Alberta Utilities Commission

Evaluation of Performance-Based Regulation in Alberta

June 30, 2021

Alberta Utilities Commission
Decision 26356-D01-2021
Evaluation of Performance-Based Regulation in Alberta
Proceeding 26356

June 30, 2021

Published by the:
Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Telephone: 310-4AUC (310-4282 in Alberta)
1-833-511-4AUC (1-833-511-4282 outside Alberta)
Email: info@auc.ab.ca
Website: www.auc.ab.ca

Contents

List of figures

List of tables

Alberta Utilities Commission
Calgary, Alberta

Evaluation of Performance-Based Regulation in Alberta — **Decision 26356-D01-2021** — **Proceeding 26356**

1 Decision summary

1. In this decision, the Alberta Utilities Commission has evaluated the performance of the first and second terms (to date) of performance-based regulation (PBR) of the electric and gas distribution utilities operating in Alberta. Measured against the founding PBR principles established by the Commission prior to implementation of PBR, the Commission finds that, on balance, PBR has achieved many of the objectives that were set out in these principles. However, there remain areas for improvement. Nonetheless, a third PBR term (PBR3) commencing in 2024, following a one-year cost-of-service (COS) rebasing year in 2023, is supported. The parameters and changes to be adopted for PBR3 will be set in a future generic proceeding initiated by the Commission.

2 Background and procedural summary

2. Rates for the electric and natural gas distribution utilities under the Commission's jurisdiction are currently set according to the PBR plans established in Decision 20414-D01-2016 (Errata).[1] These plans are effective from January 1, 2018, to December 31, 2022, and apply to the four electric distribution facility owners (DFOs): ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and the two natural gas DFOs: ATCO Gas and Pipelines Ltd., and Apex Utilities Inc. (formerly AltaGas Utilities Inc.) (collectively, "the utilities"). This is the second term of PBR in Alberta for the majority of the utilities, except for ENMAX that was under various forms of PBR since 2007.[2]

3. As communicated in Bulletin 2021-04,[3] the Commission saw merit in a recommendation from The City of Calgary (Calgary) to structurally evaluate the legacy PBR experience to identify successes and shortcomings of the first two PBR plans. The Commission issued a letter[4] stating it was initiating the present Proceeding 26356 to gather input and feedback related to evaluation of PBR in Alberta. The letter explained that the Commission was seeking structured information in support of parties' responses based on actual utility experiences and supporting data, and asked parties to respond to the following five questions:[5]

---

[1] Decision 20414-D01-2016 (Errata): 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, February 6, 2017.

[2] ENMAX was under formula-based ratemaking (FBR, a form of PBR) from 2007 to 2013, 2014 was a COS rebasing year, then joined the other utilities in their PBR plan from 2015 to 2017. ENMAX is currently regulated under the 2018-2022 PBR plan. For DFOs other than ENMAX, the first term took place from 2013 to 2017, followed by the current 2018-2022 PBR term.

[3] Bulletin 2021-04, Stakeholder consultations to evaluate performance-based regulation in Alberta and to determine process to establish 2023 rates for distribution facility owners, March 1, 2021.

[4] Exhibit 26356-X0008, AUC letter - Proceeding details, March 1, 2021.

[5] Exhibit 26356-X0008, AUC letter - Proceeding details, March 1, 2021, paragraph 4.

(i) What efficiencies have been found by utilities due to the incentives of PBR? In other words, have utilities operated differently under PBR, or has there been a shift in internal culture or actions due to PBR incentives? Please provide specific examples and quantify cost-cutting initiatives where possible.

(ii) Did customers experience lower rates under PBR than they would have had if cost-of-service regulation had continued? Have customers benefited from efficiencies found by utilities due to the incentives of PBR, and have any efficiencies resulted in customer rate reductions? Please explain how customers have benefited or been disadvantaged with specific examples and data where possible.

(iii) Has PBR resulted in regulatory efficiency and reduced regulatory burden? Please explain why or why not and provide specific examples.

(iv) Has there been an improvement or deterioration in service quality or reliability under PBR, and have the incentives provided to utilities by PBR contributed to any service quality changes? Please fully explain any experiences with service quality changes and provide specific examples referencing relevant metrics (e.g., system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI), or other metrics from Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*).

(v) Should the Commission establish a further PBR term for the regulated distribution utilities? If the Commission establishes a further PBR term, what aspects and parameters of the PBR plans could be improved to address any concerns expressed in response to the questions above? What aspects and parameters of the PBR plans have performed well and could be left unchanged?

4. After receiving the responses to the five questions from parties, the Commission asked the utilities follow-up information requests (IRs) regarding historical rates, cost allocations and a suggestion by the Industrial Power Consumers Association of Alberta (IPCAA) regarding the calculation of efficiencies achieved under PBR.[6] Following the receipt of responses, parties filed reply comments and with this step, the record for this proceeding closed on June 1, 2021.

5. The Commission's questions and parties' evidence in this proceeding by a large degree revolved around the founding PBR principles established by the Commission prior to implementation of PBR. The Commission structured its evaluation of PBR against those principles.

6. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to a particular matter.

[6] Exhibit 26356-X0034, AUC IR Round 1 to parties, May 6, 2021.

3 PBR performance to date evaluated against the Commission's PBR principles

7. The Commission has considered the evidence filed from all participants and, based on this evidence, has evaluated the performance of PBR measured against the founding PBR principles set out in Bulletin 2010-20:[7]

> Principle 1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> Principle 2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> Principle 3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> Principle 4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> Principle 5. Customers and the regulated companies should share the benefits of a PBR plan.

3.1 Principle 1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality

8. In competitive markets, companies are incented to find efficiencies to reduce their costs of doing business (e.g., delivering goods and services) to maximize profits while maintaining service quality at levels that allow them to attract and retain customers.

9. The Commission adopted a PBR approach for the utilities to create efficiency incentives that mimic those in competitive markets. Because Alberta's distribution utilities generally operate in a monopoly environment,[8] they do not have to attract and retain customers. Therefore, in setting PBR plans, the Commission recognized that the utilities may be incented to cut costs by reducing service quality, which would be detrimental to ratepayers.

10. Accordingly, when evaluating the performance of PBR in Alberta according to Principle 1, the Commission separately determined whether:

- PBR created, to the greatest extent possible, the same efficiency incentives as those experienced in a competitive market; and
- service quality was maintained.

7 Bulletin 2010-20, Regulated rate initiative - PBR Principles, July 15, 2010.

8 Alberta's distribution utilities are beginning to experience increased competition, to varying extents and in a variety of different ways. For example, see Proceeding 24116, Distribution System Inquiry – Final Report, February 19, 2021, paragraphs 31, 43-47.

3.1.1 Has PBR created, to the greatest extent possible, the same efficiency incentives as those experienced in a competitive market?

11. The Commission concludes that PBR has incented the utilities to find efficiencies in service delivery to maximize their profits, similar to what may be experienced in a competitive market, but not to the greatest extent possible.

12. The utilities agreed that PBR created incentives to find efficiencies. However, they stated that they were not able to quantify some of these efficiencies in terms of dollar savings, adding that some were not tracked because doing so would be excessively burdensome. Further, the utilities indicated that in some cases it would be impossible to attribute the efficiencies solely to PBR incentives because the initiatives would have been implemented regardless of the regulatory regime (i.e., PBR or COS). All the utilities agreed that PBR encouraged them to introduce cost-saving programs because they are able to retain earnings in excess of their approved return on equity (ROE) arising from the savings realized by implementing these programs. The utilities added that ratepayers also benefit to the extent the utilities' cost savings and efficiencies achieved during the PBR period are reflected in rebased rates.

13. The utilities provided some examples of achieved efficiencies and associated dollar savings estimates, but cautioned these were only provided as illustrations of some of the savings initiatives and were not representative of total utility savings achieved. Some of these utility cost examples are provided below.

