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Impact of multiyear rate plans on power distributor productivity: Evidence from Alberta

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ABSTRACT

Multiyear rate plans ("MRPs") are an increasingly popular alternative to traditional utility ratemaking in North America. Rate cases are less frequent, and an attrition relief mechanism ("ARM") escalates revenue between rate cases on some basis other than the utility's contemporaneous cost growth. An approach to ARM design has developed in North America that is based on price and productivity indexing. Evidence filed in support of indexed ARMs frequently includes studies of the efficiency of subject utilities. Stronger utility performance incentives are a theoretical advantage of MRPs but few empirical studies have quantified this advantage. A proceeding in Alberta, where indexed ARMs are used, has yielded evidence that MRPs can accelerate utility productivity growth.

1. Introduction

Electric utilities in North America face unfavorable business conditions today that cause financial attrition between rate cases. These conditions include a need for high capital expenditures ("capex"), sluggish growth in system use, and brisk input price inflation. In this environment, alternatives to traditional cost of service ratemaking ("COSR") — collectively known as "Altreg" — are widely used.

When conditions are chronically unfavorable, COSR entails frequent rate cases that weaken utility cost containment incentives and reduce the efficiency of ratemaking. A growing number of regulators prefer Altreg approaches such as multiyear rate plans ("MRPs") which strengthen performance incentives. These plans combine reduced rate case frequency with an attrition relief mechanism ("ARM") that escalates revenue between cases on some basis other than the utility's contemporaneous cost growth.

MRPs are considered a form of performance-based ratemaking ("PBR") because they can strengthen utility cost containment incentives while improving the efficiency of ratemaking. However, only a few empirical studies have examined the impact of MRPs on utility cost (Lowry et al., 2017).[1]

An approach to ARM design has developed in North America that is based on price and productivity indexing using industry operating data. This reduces reliance on utility cost forecasts that raise concerns about asymmetric information.[2] Cost performance is a central focus of this approach to ratemaking, and the cost performance of subject utilities is often examined using statistical methods. Canada is a North American MRP leader, and indexed ARMs are favored there.

This paper discusses MRP experience in the Canadian province of Alberta. Indexed ARMs are used, and a recent study prepared for an MRP proceeding there measured trends in the operation and maintenance ("O&M"), capital, and multifactor productivity ("MFP") trends of Alberta power distributors (Lowry, 2023). This work sheds light on the impact that MRPs can have on utility performance incentives.

2. The North American approach to ARM design

North America has developed a unique approach to ARM design that is based on statistical cost research.[3] This approach has been enabled by the availability of many years of standardized data on the operations of numerous US utilities. The approach is based on the theoretical result that, in an industry earning a competitive rate of return, the long-term

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[1] One study that measured the impact of MRPs and extended rate stayouts on cost was Lowry et al. (2017).

[2] Costello (2023) raises several concerns about MRPs, including the problem of asymmetric information when ARMs are based on utility cost forecasts.

[3] Development of the North American approach to ARM design was largely independent of that for ARMs used in Great Britain. See Lowry and Kaufmann (2002) and Kaufmann (2019).

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trend in output prices equals the trend in the industry's input prices less the trend in its MFP (Sudit, 1979).[4] This result provides the basis for price cap indexes with the following general formula[5]

$$growth\ Prices = Inflation–(\overline{MFP} + Stretch) + Y + Z. \quad (1)$$

Here $\overline{MFP}$ is an MFP growth target. Such targets are typically based on the historical trends in the MFP indexes of a sample of utilities. In a proceeding to approve a multiyear rate plan with this kind of ARM, one or more studies of industry productivity trends may be submitted in evidence. The stretch factor assures that customers receive some of the benefit of the acceleration in MFP growth that is expected under the stronger performance incentives that are expected under the plan. In several jurisdictions (e.g., Massachusetts, Québec, and Ontario), the choice of a stretch factor has been informed by the results of statistical benchmarking studies.

The inflation term in [1] is sometimes called the "I factor." The term X factor is (confusingly) applied only to $\overline{MFP}$ in some plans and to the sum of $\overline{MFP}$ and the stretch factor in others. This approach to ARM design is for these reasons sometimes called "I-X regulation."

The analogous general formula for a revenue cap index is[6]

$$growth\,Revenue^{Allowed} = Inflation–(\overline{MFP} + Stretch) + growth\,Outputs + Y + Z. \quad (2)$$

Here, *Outputs* is a measure of growth in one or more dimensions of operating scale that drive cost.[7] Growth in the number of customers served is commonly used for this purpose. Growth in allowed revenue must be converted to growth in rates, and this requires an expectation of the growth in billing determinants (e.g., delivery volumes). Revenue decoupling is often added to such revenue caps to ensure that the trend in actual and allowed revenue are the same over time. The popularity of decoupling is partly due to its ability to strengthen utility incentives to embrace energy conservation, peak load management, distributed generation, and rate designs that encourage these activities.

Price and revenue cap indexes designed in the North American style do not surge when and if utility capital expenditures surge. This has led utilities to request supplemental funding for capex in plans where these indexes are used. Controversy over the design of supplemental capital funding mechanisms has arisen in several MRP proceedings.[8] Ratepayers express concern about overcompensation for alleged capital revenue shortfalls. Some mechanisms for providing supplemental revenue weaken capex containment incentives. For example, concern about utility exploitation of information asymmetries can lead to "clawbacks" of the supplemental revenue when capex is less than forecasted.

3. MRPs in Alberta

Alberta is a province in western Canada with a large oil and gas industry. The "boom and bust" nature of Alberta economic activity has occasionally produced periods of accelerated power distribution system expansion. Population growth surged after the Leduc oil discovery in 1947 and then again from 1975 to 1982, a period of high oil prices. As assets placed in service during such periods reach the end of their service lives, a surge of replacement capital expenditures ("repex") may occur.

The Alberta Utilities Commission ("AUC") is a longtime practitioner of MRPs that use indexed ARMs.[9] It has already presided over two rounds of generic MRPs for gas and electric power distributors, which it has dubbed "PBR1″ and "PBR2″, and is currently in a proceeding to develop a third generation ("PBR3″). The AUC approved PBR1 in 2012 during a repex surge in which most of these distributors were operating under biennial rate cases (AUC, 2012). ENMAX (the power distributor serving Calgary, Alberta's largest city) was already operating under an MRP featuring a price cap index which ran from 2007 to 2013.

The AUC was at the time led by Willie Grieve, a former telecommunications utility executive, who had experience with MRPs featuring indexed price caps. In a generic proceeding on PBR begun in 2010, the AUC commented that

> This initiative proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources… Regulators … must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing… The Commission is seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected (AUC, 2010).

