Decision **27388-D01-2023**

Alberta Utilities Commission

2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities

October 4, 2023

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1 Decision summary

1. This decision establishes the parameters of the third generation PBR plan (PBR3) to be implemented for the 2024 to 2028 period. The PBR3 plan applies to four electric distribution utilities: ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and two natural gas distribution utilities: ATCO Gas and Pipelines Ltd., and Apex Utilities Inc. These six utilities are collectively referred to as the "distribution utilities" throughout this decision.

2. The PBR3 plan approved in this decision builds upon the Commission's prior PBR2 plan for the distribution utilities in effect from 2018 to 2022. For the reasons set out in this decision, the PBR3 plan comprises the following parameters:

(i) In Section 6 of this decision, the Commission sets the I factor to use (a) Alberta Fixed Weighted Index (FWI) labour price index instead of Alberta Average Weekly Earnings (AWE); (b) updated 60 per cent labour and 40 per cent non-labour weighting; and (c) a forecast and true-up approach for the I factor instead of the lagged approach.

(ii) In Section 7, the Commission approves a total factor productivity (TFP) growth factor of 0.1 per cent, based on industry TFP growth and a stretch factor. The Commission also approves an additional benefit-sharing provision in the form of an X factor premium of 0.3 per cent. With the exception of the calculation of K-bar, the total X factor to be used in PBR3 is 0.4 per cent, inclusive of the benefit-sharing premium. For K-bar calculation purposes, the X factor of 0.1 per cent must be used.

(iii) In Section 8 of this decision, the Commission modifies the funding mechanisms for each of the Type 1 and Type 2 capital from that used in prior PBR plans and approves, on a pilot basis, a new alternative remuneration scheme. Specifically:

- For Type 1 capital, the Commission (a) approves a Type 1 capital tracker mechanism with some modifications to the eligibility criteria to provide funding for expenditures directly caused by applicable law related to net-zero objectives; and (b) introduces an expanded accounting test to calculate the Type 1 capital tracker amount.

- For Type 2 capital, the Commission approves the K-bar mechanism used in PBR2 with some modifications such as using a five-year average of 2018-2022 historical actual capital additions, and using a customer growth escalator in lieu of the Q factor. The Commission further clarifies that an X factor of 0.1 per cent must be used in the K-bar accounting test.

- The Commission implements a new alternative remuneration scheme on a pilot basis which allows utilities to earn a return on certain operating costs.

(iv) In Section 9, the Commission introduces two additional benefit-sharing provisions to the PBR3 plan: (a) an X factor premium of 0.3 per cent; and (b) an asymmetric, two-tiered earnings sharing mechanism (ESM) with the following parameters:

- A deadband of 200 basis points above the approved return on equity (ROE) for a given year, within which no sharing with customers occurs. As well, no sharing with customers by way of an ESM occurs below the approved ROE rate.

- A first tier of sharing between 200 basis points and 400 basis points above the approved ROE for that year within which a distribution utility retains 60 per cent of the incremental earnings and customers receive 40 per cent of the incremental earnings in this range.

- A second tier of sharing at 400 basis points above the approved ROE for that year above which a distribution utility retains 20 per cent of the incremental earnings and customers receive 80 per cent of incremental earnings.

(v) Because of the introduction of an ESM, in Section 9.5 the Commission finds that it is no longer necessary to trigger the reopener review when an achieved ROE exceeds the approved ROE by 300 basis points in two consecutive years. Other reopener provisions will remain the same as in the first two PBR terms.

(vi) In Section 10, the Commission determines that the efficiency carryover mechanism (ECM) will not be included in the PBR3 plan.

(vii) In Section 11, the Commission directs the distribution utilities to track efficiencies using the (a) controllable operations and maintenance (O&M) per customer; (b) controllable O&M per kilometre (km) of line (pipe); (c) total cost per customer, broken out by O&M and capital additions separately; and (d) total cost per km of line (pipe), broken out by O&M and capital additions separately.

(viii) In Section 12, the Commission approves EPCOR's proposed treatment of its customer-specific rates in the PBR3 plan.

3. The Commission explored in this proceeding whether to continue regulating the electric distribution utilities under the price cap plan and natural gas distribution utilities under the revenue-per-customer cap or whether all distribution utilities can be regulated under the same type of PBR plan. In Section 5, the Commission determines that it will not direct any changes. Similarly, in Section 4, the Commission finds there is no material benefit for customers to update customer rates on July 1 rather than on January 1 of each year.

4. The remaining parameters of the PBR3 plan, such as the annual rate changes, price cap vs revenue-per-customer cap approaches, Y factor, Z factor, service quality, financial reporting and annual reporting requirements are unchanged from those established in the PBR2 plans. These parameters are set out in Appendix 5 to this decision.

2 Background

2.1 Overview of PBR and cost-of-service regimes

5. While the generation and retail segments of Alberta's electricity and natural gas industries are deregulated and open to competition, the transmission and distribution segments remain fully regulated. The Commission has a statutory mandate to set just and reasonable rates for utilities under its jurisdiction,[1] and in doing so it must balance the interests of consumers with the interests of utilities.[2] Historically, the Commission has discharged its rate-setting responsibilities using two forms of regulation: traditional cost-of-service (COS) regulation and, more recently, PBR for distribution utilities. In Decision 2012-237,[3] the Commission discussed at length the incentive properties of PBR and COS regimes;[4] the academic publications provided on the record of this proceeding highlighted much the same points.

6. At a high level, under the COS regime, the Commission reviews the utility's forecast costs and permits the recovery through customer rates of only those costs that it has determined to be reasonable. A notable feature of the COS framework is that a utility earns a return on the equity portion of its rate base (that is, a collection of capital assets used to provide service) and not on O&M expenses. For this reason, the COS framework is also referred to as rate base rate-of-return regulation.

7. In Decision 2012-237, the Commission observed that while the COS regulatory framework is relatively straightforward in its conception, it produces some incentives and disincentives that are widely recognized. There is an incentive to spend money on capital assets, on which a return can be earned, rather than spending money on O&M on which a return is not earned; this could lead to inefficient allocation of resources.[5] More generally, there is little incentive for a regulated utility to reduce costs or increase productivity because (i) its costs can be recouped from customers in frequent rate cases; and (ii) the more that is spent and included in the utility's rate base, the more return the utility can earn. Indeed, there may be an incentive to increase costs by "gold plating" – for example, overinvesting in assets by building to a capacity or reliability higher than required by customer needs. In the case of forward-looking jurisdictions like Alberta, where rates are set on the basis of forecast costs, there is an additional incentive to over-forecast costs (both capital and O&M) to increase returns.

8. Another fundamental issue is that under COS regulation there is little incentive for utilities to innovate and engage in long-term cost-cutting behaviours because any cost reductions achieved would be passed on to customers in subsequent rate proceedings, which generally happen every one to three years. In one of their publications, Dr. Mark Meitzen and Dr. Dennis Weisman observed that a utility may effectively be penalized under the COS regime for undertaking innovation:

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1 *Electric Utilities Act*, Section 121(2)(a); *Gas Utilities Act*, Section 36(a).

2 *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2015 SCC 45, paragraph 7.

3 Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029, September 12, 2012.

4 Decision 2012-237, PDF pages 9-14, sections 1.1 and 1.2.

5 This phenomenon is referred to in the academic literature as the Averch-Johnson effect. In Exhibit 27388-X0567 at paragraph 67, Dr. Weisman stated that the predictions from the Averch-Johnson model have defied consistent, empirical validation.

> For the utilities, innovation and discovery are neither costless nor riskless and successful efforts are typically "rewarded" under COSR [cost-of-service regulation] with mandated reductions in service rates. Unsuccessful efforts at innovation and discovery run the risk of cost disallowances. Hence, the expected returns to a utility from innovation under COSR are extremely limited if they exist at all. Conversely, under PBR, the utilities are permitted to retain the fruits of their successful efforts *pro tempore* which, in turn, supplies the impetus for their willingness to bear the risks associated with investment in innovation. [footnote omitted][6]

9. It should be noted that while the above theoretical problematic incentives are widely discussed in academic literature and frequently mentioned by regulators, they have largely proven elusive to corroborate in regulatory proceedings when setting rates. Nevertheless, to guard against the recognized drawbacks of the COS framework, the regulator must critically analyze management judgments and decisions to address the lack of competition and arrive at a level of reasonable costs, that, in competitive markets, would have been realized in response to market signals and economic incentives.

10. However, because a utility has better knowledge of its operations and the potential for improved efficiency and reduced costs than a regulator or interveners ever will (known as "information asymmetry"), the role of the regulator in this environment can be limited to second guessing a utility's forecast costs and its ability to reduce such costs through optimization and efficiency-seeking behaviours. In the earlier mentioned article, Dr. Meitzen and Dr. Weisman referenced a passage from Professor Kahn's book in which he observed that under COS:

> Effective regulation of operating expenses and capital outlays would require a detailed, day-by-day, transaction-by-transaction, and decision-by-decision review of every aspect of the company's operation. Commissions could so only if they were prepared completely to duplicate the role of management itself …[7]

11. PBR aims to address the mismatched incentives associated with COS regulation by more closely providing a proxy for the workings of competitive markets and focusing on prices (i.e., utility rates) and quality of service, while reducing the number of regulatory filings to permit the utility to focus its efforts on managing its costs over a longer period. This is done by temporarily severing the link between costs and prices, and permitting the utility to retain all, or a portion of, profits achieved during the PBR term by keeping its costs below authorized revenues.

12. While there are many forms of PBR (also more generally referred to as "incentive regulation" or "multiyear rate plans" in some jurisdictions), the Commission approved PBR plans for Alberta distribution utilities that employ an I-X index. Two common variants of such plans are price cap and revenue-per-customer cap plans. Under these plans, customer rates are no longer a summation of utility costs. Rather, rates are set by applying the I-X index, where an I factor tracks the rate of inflation relevant to the prices of inputs the utilities use, less an X factor

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[6] Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal*, 31 (April 2018) 39-46, filed in Exhibit 27388-X0400, PDF page 67.

[7] Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal*, 31 (April 2018) 39-46, filed in Exhibit 27388-X0400, PDF page 67 with reference to Alfred E. Kahn, The Economics of Regulation: Principles and Institutions, Volume 1, 1970, at pages 29-30.

offset, relevant to the productivity improvements the utility is expected to achieve during the PBR plan term.

13. Adjusting rates by I-X, rather than in COS proceedings, breaks the link between a utility's own costs and its revenues during the PBR term. In much the same way as prices in competitive industries are established, prices adjusted by I-X reflect industry-wide conditions that would produce industry price changes. Each utility's actual performance under PBR will depend on how its own performance compares to the industry's inflation and productivity measures. Dr. Meitzen and Dr. Weisman explained:

> The "I-X" adjustment formula follows from the basic idea that in a competitive market (which economic regulation seeks to emulate), average productivity gains in the industry are passed on to consumers in the prices that they pay for service after controlling for inflation. Firms that generate higher than average productivity are rewarded with higher profits while firms with lower than average productivity are penalized with lower profits. The basic idea behind PBR is to more closely emulate the incentive structure of firms operating in a competitive market.[8]

14. Establishing prices in this way during the term of a PBR plan creates stronger incentives for the utilities to improve their efficiency through cost reductions and other actions because they are able to retain the increased profits generated by those cost reductions longer than they would under COS regulation, where rates are typically reset every two years. The Commission's PBR plans were approved for a five-year term. At the same time, customers automatically share in the expected efficiency gains because they are built into rates through the X factor regardless of the actual performance of individual utilities. Further, PBR plans often include earnings sharing mechanisms (ESMs) for an additional sharing of benefits between the utilities and customers during the PBR term. Finally, to the extent the utilities are successful in achieving efficiencies that result in cost savings during a PBR plan, the realized cost reductions are passed on to customers at rebasing, which is done at the end of the PBR term through lower going-in rates for the next PBR plan.

15. In the same article, Dr. Meitzen and Dr. Weisman debunked the notion that because regulated utilities have a statutory obligation to be efficient, any additional rewards for achieving efficient behaviour through incentive regulation (such as the ability to earn higher returns) are unnecessary and the utilities should perform such activities regardless of regulatory regime. With reference to another publication[9] (also mentioned in Decision 2012-237), Dr. Meitzen and Dr. Weisman emphasized that "the achievement of performance gains is first and foremost a 'discovery process' in which more efficient operating practices and superior use of technology are learned over time."[10] From this perspective, "the efficiency gains realized under incentive regulation need not imply that the firm was knowingly inefficient under cost-of-service regulation."[11] It is not until enhanced incentives are provided that regulated utilities change their mindset from managing regulatory approvals to focusing on reducing costs and engage in "a

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8 Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," *The Electricity Journal*, 31 (April 2018) 39-46, filed in Exhibit 27388-X0400, PDF page 67.

9 Dennis L. Weisman and Johannes P. Pfeifenberger, Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates, The Electricity Journal, Volume 16(1), January/February 2003.

10 Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," The Electricity Journal, 31 (April 2018) 39-46, filed in Exhibit 27388-X0400, PDF page 68.

11 Mark E. Meitzen, Philip E. Schoech, and Dennis L. Weisman, "Debunking the Mythology of PBR in Electric Power," The Electricity Journal, 31 (April 2018) 39-46, filed in Exhibit 27388-X0400, PDF page 68.

discovery process that enables regulated firms to become more efficient than they previously knew how to be."[12]

16. Despite having superior incentive properties as compared to COS, PBR also has its own disadvantages. By creating strong incentives to cut costs, PBR plans may incentivize the utilities to compromise on the quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. Thus, it is typical for regulators to include enhanced service quality monitoring measures when instituting PBR.

17. As well, it is common for PBR plans to have price adjustment mechanisms in addition to I-X that allow a passthrough of certain types of costs to customers on a COS basis. In the Commission's past PBR plans, these included Z factors, Y factors and K factors (explained in Appendix 4). Ideally, assuming overall sectoral productivity, the utility's overall revenue under PBR would increase at a rate under inflation. This is another ideal that is difficult to achieve in reality. Furthermore, if cost-based adjustments in any way allow sub-optimal managerial decisions to lead to high rates for customers, the adjustments can diminish the efficiency incentives that are central to a PBR plan. Therefore, such adjustments must be carefully defined and limited in scope.