14. ATCO provided an example of its efforts to increase efficiency regarding its workforce reductions:[9]

> … in the first PBR term alone, ATCO undertook a major restructuring of its workforce, and realized labour savings of approximately $45 million and $38 million for ATCO Electric and ATCO Gas, respectively. In response to the reduced work force, ATCO had implemented hundreds of small improvements to minimize costs across the organization, with the majority of savings realized in the areas of customer accounting and distribution operating and maintenance. These major workforce reductions are clear examples of management action driven by the superior incentive properties of PBR.

15. ATCO further stated that, "… ATCO is serving more customers, supplying more load, and managing more distribution facilities, while achieving or exceeding service quality and reliability standards after reducing FTEs [full-time equivalents] by as much as 38 percent."[10]

16. ATCO noted this about the incentive properties of PBR on its organization:[11]

> … it is not possible to hypothetically determine precisely what customers' rates would have been under a COS regime had PBR not been implemented by the Commission since 2013. However, it would be unlikely that ATCO would have seen the same level of workforce reductions; organizational transformations; and the same level of capital substitution for O&M [operating and maintenance] due to technological innovations and investment as outlined above if it were not for the incentive properties of a five-year PBR term.

[9] Exhibit 26356-X0020, ATCO submission, paragraph 9.
[10] Exhibit 26356-X0020, ATCO submission, paragraph 34.
[11] Exhibit 26356-X0020, ATCO submission, paragraph 44.

17. EPCOR stated that it implemented staffing reductions for its distribution and transmission functions, with FTEs decreasing from 617 in 2012 to 531 in 2020.[12] It also reduced its net operating costs (excluding franchise fees and property taxes) from $78.83 million in 2012 to $65.14 million in 2020 while facing an increase of nearly 20 per cent in the number of sites in its service area.[13]

18. Fortis employed more automation technology to analyze power outages, locate and isolate faults, and restore un-faulted segments within minutes, and took steps to incorporate its Mobile Workforce Management technology into its operations to optimize the deployment of field staff and equipment.[14]

19. ENMAX optimized labour and materials by merging business units, reducing the use of contractors, and consolidating reporting and analytics when possible.[15]

20. Apex stated that one of its most significant process changes was the rollout of aerial automated meter reading, providing an estimated $1.7 million of annual O&M savings since its implementation in 2016.[16]

21. Interveners considered that it is not necessary to quantify the cost savings resulting from any particular initiative or program implemented by the utilities as a result of PBR. Rather, the utilities' overall performance should be evaluated according to the fair return standard during the two PBR terms.

22. The Commission regularly determines what a fair return is during generic cost of capital proceedings. These proceedings set the "approved ROE," which is the rate of return that the Commission has found to be a fair for a utility's investment in its assets during a particular year or years. In COS regulation, this rate of return on the utility's assets is added to the other costs of running a utility, such as the operating, debt and depreciation costs, to determine a revenue requirement. Using this revenue requirement and based on a utility's various customer classes, customer rates are set.[17]

23. IPCAA suggested that the utilities' efficiencies and resulting savings achieved during the PBR term could be estimated by comparing actual achieved earnings to approved earnings (calculated based on the approved ROE).[18] IPCAA used this proxy method to obtain the estimates in Table 1 below:

12 Exhibit 26356-X0022, EPCOR submission, paragraph 7 and Table 2.1.1.1-1.
13 Exhibit 26356-X0022, EPCOR submission, paragraph 8 and Table 2.1.1.2-1.
14 Exhibit 26356-X0025, Fortis submission, paragraph 16.
15 Exhibit 26356-X0024, ENMAX submission, paragraph 47.
16 Exhibit 26356-X0029, Apex submission, paragraph 16.
17 Under PBR, the approved ROE is used at rebasing for setting the going-in rates. It is also used when setting the annual rates during the PBR term in determining the utilities' K-bar amounts and certain Y factor items.
18 Exhibit 26356-X0050, IPCAA reply, PDF page 4, Table 2.

Table 1. IPCAA quantification of efficiencies achieved by utilities during PBR

Year	Fortis	ATCO Electric	ENMAX	EPCOR	ATCO Gas[1 2]	Apex
	($000)					
2013	13,034	23,926	N/A[3]	4,619	25,862	3,071
2014	17,224	13,785	N/A[3]	5,619	20,649	2,739
2015	30,367	13,636	(9,397)	7,036	22,809	(2,200)
2016	15,040	39,508	9,555	2,486	39,669	(2,838)
2017	8,072	42,080	4,219	(2,071)	68,954	1,682
2018	(795)	(2,143)	(10,371)	10,609	24,683	1,166
2019	21,122	24,497	4,557	15,178	27,375	2,545
2020	21,971	6,142	4,064	14,970	23,867	1,151
Total	**126,034**	**161,431**	**2,627**	**58,447**	**253,868**	**7,316**

Note 1: ATCO Gas North and South service territories are combined.
Note 2: The Commission used IPCAA's methodology to calculate the efficiency amounts for ATCO Gas and Apex.
Note 3: ENMAX did not join PBR until 2015.

24. All of the utilities disagreed with IPCAA's methodology, considering it an overly simplistic view that does not take into account the multitude of factors that may impact total earnings over the course of the PBR term, of which achieved efficiencies are just one. They indicated that a utility's revenue may be affected by exogenous factors outside of its control, such as the timing of Commission decisions and fluctuating prices of inputs and materials used by the utilities (e.g., copper). However, the utilities failed to offer any credible alternative to calculate the monetary value of the efficiency gains resulting from PBR, relying on their IR responses that the efficiencies are difficult to quantify.[19]

25. In the Commission's view, the amounts expressed in Table 1 support the conclusion that the utilities responded to PBR incentives in the same manner as would have been expected in a competitive market. That is, they engaged in productivity improvements to reduce their costs in order to maximize profits (higher returns). In this respect, PBR was successful. This finding is also consistent with the Commission's previous finding that "actual earnings are informative to indicate whether a PBR plan is working as expected … [even though] multiple factors may affect returns in a PBR term."[20]

26. At the same time, the Commission agrees with the utilities that quantifying the efficiencies created as a result of PBR incentives may not be as simple as looking at the difference between actual and approved returns, as suggested by IPCAA. Nevertheless, as further discussed in Section 3.5, the Commission considers it is crucial to ensure that customers share in the efficiencies achieved during the PBR term at the time of rebasing, whether the utilities are able to expressly quantify the achieved efficiencies or not.

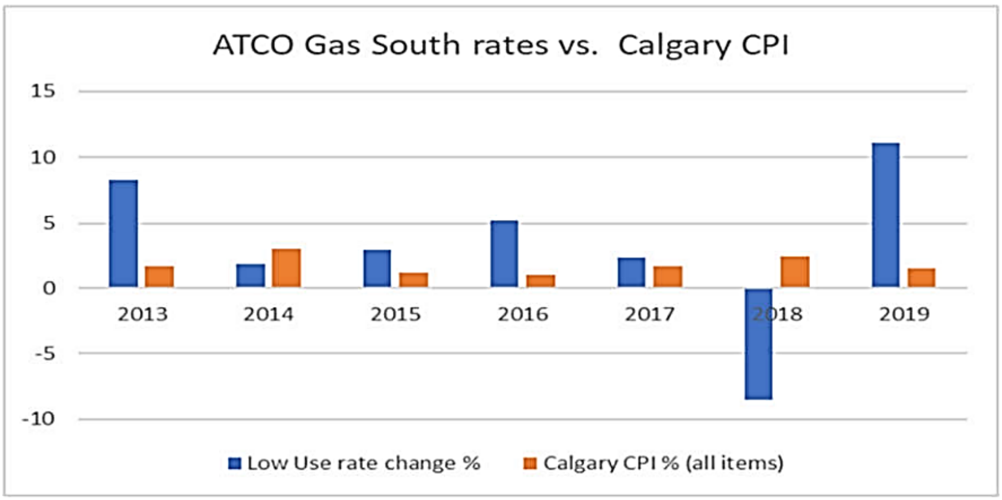
27. While PBR mimicked competitive market outcomes in one respect, it may not have created the same efficiency incentives as those experienced in competitive markets "to the greatest extent possible."