In PBR1, the ARM for each power distributor was a price cap index.[10] The inflation factor was a weighted average of growth in Alberta labor price and consumer price indexes. The price cap index formula included a 0.96% base MFP growth target that was linked to a study of US power distributor MFP trends (AUC, 2012). The formula for each ARM also included a 0.20% stretch factor. Each plan also had service quality metrics and an off-ramp provision to address extreme earnings outcomes. The plans did not include a mechanism for sharing high earnings and this strengthened cost containment incentives.

Distributors claimed that the approved ARMs could not fund their capex requirements, and took the AUC to court. The AUC ultimately decided to use capital cost trackers as the principal means of supplementing capex funding.[11] Supplemental capital revenue was therefore sensitive to the actual capex incurred. To obtain extra funding, distributors were required to demonstrate that the cost of certain proposed capital projects could not reasonably be expected to be recovered through the I-X mechanism (AUC, 2012, p. 124). "Negative" capital trackers (that is, offsetting adjustments where capital cost was expected to grow more slowly than capital revenue, which would reduce supplemental funding) were not considered.

The Commission later acknowledged that this approach to supplemental funding weakened capex containment incentives, stating for example that

[4] An early presentation of this key result is found in Sudit (1979). Later reprises of this logic include Baumol (1982) and Bernstein and Sappington (1999).

[5] The Y factor term in the formula adjusts rates for the operation of trackers that are dedicated to the recovery of certain costs (e.g., purchased power expenses). The Z factor term adjusts rates for the impact on earnings of miscellaneous events that are particularly difficult to foresee (e.g., severe storms).

[6] Theoretical support for this revenue cap index formula can be found in Denny et al. (1981).

[7] Some approved revenue cap index formulas do not have output growth terms.

[8] In addition to the Alberta Utilities Commission's PBR1 (566) and PBR2 (20414) proceedings, please see the Ontario Energy Board's fourth generation generic MRP proceeding (EB-2010–0379); Massachusetts DPU 19–120, NSTAR Gas Company dba Eversource Gas; and the most recent MRP proceedings in Ontario for Hydro One Networks (EB-2021–0110) and Toronto Hydro-Electric System (EB-2018–0165).

[9] Prior to 2008, the functions of the AUC were undertaken by the Alberta Energy and Utilities Board ("EUB"). We have used the term AUC throughout to refer to the Alberta utility regulator to avoid confusion.

[10] The two natural gas distributors operated under revenue per customer indexes with the same base MFP growth target and stretch factor. For further details of the plan see AUC (2012).

[11] A cost tracker is designed to facilitate recovery of certain costs. Costs deemed to be prudent are usually recovered promptly using a rate rider but recovery is sometimes deferred.

> Parties in this proceeding pointed out that because expenditures under the capital tracker mechanism in the 2013–2017 PBR plans were largely treated on a COS basis, they were not subject to the same high-powered incentives to control costs as the expenditures under I-X. The Commission agrees (AUC, 2017, pp. 39–40).

In 2016, the AUC approved PBR2 (AUC, 2017). This differed from PBR1 chiefly with regard to the supplemental capital funding mechanism.[12] In the generic proceeding to develop PBR2, the Commission placed a heavy weight on strengthening capex containment incentives and streamlining regulation. For example, the AUC stated in its PBR2 decision that

> the Commission has adopted a capital funding model that provides the necessary incremental capital funding for the distribution utilities while enhancing significantly the incentives to plan, design and construct capital assets efficiently (AUC, 2017, para. 286, p. 77).

Supplemental funding for most capex was provided by a mechanism called the "K-bar". A K-bar value was established for each year for each distributor based on the amount by which indexed capital revenue during PBR2 fell short of a notional capital revenue requirement calculated using the distributor's average plant additions during PBR1. Additions were adjusted for inflation and growth in operating scale. The K-bars produced timely rate adjustments that were not linked to each utility's actual capex during PBR2. In the PBR3 proceeding, several utilities acknowledged the ability of this mechanistic approach to strengthen capex containment incentives and streamline regulation.

4. Impact on productivity growth

In evidence for the PBR3 proceeding, Pacific Economics Group Research LLC ("PEG") calculated the O&M, capital, and multifactor productivity trends of the four Alberta power distributors that have operated under PBR (Lowry, 2023). The sample period encompassed years when utilities operated under MRPs with strong performance incentives and years when they operated under more traditional ratemaking. This created a natural experiment regarding the impact of MRPs on productivity growth.

4.1. The power distributor business

Understanding the empirical research considered in this paper may be aided by a discussion of the general nature of a power distributor's business. Distributors deliver power from the transmission system to the premises of end users. The voltage of the power must be reduced from the rate at which it is transmitted to the rate at which end users consume it. Voltage is reduced by transformers at substations and there are also reductions by line transformers located near customer premises. Distributors typically own the low voltage power lines and services, the poles and underground conduits that carry them, line transformers, and meters. Expenses are incurred to operate and maintain these assets and most distributors also manage customer accounts. There are also administrative costs, and some costs may be incurred jointly in the provision of distribution and other services that the utility provides.

The four power distributors subject to the AUC's generic MRPs are ATCO Electric ("ATCO"), ENMAX, EPCOR, and Fortis Alberta ("Fortis"). ATCO and Fortis are privately held, while ENMAX and EPCOR are municipal utilities. These four companies distribute power to most Alberta end users. They own, operate, and read meters and manage metering data. However, due to Alberta's approach to the restructuring of retail power markets, some billing, collection, and customer information services are provided by separate retailers, some of which are independently owned. Alberta distributors also typically do not provide extensive energy conservation services. Facilities with voltage exceeding 25 kV are classified as transmission assets.

Table 1
Steps in productivity analysis.

1. Gather Data	
Variables	*Sources*
Customers	AUC (individual distributors)
O&M Expenses	AUC (individual distributors)
Plant Values	AUC (individual distributors)
Input Prices	Statistics Canada
2. Calculate O&M and capital input quantity indexes for individual utilities using cost and input price data	
3. Calculate their multifactor input quantity trends	
4. Calculate their productivity trends using their customer and input quantity trends	
5. Compute multi-company average productivity trends	

4.2. Alberta data

EUB Directive 014 required Alberta power distributors to file extensive operating data beginning in 2005. A uniform system of accounts for power distributors was issued in 2006 (EUB, 2006). Rule 005 of the AUC has required annual reports since 2008 (AUC, 2008). These data are publicly and electronically available. While the companies are granted some latitude in how cost schedules are organized, most of the data needed for productivity research are available from Rule 005 filings and the occasional rebasing applications. Most distributors have itemized their total pension and benefit expenses and O&M salaries and wages.

Notwithstanding these advantages, Alberta data on power distributor operations have some limitations in productivity and cost benchmarking research which should be recognized.