18. Finally, by severing the link between costs and revenues for a multi-year term, PBR may also lead to utility rates that are misaligned with costs to serve. This, in turn, may result in utilities earning returns that are significantly below or above the approved fair return. For this reason, PBR plans also include such safety provisions as reopeners and offramps. In addition, some PBR plans include ESMs to share a portion of earnings above the approved return during the term of the PBR plan. Some ESMs also require customers to fund a portion of earnings when they fall below the approved return.

2.2 Prior PBR plans in Alberta

19. For over a decade, rates for the electric and natural gas distribution utilities under the Commission's jurisdiction have been set under PBR. ENMAX was the first distribution utility to be regulated under formula-based ratemaking (FBR), a form of PBR as approved in Decision 2009-035.[13] ENMAX's FBR plan was in effect from 2007 to 2013, after which the utility's revenue requirement was rebased and it joined the other distribution utilities in more generic PBR plans.[14] In Decision 2012-237,[15] the Commission implemented a PBR framework for the following distribution utilities in Alberta: Apex (formerly AltaGas), ATCO Electric, ATCO Gas, EPCOR and Fortis for the 2013-2017 term. For ease of reference, and because it was the first

12 Weisman, Dennis L., and Pfeifenberger, Johannes P., Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates, *The Electricity Journal*, January-February 2003, page 60, as quoted in Decision 2012-237, paragraph 484.

13 Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Proceeding 12, Application 1550487-1, March 25, 2009.

14 ENMAX was regulated under a traditional COS framework in 2014, after which it joined the other utilities in their PBR plan from 2015 to 2017, with some variations. See Decision 21149-D01-2016 (Errata): ENMAX Power Corporation Distribution, 2015-2017 Performance-Based Regulation – Negotiated Settlement Application and Interim X Factor, Proceeding 21149, October 3, 2016.

15 Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

PBR plan applicable to most Alberta Utilities, the Commission will refer to that plan as the PBR1 plan.

20. Decision 20414-D01-2016 (Errata)[16] established the second generation of PBR plans for all six distribution utilities for the 2018-2022 term. For ease of reference the Commission will refer to that PBR plan as the PBR2 plan. Correspondingly, the Commission will refer to the 2024-2028 plans approved in the present decision as the PBR3 plan.

21. In Decision 2012-237, the Commission adopted the following principles, which have been used as founding principles in all subsequent generations of PBR in Alberta:

> **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.[17]

22. Appendix 4 contains a description of the PBR1 and PBR2 plans; however, the ENMAX FBR plan is mentioned in certain sections of this decision dealing with various provisions of the PBR3 plan.

2.3 Rebasing for PBR3

23. In Bulletin 2021-04,[18] the Commission indicated that following the expiration of the PBR2 plans in 2022, it was necessary to review the distribution utilities' costs and revenues to achieve the following objectives: (i) identify efficiencies achieved by the distribution utilities during the 2018-2022 PBR term and pass the benefits on to customers; (ii) realign the distribution utilities' costs and revenues and examine the utilities' forecast costs and rates to ensure they are reflective of the economic situation in Alberta; and (iii) assess actual distribution utility costs in the 2018-2022 PBR term for the purposes of approving the 2023 opening rate base and to ensure forecasts are justified based on prior-period actual costs.

24. The Commission initiated two related streamlined processes: (i) a review and assessment of legacy PBR performance to date; and (ii) a COS review to establish 2023 rates.

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

17 Decision 2012-237, PDF page 15, paragraph 28.

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

25. In its review and assessment of PBR1 and PBR2 performance in Decision 26356-D01-2021,[19] the Commission found that, on balance, PBR achieved many of the objectives that were reflected in the founding PBR principles.[20]

26. Notable from Decision 26356-D01-2021 is the assessment of Principle 2, which requires that "A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return" and the comparison of the utilities' earnings over the PBR years against the approved ROE. The Commission determined that it was satisfied that Principle 2 was achieved during the PBR terms as, in the majority of the PBR years, the utilities earned returns above the approved ROE. While the ROEs for 2021 and 2022 were not available at the time that Decision 26356-D01-2021 was issued and therefore were not included in the initial comparison, the utilities have since filed the ROEs for those years. This additional data shows that generally, with the exception of ENMAX, the distribution utilities continued to earn returns above, and in some cases significantly above, the approved ROE. In this decision, the Commission places significant weight on the distribution utilities' successful response to the incentives of PBR1 and PBR2 plans as demonstrated by their robust achieved returns.

27. Table 1 shows the utilities' achieved ROEs against the approved ROE for each of the years 2013 through 2022.

Table 1. Approved and actual ROEs achieved by the distribution utilities during PBR

Year	Approved ROE	Fortis	ATCO Electric	ENMAX[1]	EPCOR	ATCO Gas North	ATCO Gas South	Apex[2]
	(%)							
2013	8.3	9.49	10.99	8.05	9.97	10.97	12.98	8.67
2014	8.3	9.77	9.74	7.82	10.39	11.86	9.81	8.75
2015	8.3	11.12	9.90	6.15	10.37	12.15	9.78	8.30
2016	8.3	9.70	13.03	9.93	8.98	13.89	11.75	7.65
2017	8.5	9.20	13.21	9.64	8.02	16.61	15.33	10.04
2018	8.5	8.43	7.85	6.53	10.81	10.03	11.20	7.90
2019	8.5	10.14	10.66	9.31	11.63	10.10	11.50	8.72
2020	8.5	10.13	9.82	9.19	11.36	11.60	9.88	8.81
2021	8.5	10.23	12.85	4.29	11.44	12.77	10.68	9.57
2022	8.5	10.50	14.52	10.21	10.00	15.39	13.26	10.79
Average PBR1 (2013-2017)	8.34	9.86	11.37	8.57 (2015-2017)	9.55	13.1	11.93	8.68
Average PBR2 (2018-2022)	8.5	9.89	11.14	7.9	11.05	11.98	11.30	9.16

Source: Utility Rule 005: *Annual Reporting Requirements of Financial and Operational Results* financial filings, the impact of the ECM have been removed from the 2018 and 2019 ROEs if applicable.
Note 1: ENMAX was regulated under formula-based ratemaking in 2013 and under COS in 2014.
Note 2: Apex ROEs are weather normalized as, unlike ATCO Gas, it does not have a weather deferral account.

28. During this proceeding, utilities and interveners disagreed on the extent to which achieved ROEs that exceed approved ROEs can be relied on as an indication that utilities were

[19] Decision 26356-D01-2021: Evaluation of Performance-Based Regulation in Alberta, Proceeding 26356, June 30, 2021.
[20] Decision 26356-D01-2021, PDF page 25, paragraph 82.

achieving efficiencies under PBR. It is therefore necessary to briefly comment on the Commission's understanding of the data in Table 1, and how it will rely on this data in this decision.

29. Some utilities and experts were reluctant to acknowledge that the difference between achieved ROEs and approved ROEs was indicative of efficiencies achieved under PBR, due to confounding variables, such as billing determinants and the timing of regulatory decisions.[21] Other utilities and experts agreed that the delta between achieved ROEs and approved ROEs can be relied upon as an indication of achieved efficiencies, at least to some extent, despite the potential confounding variables.[22] The position of the utilities on this point varied based on the context in which the achieved ROEs were being discussed. As Keegan Rutherford of the Office of the Utilities Consumer Advocate (UCA) argued:

> … therein lies the contradiction. When the topic of discussion is achieved returns, the utilities tell us their very high-achieved returns on average, even to the end of the PBR2 term, reflect that they have continued to find many efficiencies. But when the topic of discussion is now the X factor and the stretch factor, the utilities tell us essentially there are few efficiencies left to be found. Put simply, the utilities cannot have it both ways. Either there are efficiencies available or there are not.[23]

30. In its decisions dealing with PBR3 rebasing, the Commission concluded that while it can be a useful indicator, the achieved ROE cannot be fully equated to a measurement of realized efficiencies.[24]

31. Throughout this decision, the Commission often refers to the achieved ROEs of the distribution utilities as compared to the approved ROEs under PBR1 and PBR2, when considering the appropriate parameters for the PBR3 plan. The Commission wishes to emphasize that wherever it does so, it is aware of the limitations of relying on this correlation, as pointed out by the utilities. The Commission also wishes to emphasize that in referring to the difference between approved and achieved ROEs, the Commission has not designed the PBR3 plan to recover profits the utilities earned under the PBR1 and PBR2 plans, or to otherwise penalize the utilities based on their past performance. As Dr. Weisman pointed out, doing so would result in a "ratchet effect" (i.e., "no good deed goes unpunished") that would undermine the incentives for efficiency and success of PBR in the long term.

32. However, consistent with its conclusions in the rebasing decisions, the Commission is satisfied that the relatively consistent trend in PBR1 and PBR2 in Alberta is for achieved ROEs to exceed approved ROEs, and that this trend is at least directionally indicative that the utilities were able to achieve efficiencies under the PBR1 and PBR2 plans. For this reason, the Commission has considered the difference between the approved and achieved ROEs under the PBR1 and PBR2 plans as one factor among others that it must consider when designing the parameters of the plan, to result in just and reasonable rates, including a reasonable opportunity for the utilities to earn a fair return.

21 Transcript, Volume 3, page 403, lines 4-5
22 Transcript, Volume 5, page 760, lines 14-19.
23 Transcript, Volume 10, page 1871, lines 12-21.
24 Decision 26356-D01-2021, PDF page 10, paragraphs 25-26.

33. In Decision 26356-D01-2021, the Commission found it to be in the public interest that the distribution utilities return to a third PBR plan (PBR3) commencing in 2024, upon completion of the 2023 COS year, provided that certain improvements were incorporated into their PBR3 plan as discussed further in this section. For rebasing, the Commission determined that it would proceed with a one-year COS review based on 2023 forecast costs.

34. To enhance regulatory efficiency and to address the significant regulatory burden associated with COS reviews for all six distribution utilities, the Commission initiated a proceeding to determine streamlined alternatives to the traditional line-by-line review of utilities' forecast costs. In the resulting Decision 26354-D01-2021,[25] the Commission adopted a hybrid approach for the review and assessment of the 2023 revenue requirements. Under this approach, the review of expenditures was guided by the nature, size or complexity of the associated cost, allowing the Commission to focus on certain cost categories, while assessing other costs in a more streamlined manner. Among other matters, the Commission permitted the utilities to use mechanistic approaches in developing their 2023 forecasts but made it clear that the utilities were to demonstrate that their cost forecasts, including any forecasts of costs based on proposed mechanistic approaches, will result in just and reasonable rates.[26]

35. In the resulting PBR3 rebasing decisions, Decision 26615-D01-2022[27] for ATCO Electric and Fortis, Decision 26616-D01-2022[28] for ATCO Gas and Apex, and Decision 26617-D02-2022[29] for ENMAX and EPCOR, the Commission set the respective 2023 revenue requirements based on approved forecast costs. In associated compliance filings,[30] the Commission approved the resulting 2023 rates, which will be used as going-in rates for the PBR3 plan.

36. Among other matters, the Commission in the rebasing decisions emphasized the importance of going-in rates and the rebasing process as a means to share with customers efficiencies that resulted in cost savings achieved during a prior PBR plan. The Commission also recognized the existence of certain problematic incentives associated with the rebasing process such as an incentive for the utilities to increase their costs (and over-forecast if rebasing is based of forecast costs) so as to increase going-in rates for the next PBR term.[31] A notable feature of the PBR3 rebasing process was the use by most distribution utilities of a mechanistic approach to

25 Decision 26354-D01-2021: Process to Establish 2023 Rates for Alberta Electric and Gas Distribution Utilities, Proceeding 26354, June 18, 2021.
26 Decision 26354-D01-2021, PDF page 9, paragraph 27.
27 Decision 26615-D01-2022: ATCO Electric Ltd., FortisAlberta Inc., 2023 Cost-of-Service Review, Proceeding 26615, July 28, 2022.
28 Decision 26616-D01-2022: ATCO Gas and Apex Utilities Inc., 2023 Cost-of-Service Review, Proceeding 26616, September 1, 2022.
29 Decision 26617-D02-2022: ENMAX Power Corporation and EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Review – Reasons for Approval of Negotiated Settlements, Proceeding 26617, July 28, 2022.
30 Decision 27685-D01-2022: Apex Utilities Inc., 2023 Cost-of-Service Compliance Filing and 2023 Rates, Proceeding 27685, December 15, 2022; Decision 27672-D02-2022: ATCO Electric Ltd., 2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates – Reasons for Approval, Proceeding 27672, December 20, 2022; Decision 27684-D01-2022: ATCO Gas, 2023 Cost-of-Service Compliance Filing and 2023 Rates, Proceeding 27684, December 15, 2022; Decision 27651-D01-2022: ENMAX Power Corporation, 2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates, Proceeding 27651, December 13, 2022; Decision 27653-D01-2022: EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates, Proceeding 27653, Applications 27653-A001 and 27653-A002, December 13, 2022; Decision 27671-D01-2022: FortisAlberta Inc., 2023 Cost-of-Service Compliance Filing and 2023 Rates, Proceeding 27671, December 16, 2022.
31 See, for example, Decision 26616-D01-2022, PDF pages 14-15, paragraphs 42-43.

arrive at 2023 forecasts; this was done by escalating the average of 2018-2020 actual costs by the chosen inflation and customer growth escalators.

3 Development of list of issues

37. When the Commission initiated the present proceeding, the first step was to decide its scope – that is, which parameters of the PBR2 plans would be retained in the PBR3 plan, and which parameters would be subject to scrutiny and potential modification, removal or addition. In this regard, the Commission indicated it wished to build on the information obtained in the evaluation of PBR proceeding that resulted in Decision 26356-D01-2021. In that decision, the Commission generally agreed with parties that PBR3 should be more reflective of ongoing economic conditions (for both the distribution utilities and their customers) and ensure the cost efficiencies gained through PBR are shared amongst customers and the distribution utilities. The Commission also expressed interest in making PBR3 simpler as compared to the previous plans in furtherance of Principle 3 that a PBR plan should be easy to understand, implement and administer, with the overall aim of reducing regulatory burden over time.