28. Calgary analyzed how natural gas distribution rates have changed during PBR compared to inflation in Calgary and concluded that PBR rates did not accurately reflect the economic realities

19 Exhibit 26356-X0034, [RESPONDER]-AUC-2021MAY06-002.
20 Decision 25422-D01-2020: Anomaly Adjustment Applications in Rebasing the 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 25422, November 3, 2020, paragraphs 142-143.

experienced in Alberta. Specifically, Calgary provided a chart, reproduced in Figure 1 below, showing changes to ATCO Gas South's low use rates and the inflation experienced in the city of Calgary, as reported by Statistics Canada through the Consumer Price Index (CPI). Calgary observed that "low use customer rate increases were consistently higher than Calgary CPI in every year since PBR was enacted, with the exception of 2014 and 2018."[21]

Figure 1. ATCO Gas South's low use rate changes vs. the city of Calgary CPI 2013–2019: provided by Calgary[22]



29. According to Calgary, "This supports the conclusion that for the majority of years in the first and second generation PBR terms, customers have paid natural gas distribution rates which have increased at a much higher amount than the Alberta economy at large."[23] Calgary also pointed to the recent years plagued by the COVID-19 pandemic and the resulting economic turmoil in Alberta and submitted that "any future contemplation of COS or PBR must reflect the reality that utilities need to be both costs and earnings constrained. There is no appetite among ratepayers for large annual rate increases coupled with consistently enormous over-earning."[24]

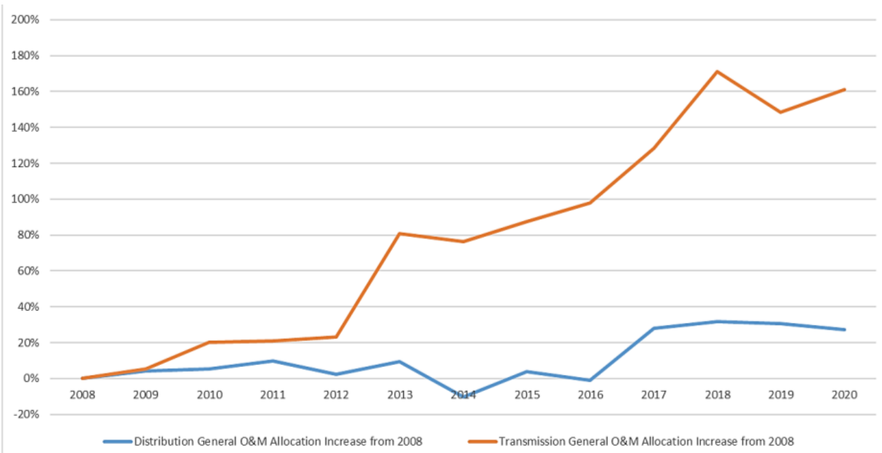
30. The Commission observes that the approved I factor is calculated as a weighted average of two indexes: one representing the price of labour (measured by the Alberta Average Weekly Earnings (AWE) index) and another, non-labour costs (represented by Alberta CPI). The labour index historically demonstrated higher growth than the provincial CPI, and this explains at least part of the discrepancy that Calgary observed.[25] Nevertheless, the Commission understands the arguments put forward in this proceeding that PBR may not have best reflected the economic realities experienced in Alberta.

31. PBR may also have failed to achieve, to the greatest extent possible, the same efficiency incentives as those experienced in competitive markets for utilities that have both distribution and transmission functions, namely, EPCOR, ATCO Electric and ENMAX.

21 Exhibit 26356-X0026, Calgary submission, paragraph 29.
22 Exhibit 26356-X0026, Calgary submission, Figure 1.
23 Exhibit 26356-X0026, Calgary submission, paragraph 29.
24 Exhibit 26356-X0026, Calgary submission, paragraph 74.
25 Please refer to Appendix 2 of this decision.

32. For example, using data provided by EPCOR, the Commission prepared Figure 2 below showing the changes in allocations of corporate and general O&M costs between distribution and transmission from 2008 to 2020.

Figure 2. EPCOR's general O&M allocation percentage change compared to 2008 levels between distribution and transmission functions[26]



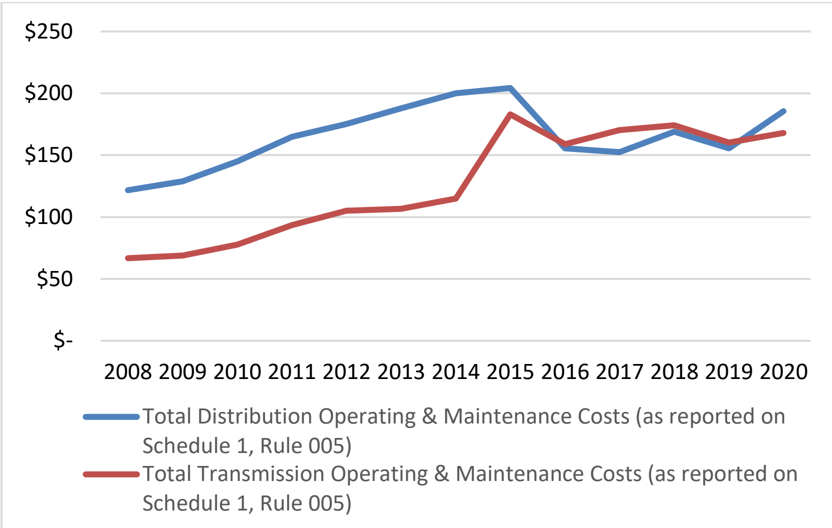
33. The graph in Figure 2 above shows that the general O&M allocations to transmission have increased significantly more than the allocations to distribution over the same time period. EPCOR explained why transmission allocations would increase more relative to distribution;[27] however, in the Commission's view, these explanations do not completely eliminate the possibility that the observed difference in allocation trends between the two functions commencing in 2013 (the first year of PBR) is at least partly the result of different incentive regimes under which EPCOR's distribution and transmission functions are regulated. An incentive may have been created for distribution companies to shift costs to an affiliated company under a COS ratemaking regime.

34. A similar observation can be made when observing how ATCO Electric's O&M cost levels have evolved under COS regulation and then during the first PBR term that commenced in 2013. As shown in Figure 3 below, sharp increases to transmission O&M costs occurred around the same time there are sharp declines in distribution O&M costs:

[26] Data source Exhibit 26356-X0045, EDTI-AUC-2021MAY06-003 Attachment 1, rows General O&M Costs Allocated to Distribution, and General O&M Costs Allocated to Transmission. Calculation example: Transmission allocation of General O&M costs in 2008 was $631,654, and in 2020 it was $1,648,663, or 161 per cent higher than 2008's allocation; whereas Distribution's allocation of General O&M costs in 2008 was $2,592,262 and in 2020 it was $3,297,141, or 27 per cent higher than 2008's allocation.

[27] Exhibit 26356-X0043, EDTI-AUC-2021MAY06-003(b).

Figure 3. ATCO Electric distribution and transmission O&M costs ($ million)[28]



35. As seen in the figure, where a large gap once existed between ATCO Electric's distribution and transmission O&M spending from 2008 to 2014 (with the difference being close to double in 2014), the two business units now have nearly equal O&M costs. While this is a high-level, cursory view of long-term utility trends and no conclusive determinations can be taken from it, the Commission observes that the two business units demonstrate a marked difference in O&M costs growth patterns.

