is one reason why some regulators have questioned the efficacy of their capex ECMs.
- Some ECMs may seem counterintuitive to some parties insofar as they can *add* to a utility's revenue requirement in the next plan to reward them for *lowering* costs in the prior plan.

Recommendation

ECMs merits continued consideration in the Advancing PBR initiative. However, they would likely be pursued for the numerous benefits that they can provide and not just to unskew distributor expenditure patterns.

Incentive-Compatible Menus

The Basic Idea

The basic idea of this approach is to present utilities with a menu of ratemaking options that encourage them by their choices to reveal their expectations of their cost containment potential and to share plan benefits with customers without recourse to a traditional full rebasing that weakens utility performance incentives in later plan years. A good example is the availability of the AIR option to Ontario electricity distributors under the OEB's Renewed Regulatory Framework. This option permits distributors to avoid rebasings in return for operating under a price cap index that has the maximum 0.6% stretch factor and no opportunity to request supplemental capital funding. Ontario electricity distributors are also permitted to request a postponement of their next rebasing, and many have done so. The AIR option could be revised, and/or additional options could be offered.

Menus Pro

The OEB is better positioned than many regulators to design good menu options. It has, remarkably, already approved one such option and also has extensive experience with statistical cost research and other MRP design tools that are useful in designing menu options.

Menus Con

Good menus of ratemaking options are difficult to design well.

Recommendation

Incentive compatible menus merit continued consideration in the Advancing PBR initiative. However, they would likely be pursued for the numerous benefits that they can provide and not just to unskew distributor spending patterns.

Earnings Sharing Mechanisms

The Basic Idea

ESMs are designed to share with customers of a utility variances between its realized ROE and its commission-approved ROE target. Approved ESMs are often asymmetrical. Most commonly, they share with customers a higher percentage of any earnings surpluses than they do of any earnings deficits. Many ESMs have dead bands where earnings variances within a certain range are not shared.

ESM Pro

ESMs can share with customers the benefits of efforts to improve efficiency in early plan years even if these gains are offset by higher costs in later plan years. Ontario's ratemaking community already has experience with ESMs, as they have been used in several plans.

ESM Con

Our incentive power research showed that ESMs can materially weaken utility incentives to achieve efficiencies. Incentives for cost containment in Ontario are already weakened by supplemental capital revenue provisions that are based on forecasts and have often been accompanied by a claw back of underspends. ESMs also raise regulatory cost modestly and can invite gaming and controversy. For example, a utility could manipulate its cost by various means to limit the sharing surplus earnings. Considering additionally that many plans have not resulted in skewed spending patterns, ESMs may be a remedy that is worse than the disease.

Recommendation

We do not recommend ESMs as a remedy for skewed spending patterns.

8.2 Capitalization Policies for OM&A Expenses

Our reviews of the ratemaking literature, accounting standards, jurisdictional precedents, and survey responses prompt the following comments about capitalization policies. These policies are an important issue in utility ratemaking. Capitalization of overhead expenses has been an issue for many years. Capitalizations of software services, CDM, and asset repair and field work expenses have recently received attention in some jurisdictions. Widespread use of MIFRS accounting in Ontario has limited changes in capitalization policies, but changes have occurred. These changes have not always been transparent.

Appropriate capitalization policies may change over time and merit periodic reexamination by regulators. Reviews of capitalization policies could be undertaken on a generic basis, or individual utilities could propose innovations in their rebasing proceedings.

The merit of capitalizing asset repair and field work expenses is a complicated issue. Arguments in favor of capitalizing some of these expenses include the following.

- Utilities have a general tendency to favor capex over opex solutions. Capex solutions are especially attractive to utilities in situations where capex containment incentives are weak. In an MRP, capex containment incentives are weaker near the end of the plan or when the cost of capex is accorded variance account treatment.

- Asset repairs and field work can be cost-effective substitutes for some kinds of traditional capital investments such as the replacement of aging assets.