- Data needed to calculate consistent capital cost and quantity indexes using monetary methods are available only since 2004. This limits the accuracy of statistical research on the capital cost and total cost performance of Alberta distributors, especially in the early years for which data are available. Accuracy of data on gross plant additions and O&M expenses is not affected by this problem.
- ENMAX made a major change in its approach to cost accounting which caused its reported O&M cost to surge in 2013.

4.3. Productivity calculations

The growth (rate) in the productivity of an enterprise is the difference between growth of its output and input quantities. Input quantity trends are calculated from data on trends in costs and input prices. The basic steps in a productivity study are set forth in Table 1 below.

The number of customers served was the sole scale variable used in our Alberta power distributor productivity calculations. In econometric studies of power distributor cost, this is typically found to be the most important scale-related cost driver. It is also highly correlated with other scale-related cost drivers such as peak demand. Our estimates of growth in distributor output do not reflect any possible changes in distribution reliability that may have occurred during the sample period. Reliability has been treated as an output variable in distribution productivity research commissioned by the Australian Energy Regulator (Lawrence et al., 2020).

The O&M expenses, plant valuations, and customer numbers that we used in our study were drawn from EUB Directive 014 and AUC Rule 005 filings and data provided by the distributors in their recent rate cases to establish a 2023 revenue requirement for PBR3. We included in our calculations the normal costs that utilities reported for distributor

[12] The sum of the base MFP growth trend and the stretch factor was reduced to 0.30%.

services with the exception of costs for taxes, franchise fees, and construction work in progress.[13] The capital costs we included encompassed some for general as well as for distribution and information plant.[14]

We calculated the wage rate trend using Statistics Canada's fixed-weight index of average hourly earnings for all employees in Alberta industry. For material and service price trends we used Statistics Canada's gross domestic product implicit price index for final domestic demand in Alberta.

The summary O&M price indexes used in our research featured price subindexes for labor and materials and services. Growth in each distributor's O&M price index was a weighted average of the growth of the two subindexes.[15] In these calculations we used company-specific, time-varying cost-share weights that we calculated from Alberta distributor data. The growth in each utility's O&M input quantity index was calculated as the difference between the growth in cost and the growth in its O&M input price index.

$$growth\ Input\ Quantities^{O\&M}_{h,t} = growth\ Cost^{O\&M}_{h,t} \text{ - } growth\ Input\ Prices^{O\&M}_{h,t} \quad (3)$$

A monetary approach was used to measure capital costs. Under this approach, the capital cost of each distributor h in each year t ("$CK_{h,t}$") is the product of a capital quantity index ("$XK_{h,t}$") and a capital service price index ("$WKS_{h,t}$").

$$CK_{h,t} = WKS_{h,t} \cdot XK_{h,t} \quad (4)$$

Geometric decay of capital quantities from each year's cohort of total plant additions was assumed in the design of both of these indexes.

The quantity of capital of each power distributor in 2004 was calculated by taking the ratio of its net ("book") value to a triangularized weighted average of 44 consecutive past values of the asset price trend index ("WKA_t "). A triangularized weighted average places a greater weight on more recent values of this index. This makes sense since more recent plant additions are less depreciated and to that extent tend to have a bigger impact on net plant value. The following geometric decay perpetual inventory equation was used to compute values of each company's capital quantity index in subsequent years of the sample period.

$$XK_{h,t} = (1-d) \cdot XK_{h,t-1} + \frac{VKA_{h,t}}{WKA_t}. \quad (5)$$

Here, the parameter d is the (constant) economic decay rate and $VKA_{h,t}$ is the value of total gross additions to utility plant. The value for d was calculated as a weighted average of the economic decay rates for distribution and general capital. Each decay rate was calculated as the ratio of a declining balance parameter and the life of plant. The decay rate for distribution was a weighted average of the decay rates of distribution structures and distribution equipment.

The formula for the corresponding capital service price indexes used in the research was

$$\mathrm{WKS}_t = \mathrm{d} \cdot \mathrm{WKA}_t + \mathrm{r}_t \cdot \mathrm{WKA}_{t-1} \quad (6)$$

where r is the smoothed real rate of return on capital ownership calculated as a three-year average of the allowed weighted cost of capital less the growth in the asset price index. The first term in [6] corresponds to the cost of depreciation. The second term corresponds to the real return on capital.

We developed the asset price trend index from the average annual growth rates of two subindexes. One was the product of the Handy Whitman Index of Public Utility Construction Costs for Total Distribution Plant in the Plateau region of the United States and the purchasing power parity for gross domestic product between the US and Canada. The other subindex was an implicit capital stock deflator for the utility sector of Alberta.[16] We assigned equal weights to the trends in these two indexes. For the rate of return on capital, we used the weighted average cost of capital based on AUC-approved capital structures and returns on equity along with the costs of debt and preferred equity that the distributors report on their Rule 005 filings.

We calculated indexes of the O&M, capital, and multifactor productivity growth of each utility in the provision of power distributor services. Growth rates were calculated logarithmically. We then took simple averages of the productivity trends of the distributors.

The annual productivity growth rate of each distributor was calculated as the difference between the growth of its output and the appropriate input quantity index. Thus.

$$growth\ Productivity^{O\&M}_{h,t} = growth\ Customers_{h,t} - growth\ Input\ Quantities^{O\&M}_{h,t} \quad (7)$$

The growth in each capital productivity index was the difference between customer and capital quantity index growth.

$$growth\ Productivity^{Capital}_{h,t} = growth\ Customers_{h,t} - growthXK_{h,t} \quad (8)$$

Growth in each multifactor productivity index is the difference between growth in customers and the growth in a multifactor input quantity index measured as a cost-weighted average of the growth rates of the O&M and capital quantity indexes.[17] Here again, company-specific and time-varying cost share weights were used.

$$growth\ Productivity^{Multifactor}_{h,t} = growth\ Customers_{h,t} \text{ - } growth\ Input\ Quantities^{Multifactor}_{h,t} \quad (9)$$

The sample period for this research was the seventeen (growth rate) years from 2007 to 2023.[18] This period encompassed the six years from 2007 to 2012 during which only ENMAX operated under an MRP while the other distributors filed frequent rate cases. Our sample period also encompasses ten years, from 2013 to 2022, when all four DFOs operated under PBR. Productivity results for 2022 and 2023 are based on company cost forecasts rather than actuals.

In 2013, ENMAX changed its approach to accounting, causing its measured O&M productivity to plunge. We accordingly exclude the ENMAX O&M and MFP growth rates for this year from our average annual productivity growth calculations. The values affected by adjusting the averaging formulas have special shading in the tables below.

4.4. Alberta productivity trends

Tables 2 and 3 and Figs. 1–3 provide results of our productivity growth calculations. Consider first the results for the first six years of the period when only ENMAX operated under an MRP. During these years, ENMAX averaged 0.1% annual MFP growth while the other three distributors averaged a 2.3% annual MFP decline. The 0.8% growth trend in the O&M productivity of ENMAX compared to a 0.7% decline in the O&M productivity of the other three. The 0.8% annual average decline in the capital productivity of ENMAX compared to the 4.3% decline in the capital productivity of the other three.