38. Based on these conclusions, the Commission invited parties in Bulletin 2022-06[32] to comment on the issues in scope of this proceeding. After consideration of parties' comments, the Commission determined that the following elements of PBR3 plan would be considered in this proceeding:

(i) Annual PBR rate adjustments

(ii) Price cap and revenue-per-customer cap

(iii) I factor

(iv) X factor

(v) Capital funding provisions

(vi) Consideration of introducing an ESM and the need for an ECM

(vii) Quantification and tracking of efficiencies

39. The Commission stated that the remaining components of the plan would be the same as in the PBR2 plan; however, it noted that there could be changes made to these remaining components as a consequence of any Commission decisions on issues included on the list of issues. Specifically, the Commission stated that changes to the reopener provision could be required if an ESM is included within the PBR3 plan. The remaining components that are unchanged from the PBR2 plan are summarized in Appendix 5 to this decision.

32 Bulletin 2022-06, Proceeding and roundtable to establish parameters for the third generation of performance-based regulation plans, May 26, 2022.

4 Annual rate adjustments

40. In the PBR1 and PBR2 plans, gas and electricity distribution rate changes were reflected on customer bills on January 1 of each year. In this proceeding, the Commission explored the possibility of implementing the annual PBR rate adjustments on July 1 of each year as a way to address concerns with rate changes taking place at a time of year when customers may already face increased utility costs and other expenses.[33]

41. In general, parties including the distribution utilities and Jan Thygesen on behalf of the CCA took the position that a change in annual rate adjustments from January 1 to July 1 was not necessary. ENMAX provided evidence that approximately 70 per cent of a typical customer's total electricity bill is made up of energy charges, which are unaffected by PBR and beyond the control of the distribution utility. ENMAX explained that the volatility of customer bills is predominantly caused by changes in energy charges and not the wire charges, and that its distribution-related delivery charges under PBR have been largely flat as a percentage of a typical customer bill.[34] ENMAX further speculated that because wholesale electricity prices are heavily influenced by the cost of natural gas, which has increased sharply between 2020 and 2022, it is likely that continued higher energy costs will influence affordability more than wires charges.[35]

42. Related to this, ENMAX pointed out that on the electricity side, there is both a winter and summer load peak in Alberta so moving the distribution rate change from January to July is not significantly better.[36] J. Thygesen for the CCA agreed, indicating that the winter peak in electricity use is not significantly different from the summer peak due to the increased use of air conditioning.[37] Fortis also filed evidence showing that over the past five years (2017-2021) there has been an annual increase in energy sales in July and August.[38] An analysis filed by ATCO Electric demonstrated that over the 2018 to 2022 period, the average impact on a customer bill of moving the rate adjustment from January 1 to July 1 is $3.10 (0.5 per cent).[39]

43. The electric utilities pointed out that changes to other components of customer bills related to transmission system costs are also implemented effective January 1 each year. As such, Fortis explained that the implementation of a July 1 rate change for distribution charges alone would not be a productive exercise and submitted that a change in the rate-setting calendar would be needed for both distribution and transmission charges to effectively mitigate the impact on customer bills. However, implementing such a change for transmission rates would require input from the transmission facility owners and a reassessment of the design and function of transmission-related deferral accounts to address the timing issues.[40]

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33 Exhibit 27388-X0046, AUC letter – Ruling of final list of issues. PDF page 6.

34 ENMAX assumed a customer was on the regulated rate option (RRO) rate – that is, the energy charge (or commodity charge) approved by the Commission every month based on prices from the wholesale electricity market. Customers in Alberta can choose to purchase their electricity from a variety of competitive retailers, whose rates are not regulated by the Commission. Eligible customers who do not choose a competitive retailer purchase electricity under a regulated rate tariff approved by the Commission.

35 Exhibit 27388-X0197, ENMAX evidence, PDF page 15.

36 Exhibit 27388-X0197, ENMAX evidence, PDF pages 14-16.

37 Exhibit 27388-X0169, J. Thygesen evidence for the CCA evidence , PDF page 6, paragraph 14.

38 Exhibit 27388-X0211, Fortis evidence, PDF pages 57-58.

39 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 10, paragraph 18.

40 Exhibit 27388-X0211, Fortis evidence, PDF page 56, paragraphs 163-164.

44. On the gas side, Apex noted that distribution charges make up less than half of typical bills, and in the winter months this proportion is smaller. Apex estimated that the average impact of shifting the annual increase from January to a later month is approximately $5.50, or 1.7 per cent, of the total January bill.[41] An analysis of the bill impact of moving the rate adjustment from January 1 to July 1 for ATCO Gas demonstrated that the impact on a typical Low-Use (residential) customer's monthly bill is $0.90 (0.5 per cent).[42] With respect to affordability, Apex explained that it offers its customers on the default rate tariff, a budget payment plan that can reduce their total estimated annual billing over 12 months. Apex also offered that the UCA's website indicates that many electricity and natural gas retailers offer similar budget plans.[43]

45. The utilities also contended that there would be difficulties if rates change on July 1, because the regulatory period would not coincide with the reporting year. Further, the utilities pointed to increased administrative burden and costs associated with changing rates on July 1. Fortis indicated that such administrative burden would include additional resourcing in information technology (IT), billing, accounting and regulatory areas due to the misalignment in the financial reporting and regulatory reporting year.[44] ENMAX stated that since PBR rate applications would need to be filed in early March and prepared in January and February for July 1 rates to be approved, this would overlap with fiscal year-end processes and put a strain on its resources.[45]

46. While some of the issues raised by the utilities are of a one-time, transitional nature, the Commission has nevertheless been persuaded by the evidence filed on bill impacts and other administrative costs that there would be no material benefit for customers if the PBR annual rate adjustment were to occur on July 1 of each year rather than on January 1.

47. The Commission further accepts the evidence that on the electric side, there has been increasing electricity use in July and August for the past number of years. To the extent electricity consumption is similar in both the winter and summer months, this would further diminish any benefits from moving the rate implementation date to July 1.

48. Finally, the Commission finds it significant that parties representing customers in this proceeding did not support the July 1 rates implementation as a means to alleviate concerns with rate changes. In his evidence for the CCA, J. Thygesen expressly indicated it was not clear that moving the implementation date of rate changes will have much impact on customers when the over-riding issue is high utility rates in general.[46] The other customer representatives, the UCA and the Industrial Power Consumers Association of Alberta (IPCAA), did not comment on the issue.

49. As a result, the Commission finds that rate changes will continue to occur on January 1 each year during the PBR3 term. Accordingly, the dates for associated PBR rate filings will remain the same as in the previous PBR2 plan (for example, the annual PBR rate adjustment

41 Exhibit 27388-X0201, Apex evidence, PDF pages 11-13.
42 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 10, paragraph 18.
43 Exhibit 27388-X0201, Apex evidence, PDF page 12.
44 Exhibit 27388-X0211, Fortis evidence, PDF page 54.
45 Exhibit 27388-X0197, ENMAX evidence, PDF page 17, paragraph 15.
46 Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF page 5, paragraph 10.

filings are due on September 10 each year). This is reflected in Appendix 5. As well, there is no need to consider any adjustments to the going-in rates as a result of the implementation date.

5 Price cap or revenue-per-customer cap

50. As referenced in Appendix 4, in the PBR1 and PBR2 plans, the electric distribution utilities were regulated under the price cap plan, and natural gas distribution utilities were regulated under the revenue-per-customer cap plan, which is a type of a revenue-per-customer cap plan.[47] Under a price cap plan, a utility's rates change every year by the I-X index percentage. Under a revenue-per customer cap, it is a utility's revenue (or revenue-per-customer on a customer class basis in the Commission's plans) that is adjusted by I-X every year. The revenue-per-customer obtained for each rate class is then divided by the forecast billing units (such as gigajoules of gas consumed, demand, or number of days) to arrive at customer rates for that year.

51. In Decision 2012-237, the Commission stated that while the two plans have similar incentive properties, there are important differences when it comes to the effect of energy consumption on rates. A price cap plan establishes annual customer rates regardless of the amount of energy consumed by customers and, correspondingly, delivered by a utility's distribution system. Accordingly, under price cap plans, a utility ordinarily bears the risk of changes to revenue caused by changes in energy throughput on its system. That is, in the presence of variable (or volumetric) charges in a distribution tariff, an increase in the amount of energy transported leads to an increase in revenue, and a decrease in the amount of energy transported decreases revenue, all other things being equal.

52. In contrast, under a revenue-per-customer cap plan, utility revenue is decoupled from energy volumes delivered through a utility's system and the risk of changes in consumption shifts to customers. Rates for each customer class are designed to recover the revenue for that customer class produced by the PBR formula and are directly affected by expected changes in consumption. All else equal, customer rates will decrease if a utility forecasts an increase in energy consumption per customer in the upcoming year; the converse is also true. In either case, a utility is expected to collect the amount of revenue-per-customer class as established by the PBR formula for that year. Because of these properties, revenue-per-customer cap plans are often implemented where declining usage is expected, such as in jurisdictions where demand side management programs are implemented.

53. In the PBR1 proceeding, ATCO Gas and AltaGas (now Apex) showed that, despite overall sales growth, both utilities were experiencing a decline in usage per customer for most customer classes averaging approximately 1.5 per cent per year.[48] The Commission approved a revenue-per-customer cap plan for the two gas distribution utilities because placing them under a price cap plan may have resulted in chronic revenue erosion because of declining deliveries per customer.[49] The Commission had no concerns with the use of a price cap PBR plan for the

[47] As the name implies, a revenue-per-customer cap plan separately indexes, by I-X, the revenue for each customer class rather than the total revenue of a utility as is done under a revenue-per-customer cap. Among other properties, a revenue-per-customer cap plan retains a utility's incentives to connect new customers because doing so increases revenue (Decision 2012-237, PDF page 38, paragraph 141).

[48] Decision 2012-237, PDF page 35, paragraph 122.

[49] Decision 2012-237, PDF page 38, paragraph 138.

electric distribution utilities as those utilities indicated that a declining use per customer or other types of volumetric risk were not issues. These provisions remained unchanged in PBR2 plans.

54. In the current proceeding, the Commission explored whether the circumstances that led to the adoption of two different types of PBR plans for gas and electric distribution utilities continue to apply or whether all distribution utilities can be regulated under the same type of PBR plan. In general, none of the parties advocated for a change from the current plans.

55. Parties confirmed the Commission's understanding that price cap and revenue-per-customer cap PBR plans have similar incentive properties as under either plan; rates are set independent of utility costs. As well, customers get meaningful price signals under both plans; Dr. Mark Lowry explained that an individual customer under revenue-per-customer cap plan would still reduce their bill by reducing consumption.[50] Finally, parties indicated that both plans are similar in terms of regulatory burden to operate under and administer.

56. Generally, the four electric distribution utilities explained that a price cap remains appropriate for the coming PBR3 term as it is unlikely that there will be a material decrease in usage. Electric distribution utilities did not foresee any significant fluctuations in customer consumption during the PBR3 term, although they did raise the possibility of higher energy consumption in the medium term due to increased electrification, including adoption of electric vehicles (EVs). ATCO Electric further observed that while customer usage may decline for the residential rate class, this is offset by increases in usage by industrial customers.[51] Electric distribution utilities noted that it would be prudent to continue to operate under a price cap plan for the next PBR term as consumption is, on balance, expected to increase. Dr. Lowry noted that it may be beneficial to put all distribution utilities under a revenue-per-customer cap plan in the future. Dr. Lowry explained that given the expectations of the increased electricity consumption as a result of decarbonization and new technologies, such as higher adoption of EVs and heat pumps (a process that Dr. Lowry referred to as "beneficial electrification"),[52] revenue-per-customer caps would be beneficial at ensuring steady revenues for utilities and fostering innovative utility rate design.

57. Russ Bell for the UCA asserted that due to the relatively flat nature of usage per customer it may not be a problem to move gas distribution utilities to a price cap plan.[53] ATCO Gas and Apex advocated to maintain the current revenue-per-customer cap plan. Both gas distribution utilities provided evidence of declining usage per customer through the last two PBR terms and explained that declining usage per customer is expected for the coming PBR term.

58. ATCO Gas showed that between 2012 and 2022, usage per customer in the Low-Use residential class decreased, on average, by 1.0 per cent per year.[54] ATCO Gas further explained that it anticipated this decrease to continue, and possibly exacerbate, due to carbon taxes and other drivers changing customer behaviour, such as home or appliance retrofits and upgrades.[55] Apex stated that it too expects declining usage per customer to persist into the next PBR term due to the same factors. Apex's actual decrease in usage per customer between 2012 and 2022

50 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF page 52, paragraph 108.
51 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 16, paragraph 39.
52 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF pages 47-48, paragraphs 97-98.
53 Exhibit 27388-X0194, R. Bell evidence for the UCA, PDF page 27.
54 Exhibit 27388-X0439, ATCO-AUC-2023FEB28-004(a)-(b) Attachment 1 "use per customer data."
55 Exhibit 27388-X0438, ATCO-AUC-2023FEB28-004(a)-(b), PDF pages 10-12.

averaged 0.5 per cent per year for its residential, commercial and rural (Rate 1/11) rate class.[56] Both gas distribution utilities further noted that any increases in consumption for other customer classes would not offset the decrease in consumption for the low-use customers, and consequently, ATCO Gas and Apex would lose revenue if they were directed to operate under a price cap plan.[57]

59. For gas distribution utilities, the decline in usage per customer was not as pronounced between 2012 and 2022 as anticipated in Decision 2012-237; however, both Apex and ATCO Gas provided evidence that they would have still experienced material revenue deficiencies had either operated under a price cap regime.[58] The Commission is persuaded that it is reasonable to expect that decline in usage of natural gas for customers in the low-use rate class would continue in the PBR3 term (and could possibly exacerbate due to beneficial electrification) and thus retaining a revenue-per-customer plan is warranted.

60. Based on the evidence in this proceeding, the Commission will not direct any changes to the type of PBR3 plan. Apex and ATCO Gas will continue to operate under a revenue-per-customer cap plan and ATCO Electric, ENMAX, EPCOR and Fortis will continue to operate under a price cap plan. The Commission finds that there is sufficient evidence on the record of this proceeding to conclude that declining customer usage could have a material impact on the revenues of gas distribution utilities. Further the Commission finds that there is no present need to shift the electric distribution utilities to a revenue-per-customer cap due to the evidence provided by the electric distribution utilities that significant changes in consumption patterns are not expected in the PBR3 term.