36. The trends for EPCOR and ATCO Electric shown in the figures above may be fully, or partly, explained by PBR incentives to find efficiencies on distribution costs. Similarly, the increase in transmission O&M costs may be fully, or partially, explained by the "big build" of transmission lines that took place in previous years. However, to the extent PBR created an incentive for distribution utilities to shift costs to an affiliate company that is subject to a different regulatory regime with less efficiency incentives, this would not be in the interest of ratepayers.

3.1.2 Have the utilities maintained service quality?

37. In Decision 2012-237 that initiated the first PBR term, the Commission recognized that while PBR "creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service."[29] Accordingly, the Commission required the utilities to maintain their service quality throughout the PBR terms.

38. The Commission monitors service quality performance through Rule 002, which sets the minimum service quality standards and reporting requirements for the utilities.

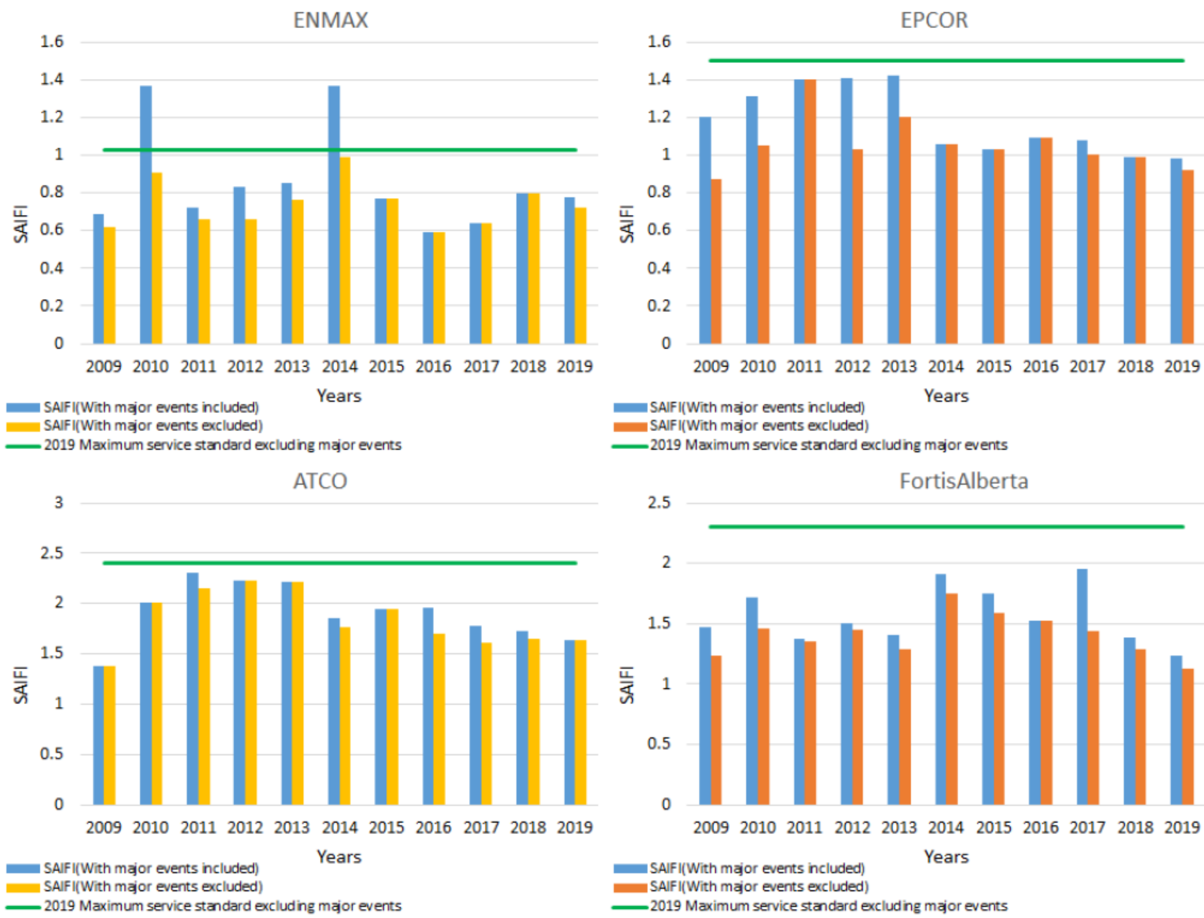
39. Using utility data submitted through the Rule 002 reports, the Office of the Utilities Consumer Advocate (UCA) provided charts, reproduced in figures 4 and 5 below, showing that all the electric distribution utilities have maintained the frequency and duration of service interruption

[28] Data source Exhibit 26356-X0042, ATCO-AUC-2021MAY06-003 Attachment 1.

[29] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012, paragraph 864.

below the thresholds required by the AUC[30] for all years during the PBR terms, when major event days are excluded.

Figure 4. System average interruption frequency index, by year and electric distribution utility[31]



30 Rule 002, Appendix A - SAIFI and SAIDI service standards for owners of electric distribution systems subject to this rule.

31 Exhibit 26356-X0030, UCA submission, Figure 6 - Interruption duration and frequency - SAIFI by year.

Figure 5. System average interruption duration index, by year and electric distribution utility[32]

40. The UCA recommended the Commission consider further reporting and comparisons to industry metrics and that predetermined service guarantees or penalties for non-compliance with service quality standards be considered by the Commission. It also referred to other jurisdictions' service quality approaches, such as the Ontario Energy Board's (OEB) use of utility scorecards and metrics that directly reflect the customer experience, and recommended the Commission consider these approaches as well. It also recommended the Commission consider a willingness-to-pay study, as has been done in other jurisdictions.[33] This type of study attempts to find a socially optimal level of reliability, that is, the level of reliability where the marginal benefits from improvements equal the marginal costs of implementation. The UCA stated that different customer classes are willing to pay differing amounts for reliability improvements and that customers' willingness to pay would change over time, especially at a time of significant change in the industry with both technology and consumer expectations changing rapidly.[34]

41. The natural gas distribution utilities similarly reported maintaining service quality during the PBR terms. There is no metric equivalent to SAIDI and SAIFI for measuring service quality

32 Exhibit 26356-X0030, UCA submission, Figure 7 - Interruption duration and frequency - SAIDI by year.
33 Exhibit 26356-X0030, UCA submission; footnote 18: Exhibit 0299.02.UCA-566, pages 6, 30, 32, 119, 192 and 207 of UCA's PBR Evidence filed December 16, 2011 in AUC Proceeding 566.
34 Exhibit 26356-X0030, UCA submission, paragraph 45.

and reliability of gas distribution systems and Rule 002 sets out alternative service quality and reliability metrics for the gas utilities.

42. ATCO Gas reported meeting or exceeding the Rule 002 requirements, particularly in customer service and response time measures.[35] Apex also reported meeting or exceeding the Rule 002 requirements.[36] For example, Apex provided the following statistics showing its compliance with some of the service quality standards set under Rule 002.

Table 2. Apex operational performance metrics under Rule 002[37]

Rule 002	PBR1					PBR2		
	2013	2014	2015	2016	2017	2018	2019	2020
	(%)							
Energized sites with actual meter readings	96	96	97	97	97	96	98	98
Average of emergencies responded to within 60 minutes	94	92	97	98	93	98	94	96
Average of emergencies responded to within 120 minutes	100	96	100	100	97	100	98	100

43. The Consumers’ Coalition of Alberta (CCA) stated that although reliability metrics all improved for the most part, because PBR was not designed to improve service quality but rather maintain levels, funding under PBR was too generous.[38]

44. On the basis of the Rule 002 reports, the Commission is satisfied that the utilities have maintained service quality during the PBR terms. The Commission will evaluate the need for more granular service quality metrics as part of the proceeding to establish the parameters of the next PBR plan.