[13] Some unusual plant additions categories were excluded from ENMAX's plant additions data.

[14] To the greatest extent possible, PEG excluded the costs of ATCO Electric's generation in remote northern communities.

[15] These indexes had a Tornqvist form.

[16] Statistics Canada includes in the utility sector power generation and transmission, gas distribution, and water and sewer utilities as well as power distribution. PEG calculated the implicit capital stock deflator as the ratio of the current and constant cost capital stock indexes as published by Statistics Canada.

[17] These indexes also had a Tornqvist form.

[18] The accuracy of the capital and total factor productivity trends is reduced in these years by the recent start of the capital quantity calculations.

Table 2
Productivity trends of Alberta power distributors.

(Logarithmic Growth Rates)

Year	O&M						Capital						Total Factor					
	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	Average less ENMAX	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	Average less ENMAX	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	Average less ENMAX
2007	-3.2%	-0.3%	23.8%	3.3%	5.9%	8.0%	-4.3%	-1.4%	0.3%	-6.3%	-2.9%	-3.4%	-3.6%	-0.8%	15.4%	-0.8%	2.5%	3.6%
2008	-5.9%	-2.6%	3.6%	3.3%	-0.4%	0.3%	-3.6%	0.2%	-1.7%	-4.6%	-2.4%	-3.3%	-5.0%	-1.4%	1.9%	0.2%	-1.1%	-1.0%
2009	-1.6%	12.5%	-11.5%	6.0%	1.4%	-2.4%	-1.2%	-1.8%	-1.1%	-8.5%	-3.1%	-3.6%	-1.5%	6.0%	-7.8%	-0.4%	-0.9%	-3.2%
2010	-8.4%	-7.2%	-6.4%	-4.5%	-6.6%	-6.4%	-3.7%	-2.0%	-2.6%	-4.4%	-3.2%	-3.5%	-6.2%	-4.3%	-4.8%	-4.4%	-4.9%	-5.1%
2011	-9.5%	4.3%	1.8%	3.5%	0.0%	-1.4%	-6.2%	0.9%	-5.2%	-4.7%	-3.8%	-5.4%	-7.8%	2.2%	-1.5%	-1.6%	-2.2%	-3.6%
2012	-1.8%	-2.0%	-1.8%	-2.7%	-2.1%	-2.1%	-8.3%	-0.7%	-5.0%	-6.3%	-5.1%	-6.5%	-5.3%	-1.2%	-3.4%	-5.0%	-3.7%	-4.6%
2013	-3.7%	-35.8%	7.7%	4.8%	2.9%	2.9%	-9.0%	-0.3%	-1.3%	-4.3%	-3.7%	-4.9%	-6.6%	-15.2%	3.2%	-1.2%	-1.5%	-1.5%
2014	0.0%	-1.3%	6.1%	-0.8%	1.0%	1.8%	-5.8%	-3.8%	-2.6%	-1.9%	-3.5%	-3.4%	-3.2%	-2.7%	1.5%	-1.5%	-1.5%	-1.1%
2015	2.7%	6.9%	0.3%	2.5%	3.1%	1.8%	-3.1%	-3.7%	-7.1%	-3.0%	-4.2%	-4.4%	-0.5%	1.1%	-3.7%	-1.2%	-1.1%	-1.8%
2016	32.7%	13.0%	1.9%	0.7%	12.1%	11.8%	-2.9%	-0.5%	-9.1%	-3.1%	-3.9%	-5.0%	10.8%	5.1%	-4.4%	-1.9%	2.4%	1.5%
2017	4.4%	-1.7%	15.3%	-0.9%	4.2%	6.2%	-1.7%	-3.5%	-8.6%	-3.3%	-4.3%	-4.5%	0.2%	-2.8%	0.3%	-2.7%	-1.2%	-0.7%
2018	-9.9%	-1.3%	18.0%	-3.4%	0.9%	1.6%	-0.4%	-3.8%	-0.8%	-2.5%	-1.9%	-1.2%	-3.4%	-2.9%	5.0%	-2.7%	-1.0%	-0.3%
2019	14.0%	9.9%	-1.3%	17.2%	9.9%	10.0%	-0.2%	-0.8%	-0.4%	-1.1%	-0.6%	-0.6%	4.3%	3.1%	-0.7%	3.9%	2.6%	2.5%
2020	-20.5%	8.6%	2.8%	0.0%	-2.2%	-5.9%	-0.5%	-0.8%	-2.9%	-1.0%	-1.3%	-1.4%	-7.4%	2.6%	-1.0%	-0.7%	-1.6%	-3.0%
2021	4.4%	-0.1%	-2.5%	-2.6%	-0.2%	-0.2%	0.4%	-0.9%	-1.5%	-0.3%	-0.6%	-0.5%	2.0%	-0.6%	-1.8%	-1.0%	-0.4%	-0.3%
2022	*2.2%*	*-2.5%*	*-9.3%*	*1.4%*	*-2.1%*	*-1.9%*	*-1.8%*	*-1.6%*	*-2.5%*	*-1.5%*	*-1.9%*	*-1.9%*	*-0.2%*	*-2.0%*	*-5.1%*	*-0.6%*	*-2.0%*	*-2.0%*
2023	*1.6%*	*0.0%*	*10.5%*	*0.8%*	*3.2%*	*4.3%*	*-2.5%*	*-2.4%*	*-0.8%*	*-0.8%*	*-1.6%*	*-1.4%*	*-0.8%*	*-1.4%*	*3.5%*	*-0.3%*	*0.2%*	*0.8%*
Average Annual Growth Rates																		
2007-2022 (16 years)	**-0.3%**	**2.4%**	**3.0%**	**1.7%**	**1.7%**	**1.5%**	**-3.3%**	**-1.5%**	**-3.2%**	**-3.5%**	**-2.9%**	**-3.4%**	**-2.1%**	**0.1%**	**-0.4%**	**-1.3%**	**-1.0%**	**-1.3%**
2007-2012 (Pre-PBR)	**-5.1%**	**0.8%**	**1.6%**	**1.5%**	**-0.3%**	**-0.7%**	**-4.6%**	**-0.8%**	**-2.5%**	**-5.8%**	**-3.4%**	**-4.3%**	**-4.9%**	**0.1%**	**0.0%**	**-2.0%**	**-1.7%**	**-2.3%**
2013-2022 (PBR1 and PBR2)	**2.6%**	**3.5%**	**3.9%**	**1.9%**	**3.0%**	**2.8%**	**-2.5%**	**-2.0%**	**-3.7%**	**-2.2%**	**-2.6%**	**-2.8%**	**-0.4%**	**0.1%**	**-0.7%**	**-1.0%**	**-0.5%**	**-0.7%**
2013-2017 (PBR1)	**7.2%**	**4.2%**	**6.3%**	**1.3%**	**4.7%**	**4.9%**	**-4.5%**	**-2.4%**	**-5.7%**	**-3.1%**	**-3.9%**	**-4.5%**	**0.1%**	**0.2%**	**-0.6%**	**-1.7%**	**-0.6%**	**-0.7%**
2018-2022 (PBR2)	**-1.9%**	**2.9%**	**1.5%**	**2.5%**	**1.3%**	**0.7%**	**-0.5%**	**-1.6%**	**-1.6%**	**-1.3%**	**-1.2%**	**-1.1%**	**-0.9%**	**0.0%**	**-0.7%**	**-0.2%**	**-0.5%**	**-0.6%**

Notes: Shading indicates years during which the utility operated under a multiyear rate plan. Special shading indicates a number that was supported by a special calculation to remove the 2013 value for ENMAX. Italicized data reflect utility forecasts.