- Utilities may favor capex solutions in some situations where asset repair and field work are more cost effective.

- Capitalization of some asset repair and field work expenses is one way to encourage more of this work. The British regulator Ofgem has taken the big step of capitalizing a share of totex.

Regulators should nonetheless be cautious about increasing capitalization of asset repair and field work expenses for reasons that include the following.

- Capitalization of these expenses raises the cost of using OM&A inputs and thereby narrows their advantage over inputs that have traditionally been considered capital goods.

- In North America, capitalization of OM&A expenses has rarely been proposed in combination with a diminution in the capitalized share of traditional capital goods so as to increase the likelihood that customers benefit from hoped-for cost savings.

- If undertaken during MRPs, increased capitalization of opex can bolster utility profits for reasons other than performance gains and reduce customer benefits from these plans.

- Debates over capitalization policies proved to be a major headache for Ofgem and was one of the reasons that they turned to totex accounting.

- Even if a revenue supplement is needed to get utilities to use more OM&A inputs efficiently, the particular revenue supplement produced by capitalization of these expenses is not necessarily the right one.

- Other ratemaking tools are available to help balance capex and opex incentives. The case of CDM is illustrative. Peak load management and other CDM programs are often mentioned today as utility capex substitutes. These programs can be encouraged by capitalizing expenses for these programs, and CDM expenses of electric utilities have been capitalized in some jurisdictions, including British Columbia. However, other policy measures can also encourage utility CDM. One such measure is to grant variance account treatment to utility CDM expenses. This approach is more effective to the extent that revenue for capacity expansions is less elastic with respect to their cost. Other alternatives for encouraging CDM include a targeted performance incentive mechanism or a management fee for CDM. It should also be noted that efficiency carryover mechanisms have been touted in some jurisdictions (e.g., New Zealand) as a tool for balancing capex/opex incentives.

- The ability of various kinds of OM&A inputs to substitute cost effectively for capex varies widely. Just because peak load management is an appealing substitute for capacity expansions (at least in the short run) does not mean that the case for substituting asset repair and field work expenses for replacement capex is equally compelling.

- There is a general tendency to substitute capital for OM&A inputs in many industries that are not subject to rate regulation and the capex bias that it encourages. Labor shortages and rising real wage weights have encouraged this phenomenon.

Considering this analysis, here are some notable recommendations concerning capitalization of asset repair and field work expenses.

- The OEB and stakeholders should sharpen their understanding of desirable capitalization policies for costs of asset repair and field work. Generic proceedings and/or utility rebasing proceedings may both prove useful for this purpose. The merits of totex accounting may be explored in the ongoing Advancing PBR proceeding.

- Customers should be protected from utility-initiated increases in the capitalization of opex during MRPs. Utilities should be required to notify the regulator when they change capitalization policies during the term of an MRP. Such changes could be prohibited or, more flexibly, customers could be compensated for detrimental short-term effects of the changes, such as paying for opex in one rate plan only to pay again for its capitalized balance in the next plan.

- Changes in capitalization policies can complicate benchmarking. This raises the question of whether standardized capitalization rules should apply to data used in benchmarking. This has been a problem in Australian and British ratemaking. Capitalization policies are an issue worth exploring in the TCBTFP proceeding.

Appendix

A.1 Glossary of Terms

Advanced Metering Infrastructure ("AMI"): An integrated system of smart meters, communications networks, and data management systems that record and share time-of-use data and enable two-way communication between a utility and its customers.

Attrition Relief Mechanism ("ARM"): A key component of multiyear rate plans which uses a predetermined formula to adjust utility rates between general rate rebasings without closely tracking growth of the company's *own* costs during the plan, like a variance account would. Methods used to design ARMs include cost forecasts, indexation to quantifiable external cost drivers such as inflation and customer growth, and hybrids of these approaches.