61. Notwithstanding the above, in the Commission's view, the impact of customer energy consumption on utility revenue is a part of a distribution utility's business risk that could be managed in a number of ways, of which a type of PBR plan (price cap or revenue-per-customer cap) is just one. For example, in this proceeding, the Commission explored another potential way to manage this risk through transition to a higher proportion of fixed charges.[59] The Pacific Economic Group (PEG) noted that "some of the most innovative time-sensitive rate designs in North America have recently been developed in the context of revenue caps and decoupling."[60] Given the expectations of the advent of mass, beneficial electrification in the medium term and possible corresponding further decline in natural gas consumption, it is the Commission's view that all distribution utilities must proactively manage their business risks in the evolving industry environment. The upcoming Phase 2 applications present an opportunity for the distribution

56 Exhibit 27388-X0526, ATCO-APEX-AUC-2023FEB28-003, PDF page 6.

57 Exhibit 27388-X0201, PDF page 17, paragraphs 45-46; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 16, paragraph 38.

58 ATCO Gas provided evidence showing that over both PBR terms, between 2013 and 2022 if it was under a price cap plan it would have received $24.3 million less in revenue. Apex provided a similar analysis providing evidence showing a revenue deficiencies had it been under a revenue-per-customer cap in the 2018-2022 PBR term of approximately $4.1 million. (Exhibit 27388-X0438, ATCO-AUC-2023FEB28-006, PDF page 22 and Exhibit 27388-X0526, ATCO-APEX-AUC-2023FEB28-005, PDF page 18.)

59 This relates to another fundamental issue of the extent to which distribution utility revenue should vary with customer consumption. Currently, while a large proportion of distribution utilities' costs are fixed, a significant amount of these costs is recovered through variable (or volumetric) charges such as $/KWh of electricity or $/GJ of natural gas, which may lead to what the economists call "inefficient pricing." This complex issue of rate design is not unique to Alberta and addressing it is outside of the PBR framework. For a more detailed discussion please refer to AUC Distribution System Inquiry final report, Section 5 (Proceeding 24116, issued February 19, 2021).

60 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF page 48, paragraph 99.

utilities to consider necessary changes to rate design to move away from heavy reliance on volumetric charges over time.[61] Further, changes to the price cap and revenue-per-customer cap, along with other possible regulatory changes may be required after the conclusion of the PBR3 term to respond to changes in the energy sector.

6 I factor

62. The I factor, or inflation factor, is a component of a PBR plan that is intended to reflect the year-over-year changes in the prices of inputs that the utilities use. By adjusting utilities' rates every year by the chosen I factor less the productivity offset X, forming the so called "I-X index," PBR creates incentives similar to those in competitive markets.

63. In competitive industries, when faced with a universal economy-wide increase in input prices, such as an increase in salaries and wages or in costs of materials and supplies, that cannot be managed through a more efficient use of those inputs (i.e., increased productivity), companies may be left with no choice but to pass on these higher costs to customers. When the prices of inputs go down, competition in the market forces companies to lower their prices. Adjusting a utility's rates by the I-X index is intended to mimic the workings of a competitive market and to result in prices that reflect industry-wide conditions in much the same way as prices in competitive industries are established.

64. In Decision 2012-237, the Commission established the following characteristics for the I factor:[62]

- It should be indicative of the change in input prices that the utilities are expected to experience.
- It should be transparent, simple to calculate and easy to understand.
- It should not be overly volatile.
- It must be published on a regular basis by a reputable independent agency.
- It should not be overly influenced by the utility itself.

65. Regarding the last characteristic, in prior decisions the Commission expressed its preference for an I factor reflective of broader industry inflation measures rather than tracking the experience of a specific utility. The Commission indicated that the more the selected inflation measure tracks the actual performance of an individual company, the more it resembles COS regulation and the more the incentive properties of PBR are diminished.[63]

61 As noted in Exhibit 27388-X0046, AUC letter – Ruling on final list of issues, PDF page 3, if a distribution utility does not have either a depreciation study or a Phase 2 application approved within the last five years, it must file an application for approval in either 2024 or 2025.
62 Decision 2012-237, PDF page 42, paragraph 155.
63 Decision 2012-237, PDF page 46, paragraph 180.

66. For the PBR1 and PBR2 plans, the Commission used a composite I factor consisting of two indexes published by Statistics Canada: Alberta AWE[64] index for tracking changes in the prices of labour and Alberta consumer price index (CPI)[65] for changes in prices for non-labour. The I factor was calculated as follows:

$$\boldsymbol{I_t = 55\%\ x\ AWE_{t-1} + 45\%\ x\ CPI_{t-1}}$$

where:

$\boldsymbol{I_t}$	Inflation factor for the following year.
$\boldsymbol{AWE_{t-1}}$	Alberta AWE index for the previous July through June period.[66]
$\boldsymbol{CPI_{t-1}}$	Alberta CPI for the previous July through June period.[67]

67. In Proceeding 26356 where the PBR1 and PBR2 terms were evaluated, the distribution utilities raised concerns that the I factor may not have captured accurately the inflationary pressures they experienced during those PBR terms. Therefore, in the resulting Decision 26356-D01-2021, the Commission indicated it would consider evidence on whether modifications were necessary to the I factor, to ensure that it reflects the inflationary pressures expected during the PBR3 term.[68]

68. In this proceeding, parties generally agreed with the characteristics of the I factor adopted in the Commission's previous PBR plans as set out in Appendix 4. Parties also favoured the use of a composite I factor, consisting of two indexes tracking changes in the prices of labour and non-labour costs. As well, parties agreed with the use of Alberta inflation indexes rather than national indexes.

69. EPCOR stated that the currently approved I factor will adequately reflect the expected changes in the prices of inputs and did not propose any changes.[69] Other parties proposed modifications to the I factor, which concerned the following four areas: (i) use of a different

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64 The Alberta AWE series from Statistics Canada data Table 14-10-0223-01, formerly Canadian Socio-Economic Information Management System (CANSIM) Table 281-0063, vector V79311387. Defined by Statistics Canada as Alberta average weekly earnings, including overtime for all employees and seasonally adjusted: https://www150.statcan.gc.ca/t1/tbl1/en/sbv.action?vectorNumbers=v79311387&searchOption=2&latestN=1. Decision 2012-237 approved Statistics Canada CANSIM Table 281-0028, vector V1597350, as a source of the AWE data; however, it was later terminated by Statistics Canada and was replaced by CANSIM Table 281-0063 as was observed by the Commission in 2014 annual PBR rate adjustment decisions (for example, Decision 2013-461: ATCO Electric Ltd., 2014 Annual PBR Rate Adjustment Filing, Proceeding 2824, Application 1609913, December 20, 2013). In 2018, Statistics Canada has replaced CANSIM tables with data tables with the same or similar content; however, as of the date of this decision, it was still possible to search tables using former CANSIM vectors.

65 The Alberta CPI series from Statistics Canada data Table 18-10-0004-01, formerly CANSIM Table 326-0020, vector V41692327.

66 The selection of the start and ending months for the 12-month period reflects the latest published Statistics Canada data on Alberta AWE prior to the September 10 filing date for the annual rate adjustment applications.

67 The Commission recognized that Alberta CPI information for July might be available by the September 10 filing date for the annual rate adjustment applications; however, the Commission directed using the July through June period for consistency with the AWE index and to ensure the distribution utilities have enough time to prepare their filings.

68 Decision 26356-D01-2021, PDF page 21, paragraphs 65 and 69; Bulletin 2022-06, PDF page 1.

69 Exhibit 27388-X0212, EPCOR evidence, PDF page 12, paragraph 19.

labour price index; (ii) weighting of the I factor components; (iii) use of forecast inflation indexes with subsequent true-up; and (iv) applying a floor of zero for the I factor. Each of these proposals is discussed in the sections that follow.

70. Based on the Commission's findings in this section, the I factor approved for the PBR3 term will be calculated as follows:

$$\boldsymbol{I_t = 60\%\ x\ FWI_t + 40\%\ x\ CPI_t}$$

where:

$\boldsymbol{I_t}$	Inflation factor for the year.
$\boldsymbol{FWI_t}$	Alberta fixed weighted index[70] for the January to December period. (A placeholder value for the July to June period from the preceding year will initially be used.)
$\boldsymbol{CPI_t}$	Alberta consumer price index[71] for the January to December period. (A placeholder value for the July to June period from the preceding year will initially be used.)

71. If a termination, substantial revision or substantial modification to the Statistics Canada FWI or CPI data series used in the I factor occurs, such changes should be brought to the Commission as part of the annual PBR rate adjustment filings.

6.1 Labour and non-labour input price indexes

72. The continued use of the Alberta CPI for tracking the prices of non-labour inputs was generally not contested. Similar to the discussion set out in Decision 2012-237, most parties in this proceeding pointed out that while the CPI represents a very broad-based measure of inflation that does not focus specifically on goods and services purchased by a utility, it nevertheless adequately captures the impact of inflation on the non-labour component of utilities' costs.[72] PEG for the CCA submitted that Alberta's core CPI is more stable than Alberta all-items CPI because it excludes fluctuations in food and energy prices that have little impact on the cost of energy distributor services.[73]

73. For tracking the changes in the price of labour (i.e., salaries and wages of utility employees), Fortis, Apex and the ATCO Utilities (ATCO Electric and ATCO Gas) proposed using the Alberta FWI rather than the Alberta AWE.[74] In their respective evidence, ENMAX and

70 Statistics Canada data, Table 14-10-0213-01, data vector V1606326.
71 Statistics Canada data, Table 18-10-0004-01, data vector V41692327.
72 Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF page 28, Q/A 30; Exhibit 27388-X0197, ENMAX evidence, PDF page 23, paragraphs 36 and 40; Exhibit 27388-X0201, Apex evidence, PDF page 22, paragraph 59; Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 23-24, paragraph 57; Exhibit 27388-X0211, Fortis evidence, PDF page 13, paragraph 24.
73 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF page 37, paragraph 83.
74 Exhibit 27388-X0211, Fortis evidence, PDF page 16, paragraph 35; Exhibit 27388-X0201, Apex evidence, PDF pages 22-23, paragraph 61; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 23, paragraph 56.

EPCOR proposed to continue using AWE but later in the proceeding stated that they would not be opposed to using FWI as an alternative labour price index.[75]

74. The Alberta FWI is defined by Statistics Canada as the "fixed weighted index of average hourly earnings for all employees, by industry, monthly."[76] In its evidence for the ATCO Utilities and Apex, Brattle recommended using the Alberta FWI index as it is not influenced by changes in the mix of occupations or changes in hours worked per week and has performed better than the Alberta AWE at tracking actual labour inflation experienced by the Alberta distribution utilities over the PBR1 and PBR2 plan terms.[77] Similarly, Fortis observed that overtime components are excluded from FWI and noted that overtime hours and associated compensation are prone to volatility and can skew the assessment of underlying wage trends. Fortis added that Alberta FWI is a less volatile labour index and corresponds more closely with actual changes in utilities' labour costs.[78] The ATCO Utilities explained that the Alberta FWI is transparent, does not require subjective adjustments and is closer to the actual inflation experienced by the distribution utilities than the Alberta AWE index.[79] In response to a Commission IR, EPCOR stated that "FWI appears to more closely track EDTI's actual labour input compared to AWE" and "FWI appears less volatile than AWE."[80] In argument, ENMAX submitted that London Economics International LLC (LEI) in its evidence evaluated Alberta FWI against Alberta AWE and showed that there was not really a material difference.[81]

75. In his evidence for the CCA, J. Thygesen proposed to use the monthly Alberta Bargaining Update that provides prospective, actual wage settlements in Alberta typically for two and sometimes three years into the future.[82] In response to a Commission IR, J. Thygesen stated that FWI can be used and it addresses the concern with the volume effects of the AWE index.[83] Similarly, PEG for the CCA supported using FWI for the labour price index of the I factor because it is more stable as well as a more accurate measure of wage rate trends.[84]

76. The Commission agrees with the apparent consensus among parties in this proceeding that using Alberta FWI would be an improvement over using Alberta AWE because it is less volatile and is likely to track the prices of utility labour inputs more closely. The Commission considers it to be a benefit that the FWI is not influenced by changes in the mix of occupations or changes in hours worked per week and excludes overtime, which makes it less volatile. The Commission is satisfied that the Alberta FWI, which includes average hourly earnings for all employees, by industry in the Alberta economy, is sufficiently broad-based to avoid potential concerns about the distribution utilities' actual experience significantly influencing these measures. Therefore, the Commission considers that using the Alberta FWI index published by

75 Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-003(a), PDF page 14. Transcript, Volume 9, page 1756, lines 20-23.
76 https://www150.statcan.gc.ca/t1/tbl1/en/sbv.action?vectorNumbers=v1606326&searchOption=2&20atest=1
77 Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF pages 23-25.
78 Exhibit 27388-X0211, Fortis evidence, PDF pages 16-17, paragraphs 35-38.
79 Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 23-24, paragraph 57.
80 Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-003(a), PDF page 14.
81 Transcript, Volume 9, page 1756, lines 20-23.
82 Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF pages 23-24, paragraphs 46, 54, 62-63.
83 Exhibit 27388-X0492.02, CCA-AUC-2023FEB28-026(d), PDF page 59.
84 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-004©, PDF page 11.

Statistics Canada[85] as a labour cost component of the I factor for the Alberta companies provides a reasonable overall reflection of labour price changes.

77. Regarding Dr. Lowry's proposal to use core CPI rather than all-items CPI, the Commission is not persuaded that fluctuations in energy prices do not affect the costs of distribution utilities. In their rebuttal evidence, the ATCO Utilities stated that:

> Both food and energy prices are input costs for utilities. For example, fuel is required to operate utility vehicles and equipment, electricity, heating and cooling are required for utility buildings, and the utility incurs meal expenses for employees and contractors completing work away from their homebase and employees who travel for company business. An input cost cannot be ignored simply because it is not stable.[86]

78. More importantly, the Commission notes that the purpose of the I factor is to accurately capture the changes in prices of all inputs the utility uses in aggregate, rather than tracking individual cost items. In this regard, the Commission acknowledged in the PBR3 rebasing decisions that prices of some components of distribution utilities' costs such as materials and transportation equipment may have been elevated and exhibited high volatility in recent years.[87] The Commission, therefore, places greater weight on distribution utilities' submissions[88] that the I factor that includes the all-items Alberta CPI for the non-labour component more accurately captures the prices of inputs the utilities use and rejects Dr. Lowry's proposal to use core CPI.