3.2 Principle 2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return

45. Provincial legislation governing the regulation of distribution utilities includes direction to the Commission to provide the utility with a reasonable opportunity to recover its prudently incurred costs, including a fair rate of return.[39] In each of the *Public Utilities Act*, the *Gas Utilities Act* and the *Electric Utilities Act*, the fair return is referenced as a component of just and reasonable rates. The *Gas Utilities Act* requires the Commission, in fixing just and reasonable rates, to determine a rate base upon which it shall fix a fair return.[40] The *Electric Utilities Act* requires the Commission to ensure that a tariff is just and reasonable and provides the owner of an electric utility with a reasonable opportunity to recover a fair return on the equity of shareholders of the electric utility.[41]

35 Exhibit 26356-X0020, ATCO submission, paragraph 58.
36 Exhibit 26356-X0029, Apex submission, paragraphs 46-52.
37 Exhibit 26356-X0029, Apex submission, Table 2.4-1.
38 Exhibit 26356-X0051, CCA reply comments, paragraph 16.
39 *Public Utilities Act*, Section 90(1); *Gas Utilities Act*, Section 37(1); *Electric Utilities Act*, sections 121(2)(a) and 122(1)(a)(iv).
40 *Gas Utilities Act*, Section 37(1).
41 *Electric Utilities Act*, sections 121(2)(a) and 122(1)(a)(iv).

46. It is important to note that a PBR plan does not guarantee a return; only the opportunity to do so. As stated by the Alberta Court of Appeal in *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2014 ABCA 397:

> [2] The general concept is that in return for the undertaking to serve all customers in a defined service area, the utility is granted an *opportunity* both to earn a reasonable return on its prudent investment and to recover its prudently incurred expenses. However, the regulatory compact was never an arrangement under which utility companies were entitled to find pockets deeper than their own – their ratepayers – in order to recover every expense incurred in pursuit of their corporate and shareholders' interests. Put simply, the regulatory compact did not confer on utilities an absolute guarantee that they would be entitled to recover all incurred costs and expenses, reasonable or otherwise. [emphasis in original]

47. As set out in paragraph 22 above, the Commission generally determines what a fair return is during generic cost of capital proceedings in which an approved ROE for the utilities is established.

48. The Commission is satisfied that Principle 2 was achieved during the PBR terms. In the majority of the PBR years, the utilities earned returns above the Commission's generically approved ROE and for some utilities, by a significant amount. The Commission prepared Table 3 below that compares the actual achieved ROEs with the approved ROE.

Table 3. Approved and actual ROEs achieved by utilities during PBR

Year	Approved ROE	Fortis	ATCO Electric	ENMAX[1]	EPCOR	ATCO Gas North	ATCO Gas South	Apex
	(%)							
2013	8.30	9.49	10.99	8.05	9.97	10.97	12.98	11.96
2014	8.30	9.77	9.74	7.82	10.39	11.86	9.81	11.27
2015	8.30	11.12	9.90	6.15	10.37	12.15	9.78	6.16
2016	8.30	9.70	13.03	9.93	8.98	13.89	11.75	5.83
2017	8.50	9.20	13.21	9.64	8.02	16.61	15.33	9.80
2018	8.50	8.90	8.34	6.53	10.81	10.49	11.66	9.37
2019	8.50	10.14	11.15	9.31	11.63	10.57	11.96	10.26
2020	8.50	10.13	9.82	9.19	11.36	11.60	9.88	9.25

Source: Utility Rule 005 financial filings.
Note 1: ENMAX was regulated under formula-based ratemaking in 2013 and under COS in 2014.

49. It should be noted, however, that a return in excess of the approved ROE, in itself, does not necessarily indicate that there is a problem with the PBR plans. For example, in the ATCO utilities reopener decision,[42] the Commission found there was no basis to conclude that the earnings achieved by the ATCO utilities above the approved ROE were the result of a problem with the design or operation of the 2013-2017 PBR plans.[43]

42 Decision 23604-D01-2019: AUC-Initiated Review Under the Reopener Provision of the 2013-2017 Performance-Based Regulation Plan for the ATCO Utilities, Proceeding 23604, February 27, 2019.
43 Decision 23604-D01-2019, paragraph 115.

3.3 Principle 3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time

50. Apart from Calgary, the Alberta Electric System Operator (AESO) and the Alberta Federation of Electrification Associations (AFREA), parties submitted that there have been some successes in improving regulatory efficiency and reducing regulatory burden through implementation of the PBR plans. These were largely attributable to the implementation of regular and routine annual PBR rate adjustment filings and the adoption of the K-bar mechanism in lieu of capital trackers in the 2018-2022 PBR plan. Additional regulatory efficiencies identified included reductions to overall processing time, scoping issues and setting submission length limits in Commission proceedings. These latter regulatory efficiency initiatives were introduced by the Commission to improve adjudicative efficiency and although not specific to the PBR plan, took place during the current PBR term.

51. Parties also identified areas where the goals of increased regulatory efficiency and reduction of regulatory burden were not achieved.[44]

52. Calgary submitted a hypothetical COS scenario of the proceedings it believed ATCO Gas would have filed after 2013 if COS was in place instead of PBR and compared it against the actual proceedings filed by ATCO Gas under PBR.[45] Based on this analysis, Calgary stated that both the number of proceedings and the average days per proceeding for ATCO Gas would be lower under a COS regulation scenario versus PBR.[46]

53. There are a number of flaws with the assumptions used in Calgary's analysis. For example, Calgary included ATCO Gas's 2018 depreciation application under PBR but did not appear to consider that a depreciation study could have also been part of a COS application or as a stand-alone application. Also, Calgary's PBR schedule did not account for instances where there was a time gap between when a proceeding was opened and the application was filed. For example, Proceeding 2738: ATCO Gas Z factor for flood costs was opened on July 25, 2013, and ended on March 16, 2016. When it calculated the total of 965 days for this proceeding, it did not account for the fact that ATCO Gas had filed a letter on July 24, 2013, to state it would be filing for a Z factor application once it completed its financial analysis of the impacts of the flood.[47] On July 9, 2015, almost two years after the initial letter, ATCO Gas filed its Z factor application. Using July 9, 2015, as the start date, the application was processed by the Commission in 251 days, not the 965 days used by Calgary. A similar issue arises with the calculation of proceeding days for ATCO Gas's Z factor application for the Wood Buffalo wildfire, Proceeding 21608.

54. The UCA also undertook an analysis of the number of proceedings over the years under each regime. The UCA found that during the 2013-2017 PBR term, there were 95 proceedings (excluding ENMAX's formula-based ratemaking proceedings and its interim 2015-2017 PBR

---

[44] Exhibit 26356-X0029, Apex submission, paragraphs 36-40; Exhibit 26356-X0020, ATCO Utilities submission, paragraphs 47-53; Exhibit 26356-X0027, CCA submission, paragraphs 43-44; Exhibit 26356-X0024, ENMAX submission, paragraphs 82-87; Exhibit 26356-X0022, EPCOR submission, paragraphs 22-23; Exhibit 26356-X0025, Fortis submission, paragraphs 23-27; Exhibit 26356-X0030, UCA submission, paragraph 31.

[45] Exhibit 26356-X0026, Calgary submission, appendixes A and B.