Base Rates: The components of a utility's rates which provide compensation for costs of non-energy inputs such as labor, materials, services, and capital.

Capex: The term capex is short for capital expenditures, although the term is often applied to the value of gross plant additions that bolster a utility's rate base.

Cost of Service Regulation ("COSR"): The traditional North American approach to ratemaking that rebases rates in irregularly timed proceedings to reflect the cost of service that regulators deem prudent.

Demand-Side Management: Energy conservation, peak load management, and other activities intended to reduce use of a utility system.

Energy Transition: The transition of the economy to greater reliance on electricity that is generated from clean resources. This transition may eventually entail brisk demand growth and a need for a more resilient power grid.

Federal Energy Regulatory Commission ("FERC"): The U.S. agency responsible for regulating rates for utility services offered in interstate commerce. These services include power transmission, bulk power supply, and interstate gas pipeline transmission and storage.

Formula Rate Plan ("FRP"): A formula rate plan is designed to make a company's revenue closely track its own cost of service. It typically entails a mechanism for truing up a utility's revenue to the portion of its actual costs that regulators deem prudent. Formula rates are widely used by the U.S. Federal Energy Regulatory Commission in power transmission regulation.

Multiyear Rate Plan ("MRP"): A common approach to PBR that features a multiyear moratorium on rate rebasings, an attrition relief mechanism, and several PIMs.
Opex: Operation, maintenance, and administrative ("OM&A") expenses.

Performance-Based Regulation ("PBR"): An approach to ratemaking designed to strengthen utility performance incentives. Some PBR approaches also streamline ratemaking.

Performance Incentive Mechanism ("PIM"): A mechanism consisting of one or more metrics, targets, and financial incentives (rewards and/or penalties) that is designed to strengthen performance incentives in a targeted area such as reliability or energy efficiency.

Productivity: The ratio of output to input quantities, which is a rough measure of operating efficiency that controls for the impact of input prices and operating scale on cost. Studies of total factor productivity trends (which consider both capital and OM&A inputs) have been used in many MRPs to set the X factors of indexed ARM formulas.

Rate Rider: A mechanism, frequently outlined on tariff sheets, which allows a utility to make rate adjustments between rate rebasings.

Rebasing: A proceeding to reset an electric company's base revenue requirement to better reflect the cost of service. These proceedings may also consider other issues such as rate designs.

Rebasing Moratorium: A set period of time without general rebasing proceedings.

Revenue Cap Index: A formula sometimes used for escalating allowed revenue in MRPs. The formula typically includes an inflation index, an X factor, and may also include a factor for growth in operating scale.

Revenue Requirement: The annual revenue that the electric company is entitled to collect as compensation for the cost of service. The amount is periodically recalculated in rate reviews to reflect costs and may be escalated by other mechanisms (e.g., cost trackers and ARMs) between rate reviews. The corresponding cost is typically the sum of OM&A expenses, depreciation, taxes, and a return on rate base less other operating revenues.

RIIO: An approach to energy utility ratemaking used by Great Britain's Office of Gas and Electricity Markets ("Ofgem") that combines revenue decoupling, targeted incentives for underused practices, multiyear rate plans, and various metrics and targeted performance incentive mechanisms. The term RIIO stands for Revenue = Incentives + Innovation + Outputs.

Targeted Incentives for Underused Practices: Direct incentives for utilities to embrace practices that they tend to underuse because they are novel, save tracked or external costs, or reduce capex. Demand-side Management is a classic application. Incentives that have been used to encourage underused practices include tracker treatment for their costs, capitalization of their costs (if OM&A expenses), management fees, and pilot programs.

Test Year: A specific period in which an electric company's costs and billing determinants are jointly considered in a rebasing proceeding. Some jurisdictions use a historical test year and adjust billing determinants and costs for known and measurable changes. Others use a fully forecasted test year that considers other possible changes.