6.2 Weighting of the I factor components

79. Consistent with its overall proposal to keep the I factor methodology unchanged from the prior PBR plans, EPCOR proposed to use the weights of 55 per cent for labour costs and 45 per cent for the non-labour costs, as approved in Decision 2012-237. All other distribution utilities proposed different weightings based on historical proportions of labour and non-labour costs as a percentage of total O&M expense and capital costs.

80. Even though all distribution utilities relied on the same principle of setting the I factor weightings based on the shares of labour and non-labour costs, they differed in the time frame chosen for the weightings calculations and their treatment of contractor costs. The ATCO Utilities, Apex and EPCOR classify contractor costs as labour costs, while ENMAX and Fortis classify those costs as non-labour, which largely explains the variations in proposed weightings. This is shown in Table 2 below that summarizes the proposed weightings in each utility's evidence:

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85 Statistics Canada Table 14-10-0213-01, data vector V1606326.

86 Exhibit 27388-X0587, ATCO Utilities rebuttal evidence, PDF page 11, paragraph 25.

87 Decision 26615-D01-2022, PDF page 28 paragraph 99, PDF page 30, paragraph 105, PDF pages 87-89, paragraphs 357-358 and 362.

88 Exhibit 23788-X0201, Apex evidence, PDF page 22, paragraph 59; Exhibit 27388-X0197, ENMAX evidence, PDF page 23, paragraph 36; Exhibit 23788-X0198, LEI evidence for ENMAX, PDF page 39; Exhibit 27388-X0211, Fortis evidence, PDF page 16, paragraph 35; Exhibit 27388-X0212, EPCOR evidence, PDF page 12, paragraph 19; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 31, paragraph 82; Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF page 27, Q/A49.

Table 2. Weightings of labour to non-labour I factor indexes proposed by each distribution utility[89]

	ENMAX [Note 1]	ATCO Electric [Note 3]	ATCO Gas [Note 3]	Fortis	EPCOR	Apex
Time period	2017-2021	2018-2021	2018-2021	2023	N/A [Note 2]	2018-2021
Proposed weights (labour/non-labour)	25:75	63:37	68:32	30:70	55:45	70:30
Contractor costs included in labour	No	Yes	Yes	No	Yes	Yes

Note 1: Based on the LEI calculation of average proportions of labour and non-labour costs for the four electric distribution utilities. Note 2: In its evidence, EPCOR did not propose any change to the I factor from prior PBR plans. Note 3: In their evidence, the ATCO Utilities proposed to update the I factor weighting to 66:34 ratio as a midpoint for both ATCO Electric and ATCO Gas.

81. The ATCO Utilities stated that the majority of their contractor costs tend to be driven by a labour cost escalation rather than general inflation indicating that contractor inflation rates can be volatile and are more impacted by pressures in the labour market than pressures related to supplies.[90] Apex explained that in terms of how they use contractors, it is "almost exclusively" contract labour.[91] Similarly, ENMAX and EPCOR confirmed that the majority of their contractor costs are associated with labour.[92] Fortis acknowledged that labour does form a part of its contractor costs but indicated that it cannot easily split out the vehicle, material, equipment, and other non-labour costs from its overall contractor costs.[93]

82. Based on the record of this proceeding, the Commission accepts that the distribution utilities' contractor costs relate mostly to labour and move in line with the labour costs escalation. Therefore, the Commission agrees with the inclusion of contractor costs in the labour component of the I factor. The Commission also agrees with those parties that used a four- or a five-year period in calculating the I factor weightings. Doing so is an improvement over using one-year data as it eliminates irregularities from a single year and reflects the distribution utilities' actual experiences over the PBR2 term. The following table summarizes the I factor weightings if the contractor costs are classified as labour and calculated over the preceding four- or five-year period and prior to adjustment for labour in CPI.

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89 Exhibit 27388-X0212, EPCOR evidence, PDF page 12, paragraph 19; Exhibit 27388-X0544, Attachment FAI-AUC-2023APR05-002; Exhibit 27388-X0501 (Blackline); Exhibit 27388-X0201, Apex Evidence, PDF page 25, paragraphs 69-70; Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 23-24, paragraph 57 and PDF page 26, paragraph 66; Exhibit 27388-X0197, ENMAX evidence, PDF page 25, paragraph 44.

90 Transcript, Volume 2, page 328, lines 20-22 and page 329, lines 7-10.

91 Transcript, Volume 2, page 229, lines 10-12.

92 Transcript, Volume 3, page 522, lines 14-16; Transcript, Volume 5, page 744, lines 23-24.

93 Transcript, Volume 6, page 993, lines 5-8.

Table 3. Weightings of labour to non-labour I factor indexes using consistent assumptions[94]

	ENMAX	ATCO Electric	ATCO Gas	Fortis	EPCOR	Apex
Time period	2018-2022	2018-2021	2018-2021	2018-2022	2018-2021	2018-2021
Index weights (labour/non-labour)	57:43	63:37	68:32	67:33	55:45	72:28
Weights with contractors in labour	Yes	Yes	Yes	Yes	Yes	Yes

83. As stated in Decision 2012-237, components comprising the I factor should ideally reflect the industry-wide proportions of the relevant costs, rather than utility-specific experience, in order to provide the strongest competitive incentives. In the absence of such industry data, the Commission approved the I factor weights in that decision by examining the historical proportion of labour and non-labour costs across the six Alberta distribution utilities (both electric and gas).

84. In this proceeding, PEG for the CCA provided calculations of I factor weights for its industry sample of 90 distribution utilities based on the share of O&M labour only. However, as discussed in the next section, the Commission does not accept PEG's method for purposes of this decision.

85. Using consistent assumptions on the time period of four to five years and classification of contractor costs as labour, as summarized in Table 3 above, the historical cost ratios are approximately 64 per cent labour and 36 per cent non-labour across all six distribution utilities. As observed in Decision 2012-237,[95] the CPI includes some embedded labour costs. In addition, there are some non-labour expenses in contractor costs. Therefore, to address the potential for over-weighting labour costs, the Commission adjusts this historical ratio to 60:40 for labour to non-labour components. The Commission notes that in coming up with their proposed I factor weights, LEI, Apex, and the ATCO Utilities[96] adopted a similar methodological adjustment ranging between 2 and 6 per cent to reduce the weight of labour costs.

86. Finally, the Commission agrees with the distribution utilities that the approved I factor weightings will remain the same throughout the PBR3 plan. As explained in Decision 2012-237, this will ensure that the distribution utilities' incentives will not be influenced by the relative rates of inflation between the components in the I factor.[97]

6.2.1 PEG's alternative proposal

87. In its rebuttal evidence for the CCA, PEG submitted that:

94 Exhibit 27388-X0543, EDTI-AUC-2023APR11-002, Attachment 1; Exhibit 27388-X0700, Fortis Undertaking; Exhibit 27388-X0201, Apex evidence, PDF page 25, paragraph 69; Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 23-26, paragraphs 57 and 66; Transcript, Volume 3, ENMAX, page 523, lines 10-15.

95 Decision 2012-237, PDF page 56, paragraph 228.

96 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-002(b), PDF page 11; Exhibit 27388-X0201, Apex evidence, paragraph 70; Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 46.

97 Decision 2012-237, PDF page 56, paragraph 229.

> 86. The labour component of capital costs should not be addressed by labour price index unless it can be convincingly demonstrated that the trend in the chosen macroeconomic price index is an unsatisfactory summary measure of the trends in capital, material, and service prices. The relevant capital price in such an analysis is the inflation inherent in the annual cost of capital.…
>
> 88. … the weight on any labour price subindex in an I factor formula should be commensurate with the share of labour, O&M expenses, and total cost, not total annual expenditures.[98]

88. The Commission acknowledges there is merit in PEG's rationale that capitalized labour is accounted for differently and, consequently, has a different effect on a utility's reporting of costs and the resulting ROE, than O&M labour. However, employees eventually classified as capitalized and O&M labour are subject to the same salary escalations and the same employees may be assigned to capital or O&M projects throughout a year.

89. When questioned at the oral hearing on the principles behind his recommended approach to use the O&M share of labour and why that is a more accurate reflection of the input costs facing distribution utilities compared to the total labour cost approach, Dr. Lowry responded that it is "self-serving to keep grabbing the labour piece out of everything and then assuming that the residual is perfectly addressed by the CPI."[99] In rebuttal evidence, PEG stated that lowering the labour cost share in the I factor formula is a way for the Commission to make PBR3 plan share benefits more fairly with customers without weakening utility performance incentives or raising regulatory cost.[100] Thus, it is not clear to the Commission whether PEG's recommended approach would result in I factor weights that better track the prices of inputs the distribution utilities use (as is the purpose of the I factor), or whether its principal intent is to lower the I factor to counter the distribution utilities' proposal (which is not the purpose of the I factor).

90. For these reasons, the Commission rejects PEG's proposal to calculate the labour share in the I factor based on O&M labour only. However, from the jurisdictional scans provided by parties, the Commission does agree with PEG that the proportion of labour costs in the I factor approved in AUC PBR plans is higher than in other jurisdictions. The Commission is interested in exploring this issue further on a principled basis in designing future PBR plans.

6.3 Historical data or forecast with true-up

91. In the PBR1 and PBR2 plans, the I factor was calculated using the actual inflation for the most recent 12-month (July to June) period to calculate the I factor for the upcoming year, with no subsequent true-up. This was referred to as "the lagged approach." In Decision 2012-237, the Commission explained that "in order for the companies to be concerned with the lagged approach and the compounding effect to take place, the rate of inflation in each year would have to be consistently higher (or lower) than in the previous year. If it is higher in some years and lower in other years, as appears to be the general case in the economy, then using the most recent past inflation rate will average out the effect of the lags over the PBR period."[101] In their evidence, some distribution utilities noted that because inflation was consistently rising

98 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF pages 39 and 43, paragraphs 86 and 88.
99 Transcript, Volume 7, page 1307, lines 22-25.
100 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF page 43, paragraph 89.
101 Decision 2012-237, PDF page 59, paragraph 246.

throughout the PBR2 term, the effect of the lags did not average out.[102] Therefore, using the lagged approach in determining the I factor was one of the main contributors of the I factor not accurately tracking against actual inflation experienced by the distribution utilities.[103]

92. Both Dr. Lowry and Dr. Toby Brown stated that circumstances have changed from the time of the PBR1 and PBR2 plans with inflation becoming more unstable, and that the forecast and true-up method should be adopted for the I factor in PBR3 instead of the lagged approach. Given the difficulty in forecasting future inflation rates accurately, true-up to actual inflation experienced in a year would more accurately reflect current economic conditions in that year.[104] Apex and the ATCO Utilities agreed with the recommendation of Dr. Brown and proposed the implementation of a calendarized I factor (i.e., for January to December time period), with a subsequent true-up to allow more accurate alignment of the change in input prices with the period for which rates are set.[105] J. Thygesen agreed with Dr. Lowry that a forecast and true-up approach should be adopted.[106]

93. EPCOR and Fortis stated they would not be opposed to using the forecast and true-up approach because it could provide distribution utilities with price adjustments that better track actual changes in input costs. EPCOR also noted that the use of forecasts may not average out over the PBR3 period.[107] ENMAX submitted that it is not strongly opposed to an I factor true-up but it would prefer to continue with the lagged approach because it believes this provides "greater certainty about the PBR revenue envelope in any given year" and a true-up will create additional administrative complexity and regulatory burden for little material impact.[108]

94. IPCAA stated that reliance on a forecast I factor is subject to significant judgment. Further, given a two-year lag between I factor forecast and true-up, the true-up creates uncertainty for customers in the future as they would be expected to pay or benefit from any variance in the forecasts which could be material. Dustin Madsen for IPCAA stated that the utility will not be able to forecast with certainty the amount of any future true up to revenues. Therefore, decisions in the year will be made based on the revenues approved.[109] The UCA echoed IPCAA that a true-up will mute the incentives of a utility as it will create uncertainty about the envelope of funding available to the utility as the total revenue available to a utility will not be finalized for two years after the year in question.[110]

95. The Commission agrees that because the inflation environment has become more uncertain in recent years, it may no longer be reasonable to presume that inflation will average out over the PBR3 term, as was the case under the lagged approach used during PBR1 and

102 Exhibit 27388-X0201, Apex evidence, PDF page 28, paragraph 81; Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 31-32, paragraphs 84-87; Exhibit 27388-X0222, PEG evidence for the CCA, PDF page 27, Q/As 45-46.

103 Exhibit 27388-X0201, Apex evidence, PDF page 30, paragraphs 90-91.

104 Transcript, Volume 7, page 1311, lines 9-17, page 1312, lines 20-25, page 1313, lines 1-16; Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF page 27, Q/As 36 and 46.

105 Exhibit 27388-X0201, Apex evidence, PDF pages 26 and 29, paragraphs 73 and 85; Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 23-24, paragraph 57.

106 Transcript, Volume 8, page 1461, lines 16-25 to page 1462, lines 1-16.

107 Transcript, Volume 9, page 1775, lines 2-8 (Fortis argument); Exhibit 27388-X0212, EPCOR evidence, PDF pages 13-16, paragraphs 22, 24 and 26.

108 Transcript, Volume 9, page 1757, lines 16-24 (ENMAX argument).

109 Exhibit 27388-X0368, AllParties(IPCAA)-AUC-2023FEB28-005(a) and (c), PDF pages 11-12.

110 Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-005(a) and (c), PDF page 15.

PBR2. Thus, the Commission agrees that the forecast and true-up approach should be used in PBR3 to more closely reflect ongoing economic conditions and corresponding changes in input prices. The Commission shares Dr. Lowry's view that this approach serves to reduce risk without weakening performance incentives.[111] As explained in Decision 2012-237, an I factor true-up represents a true-up to the inflation indexes and does not imply a true-up to the actual costs of a utility, thus preserving the incentive properties of the PBR regime.[112] In the hearing, the distribution utilities also confirmed that they would accrue revenue based on the forecast and expected true-up.[113]

96. To minimize regulatory burden and remove subjectivity in selecting appropriate forecasts, the Commission finds that the best approach is to use the I factor values for the most recent July to June period (as was calculated under the lagged approach in PBR1 and PBR2) as a placeholder.[114] This placeholder will be trued up to calendarized inflation (January to December) in a subsequent annual rate adjustment filing.