Table 3
Total factor productivity trends of Alberta power distributors.

(Logarithmic Growth Rates)

Year	Output (Customers)					Multifactor Inputs					Total Factor				
	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Average
2007	3.2%	2.1%	2.6%	3.7%	2.9%	6.8%	3.0%	-12.8%	4.5%	0.4%	-3.6%	-0.8%	15.4%	-0.8%	2.5%
2008	2.7%	2.3%	2.0%	3.4%	2.6%	7.8%	3.7%	0.1%	3.2%	3.7%	-5.0%	-1.4%	1.9%	0.2%	-1.1%
2009	2.0%	1.5%	1.3%	4.2%	2.3%	3.5%	-4.5%	9.2%	4.7%	3.2%	-1.5%	6.0%	-7.8%	-0.4%	-0.9%
2010	1.7%	1.8%	1.6%	2.1%	1.8%	7.9%	6.0%	6.4%	6.5%	6.7%	-6.2%	-4.3%	-4.8%	-4.4%	-4.9%
2011	1.1%	1.4%	1.6%	1.8%	1.5%	8.9%	-0.8%	3.1%	3.4%	3.7%	-7.8%	2.2%	-1.5%	-1.6%	-2.2%
2012	1.4%	1.7%	2.0%	1.7%	1.7%	6.6%	2.9%	5.4%	6.7%	5.4%	-5.3%	-1.2%	-3.4%	-5.0%	-3.7%
2013	1.8%	2.1%	2.5%	1.9%	2.1%	8.4%	17.4%	-0.7%	3.0%	3.6%	-6.6%	-15.2%	3.2%	-1.2%	-1.5%
2014	1.5%	2.1%	2.5%	2.0%	2.0%	4.7%	4.8%	1.1%	3.5%	3.5%	-3.2%	-2.7%	1.5%	-1.5%	-1.5%
2015	1.6%	2.3%	2.9%	2.0%	2.2%	2.2%	1.2%	6.6%	3.2%	3.3%	-0.5%	1.1%	-3.7%	-1.2%	-1.1%
2016	0.0%	2.4%	2.6%	1.8%	1.7%	-10.8%	-2.7%	7.0%	3.7%	-0.7%	10.8%	5.1%	-4.4%	-1.9%	2.4%
2017	-0.1%	1.7%	1.9%	1.5%	1.3%	-0.3%	4.5%	1.7%	4.1%	2.5%	0.2%	-2.8%	0.3%	-2.7%	-1.2%
2018	0.6%	1.7%	1.8%	1.3%	1.4%	4.0%	4.6%	-3.2%	4.0%	2.3%	-3.4%	-2.9%	5.0%	-2.7%	-1.0%
2019	0.5%	2.0%	1.7%	1.1%	1.3%	-3.8%	-1.1%	2.4%	-2.7%	-1.3%	4.3%	3.1%	-0.7%	3.9%	2.6%
2020	0.2%	1.9%	1.7%	0.8%	1.1%	7.6%	-0.7%	2.7%	1.5%	2.8%	-7.4%	2.6%	-1.0%	-0.7%	-1.6%
2021	0.2%	1.9%	1.6%	0.9%	1.1%	-1.8%	2.5%	3.4%	1.8%	1.5%	2.0%	-0.6%	-1.8%	-1.0%	-0.4%
2022	*0.3%*	*1.4%*	*1.2%*	*1.2%*	*1.0%*	*0.5%*	*3.4%*	*6.2%*	*1.8%*	*3.0%*	*-0.2%*	*-2.0%*	*-5.1%*	*-0.6%*	*-2.0%*
2023	*0.3%*	*2.3%*	*1.9%*	*1.2%*	*1.4%*	*1.1%*	*3.7%*	*-1.6%*	*1.5%*	*1.2%*	*-0.8%*	*-1.4%*	*3.5%*	*-0.3%*	*0.2%*
Average Annual Growth Rates															
2007-2021 (16 years)	**1.2%**	**1.9%**	**2.0%**	**2.0%**	**1.8%**	**3.4%**	**1.7%**	**2.2%**	**3.4%**	**2.7%**	**-2.1%**	**0.1%**	**-0.4%**	**-1.3%**	**-0.9%**
2007-2012	**2.0%**	**1.8%**	**1.9%**	**2.8%**	**2.1%**	**6.9%**	**1.7%**	**1.9%**	**4.8%**	**3.8%**	**-4.9%**	**0.1%**	**0.0%**	**-2.0%**	**-1.7%**
2013-2021	**0.7%**	**2.0%**	**2.1%**	**1.5%**	**1.6%**	**1.1%**	**1.6%**	**2.3%**	**2.5%**	**1.9%**	**-0.4%**	**0.4%**	**-0.2%**	**-1.0%**	**-0.4%**
2013-2017	**1.0%**	**2.1%**	**2.5%**	**1.8%**	**1.9%**	**0.8%**	**2.0%**	**3.1%**	**3.5%**	**2.4%**	**0.1%**	**0.2%**	**-0.6%**	**-1.7%**	**-0.6%**
2018-2021	**0.4%**	**1.9%**	**1.7%**	**1.0%**	**1.2%**	**1.5%**	**1.3%**	**1.3%**	**1.1%**	**1.3%**	**-1.1%**	**0.6%**	**0.4%**	**-0.1%**	**-0.1%**
2018-2022	**0.4%**	**1.8%**	**1.6%**	**1.1%**	**1.2%**	**1.3%**	**1.7%**	**2.3%**	**1.3%**	**1.6%**	**-0.9%**	**0.0%**	**-0.7%**	**-0.2%**	**-0.5%**

Notes: Shading indicates years during which the utility operated under a multiyear rate plan. Special shading indicates a number that was supported by a special calculation to remove the 2013 value for ENMAX. Italicized data reflect utility forecasts.