Variance Account: A mechanism providing expedited recovery between rate cases of targeted costs that are deemed prudent by regulators. The account tracks costs that are eligible for recovery. These costs can be recovered promptly with a rate surcharge (aka "rider"). Variance account treatment was traditionally limited to costs that are large, volatile, and largely beyond the control of the utility. In more recent years, such accounts have also been used to address rapidly rising costs and costs of underused practices.

X-Factor (aka Productivity Factor): A term in an indexed ARM formula which reflects the typical impact of productivity growth on cost growth. The X factor may also incorporate a stretch factor and an adjustment for the inaccuracy of the inflation measure that is used in the ARM formula. In some jurisdictions, the stretch factor is treated as a separate term.

A.2 Further Details of the Empirical Research

Elasticity-Weighted Scale Index

Growth in the opex and capex of electricity distributors is sensitive to growth in their operating scale. We developed multidimensional scale indexes with econometric cost elasticity weights for the opex and capex of Ontario electricity distributors. This required econometric estimation of the elasticities of these costs with respect to the scale variables in these indexes.

Cost Model Selection and Functional Form

Econometric models of OM&A expenditures and capex were estimated in the statistical software application Stata using data for the full sample of 53 Ontario electricity distributors. The sample period was the ten years from 2014 to 2023.[144] The statistical estimation procedure was pooled Ordinary Least Squares ("OLS") regression with Driscoll-Kraay standard errors and a fixed-b asymptotic inference framework.[145] The dependent variable in each model was the natural logarithm of real expenditures (opex or capex). Real expenditures were in each case the ratio of cost to a corresponding input price index. Most independent (aka right-hand side) variables were mean scaled, and natural logs were applied to variables that did not contain zeros or negative values in their range. We used models that are similar to those we are developing for the OEB's TCB/TFP project.

Table A.1 shows the estimated cost elasticities and corresponding elasticity weights at mean values of the variables which we drew from the two econometric models. It can be seen that the number of customers served has the highest estimated cost elasticity for both opex and capex.

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[144] Algoma Power was excluded.

[145] This method adjusts the standard error estimates for spatial correlation, heteroskedasticity, and autocorrelation and for a small-N, small-T sample. These adjustments only affect the model statistics calculations and do not affect the parameter estimates.

Table A.1

Estimated Cost Elasticities of Scale Variables

	Capex		OM&A	
Output	Estimated Elasticities	Share of Total	Estimated Elasticities	Share of Total
Customers	0.892	76.70%	0.570	58.82%
Ratcheted Peak	0.271	23.30%	0.399	41.18%

Details of the Input Price Indexes

For OM&A, we calculated labor price levels in 2021 that varied regionally using labor income data from the census. Labor prices for other years were calculated using average weekly earnings data from Statistics Canada. As for capital expenditures, construction costs were assumed to vary in 2021 on the basis of construction cost indexes in various Ontario cities that are available for RS Means. Values for other years were calculated to be consistent with the Handy-Whitman construction cost trend index for power distribution in the North Atlantic U.S.

A.3 Additional Jurisdictional Precedents

California

Since the establishment of a policy called the Rate Case Plan in 1984, California gas and electric utilities have generally provided retail services under MRPs.[146] Plans typically had three-year terms at the outset but have since been extended to four years for the largest energy utilities.[147] ARMs, which are sometimes called post-test year ratemaking mechanisms in California, have had various designs including indexing, the averaging of a utility's recent historical capex to establish a capex budget, and mechanisms that combine these approaches.[148] The California Public Utilities Commission ("CPUC") has frequently rejected utility proposals for revenue requirements to be set based on comprehensive multiyear capex budgets. Its rationale for these rejections was provided in a rate case decision for Southern California Edison ("SCE").