97. In Decision 2012-237, the Commission observed that Statistics Canada may revise the published indexes. Consistent with the findings in that decision, the distribution utilities should use the unrevised actual index values from the prior year's I factor filing as the basis for the next year's I factor calculations[115] for both the placeholder and final I factor values.

6.4 Floor of zero

98. In its evidence for ENMAX, LEI recommended that a floor of zero be set for the I factor to account for price volatility observed in recent months as well as uncertainties surrounding the inflation outlook.[116] ENMAX agreed with LEI and stated that wage costs for most employees are unlikely to fall even if the AWE index does.[117] Fortis also proposed to set a floor of zero for the I factor because distribution utilities do not generally experience decreases in cost rates, particularly for labour.[118] Apex expressed a similar view.[119] The ATCO Utilities submitted that a floor of zero can help utilities recover prudently incurred costs including a fair return when the labour component of the I factor becomes sufficiently negative.[120]

99. Apex and Fortis clarified in argument that if the labour component of the I factor is changed to FWI, a floor of zero is not necessary.[121] In contrast, LEI indicated that its recommendation to set a zero floor seeks to address concerns regarding potential earnings

111 Transcript, Volume 7, page 1311, lines 13-17 (Dr. Lowry).
112 Decision 2012-237, PDF pages 58-59, paragraph 242.
113 Transcript, Volume 2, page 331, lines 8-12 (ATCO, J. Bagnall). Transcript, Volume 3, page 532, lines 22-23 (ENMAX, A. Grogan). Transcript, Volume 5, page 747, lines 19-24 (EPCOR, S. Chaudhary). Transcript, Volume 6, page 998, lines 5-7 (Fortis, A. Johnson).
114 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 33, paragraph 89; Exhibit 27388-X0201, Apex evidence, PDF page 29, paragraph 84.
115 Decision 2012-237, PDF page 60, paragraph 249.
116 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 46.
117 Exhibit 27388-X0197, ENMAX evidence, PDF pages 23-25.
118 Exhibit 27388-X0211, Fortis evidence, PDF pages 17-18.
119 Exhibit 27388-X0531, AllParties(Apex)-AUC-2023FEB28-004(a), PDF page 14.
120 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-004 (c), PDF pages 18-19.
121 Exhibit 27388-X0867; Transcript, Volume 9, page 1658, lines 2-4, and page 1772, lines 23-25.

volatility instead of the labour component index and does not depend whether the labour component is represented by AWE or FWI.[122]

100. EPCOR considered that a floor of zero would not be necessary if an appropriate I factor is selected for PBR3.[123] IPCAA, the UCA and the CCA opposed placing a floor on the I factor. IPCAA stated that just as the I factor does not have a cap, the I factor should not be arbitrarily limited and, if the proposal is approved, the utility costs would not track the changes in the price of inputs that the distribution utilities use, which is inappropriate.[124] R. Bell for the UCA stated that setting a floor of zero would mute the incentives for a utility to pursue lower wage increases, or where possible, decreases in labour costs in conjunction with the overall changes in the economy.[125] The CCA responded that as the all-items CPI affords utilities the benefit of high inflation when food and fuel prices are soaring, it may be unfair to customers to eliminate the possibility of negative inflation.[126] J. Thygesen indicated that if the utilities do not believe that the I factor is reflective of the costs that they incur, they should propose an I which more accurately reflects their costs and not suggest that there is a zero boundary.[127]

101. The Commission agrees that any floors (or ceilings) on the I factor reflect an implicit assumption that the chosen inflation indexes do not accurately track the changes in the prices of inputs the utilities use and therefore, require extra measures to protect either the distribution utilities or their customers from price swings that do not affect utility input prices. Based on the approved I factor indexes and earlier determinations that they reasonably track changes in the prices of inputs the distribution utilities use, the Commission will not set any floors or ceilings for the I factor or for the overall I-X index. Just as utility rates will increase with high I factor values, they should decrease with lower, or negative, I factor values. As explained at the start of Section 6, this is how the I factor is intended to mimic how prices are set in a competitive market.

7 X factor

102. In this section, the Commission has weighed the evidence on the record, which included three separate TFP growth studies filed by each of Dr. Lowry, Dr. Meitzen and Dr. Jeff Makholm and used its expertise to conclude that an X factor of 0.1 per cent, inclusive of a stretch factor, is reasonable for the PBR3 term. The Commission considers that TFP growth studies continue to be useful in setting an X factor based on industry productivity growth. The Commission benefitted from examining the different TFP growth studies, which relied on different assumptions, including the output measure used and the sample time period. Additionally, the Commission has determined that the inclusion of a stretch factor is warranted in the PBR3 term, based on the two-part rationale for a stretch factor established in Decision 2012-237.[128]

[122] Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-004(b), PDF pages 10-11.
[123] Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-004(c), PDF page 16.
[124] Exhibit 27388-X0368, AllParties(IPCAA)-AUC-2023FEB28-004(c), PDF page 9.
[125] Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-004(c), PDF page 12.
[126] Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-004(c), PDF pages 11-12.
[127] Exhibit 27388-X0569, J. Thygesen rebuttal evidence for the CCA, PDF page 8, paragraph 21.
[128] Decision 2012-237, PDF pages 108-109, paragraphs 482-483.

103. As set out in Section 9, the Commission also approves an additional benefit-sharing provision in the form of an X factor premium of 0.3 per cent. With the exception of the calculation of K-bar, the total X factor to be used in PBR3 is 0.4 per cent, inclusive of the industry TFP growth, a stretch factor, and a benefit-sharing premium. For K-bar calculation purposes, the X factor of 0.1 per cent must be used.

7.1 Purpose of and theory behind the X factor

104. The X factor is another central component of PBR plans based on an I-X index. It represents the annual productivity growth a utility is expected to achieve during the PBR term. For this reason, the X factor is often referred to as a "productivity offset."

105. There are several approaches to setting the X factor. In approving prior PBR plans, the Commission expressed its preference for an approach to setting the X factor that is based on the average rate of long-term productivity growth in the utility industry. Under similar but alternative approaches, an X factor can be based on a utility's own historical performance or on the performance of a selected group of peer utilities, chosen because some of the characteristics of these peer utilities are deemed comparable. Under these methods, historical productivity growth is calculated in the TFP growth studies.

106. There are methods other than TFP growth studies that could be used to establish the X factor in a PBR plan. One such approach, generally advocated by PEG for the CCA and Dr. Lowry, is statistical benchmarking.[129] Another approach, generally advocated by Dr. Brown is a "building blocks" approach.[130] In prior decisions, the Commission observed that these alternative approaches have a different theoretical basis for utilizing the X factor in PBR plans and rejected them. Based on the reasoning in these prior decisions and on the record of this proceeding where the majority of parties based their X factor recommendations with reference to industry productivity, the Commission is not persuaded that there are good reasons to depart from the approach it adopted in prior PBR plans of setting the X factor based on industry productivity growth.

107. Determining an X factor through an industry TFP growth study has historically been a widely used approach by regulators in North America and has sound theoretical underpinnings. As explained in an article filed by Dr. Meitzen on the record of this proceeding, the I-X mechanism "follows from the basic idea that in a competitive market (which economic regulation seeks to emulate), average productivity gains in the industry are passed on to consumers in the prices they pay for service after controlling for inflation."[131] In PBR plans, this sharing occurs because the rate of growth in customer rates is reduced by the value of the approved X factor, regardless of the actual performance of the utility. At the same time, utilities that achieve higher than average productivity growth rates (i.e., firms that achieve a productivity

[129] When using the statistical benchmarking method, a utility's X factor for the PBR plan is established by observing its cost efficiency in relation to the rest of the industry or a peer group at a point in time. If the benchmarking study shows that a particular utility is more efficient in relation to the comparator utilities, that utility is rewarded with a relatively low X factor. Conversely, if a utility is less efficient than the comparator utilities, it is assigned a relatively high X factor. Statistical benchmarking has been used in other PBR jurisdictions such as Ontario and Massachusetts.

[130] The "building blocks" approach to set the X factor has been used in several jurisdictions including California, Great Britain and Australia. This approach analyses the different elements of a utility's revenue requirement separately, and the trends across all components of the revenue requirement are built up to derive an X factor.

[131] Exhibit 27388-X0400, EDTI-AUC-2023FEB28-018, PDF page 67.

growth rate above the rate implicitly mandated by the approved X factor) earn higher profits, while utilities that experience lower than average productivity growth rates (i.e., firms with achieved productivity growth rates below the rate implicitly mandated by the approved X factor) earn lower profits.

108. The first step in determining the X factor when using this methodology is to examine the growth in industry productivity over time, which is commonly determined by measuring the average TFP growth rate for as many utilities in the industry as possible (for which data is available for a chosen period of time). The measured industry TFP growth rate may then be adjusted by a stretch factor, to arrive at a final X factor.

109. This approach was employed to set the X factor in both the PBR1 and PBR2 plans. For PBR1, an X factor of 1.16 per cent was established, comprised of a long-term industry TFP growth value of 0.96 per cent and a stretch factor of 0.2 per cent.[132] For PBR2, the X factor was set at 0.3 per cent, which consisted of the industry TFP growth value and a stretch factor, but the Commission did not explicitly state the value of each component.[133]

110. Dr. Orans for Fortis pointed to the relationship between the I factor and the X factor and stated that if an economy-wide output inflation index is used (such as CPI or GDP-PI), the X factor calculation requires two components: (i) the differential in expected productivity growth between the industry and the overall economy; and (ii) the differential in expected input price growth between the overall economy and the industry.[134] However, because the Commission approved an I factor that can be considered an industry-specific input price index, meaning that it is supposed to mirror the inflationary pressures that an electricity or gas distribution utility faces in Alberta, parties to this proceeding (including Dr. Orans) agreed there is no need for such adjustments to the X factor. Dr. Lowry stated that the composite I factors used by Canadian regulators "are superior to the sole reliance on a single macroeconomic inflation measure and reduce the need for X factor adjustments."[135]

7.2 Industry historical TFP growth

111. Although the majority of parties in this proceeding based their X factor recommendations with reference to industry productivity, not all of them relied on the TFP growth studies to do so. Therefore, in Section 7.2 the Commission considers whether it should rely on the TFP growth studies as an estimate of industry productivity for setting the X factor and evaluates the three TFP growth studies undertaken in this proceeding.

7.2.1 Usefulness of TFP growth studies and alternative approaches

112. While they did not file a TFP growth study on the record of this proceeding, the ATCO Utilities, Apex, Fortis and ENMAX suggested that an X factor of zero per cent, with no stretch factor, would be appropriate given their review of recent TFP growth studies in other jurisdictions and the TFP growth studies filed on the record of this proceeding. These parties

132 Decision 2012-237, PDF page 115, paragraphs 514-515.

133 Decision 20414-D01-2016 (Errata), PDF page 55, paragraph 169.

134 Exhibit 27388-X0211, Dr. Orans evidence, PDF page 10; Exhibit 27388-X0400, EDTI-AUC-2023FEB28-018, PDF page 67. When the I factor is a measure of economy-wide output price growth formula for the X factor is $X(I_E) = (TFP_I – TFP_E) + (W_E + W_I)$, where TFP_I is the TFP growth in the regulated industry, TFP_E is the TFP growth in the overall economy, W_E is the input price growth in the overall economy and W_I is the input price growth in the regulated industry.

135 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF page 46, paragraph 94.

cautioned that the TFP growth methodology is not without its flaws.[136] Dr. Brown, on behalf of the ATCO Utilities and Apex, stated in evidence that there are some potential issues associated with using a TFP study for the purpose of setting the X factor. For example, a TFP growth study often uses sample data from a very long time period and is therefore not well-suited for determining an X factor that will apply for a much shorter amount of time.[137] Dr. Brown noted that the use of a long time period has the potential to mask the short- and medium-term trends in the industry and incorporate a good deal of out-of-date information.[138] LEI expressed similar reservations in its response to a Commission IR stating that TFP growth studies can provide a useful perspective on the efficiency of a utility's use of inputs, but that it cannot tell the entire story and may not be as useful in a fast-changing business environment like the one that prevails today.[139]

113. Dr. Makholm of NERA Economic Consulting (NERA) stated that the underlying changes in the electricity distribution industry have undone the basic intentions of using a TFP growth study, and suggested that despite its reasonable theoretical foundations, the implementation of a useable TFP growth study has become increasingly problematic, contentious and costly in a way that cannot be reasonably held to contribute to the welfare of consumers.[140] Dr. Makholm's reasoning was two-fold.

114. First, in Dr. Makholm's view, there are limitations to the Federal Energy Regulatory Commission Form 1 data that is used in TFP growth studies as it no longer does an adequate job of reflecting all of the various types of services that a utility provides. For example, utilities could spend a great deal on cybersecurity, which is a very important output for consumers and businesses, but there is no way to measure that output reliably. Because these services are not reflected in the output measure used, Dr. Makholm felt that a TFP growth study no longer does a fair job of measuring the TFP growth of utilities in the context of a contested regulatory proceeding.[141]

115. Second, Dr. Makholm expressed a view that it not reasonable to search for an objective index number as part of a contested regulatory proceeding among interested parties because it is impossible to disentangle whether a party recommends a particular assumption or calculation method because it is most reasonable, or because it benefits their particular interest group. For example, parties may "fiddle with the time period … or the elements of the measurement of … productivity growth to basically pick any number they want."[142] Based on this belief, apart from updating the NERA study to incorporate most recent data available since the time of the PBR1 proceeding, Dr. Makholm refused to consider any revisions to the methods and assumptions used in the original study and rejected critiques of his assumptions and methods by other parties.