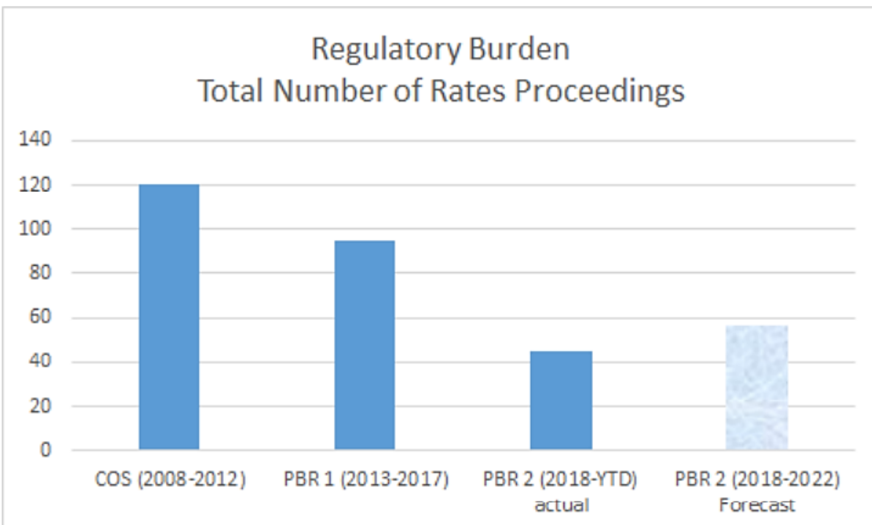
[46] Exhibit 26356-X0026, Calgary submission, paragraph 45.

[47] Proceeding 2738, Exhibit 0001.00.ATCO GAS-2738, notification of potential Z factor adjustment letter, July 24, 2013.

plan). In the five COS years that preceded it, the UCA determined there were a greater number of proceedings, approximately 120.

55. To date under the 2018-2022 PBR plan, the UCA stated, "… there have been about 45 PBR related proceedings and the term is nearly two thirds complete."[48] The UCA noted that there were 56 capital tracker-related proceedings during the first generation of PBR, and only two Type 1 capital tracker applications so far. Additionally, the UCA observed that the annual PBR rate adjustment proceedings for all six distribution utilities are less complex. According to the UCA, COS appeared to involve more frequent tariff proceedings, compliance filings and deferral account applications resulting in a greater regulatory burden than PBR. The chart below illustrates the number of proceedings under each type of regulation, assuming the last two years of the current PBR term will follow a similar pattern to the first three years.[49]

Figure 6. Total number of rates proceedings counted and/or forecasted by the UCA[50]



56. The AESO stated that it was not in a position to comment on whether PBR has resulted in greater regulatory efficiency; however, it observed that in comparison to other system access service requests received in the AESO connection process, it experienced higher regulatory burden on a number of DFO projects because it was required to defend its position on those projects to the Commission.[51] AFREA noted that PBR seems to be a more complex process and that it is difficult for the average small consumer to understand resulting in a disconnection between the utility and the public that the utility serves.[52]

57. Some parties suggested areas where PBR still needs to be improved to reduce regulatory burden and make it easier to understand. ENMAX suggested that certain aspects of the current PBR plan that have contributed most to regulatory burden and uncertainty (such as consideration of anomalies in rebasing and the Type 1 capital mechanism), should be modified in future PBR terms to enhance regulatory efficiency to benefit customers and provide more certainty to DFOs.[53]

48 Exhibit 26356-X0030, UCA submission, paragraph 30.
49 Exhibit 26356-X0030, UCA submission, paragraphs 30-32.
50 Exhibit 26356-X0030, UCA submission, paragraph 32, Figure 5.
51 Exhibit 26356-X0021, AESO submission, page 5.
52 Exhibit 26356-X0018, AFREA submission, paragraph 9.
53 Exhibit 26356-X0024, ENMAX submission, paragraph 86.

Apex expressed a similar view and agreed that the capital tracker process used in the 2013-2017 PBR term was resource intensive and there was a need for streamlining; however, the streamlining may have gone too far in the current PBR term given the very narrow interpretation of the Type 1 criteria. Given the need to find the appropriate balance between PBR principles 2 and 3, Apex submitted that there is a need to re-evaluate the approach to incremental capital funding, such that a middle ground may be found between the resource intensive approach to capital during the 2013-2017 PBR term and the very streamlined approach of the 2018-2022 PBR term which effectively involves complete reliance on K-bar funding.[54]

58. The ATCO utilities hoped that with any future changes to PBR plan parameters, there would be less need for clarifying proceedings that took place in previous PBR terms (such as consideration of anomalies, impact of depreciation changes, supplemental funding for Rural Electrification Association (REA) acquisitions), given parties' and the Commission's experience with such matters.[55]

59. Apex suggested that if the Commission introduces novel concepts or mechanics of calculating certain amounts, it is necessary to ensure parties understand the intended scope of a concept and are provided with an opportunity to assess it; for example, by holding technical meetings or roundtables.

60. The Commission observes that parties were divided as to whether the objectives of Principle 3 were met during the two PBR terms. The Commission recognizes that while certain challenges were experienced during the two terms, there were notable achievements recognized by the majority of parties. The annual PBR rate adjustment filings that are routine, regular and mechanical in nature, allowed for an expedited review by the Commission and customer groups, while allowing the utilities to plan for the development of their applications and any subsequent related proceedings. The introduction of a K-bar mechanism in lieu of the legacy capital tracker mechanism reduced the number of regulatory proceedings by avoiding the need to forecast and review the vast majority of capital spending, activities that required a lot of time and effort from all stakeholders.

61. There is still room for improvement to achieve the objectives set out in Principle 3 and the Commission considers that future PBR plans will benefit from clearer rules and parameters to both ensure that all stakeholders understand the plans and to reduce the number and length of future regulatory proceedings.

3.4 Principle 4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design

62. This principle was not the specific topic of a question put to parties during this proceeding and, as such, this principle did not receive significant attention. However, parties did discuss the success of PBR meeting the five PBR principles to date in their responses.

63. As set out in Decision 2012-237[56] and Decision 20414-D01-2016 (Errata),[57] the Commission recognized the unique circumstances of each utility in designing the first and second

[54] Exhibit 26356-X0029, Apex submission, paragraphs 43-44.
[55] Exhibit 26356-X0020, ATCO Utilities submission, paragraph 50.
[56] Decision 2012-237, paragraphs 34, 527.
[57] Decision 20414-D01-2016 (Errata), paragraphs 52, 183, 288.

PBR terms, respectively. The Commission designed the following PBR plan features to recognize the utilities' unique circumstances:

- Introduced a revenue-per-customer cap design for natural gas distribution utilities and a price cap for electric distribution utilities.[58]
- Established Y and Z factors.[59]
- Established a reopening mechanism.[60]
- Established supplement capital funding outside of I-X.[61]
- Rebased the current 2018-2022 PBR plan using historical actual O&M and capital spending during the 2013-2017 PBR term specific to each utility.
- Allowed utilities and interveners to provide evidence for adjustments that would be required due to anomalies experienced by the utility.
- Provided utilities the opportunity to file Phase II applications to reflect changes to their customer rate design and depreciation studies to recognize the changes in their assets' service lives.

64. During the PBR term, rates change from year to year based on the annual I-X index, where I represents inflation and X is the productivity offset. Although parties did not reference any of the above in their submissions on Principle 4, parties identified both the I and X factors as matters for consideration going forward.

65. All of the utilities submitted that the I factor has not proven to be reflective of the inflationary pressures they have experienced during the PBR term.[62] Calgary came to a different conclusion – as discussed in Section 3.1.1, based on a comparison of the I factor to the city of Calgary CPI, Calgary implied the I factor exceeded the inflationary pressure experienced in the city of Calgary.

---

58 Decision 2012-237, paragraph 34.

59 Decision 2012-237, sections 7.2, 7.4. Y factor costs are recurring, material flow-through costs attributable to events outside of management's control and that the Commission considers should be directly recovered from customers or refunded to them. Z factor costs are to account for a significant financial impact (either positive or negative) of an exogenous event outside of the control of the DFO and for which it has no other reasonable opportunity to recover the costs within the PBR formula.

60 Decision 2012-237, Section 8. DFOs are protected from events that could cause their earnings to go above or below established thresholds, and if this occurs there is a mechanism to share gains or losses with customers, which can be initiated by the utility or the Commission.