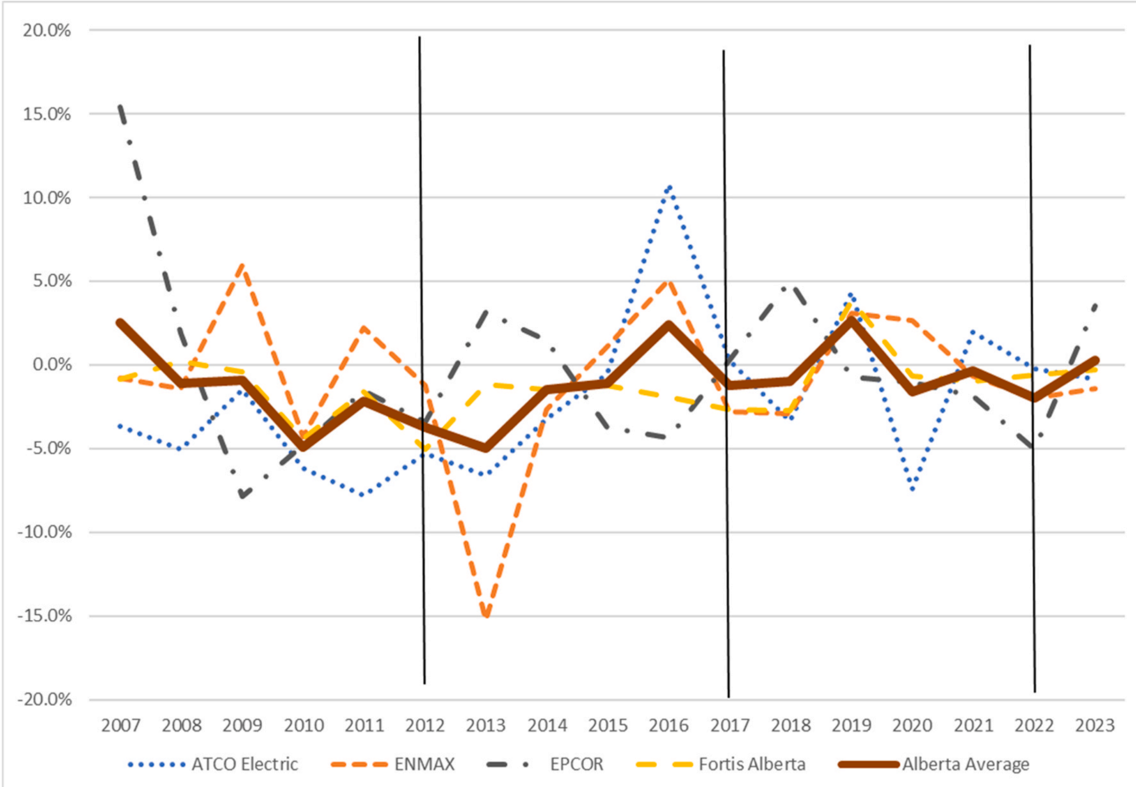

Fig. 1. Multifactor productivity growth of Alberta distributors.

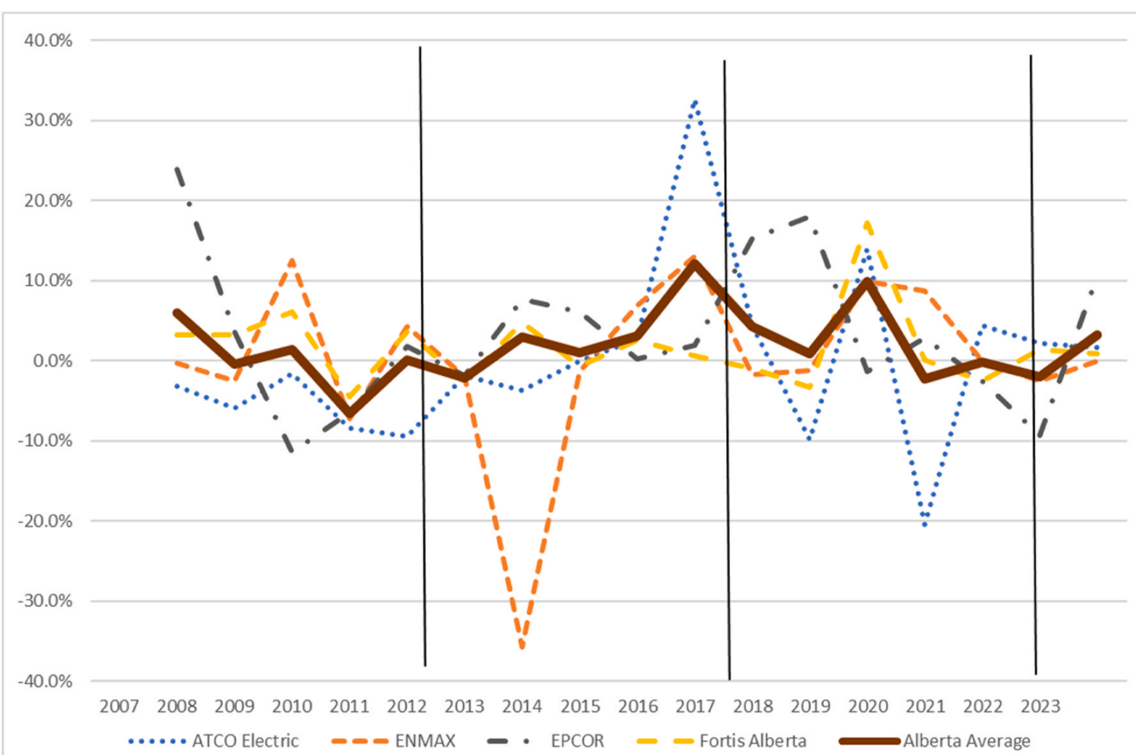

Fig. 2. O&M productivity growth of Alberta distributors.