> 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

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146 California Public Utilities Commission, Resolution ALJ-151, June 6, 1984.
147 California Public Utilities Commission, Decision 20-01-002.
148 Budgets have been included as part of hybrid attrition relief mechanisms in some instances. For example, the California Public Utilities Commission approved the use of budgeted capital additions for wildfire mitigation projects in a recent Southern California Edison MRP.

implemented as planned. In addition, no party other than SCE provided or analyzed detailed post-[test year] plant addition budget forecasts in determining increases. We cannot fault other parties for not recommending detailed [post test year] capital budgets. As we have noted in past [rate cases], analyzing such budgets for two additional years imposes a significant burden on resources.[149]

The CPUC has periodically expressed concern about utility spending patterns. Deferrals of projects to later years of the MRP term and to the next MRP term have both been discussed. In a recent decision in rate cases for the two large Sempra utilities [San Diego Gas and Electric and Southern California Gas (SoCalGas)], for instance, the commission noted that

> In our review of Sempra's [rate case], we observed that Sempra deferred investments for a few years and then made rapid capital investments in later years. Using data from the later [plan years] to forecast the next [rate case] could lead to overestimating expenses. This, in turn, could result in a deviation from reasonable capital expense forecasts needed to serve customers effectively.[150]

In cases where the CPUC identified deferrals that it believed would lead to overstated historical trend data, if it did not reject the proposed cost of the project outright, it often used a historical average based on a longer period to cover both the period of the deferral and the catch-up funding. For example, in its recent SoCalGas rate case decision, the CPUC rejected the company's proposed capex in one cost category due to such concerns, saying that

> We also reject SoCalGas's forecasting methodology for the overall cost category because it relies on skewed data that only reflects increased spending on infrastructure and construction. SoCalGas eliminates a dataset with lower capital expenditure by excluding the 2017-2018 data from its estimation. Changes in scope, project delays, increased costs due to COVID-19 impacts, and supply chain disruptions are all factors that can cause cost fluctuations. However, deferring investments for a few years and following up with rapid capital investments in [the later years of an MRP] falls outside the range of normal costs authorized in the previous Test Year. Relying solely on data with increased costs will lead to overestimating expenses, resulting in a deviation from reasonable capital expense forecasts necessary to serve customers…
>
> The reasons for delaying construction projects and changes in scope that result in higher costs should be considered extraordinary conditions. Similarly, deferred expenditures should not become a normal pattern, which are then excluded by the utility under the pretext of not representing future spending… we find it reasonable to consider all six years of data from 2017-2022 for the Infrastructure and Improvements cost category to capture the impact of cost fluctuations and deferred projects.[151]

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[149] California Public Utilities Commission, Decision 09-03-025, p. 305.
[150] California Public Utilities Commission, Decision 24-12-074, December 19, 2024, p. 28.
[151] California Public Utilities Commission, Decision 24-12-074, December 19, 2024, pp. 608-609.

Deferrals have also been found to occur with OM&A expenses. For example, SoCalGas proposed that its OM&A expenses related to real estate administration and facility operations for its rebasing test year be based on a three-year historical average that excluded two earlier years where costs were low and may have been deferred.

Chile

Dyck and Di Tella studied the cost performance of Chilean investor-owned electric utilities over the 1988-99 period, during which they operated under MRPs with four-year terms. They report that

> we find a U-shaped pattern in cost reductions. Trends in cost reductions are reversed every four years with costs 1.4% greater than would be expected on the basis of time trends alone. These happen to be years prior to regulatory reviews, where a new price cap is set for the next four-year interval. This pattern is consistent with strategic behavior of firms. Although caps are supposed to ignore information from specific firms and follow the costs of an ideal "efficient company", as in the yardstick models, in practice there is a limited number of firms from which to draw the information so the probability of each firms' cost reports influencing the future price caps is high."[152]