116. Based on the above considerations Dr. Makholm concluded that the best course of action for the Commission "is to dispense with attempts to create its own index number by which to adjust external published inflation indexes when available data no longer reasonably tracks

136 Exhibit 27388-X0197, ENMAX evidence, PDF pages 26-27, paragraphs 50-52; Exhibit 27388-X0201, Apex evidence, PDF page 33, paragraph 98; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 34, paragraph 96.
137 Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF page 35.
138 Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF page 35.
139 Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-007(a), PDF page 19.
140 Exhibit 27388-X0475, AllParties(NERA)-AUC-2023FEB28-007(a), PDF page 9.
141 Transcript, Volume 1, pages 20-22 (J. Makholm).
142 Transcript, Volume 1, pages 22-23 (J. Makholm).

distribution utility products and services objectively."[143] In other words, Dr. Makholm recommended that the Commission stop computing the X factor as part of its PBR plans and let the I factor do the work of dealing with price changes. In support of this recommendation, Dr. Makholm stated that only two of the American states engage in a TFP growth methodology similar to the one used in Alberta, with the other jurisdictions dropping TFP growth studies in favour of published inflationary statistics.[144]

117. PEG for the CCA submitted that TFP growth studies can still be quite useful in ratemaking and suggested that it is the assumptions made (or refusal to update these assumptions) that limit the applicability of the NERA TFP growth study. Similarly, EPCOR's productivity experts, Dr. Meitzen and N. Crowley, stated that the economic theory that underlies the use of an X factor remains sound and that the NERA study continues to be a reliable approach if the model is adjusted for certain assumptions, as Meitzen and Crowley did.[145] Fortis's expert, Dr. Orans, submitted that the Commission should not discontinue its reliance on TFP growth studies to inform the setting of the X factor, but the Commission should be cognizant of the weaknesses of TFP growth studies.[146] For example, Dr. Orans suggested that any TFP growth study used to inform the magnitude of the X factor should incorporate the use of the most recent 15-year data set and a more accurate accelerated non-linear approach to depreciation.[147]

118. Dr. Meitzen and N. Crowley stated in rebuttal that Dr. Makholm overlooked the important fact that the measure of TFP growth for the purpose of calibrating a price cap X factor is not equivalent to a pure efficiency measure of TFP growth. They referred to a recent article in *The Electricity Journal* that Dr. Meitzen co-authored, which stated that whether TFP growth or the X factor is positive or negative is not a theoretical matter, but an empirical one. The article further stated that the fact that electric distribution industry TFP growth has turned negative in recent time periods is not dispositive of the industry becoming less efficient. Two elements of measured TFP growth – how output is specified for an indexed PBR plan, and the relationship between measured output growth and capital input growth – are reasons why negative TFP growth does not necessarily imply that any individual utility or the industry is becoming less productive. The article goes on to say that when the TFP growth measurement is used in calibrating the X factor for a price or revenue-per-customer cap, the output measure should reflect the elements of output associated with price or revenue generation – i.e., billed output. This is likely not the output that would be used in a pure efficiency measure of TFP growth since the TFP growth measurement used in setting the X factor for a price or revenue-per-customer cap would include only those aspects of output produced by the firm or industry that are explicitly related to price or revenue generation subject to the cap. In most cases, billed output would be a proper subset of the total output produced.[148]

119. The Commission does not agree with Dr. Makholm's views about the regulatory system and its ability to come to reasonable conclusions. The singular fact that regulatory proceedings involve expert witnesses that are engaged by parties does not invalidate the evidence put forth by

143 Exhibit 27388-X0475, AllParties(NERA) – AUC-2023FEB28-007(c), PDF page 9.
144 Transcript, Volume 1, page 34 (J. Makholm).
145 Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-007, PDF pages 25-27; Exhibit 27388-X0400, EDTI-AUC-2023FEB28-019, PDF page 84.
146 Exhibit 27388-X0500, AllParties(Fortis)-AUC-2023FEB28-007(c), PDF page 18.
147 Exhibit 27388-X0500, AllParties(Fortis)-AUC-2023FEB28-007(b), PDF page 18.
148 Exhibit 27388-X0568, M. Meitzen and N. Crowley rebuttal evidence for EPCOR, PDF pages 16-17 paragraph 40.

them, provided the experts are sufficiently qualified and independent. As further discussed in Section 7.2, what bolsters the Commission's confidence in the Meitzen and PEG studies (and in using the TFP growth study results in this decision generally) is that despite different assumptions, methods and data sets used, once these studies have been adjusted to use a common composite output measure, the results that they produce fall within a similar range. Furthermore, PEG and Christensen and Associates observed that the difference between the two study results can be almost entirely explained by three features with Dr. Meitzen stressing that Christensen and Associates and PEG would likely be able to work out their differences and come to a common recommendation for a TFP growth number, if the major assumptions in the two studies were harmonized.[149]

120. In the PBR1 Decision 2012-237, the Commission relied solely on the NERA study to inform the industry TFP growth calculations as it was the only study accepted by the Commission in that proceeding. In the PBR2 Decision 20414-D01-2016 (Errata), the Commission did not agree with the notion that there is just one correct TFP growth number, indicating that it had benefitted from examining different TFP growth studies that rely on different assumptions and calculations pertaining to the input and output measures. One of the Commission's key learnings in that proceeding was that TFP growth studies can be very sensitive to certain underlying assumptions and that changes in those assumptions can produce a dramatic effect on the resulting TFP growth number. The Commission stated:

> Had only one objective and transparent study been filed in evidence, the variability inherent in the TFP growth value, which is a function of the assumptions and data used, and is evident from a comparison of the three studies, easily could have remained unknown. This could have led the Commission to conclude that there is a single TFP growth value that could be regarded as "correct." Rather, the Commission views the variety of results that have been provided as confirming that the TFP growth value is likely not a correct single number, but that a reasonable value likely falls within a range of values, demarcated by the breadth of assumptions and data sets that may be reasonably employed in producing the studies.[150]

121. Further, in the Commission's view, it is natural that new, improved methods may be developed over time or that researchers may change their assumptions or methods based on more recent studies, advances in research and/or an evolving industry environment. For example, as noted earlier, the authors of the Meitzen study indicated they felt they improved the NERA model by using 15 years of data, including customer accounts and sales expenses, using a portion of administrative and general costs, and using the hyperbolic model of capital decay to estimate capital stock.[151] The Commission considers it is too simplistic to dismiss any proposed updates or modifications to the original NERA study, filed in 2010, as "it gives interested parties too many ways to fiddle with the parameters of the research" to get at a desired TFP growth number.[152]

122. The Commission also found helpful Dr. Meitzen's explanations that when the TFP growth measurement is used for setting the X factor for a price or revenue-per-customer cap plan, the output measure should reflect the sources of revenue to a utility – i.e., billed output such as customer, demand and energy charges. While these are likely not the outputs (or at least,

149 Transcript, Volume 5, pages 775-777.
150 Decision 20414-D01-2016 (Errata), PDF pages 50-51, paragraph 154.
151 Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-007, PDF pages 25-26; Exhibit 27388-X0400, EDTI-AUC-2023FEB28-019, PDF page 84.
152 Transcript, Volume 1, page 43 (J. Makholm).

not all of the outputs) one may contemplate when assessing the productivity of a company in general, i.e., what Dr. Meitzen referred to as a "pure efficiency measure," the Commission recognizes the logic that for regulatory purposes, TFP growth measure is based on only those aspects of output produced by the utility that are explicitly related to price or revenue generation subject to the cap. This explanation further allows for the reconciliation of the two otherwise potentially conflicting notions that while most parties in this proceeding did not believe that Alberta distribution utilities are becoming less productive, TFP growth studies almost invariably point to consistently negative industry TFP in the last two decades or so of observations.

123. In summary, the Commission remains of the view that using a TFP growth study to set the X factor plan is appropriate, provided that the assumptions in the study are well-documented, justified and reasonable. However, the Commission also agrees with those parties who stated that TFP growth studies are not without their limitations.

124. Again, as stated in Decision 20414-D01-2016 (Errata), the TFP growth value is likely not a correct single number. Rather, it is a reasonable value that falls within a range of values, depending on the assumptions made and the data sets used in producing the studies. It is not an exact science because many assumptions used in the studies "reflect the practitioner's decisions and beliefs based on the available choices that can be applied to the data, and there is generally no test presented in evidence that can be applied to determine which assumptions are more applicable to particular data or the purposes for which it is used."[153]

125. From the jurisdictional scans filed by parties, the Commission observes that many regulators approved an X factor of zero in recent PBR plans, even when the TFP growth studies suggested a negative number. In this proceeding, five out of six distribution utilities proposed to set the X factor at zero based on recent determinations of other regulators, their judgment and the judgment of their retained experts.

126. Lastly, while mathematically an X factor of zero would have the same effect as Dr. Makholm's recommendation to eliminate the X factor altogether and escalate prices or revenues by the I factor alone, in the Commission's view, it is important to distinguish between the two approaches. An X factor reflects the combination of industry TFP growth as well as adjustments to it (such as a stretch factor) that a regulator applies in a particular decision at a specific point in time. Future decisions may arrive at a different X factor value. Eliminating the X factor altogether appears to undermine the rationale and the fundamentals of the framework underlying the price cap and revenue-per-customer cap incentive regimes based on the I-X index.[154] It appears from the jurisdictional scans provided that other regulators have recently approved X factors of zero rather than eliminating the concept of X factors from their PBR plans altogether.

[153] Decision 20414-D01-2016 (Errata), PDF page 40, paragraph 120.

[154] In Decision 20414-D01-2016 (Errata), at PDF pages 54-55, paragraph 166, the Commission observed that the incentives of a PBR plan are not affected by the choice of a particular value of the X factor, whether it is negative, zero or positive. Rather, these incentives derive from the decoupling between revenues and costs under PBR. However, indexing prices or revenues by I-X is based on the idea that part of the expected efficiency gains from PBR are passed on to consumers during the PBR plan term through the X factor, regardless of the actual performance of the distribution utilities.

7.2.2 TFP growth calculations

127. In the PBR1 proceeding, the Commission engaged NERA as an independent expert to conduct a TFP growth study. NERA's study involved an analysis of the distribution component of 72 U.S. electric and combined electric/gas utilities over the period from 1972 to 2009. Although NERA's study was not the only TFP growth study filed in that proceeding, the Commission found the NERA study to be preferable because of the "objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution utilities from the United States."[155] The final approved TFP growth value of 0.96 per cent, determined to be the difference between growth in output and growth in inputs, was the average of 37 annual TFP growth values for the 1972-2009 period, where each annual value comprised a weighted average of TFP growth values for the 72 individual firms for that year, with weights based on relative firm size in terms of sales volume in megawatt hours (MWh). These sales were also used as the output measure for the distribution utilities.

128. In the PBR2 proceeding, three TFP growth studies were considered with a relatively wide range of TFP growth values; however, all of them produced a TFP growth number lower than 0.96 per cent adopted in Decision 2012-237, as shown in Table 4 below. In Decision 20414-D01-2016 (Errata), the Commission noted the issue was not whether the TFP growth component needed to be lowered, but rather the extent to which it needed to be lowered.[156] Based on the evidence in that proceeding, the Commission determined the X factor, inclusive of a stretch, to be 0.3 per cent.[157]

Table 4. Summary of PBR2 TFP growth study results[158]

Study	Output measure	Recommended data period	Number of firms	TFP growth rate (%)	
				Initial	Final
NERA 2012	Volume (MWh)	1972-2009	72	-	0.96
Brattle	Volume (MWh)	2000-2014	67	-0.89	-0.79
Meitzen	Volume (MWh)	Average of last 15 (2000-2014) and last 10 (2005-2014) years	68-72	-1.11	-1.11
Lowry	Number of customers	1997-2014	88 21	+0.48 +0.80	+0.43 +0.78

129. In the present proceeding, three TFP growth studies were filed. The Commission retained NERA to update its study from the PBR1 proceeding with the latest available data from 2010-2021.[159] The second TFP growth study was filed by Dr. Meitzen and N. Crowley of Christensen Associates for EPCOR (the Meitzen study).[160] They described their approach as being consistent with the TFP growth study that Dr. Meitzen presented in the PBR2 proceeding (which in turn was presented as an update to the NERA study from PBR1), with two refinements in methodology.[161] The third study was prepared by Dr. Lowry of PEG for the CCA (the PEG

155 Decision 2012-237, PDF page 94, paragraph 411.
156 Decision 20414-D01-2016 (Errata), PDF page 51, paragraph 156.
157 Decision 20414-D01-2016 (Errata), PDF page 55, paragraph 169.
158 Decision 20414-D01-2016 (Errata), PDF page 34, Table 1.
159 Exhibit 27388-X0182, NERA evidence, PDF pages 3-4.
160 Exhibit 27388-X0214, M. Meitzen and N. Crowley evidence for EPCOR, PDF pages 12-16 and 24-36.
161 Exhibit 27388-X0214, M. Meitzen and N. Crowley evidence for EPCOR, PDF page 12. The Meitzen study included certain customer accounts and sales expenses, as well as a portion of administrative and general expenses in the computation of total input to ensure that distribution costs typically considered in traditional

study).[162] The PEG study relied on its own data set, assumptions and calculation methodologies. The primary source of U.S. data for the PEG study was reports of U.S. utilities to the federal government. There were 90 U.S. utilities in the sample for the productivity research and 88 in the sample for the econometric research. The PEG study calculated trends in the partial factor productivity of capital and O&M inputs, as well as the TFP growth of sampled U.S. electric utilities.

130. Table 5 summarizes the TFP growth rates produced by the three studies filed in this proceeding.

Table 5. Summary of current TFP growth study results

Study	Output measure	Recommended data period	Number of firms	TFP growth rate (%)	
				Initial	Composite output measure
NERA	Volume (MWh)	1972-2021	65	0.002	N/A
Meitzen	Volume (MWh)	2007-2021	65	-1.08	-0.51
PEG	Number of customers	2006-2021	88	0.08	-0.28

131. As previously mentioned in Section 7.1, in Decision 20414-D01-2016 (Errata), the Commission viewed the variety of results as confirming that the TFP growth value was likely not a correct single number, but that a reasonable value would likely fall within a range of values, determined by the assumptions, calculations and data sets that may be reasonably employed in producing the studies.[163] The Commission observed that TFP growth studies can be very sensitive to certain underlying assumptions and a change in those assumptions can greatly influence the resulting number. In this regard, while the Commission reiterated the findings from Decision 2012-237 that for many assumptions there is no right or wrong answer and the choice simply reflects the practitioner's decisions and beliefs, it stated that studies must provide information describing all aspects of the study, and on the effects, both separately and jointly, of changing each of the assumptions used, to allow the Commission to make an informed determination.[164]

132. As also discussed in Section 7.2.1, apart from updating the NERA study to incorporate the most recent data available since the time of the PBR1 proceeding, Dr. Makholm did not consider any revisions to the methods and assumptions used in the original study[165] and rejected critiques of his assumptions and methods by other parties based on his view that in a contested regulatory proceeding, parties may opt for an assumption that delivers a desired productivity number.[166] Dr. Makholm also appeared to be of the view that the Commission had settled most of the issues related to TFP growth studies in Decision 2012-237 and the Commission's conclusions there should not be changed in subsequent proceedings. For this reason, Dr. Makholm recommended that if the Commission were to rely on a TFP growth study for

ratemaking are represented in the model. The Meitzen study also used the hyperbolic model of asset efficiency decay in the estimation of capital input rather than the one hoss shay model.