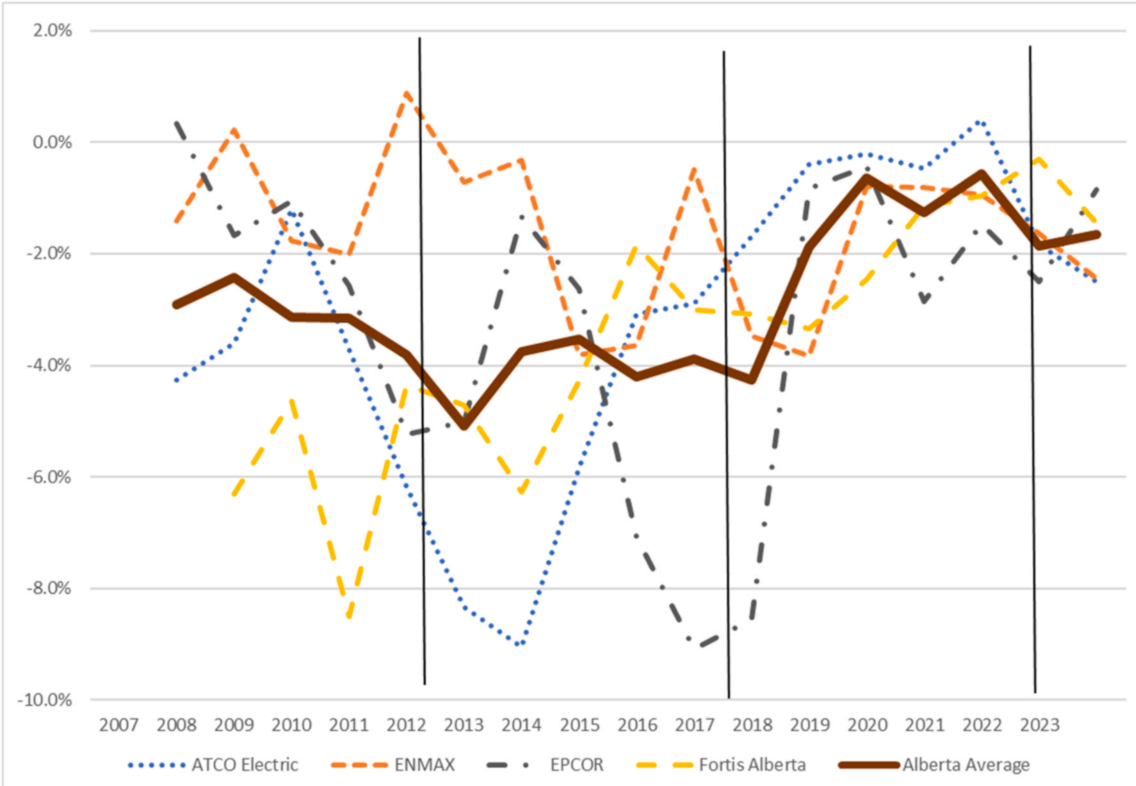

Fig. 3. Capital productivity growth of Alberta distributors.

During the five years of PBR1, the O&M productivity growth of the three distributors who were new to MRPs accelerated markedly, rising from a 0.7% average annual decline to 4.9% average annual growth. However, capital productivity growth worsened slightly for these three distributors. The acceleration in the multifactor productivity growth of these three distributors was nonetheless material. MFP growth improved from a 2.3% to a 0.7% average annual decline.[19]

During PBR2, the average O&M productivity growth of the four distributors slowed but was still brisk, averaging 1.3% annually. The capital productivity growth of these distributors, while still negative, improved from a 3.9% average annual decline in PBR1 to a 1.2% decline in PBR2. The multifactor productivity growth of the four distributors held steady at around a 0.5% annual decline.

Table 4 and Fig. 4 provide companion results on the inflation-adjusted (real) capex per customer of the four distributors. The results are directionally the same as those for capital productivity growth. For example, the aggregate real capex per customer of ATCO, EPCOR, and Fortis were materially lower under PBR2 than in the prior years of the sample period.

4.5. Discussion

Alberta's experience with MRPs provides a valuable opportunity to assess the impact of these plans on distributor cost performance. The Commission's experiments with low- and high-incentive approaches to supplemental capex funding are one reason that the data are so pertinent. Because of the indexed ARM, testimony-quality research has been undertaken on the productivity trends of subject utilities and the results can be used to measure the performance impact.

In the 2007–2012 period, before PBR1, when three power distributors operated under frequent rate cases while ENMAX operated under an MRP, we would expect ENMAX to have had more rapid productivity growth. In the five years from 2013 to 2017, PBR1 strengthened incentives of the other three distributors for O&M but not for capital cost containment. We would therefore expect the O&M but not the capital productivity growth of these distributors to have accelerated. During the five years of PBR2 (2018–2022), incentives were strong for capital as well as O&M cost containment. We would expect capital productivity growth to have been faster for all four distributors during PBR2 than in the prior five years. O&M productivity growth would not necessarily accelerate under PBR2 compared to PBR1 and could slow to the extent that utilities addressed the "low hanging fruit" during PBR1.[20]

Our research on the productivity trends of Alberta power distributors supports the hypothesis that MRPs can materially slow utility cost growth by strengthening incentives. The O&M, capital, and multifactor productivity trends of ENMAX all materially exceeded the average trends of the other three distributors in the six years before PBR1. During PBR1, the O&M productivity growth of the other three distributors accelerated greatly while their capital productivity growth did not. In PBR2 the O&M productivity growth of these distributors was slower on average than during PBR1 but tended to be materially faster than in the years before PBR. The capital productivity growth of all four distributors tended to accelerate markedly during PBR2.

The question arises of the extent to which the noted changes in productivity growth trends were driven by business conditions other than changes in ratemaking incentives. Here are some reasons to believe that the noted changes were materially affected by changing incentives.

[19] A reduction of negative productivity growth constitutes an improvement in performance. Even a good cost performer can have negative productivity growth due to unfavorable business conditions such as a need for high repex.

[20] Low hanging fruit is less likely to occur on the capital side since a utility is continually presented with new capex challenges due, for example, to additional assets nearing retirement age.

Table 4
Real plant additions per customer.

Year	ATCO Electric	ENMAX	EPCOR	Fortis Alberta	Alberta Aggregate	Alberta Aggregate less ENMAX
2007	10.78	2.91	2.00	7.23	5.26	6.23
2008	9.46	2.40	2.40	6.63	4.82	5.82
2009	11.02	2.85	2.08	9.63	6.15	7.49
2010	10.56	3.09	2.64	6.66	5.27	6.15
2011	7.86	1.91	3.59	7.02	4.89	6.09
2012	10.37	2.61	3.82	8.33	5.94	7.29
2013	12.81	2.63	2.86	7.54	5.79	7.07
2014	16.49	3.98	3.38	6.15	6.32	7.28
2015	19.44	4.15	5.26	7.14	7.54	8.92
2016	16.44	3.03	6.39	7.25	7.07	8.72
2017	13.66	4.02	6.48	7.44	7.05	8.30
2018	11.35	4.31	3.29	6.82	5.86	6.50
2019	9.66	3.21	3.06	5.72	4.88	5.57
2020	8.89	3.22	4.23	5.37	4.92	5.64
2021	8.41	3.30	3.64	4.92	4.58	5.13
2022	*8.34*	*3.45*	*4.01*	*6.22*	*5.14*	5.86
2023	*6.95*	*4.26*	*3.61*	*5.71*	*4.93*	5.22
Average Levels						
2007–2022 (17 years)	**11.60**	**3.19**	**3.70**	**6.88**	**5.72**	**6.75**
2007–2012 (Pre-PBR)	**10.01**	**2.63**	**2.75**	**7.58**	**5.39**	**6.51**
2007–2017 (Pre-PBR and PBR1)	**12.74**	**3.08**	**3.82**	**7.36**	**6.05**	**7.27**
2013–2017 (PBR1)	**15.77**	**3.56**	**4.87**	**7.11**	**6.76**	**8.06**
2018–2022 (PBR2)	**9.33**	**3.50**	**3.65**	**5.81**	**5.08**	**5.74**

Notes: Italicized data reflect utility forecasts.