Dublin, Ireland Airport

Dublin Airport's charges for airport services have for some time been subject to revenue per passenger regulation by Ireland's Commission for Aviation Regulation ("CAR").[153] After operating under MRPs with British-style ARMs since 2001, CAR in 2008 initiated a stakeholder consultation on the "distortion to efficiency incentives that arises in a price cap setting due to the timing of efficiency incentives.[154] In discussing a hypothetical MRP with standard rebasing, CAR stated that

> The power of the incentives faced by the firm to seek additional efficiencies beyond those assumed in the price cap depend on the number of years it can retain the benefits of outperformance. An annual saving realized early in the regulatory cycle and one made later in the cycle are both retained by the firm until the end of the cycle. Thereafter, the benefits of the saving accrue to users. This means that the regulated firm enjoys a smaller benefit and a smaller share of the benefits from a cost saving if it is made later in the regulatory period.[155]

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[152] I.J. Alexander Dyck, and Rafael Di Tella, "Cost Reductions, Cost Padding and Stock Market Prices: The Chilean Experience with Price Cap Regulation," October 8, 2002. Available at SSRN: https://ssrn.com/abstract=385261 or http://dx.doi.org/10.2139/ssrn.385261
[153] A recent restructuring folded CAR into the Irish Aviation Authority.
[154] Commission for Aviation Regulation, Efficiency Incentives (Rolling Incentives Schemes)," Commission Paper 4/2008, June 2008, p. 1.
[155] Ibid., p. 5.

Furthermore,

> The reduced benefits to the firm of realizing an annual saving later in the regulatory period actually give rise to a perverse incentive: the firm may be better off deferring the saving until after the next price cap is set.[156]

In its final decision in that proceeding, CAR decided to implement an ECM for a subset of OM&A expenses (e.g., only certain labor OM&A expenses were included). This was due in part to uncertainties involving the construction of a new terminal at Dublin airport, as well as a desire to limit incentives to costs that were controllable by the airport operator and not tied to the number of passengers. A forecast of eligible OM&A expenses was established, and the airport operator could retain any estimated incremental savings achieved in each year of the plan for five years.

The CAR later broadened the ECM to cover most OM&A expenses. In this plan, no rewards were earned from the ECM due to the Dublin airport operator having significantly higher OM&A expenses than forecasted. CAR attributed this to passenger levels significantly exceeding its forecasts.

In considering the next plan, CAR expressed concern about the interplay between the ECM and an incentive mechanism that was designed to encourage the airport operator to maximize commercial revenues. Having failed to see benefits for customers after two full MRP terms, CAR announced its decision to discontinue the ECM, saying

> we do not believe they are providing any significant added value to the regulatory model and therefore are simply adding complexity.
> We have not seen any evidence that they have been effective in fulfilling their intended purpose, or indeed evidence that their intended purpose is an issue which needs to be addressed.[157]

A.4 Summary of SPA Regulator Responses

Current or, in one case, past utility regulators in Australia, Great Britain, and New Zealand were kind enough to share some thoughts about spending pattern and capitalization issues.[158] Here is a high-level summary of their comments.

Identified Spending Patterns

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[156] Ibid., p. 5.
[157] Commission for Aviation Regulation (2019), "Maximum Level of Airport Charges at Dublin Airport 2020-2024, Draft Determination," p. 22.
[158] PEG's discussions regarding British energy regulation were with a former Ofgem staffer.

Several regulators noted that there had been patterns of accelerated spending towards the end of plan terms. Patterns in British MRPs had been noted by several observers, and the AER had studied the phenomenon. However, one of the responding regulators that had implemented a rolling incentive form of efficiency carryover mechanism had never done a formal empirical study of the matter and was instead driven by theoretical concerns and Australian precedent.

Drivers of Spending Patterns

Numerous comments were ventured regarding the causes of spending patterns.

Incentives Driven by MRPs

One regulator noted that in the early years of its ratemaking, utilities were not subject to a thorough ex-post review of capex. This encouraged utilities to grow their rate bases, particularly towards the end of MRPs. Reviews of historical capex subsequently intensified.