61 Decision 2012-237, Section 15.1.3 and Decision 20414-D01-2016 (Errata), Section 6.4.3. The 2013-2017 PBR term contained capital trackers that allowed capital projects that required more than I-X funding above a certain threshold to apply for COS-type treatment. The 2018-2022 PBR term contained the K-bar mechanism, which provided utilities with additional capital funding calculated by that utilities specific average 2013-2016 capital additions. Additionally, Type 1 capital funding is available for capital projects that are extraordinary in nature, not previously included in rate base and required by a third party.

62 Exhibit 26356-X0024, ENMAX submission, paragraphs 125-129; Exhibit 26356-X0020, ATCO Utilities submission, paragraph 66; Exhibit 26356-X0022, EPCOR submission, paragraph 44; Exhibit 26356-X0025, Fortis submission, paragraph 47; Exhibit 26356-X0029, Apex submission, paragraph 63.

66. A number of utilities also submitted that the X factor value in the 2018-2022 PBR term is not reflective of current expected productivity growth in the utility sector. ENMAX stated that even though it was on its third incentive ratemaking plan compared to the other utilities' second generation PBR plan, ENMAX's X factor approved by the Commission is the same as the X factor for all other DFOs' plans. ENMAX further stated that it is difficult to reconcile that difference with the Commission's PBR Principle 4. It added that a "one-size-fits-all" PBR plan for gas and electric DFOs has not and will not reflect the unique circumstances of each DFO.[63]

67. The utilities also raised concerns with obtaining sufficient capital funding to keep pace with the new trends affecting the grid such as decarbonization and customer adoption of electric vehicles, as well as the general need for grid modernization to accommodate advancing technologies. As discussed in Section 3.3 of this decision, the utilities also advocated revising the qualification criteria for Type 1 capital funding (capital funded outside the K-bar funding mechanism).

68. The UCA noted that the OEB has differentiated PBR plans in place to recognize the unique circumstances of distribution utilities.[64]

69. The Commission is satisfied that through the PBR plan features discussed above, Principle 4 was achieved during the PBR terms. In establishing future PBR plans, the Commission will consider evidence on whether modifications are necessary to the I and X factors and any incremental capital funding provisions.

3.5 Principle 5. Customers and the regulated companies should share the benefits of a PBR plan

70. There is considerable disagreement among parties as to whether the PBR framework delivered on Principle 5 over the first two PBR terms. The Commission finds that this is an area of universal concern that needs to be carefully assessed and factored into the design of future PBR plans.

71. In Decision 20414-D01-2016 (Errata), the Commission explained the following:[65]

> 13. The Commission does not share the customer groups' view that company returns for 2013 and 2014, by themselves, indicate that the existing PBR plans should be subject to significant revision in the current proceeding. The PBR plans are designed to provide the companies with incentives to pursue productivity improvements and to lower costs. These incentives may result in higher returns for a company, which the company is allowed to keep for a certain period of time. While the company is pursuing higher returns induced by productivity improvements and lower costs, the customers benefit from rate increases being limited by the PBR formula. Ultimately, customers will share in the benefits received from productivity improvements and lower costs achieved by the company during rebasing. In addition, in accordance with the provisions of the PBR plans approved in Decision 2012-237, if a company's return exceeds the specified threshold amount, the plan may be reopened.

[63] Exhibit 26356-X0024, ENMAX submission, paragraph 25.
[64] Exhibit 26356-X0030, UCA submission, paragraph 53.
[65] Decision 20414-D01-2016 (Errata), Appendix 4, PDF pages 106-107.

72. In this proceeding, customer groups, UCA, CCA and IPCAA,[66] unanimously agreed that PBR has resulted in enhanced efficiencies and cost savings for the utilities but consumers have yet to benefit. In their view, this is clearly demonstrated by the utilities' consistent earnings above the approved ROE. Interveners also raised concerns with high and increasing customer rates at the time of economic depression in Alberta. They indicated that rebasing needs to ensure customers share in these efficiencies. Further, they advocated that an earnings sharing mechanism (ESM) should be incorporated in the next PBR plan to allow customers to share in the benefits of PBR at more regular intervals. The UCA and Calgary[67] also provided specific suggestions for ESM thresholds.

73. EPCOR, ATCO and Apex were opposed to an ESM stating that it would blunt PBR incentives and increase regulatory burden.[68] Fortis submitted that an ESM is a ratemaking tool that should not be considered in isolation and stated that "… the altering of one parameter or the introduction of a new parameter must be carefully considered to assess the resulting overall impact."[69]

74. Regarding whether customers received benefits during the prior and current PBR terms, the utilities contended that customers benefitted from rates lower than they would otherwise be under COS because of the application of the I-X indexing and from passing on to customers the savings achieved during the 2013-2017 PBR plans at the time of the rebasing when going-in rates for the 2018-2022 PBR plans were set. In particular, Fortis presented information that from 2005 to 2012 under COS, the average annual rate increase was 3.6 per cent. Over the first and second PBR terms, the compounded annual growth rate in customer rates was approximately 2.3 per cent and 1.3 per cent, respectively.[70]

75. The ATCO utilities presented analysis demonstrating that rates under PBR were further reduced at the time of the rebasing for the 2018-2022 PBR plans. For ATCO Gas, the 2018 going-in distribution revenue was reduced by $69.6 million compared to the 2017 actual revenue. This initial reduction was annually escalated by I-X and growth (Q), resulting in total projected benefits to customers (in both North and South service territories) in excess of $373 million over the five-year PBR term. Similarly, for ATCO Electric, at rebasing, the 2018 going-in distribution revenue was reduced by $46.9 million compared to the 2017 actual revenue. This initial reduction was annually escalated by I-X and growth (Q), resulting in total projected benefits to customers in excess of $274 million over the five-year term.[71] EPCOR and ENMAX did not perform such quantitative analysis but agreed that the rebasing approach chosen by the Commission for the 2018-2022 PBR term resulted in lower customer rates.[72]

76. In the Commission's view, the historical rate information provided by the utilities in this proceeding suggests that under both PBR plans, which incented and continue to incent the utilities to lower their costs, customers experienced lower rates under PBR than would be expected under

66 Exhibits 26356-X0030 to 26356-X0033; exhibits 26356-X0026 to 26356-X0028; Exhibit 26356-X0019; April 22, 2021.
67 Exhibit 26356-X0030, UCA submission, paragraph 48; Exhibit 26356-X0053, Calgary reply, paragraph 45.
68 Exhibit 26356-X0022, EPCOR submission, paragraph 35; Exhibit 26356-X0054, ATCO reply, paragraphs 64-67; Exhibit 26356-X0059, Apex reply, paragraphs 37-38.
69 Exhibit 26356-X0057, Fortis reply, paragraph 12.
70 Exhibit 26356-X0025, Fortis submission, paragraph 21.
71 Exhibit 26356-X0020, ATCO submission, paragraphs 42-43.
72 Exhibit 26356-X0022, EPCOR submission, paragraph 17; Exhibit 26356-X0024, ENMAX submission, paragraph 76.

COS regulation. For example, Table 4 below presents the information on rate changes for residential customers during COS and the two PBR terms. The Commission nevertheless notes that these bill increases have much exceeded the I-X index[73] by which customer rates are commonly expected to change under the PBR price cap plans; although to be clear, these represent bill changes that include flow-through charges (for example, transmission access charges for the four electric DFOs) and municipal fees.