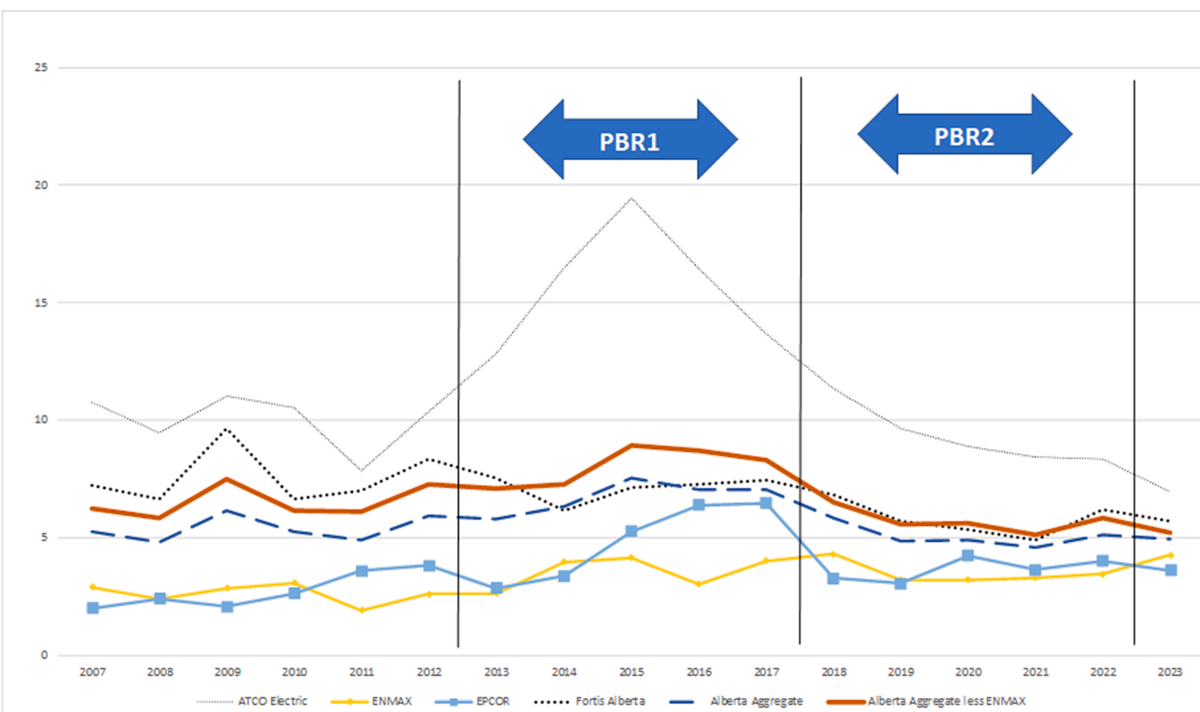

Fig. 4. Real plant additions per customer.

- Customer growth is an important driver of productivity growth since it creates opportunities to boost capacity utilization and to realize economies of scale. Table 3 shows that the 1.9% average annual customer growth during PBR1 was a little slower than the 2.1% average in the six prior years and then fell to a 1.2% annual average during PBR2.
- The O&M productivity growth of the three utilities that were new to PBR accelerated during PBR1 while their capital productivity growth did not.
- PEG's research in the PBR3 proceeding also included a study of US power distributor productivity trends and econometric benchmarking of each Alberta distributor's O&M, capital, and total cost (Lowry, 2023). The sampled US distributors did experience accelerated O&M productivity growth in the years of PBR1 but these distributors experienced slower rather than faster capital productivity growth during the years of PBR2. PEG's econometric benchmarks for O&M, capital and total cost controlled for numerous external business conditions. The benchmarking results indicated

patterns of performance improvement that were similar to those found in the Alberta productivity research.

- While it is possible that the need for repex slowed during the PBR2 years (2018–22), this seems unlikely since 1982 was the last year of rapid population growth and the service lives of some important kinds of distribution assets exceed forty years.

5. Alberta postmortem

In 2021, the AUC established Proceeding 26356 to undertake a streamlined assessment of Alberta's experience with two rounds of generic MRPs. Utilities and consumer groups alike were generally supportive of continuing PBR with modifications. The Commission ruled in June 2021 that its generic MRPs, especially in the second round of plans, were effective at strengthening performance incentives, maintaining service quality, streamlining regulation, and providing utilities a reasonable chance to earn their allowed ROE. On this basis, the Commission decided to proceed to the development of PBR3.

The Commission did, however, express concern as to whether the first two rounds of generic PBR shared benefits reasonably between the utilities and their customers. Customer groups have expressed concern about chronically high utility ROEs during both PBR1 and PBR2. Utilities have argued that rates may nonetheless be lower than would have occurred under a continuation of traditional ratemaking.

A failure to share benefits would violate the Commission's 5th founding PBR principle which is "Customers and the regulated companies should share the benefits of a PBR plan (AUC, 2021, p. 18)." The AUC stated in 26356-D01–2021 that "Overall, Principle 5 … was not adequately met during the two PBR terms" (AUC, 2021, p. 20) and that benefit sharing "is an area of universal concern that needs to be carefully assessed and factored into the design of future PBR plans (AUC, 2021, p. 18)." AUC Bulletin 2022–06, which established the proceeding to develop PBR3, states that "PBR3 should be more reflective of ongoing economic conditions… and ensure the cost efficiencies gained through PBR are shared amongst customers and regulated companies (AUC, 2022)."

In conclusion, the experience of Alberta (and Canada generally) shows that the design of MRPs is complicated by periods of high capex. However, MRPs are particularly useful in periods of high capex in order to bend the cost growth trajectory. The AUC has devised an approach to MRP design that materially strengthens incentives to contain O&M and capital costs, streamlines regulation, and minimizes the role of cost forecasts. This approach merits the attention of ratemaking practitioners in other jurisdictions. Despite progress, there remain concerns about a fair sharing of plan benefits with customers.

Declaration of Competing Interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Pacific Economics Group Research LLC undertakes statistical cost research for a diverse clientele that includes utilities, regulators, government agencies, and consumer groups. This research was funded by the Alberta Utilities Commission and sponsored by the Consumers' Coalition of Alberta ("CCA"). Canadian law requires the provision of objective evidence in utility rate proceedings. The CCA complies with this law and had no involvement in PEG's empirical work.

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