This regulator was concerned that the utilities may be testing the limits of cost containment and seeing how far they can go before the regulator decides to punish them. Some distributors may be timing their capex in order to support future revenue requirement forecasts.

Rate Rebasings

One regulator believed that spending delays in older plans were at least partly attributable to the distributors waiting to get a decision from the regulator before committing spending (e.g., the distributor would wait for the regulator's decision prior to signing contracts with vendors). Another regulator commented relatedly that the distributors may be viewing the revenue requirement as a budget.

Distribution System Planning

One regulator thought that distributors may be encouraged to spend in the latter years of the plan to ensure that they meet targets for asset risk reduction by the end of the plan term.

External Business Conditions

- Data centers are a big driver of capex in Australia. Network resilience and cybersecurity are also big capex drivers. The energy transition drives capex to a lesser extent there.

- The timing of investment may be different from the approved forecasts because load materializes at a different pace than forecast.

- One driver of spending surges is that the utilities may have been identifying and addressing safety issues.

- During the term of the plan, the utility may identify asset risks that vary from those outlined in the previous rebasing proceeding.

- It's unclear to what degree the effects of the Covid-19 pandemic affected capex decisions.

- The utility may need to reprioritize planned work to account for changing business conditions and system risk.

Spending Pattern Remedies

Australia

The AER first adopted a rolling incentive form of ECM for opex that it called the EBSS. A recent AER study found that under the EBSS, there was no obvious opex pattern except that opex is a little higher in the first two years. Statistical benchmarking has had a bigger impact on opex and has made a clear difference. Opex productivity growth has been brisk in Australia.

The AER then adopted a rolling incentive mechanism for capex called the CESS because capex was rising rapidly and exhibiting a sawtooth pattern. Under the CESS, overspends relative to the revenue requirement are not fully recovered even if they are deemed fully efficient (e.g., networks only get 70% funding of overspends). Inefficient overspends are disallowed in their entirety.

The AER is less certain about the effectiveness of the CESS. The benchmark for the CESS is the *forecast* of capex that the AER approves. The AER expressed concerns that it is more difficult to accurately forecast capex than opex. This is due in part to new types of projects continually being proposed in rebasing proceedings, which the regulator lacks experience forecasting. Their forecasting techniques improve with experience (for example, the AER has a model for estimating the need for replacement capex), but there are always new areas to forecast in later rebasings. The CESS also applies to power transmitters, which have several large projects underway to support demand growth.

For the first five years after the CESS was implemented, the AER noticed that distributors would tend to spend at or under their forecasts. However, the overall spending pattern remained (e.g., utilities tended to have significant underspends at the start of the rate plan and sometimes overspent towards the end of the rate plan). More recently, the AER has noticed that the pattern has continued, but utilities are tending to *over*spend their allowances over the course of the plan. One distributor overspent to the point where they were subject to an ex-post review, and the overspending was deemed inefficient.[159]

The design of the CESS is largely the same as at initial implementation, but the AER is currently reviewing the CESS, and changes may need to be made. Utilities are concerned about the automatic 30% penalty even for efficiently-incurred overspends. A second issue with the CESS surrounds whether it should be limited to addressing *controllable* capex. The AER is also concerned that the power of the incentives may be insufficient to address utility capex bias.

New Zealand

The CC adopted a rolling incentive form of ECM that it called IRIS. At the time of adoption, it was more concerned about the risk of spending patterns on a theoretical level, including a concern that utilities would get better at gaming the regulatory system in time. IRIS has also helped them equalize opex/capex incentives, and they have chosen to stick with IRIS for this purpose instead of adopting totex accounting. There was anecdotal evidence that spending patterns were an issue in other utility sectors after the CC adopted IRIS for electricity distributors. For example, a gas utility did not adequately invest for most of the plan term but spent a lot towards the end of the plan.