Table 4. Residential customers average annual bill changes, 2008-2021

Utility	COS (2008-2012)	PBR 1 (2013-2017)	PBR 2 (2018-2021)
	(%)		
ATCO Electric	13.5	5.2	5.5
EPCOR	17.3	3.9	6.9
Fortis	15.8	4.1	5.5
ATCO Gas North	6.4	4.8	1.4
ATCO Gas South	3.9	6.3	2.8
Apex	9.3	5.8	5.8
	COS (2014)	**PBR 1 (2015-2017)**	**PBR 2 (2018-2021)**
ENMAX (Note 1)	4.9	-10.5	12.4

Source: Average percentage change was calculated on typical residential bills as of January 1 of each year, using the information provided by the utilities in response to Commission IR Exhibit 26356-X0034 [RESPONDER]-AUC-2021MAY06-001. ENMAX figures include the retail component of the bill. All other utilities exclude retail.
Note 1: COS for ENMAX includes only 2014 as ENMAX began PBR in 2015.

77. As discussed in Section 3.1, the financial results achieved by the utilities over the current PBR term suggest that they have continued to respond to the incentives of PBR and achieved efficiencies to reduce their costs. The utilities were allowed to retain these earnings during the PBR term; however, as parties pointed out in this proceeding, consistent with Principle 5, customers should share in these benefits by having these efficiencies reflected in the 2023 rates at the time of the 2023 COS rebasing.

78. As also discussed in Section 3.1, the utilities indicated they could not precisely quantify the efficiencies in terms of dollar savings and that the efficiencies were not tracked on a granular basis, as doing so would have increased regulatory burden contrary to PBR incentives. All of the utilities disagreed with IPCAA's methodology of estimating the utilities' efficiencies and resulting savings achieved during the PBR term by comparing actual achieved earnings to earnings implied by the approved ROE. However, none of the utilities provided a different method to calculate the monetary value of the efficiency gains. Some of the utilities commented that the best way to determine the efficiencies achieved under PBR is for the Commission to examine the most up-to-date cost structure of the utilities during the 2023 rebasing process. They submitted that efficiencies achieved under the 2018-2022 PBR will be reflected in these cost structures and thus captured in the 2023 rates, and in this way will be shared with customers and carried forward into the next PBR term.

79. Overall, Principle 5, namely the sharing of benefits among customers and the utilities, was not adequately met during the two PBR terms. Although the evidence suggests that customers experienced lower rates under PBR than would be expected under COS regulation and some sharing of savings occurred during rebasing for the 2018-2022 PBR plans, rates continued to

[73] Please refer to Appendix 2 of this decision.

increase during an economic downturn in Alberta and utility earnings during this same period were characterized by the interveners as excessive.

80. In this light, it is imperative to ensure that the 2023 COS rebasing achieves the objective set out in Principle 5. To this end, as set out in Decision 26354-D01-2021,[74] the Commission will allow each utility to develop its 2023 forecast on its own accord with an understanding that the utility bears the onus of demonstrating and supporting the reasonableness of the elements comprising its revenue requirement. The utilities were directed to "Quantify and clearly demonstrate how the efficiencies found, and cost reductions achieved, during the current PBR term are reflected in their forecast revenue requirement, and will be passed on to customers."[75] Further, the Commission stated that if "a DFO is not able to satisfactorily demonstrate to the Commission how cost reductions will be flowed through to its customers in its forecast 2023 revenue requirement, the Commission may consider a more mechanistic, high-level approach to ensure ratepayers benefit from the efficiencies achieved during the PBR term."[76] Two examples of such mechanistic, high-level approaches were discussed in this proceeding: the first example is IPCAA's approach of examining the actual vs. approved ROE; the second example is the Commission's approach to the last rebasing, where the utility rates were based on notional (lowest cost year or cost averages), rather than actual or forecast costs. To the extent the utilities are not able to expressly quantify the achieved efficiencies, the Commission encourages utilities to propose their own mechanistic methods as part of the 2023 COS proceedings to ensure ratepayers receive the benefit of reduced utility costs achieved during the current PBR term.

81. Regarding the introduction of an ESM, the Commission considers that there may be benefit to sharing the benefits of PBR among customers and the utilities *during the PBR term*, especially during challenging economic conditions such as those experienced during the current PBR plan. The Commission will, therefore, consider evidence of whether an ESM, or any other proposed benefit sharing mechanism, should be included in the next PBR plan.

4 Conclusions from the evaluation of PBR in Alberta and next PBR term

82. In previous sections of this decision, the Commission determined that, on balance, PBR has achieved many of the objectives that were set out in the founding PBR principles. All parties had recommendations on the parameters of the next PBR plan that they submitted must be improved or changed in order to gain their full support for another PBR term. The Commission agrees that there are areas for improvement. On balance, the Commission finds it to be in the public interest that the distribution utilities return to a third PBR term commencing in 2024, upon completion of the 2023 COS year, provided that the next PBR plan incorporates improvements in the areas explored throughout this decision.

83. Based on the record of this proceeding, and as discussed in previous sections, the Commission generally agrees with parties that future PBR plans should be more reflective of ongoing economic conditions. In this proceeding, parties pointed to the need to review the following parameters to facilitate this objective:

[74] Decision 26354-D01-2021: Process to Establish 2023 Rates for Alberta Electric and Gas Distribution Utilities, Proceeding 26354, June 18, 2021.
[75] Decision 26354-D01-2021, paragraph 40.
[76] Decision 26354-D01-2021, paragraph 41.

- A review of incremental capital funding provisions.
- A review of the I factor.
- Consideration of introducing a mechanism to share earnings.

84. The Commission agrees that these items should be among the matters to be considered in the design of the next PBR plan. The Commission is also interested in simplifying future PBR plans in furtherance of the principle of making a PBR plan easy to understand, implement and administer, with the overall aim of reducing regulatory burden over time.

85. Considering the heavy workload associated with 2023 COS applications, the Commission will initiate a proceeding to establish the parameters of the next PBR plan in mid 2022. To assist with workload planning for all parties, a tentative timeline is provided below:

Proceeding step	**Date**
Collaborative issues scoping and creating an issues list (i.e., parameters to be changed in the PBR3 plan)	Q3 2022
Commence PBR3 proceeding (parties submissions on in-scope parameters)	Q4 2022
Decision on PBR3 parameters	Q3 2023
PBR3 compliance applications	Q4 2023
PBR3 term commences	January 1, 2024*

*Note: length of term to be determined in the proceeding.

Dated on June 30, 2021.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Douglas A. Larder, QC
Vice-Chair

(original signed by)

Kristi Sebalj
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Gas
ATCO Electric Ltd. Bennett Jones LLP
ENMAX Power Corporation (ENMAX)
EPCOR Distribution & Transmission Inc. (EPCOR) Borden, Ladner Gervais LLP
Apex Utilities Inc. (Apex)
FortisAlberta Inc. (Fortis)
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Russ Bell & Associates Inc. Brownlee LLP
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
Alberta Federation of Rural Electrification Associations (AFREA) Main Street Law LLP
Industrial Power Consumers Association of Alberta (IPCAA)
Heartland Generation Ltd.
Independent System Operator (ISO)

Alberta Utilities Commission

Commission panel
C. Dahl Rees, Chair
D.A. Larder, QC, Vice-Chair
K. Sebalj, Commission Member

Commission staff
C. Wall (Commission counsel)
C. Robertshaw
E. Deryabina
D. Fedoretz
P. Howard
R. Lucas
A. Spurrell

Appendix 2 – Inflation indexes and the resulting I-X for 2013-2021

(return to text)

Year	Alberta CPI	Alberta AWE	I factor	I-X
	(%)			
2013	2.17	3.44	2.87	1.71
2014	1.00	4.18	2.75	1.59
2015	2.17	3.05	2.65	1.49
2016	1.59	2.45	2.06	0.90
2017	1.54	-2.64	-0.76	-1.92
2018	1.08	-0.73	0.08	-0.22
2019	1.89	2.32	2.13	1.83
2020	2.26	0.62	1.36	1.06
2021	1.41	3.24	2.42	2.12

Note: The approved X factor was 1.16 for the 2013-2017 PBR term and 0.3 for the 2018-2022 PBR term.