IRIS has been in effect for two generations of MRPs of New Zealand electricity distributors. The CC is broadly happy with the mechanisms but has not yet undertaken a formal review of their efficacy. However, it's difficult for some of the smaller utilities to understand how the IRIS functions and why it's needed. The complexity of IRIS is an issue. New Zealand law allows customer-owned distributors greater discretion in rate setting, and the IRIS does not apply to them.

Great Britain

Rolling incentives and totex were introduced in Britain for several reasons. Cost reporting and capitalization rules had become increasingly complicated and difficult to police and added limited value for customers or the industry. There was a concern that incentives were distorted in favor of capex solutions. The regulator believed it was important to give the utilities greater flexibility to reprioritize spending between opex and capex to drive greater efficiencies.

Ofgem first experimented with rolling incentives and then adopted totex accounting. This appears to have reduced the tendency of distributors to engage in late-year spending surges. A longer price control term may also have helped to flatten the cyclical spending pattern.

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[159] About 3% of this distributor's proposed rate base for 2024-2025 was disallowed on the grounds of inefficient capex.

Capitalization Policies

Accounting Standards

Australian utilities use Australian accounting standards, which are in turn linked to international standards. New Zealand utilities use GAAP. PEG's understanding is that this is New Zealand GAAP, which is related to IFRS.

Issues identified with Capitalization Policies

The AER does not approve capitalization policies. Issues that the AER has with regard to capitalization policies have mainly been the result of changes in accounting standards for capitalized leases and software as a service. Field work or repair expenses have generally not been an issue.

The CC believes that, due to the accounting standards and input methodologies, there is not much discretion in terms of capitalization policies, but there are always marginal cases. The CC has not noticed much expense shifting between capex and opex and believes that IRIS provides utilities with less benefit from doing so. There are differences between utilities, but the CC is not especially concerned about these.

The CC's understanding of British regulation was that Ofgem thought the utilities were capitalizing any time that they had "wiggle room." This is no longer an issue in Britain due to the adoption of totex accounting. Prior to the adoption of totex, Britain's regulator identified differences in capitalization policies amongst distributors. Capitalization rules had created boundary issues, with the distributors incentivized to record expenditures in the areas with the highest rates of capitalization. This led to considerable effort by Ofgem to monitor distributors' reported expenditures. Ofgem was concerned that this led to the distributors failing to adopt innovative solutions. With Ofgem's capitalization rules, there was a concern that distributors were better off adopting a capex solution rather than a more cost-effective opex solution.

Changing Capitalization Policy in the Middle of the Plan

The AER prefers that utilities minimize changes to capitalization policies during the term of a plan. AER disallowed some of one transmission utility's proposed EBSS reward due to the reward partly being the result of a change in capitalization policy related to software as a service (e.g., AER viewed this as a windfall gain rather than a legitimate efficiency gain).

The CC only mentioned operating leases as a change to capitalization policy that occurred during the term of an MRP. This was triggered by a change in accounting standards.

With the introduction of totex in Britain, how distributors report costs does not have an effect on their funding or incentives. However, Ofgem's Cost Reporting Regulatory Instructions and Guidance requires costs to be reported on a consistent and accurate basis to support its cost benchmarking program. Ofgem has for some time used benchmarking of totex and disaggregated costs to inform its decisions on the appropriate levels of costs in rebasing proceedings. Presumably, there would still be a small incentive for distributors to report costs in ways that would make them look better in the disaggregated benchmarking.

Capitalization of field work and repair expenses should be reported and capitalized consistently by all utilities to assist in the development of plans and recording spending between plans. Increased capitalization of these costs would help remove some boundary issues between these costs and current capex activities and spread out the recovery of these costs over time. However, the increased financial return on the extra costs that were capitalized may lead to increased rates.

Confidentiality

The responding regulators varied in their comfort with the confidentiality of their comments. Some wanted their comments not attributed to them, while others wanted only some comments to be kept confidential.

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