162 Exhibit 27388-X0204, PEG evidence for the CCA, PDF pages 13-50.

164 Decision 20414-D01-2016 (Errata), PDF page 53, paragraph 164.

165 Dr. Makholm's original study can be found in Proceeding 566, Exhibit 566-X0080.02, NERA Expert Report.

166 Transcript, Volume 1, pages 22-60.

setting the X factor, it should use his updated TFP growth number of 0.002 per cent without any changes.[167]

133. Many aspects of the three TFP growth studies in this proceeding have addressed some of the Commission's concerns and observations from the PBR1 and PBR2 decisions. For example, the Commission finds that all three studies meet the requirements of objectivity, consistency and transparency as they clearly presented the calculations and data and explained the assumptions used.

134. As well, in past decisions, the Commission expressed its preference for TFP growth studies to use broad samples of as many utilities as possible to reflect the variation of utility circumstances and characteristics that influence productivity. All three studies in this proceeding included all U.S. electric and gas distribution utilities for which data was available in their chosen time periods. PEG also presented the results of its "western productivity peer group" sample. In Decision 20414-D01-2016 (Errata), the Commission considered that, in general, it is likely that in competitive markets, there are a variety of factors that influence a firm's ability to achieve productivity gains, and since the design of a PBR plan is meant to emulate these aspects of competitive markets, it is preferable to use broad samples that will embody variation in more of the characteristics that influence productivity, as would be found in a competitive market. Accordingly, the Commission found that analysis using the full sample, or subsamples selected on multiple criteria as opposed to analysis using subsamples selected on a single criterion, will better inform the Commission's judgment as to the possible range of TFP growth values that are reflective of competitive markets.[168] The Commission finds that the reasons outlined in Decision 20414-D01-2016 (Errata)[169] continue to apply, and therefore, the Commission will give the most weight to the result of PEG's full sample.

135. The three TFP growth studies disagreed on certain assumptions pertaining to measuring the growth of inputs, most prominently on the method to account for capital costs.[170] However, Dr. Meitzen and Dr. Lowry largely accepted the Commission conclusions from the prior PBR decisions that there is no right or wrong answer for TFP growth studies generally and in relation to the assumptions used in such studies. For this aspect of the analysis, the Commission will therefore not specify a preference for the set of assumptions used by any particular one of the three TFP growth studies.

136. Nevertheless, as in the past PBR proceedings, disagreements among the three TFP growth studies remained on the chosen output measure and relevant time period that should be used. Each of these two aspects is discussed in turn below.

137. The NERA study and the Meitzen study both used a volumetric output measure (megawatt hours sold by distribution utilities in their samples), whereas the PEG study used the number of customers as the output measure. Dr. Lowry and Dr. Meitzen explained that from a theoretical perspective, the ideal output measure for a price cap PBR plan should reflect the sources of revenue for the utilities included in the study or more technically, it should be a revenue-weighted average of growth in all of utility billing determinants (i.e., charge per day, per

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167 Exhibit 27388-X0182, NERA evidence, PDF page 4.
168 Decision 20414-D01-206 (Errata), PDF pages 38-39, paragraph 114.
169 Decision 20414-D01-2016 (Errata), PDF pages 38-39, paragraphs 114-115.
170 For capital costs, NERA used the one hoss shay depreciation pattern specification, whereas PEG used geometric decay specification, and Meitzen and Crowley used the hyperbolic decay capital cost specification.

KWh, per unit of demand, etc.). Because most available datasets contain information only on customers and volumes, a reasonable approximation is to reflect the proportion of revenues generated through fixed versus variable (volumetric) charges. However, Dr. Meitzen and N. Crowley stated that even in that case, calculating such output measures for each company and each year of the study would be a substantial undertaking and that it was potentially impossible to acquire this data.[171] Despite agreeing on the theoretical underpinnings, Dr. Lowry and Dr. Meitzen each chose to use their preferred single output measure based on their respective opinions of what is the most important revenue source for the utilities in their sample.

138. In Decision 20414-D01-2016 (Errata), the Commission accepted that because distribution utilities collect revenue based on both fixed and variable charges, both volume and number of customers are valid output measures. The Commission indicated that a useful way to proceed in future TFP growth studies might be to use some combination of the output measures and, as a starting point, to examine the sensitivity of the TFP growth results to different combinations of output measures.[172] In response to a Commission IR, Dr. Meitzen and PEG provided the results of their TFP growth studies using an output measure that weighted a volumetric output measure and the number of customers equally. When using such combined output measures, the Meitzen study calculated a TFP growth rate of -0.51 per cent, compared to its original calculation of -1.08 per cent. PEG stated its analysis using a 50:50 weighting of customers and volumes resulted in a "TFP trend that was modestly slower" than its initial calculation of 0.08 per cent, averaging -0.28 per cent.[173]

139. This sensitivity analysis clearly demonstrated that assigning more weight to a volumetric output measure of KWh sold results in a smaller TFP growth number and assigning more weight to the number of customers output measure results in a larger TFP growth number. PEG observed that over the lengthy 1973-2016 period, the total sales volume per customer of distributors in NERA's sample averaged 0.4 per cent annual growth while the residential and commercial sales volume per customer averaged 0.9 per cent annual growth. In the nine years from 2008 to 2016, however, the total sales volume per customer in NERA's sample averaged a 1.2 per cent average decline, while the residential and commercial volume per customer averaged a 1.0 per cent decline. PEG also observed that during 2008 to 2021, the customer growth of the companies in Dr. Meitzen's and N. Crowley's sample averaged 0.68 per cent growth annually. During the same sample period, the total sales volume growth of these companies averaged a 0.36 per cent decline. Based on these numbers, PEG concluded that using an entirely volumetric output measure is a major source of the TFP growth slowdown observed in recent years.[174]

140. While Dr. Meitzen and N. Crowley commented that a 50:50 weighting of customers and volumes is somewhat arbitrary, they could not calculate the theoretically correct output measure reflecting the actual weights for each company and each year of the study given the practical difficulties of doing so.[175] Dr. Lowry pointed to the information in an IR response that the average ratio between fixed charges and energy charges across all Alberta distribution utilities is 42:58 and stated an equal weighting of customer and volume outputs would be preferable in

171 Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-007(d), PDF pages 25-26.
172 Decision 20414-D01-2016 (Errata), PDF page 43, paragraph 130 PDF page 52, paragraph 160.
173 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-007(e), PDF page 24.
174 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, paragraphs 15-17.
175 Exhibit 27388-X0407, EDTI-CCA-2023FEB28-002(a).

setting the X factor for price cap plans as compared to the entirely volumetric output.[176] In the Commission's view, the same can be said about using number of customers as the only output measure as is the case in PEG's study. Given that is it very unlikely that the majority of the utilities in PEG's and Dr. Meitzen's studies obtain their revenue entirely from either volumetric or fixed charges, the Commission considers that a composite output measure reflecting a 50:50 weighting of customers and volumes to be a more reasonable assumption for the purposes of this decision as compared to relying entirely on either of those measures. In future PBR proceedings, the Commission will consider evidence on more precise output weightings that are feasible, practical, reasonable and do not result in significant regulatory burden.

141. The three studies also differed in the time period used. As in the PBR1 proceeding, the NERA study relied on the longest time period available, from 1972 to 2021. In contrast the Meitzen and Lowry studies used data from a more recent time period. The Meitzen study employed data for the most recent 15 years, from 2007 to 2021. In evidence, Dr. Meitzen stated that using a 15-year period strikes a reasonable balance between using the most recent and relevant information for determining forward-looking changes in productivity and using a period long enough to account for short-term variation in results.[177] The PEG study used a 16-year sample period to calculate the TFP growth rate and explained that a sample period of this length will provide a TFP growth rate that is more "forward looking" while still including enough years to smooth out the year-to-year oscillations in TFP.[178]

142. In Decision 20414-D01-2016 (Errata), the Commission placed weight on the TFP growth numbers being based on both the longest time period for which data is available, as was advocated by NERA in the PBR1 proceeding and accepted by the Commission in Decision 2012-237, as well as on the shorter time period of approximately 15 most recent years. The Commission stated that the time period that should be used to determine TFP growth remains an open question.[179]

143. In this proceeding, most parties agreed that if a TFP growth study were to be used in the determination of the X factor, the time period should be shortened considerably.[180] PEG, however, stated that if NERA's study were to be used, it should rely on the full sample period because NERA's capital cost specification is designed to measure capital quantity trends over its full sample and that it would lead to inaccuracies if a truncated sample period was used.[181] PEG observed that the Meitzen study employs some of the updated assumptions (including a different capital cost specification method) and thus "is free of some of the problems that PEG has identified with regard to NERA's work."[182]

144. In the current proceeding, the Commission has no concerns with the shorter time periods used in the PEG and Meitzen studies finding that these periods are sufficiently long to smooth out any short-term variations while using the most recent, relevant and representative

176 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF page 14, paragraphs 33-34.
177 Exhibit 27388-X0214, M. Meitzen and N. Crowley evidence for EPCOR, PDF page 29.
178 Exhibit 27388-X0204, PEG evidence for the CCA, PDF page 22.
179 Decision 20414-D01-2016 (Errata), PDF page 52, paragraph 161.
180 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-009(b), PDF page 37; Exhibit 27388-X0500, FAI-AUC-All-2023FEB28-009(b), PDF page 24; Exhibit 27388-X0379, AllParties(ENMAX)-AUC-2023FEB28-009(b), PDF page 26; Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-009(b), PDF pages 55-57; Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-009, PDF page 30.
181 Exhibit 27388-X0570.01, PEG rebuttal evidence for the CCA, PDF pages 5-6, paragraph 12.
182 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-007(a), PDF page 23.

information of forward-looking changes in productivity. The Commission's reliance on the composite output measure reflecting both the number of customers and volumes in this decision provides further support for, and confidence in, using the data from the most recent 15-year period in these studies.

145. Overall, and based on the above considerations, for the purposes of this decision the Commission has assigned greater weight to the Meitzen and PEG studies, adjusted to reflect the composite output measure reflective of equally weighted number of customers and KWh (GJ) sold. As shown in Table 5 above, the resulting TFP growth numbers resulting from the use of this data set are in the range of -0.28 to -0.51 per cent.

146. The Commission's confidence in the Meitzen and PEG studies (and in using the TFP growth study results in this decision generally) is further bolstered by the fact that that despite the different assumptions, methods and data sets used, once the filed studies are adjusted to use a common composite output measure, the results fall within a range much narrower than the results of the TFP growth studies filed in the PBR2 proceeding. Furthermore, the difference between the two study results can be almost entirely explained by the following: (i) the Meitzen study includes three large California utilities in its size-weighted TFP growth trends, which the PEG study excludes;[183] (ii) the Meitzen study employs 15 years of data whereas the PEG study includes 16 years of data; and (iii) the Meitzen study uses hyperbolic decay for capital cost inputs whereas the PEG study uses geometric decay.[184] The Commission considers that there is merit to each of these assumptions and will not attach a higher weight to one study or the other based on these differences in underlying assumptions.

147. NERA's study provided a useful verification of the numbers and assumptions against TFP growth studies in PBR1 and PBR2 proceedings as well as the two other studies filed in this proceeding and allowed the Commission to examine the sensitivity of the studies to various assumptions and parameters to make an informed decision. However, Dr. Makholm's refusal to consider alternative assumptions or at least provide calculations based on assumptions different from his, limited the usefulness of his TFP growth study results for the Commission's X factor determinations in this decision.

7.3 Stretch factor

148. The stretch factor is an addition to the X factor that would further restrain the rate at which prices (under price cap plans) or revenue (under revenue-per-customer cap plans) can increase during the PBR term. By adding a stretch factor to the X factor, expected efficiency gains incremental to those reflected in the industry historical TFP growth are shared with customers, by means of lower rates, from the start of the PBR plan, rather than waiting until rebasing at the end of the PBR term.

149. In PBR1, the Commission identified two issues that are salient when considering the need for a stretch factor. The first issue was that NERA's TFP growth study, on which the productivity component of the X factor was based, provided an industry productivity trend using a sample of comparator utilities predominantly regulated under COS, which resulted in a

183 PEG excluded these due to the utilities suffering from extensive damage to their distribution system from wildfires. As a result of these and other wildfires, California's government mandated the development of costly wildfire mitigation plans beginning in 2019, causing TFP growth for these utilities to plunge.

184 Exhibit 27388-X0568, M. Meitzen and N. Crowley rebuttal evidence for EPCOR, PDF page 6.

productivity trend that needed to be "stretched" to account for the higher incentives under PBR.[185] The second issue was the potential for the Alberta distribution utilities to collect the "low-hanging fruit" when transitioning from COS to a PBR framework.[186] Based on these considerations, the Commission found a stretch factor of 0.2 per cent to be reasonable for the PBR1 term.[187]

150. In PBR2, the Commission determined that the X factor should exceed the level that historic TFP growth estimates alone might suggest; however, it did not explicitly state the value of the stretch factor. The Commission found that there was merit in including a stretch factor on the basis that capital funding was changed from a low-incentive mechanism in capital trackers, to the high-incentive K-bar mechanism.[188]

151. In this proceeding, parties disagreed on whether a stretch factor should be applied in the PBR3 plan. The utilities and their experts contended that because the transition to PBR is over, a stretch factor is not warranted.[189] The ATCO Utilities stated that even though the utilities' 2023 rates were set on a COS basis, it was a streamlined process, not a typical COS proceeding.[190] The distribution utilities submitted that they have sought out and achieved all of the readily available efficiencies in the past two PBR terms, or in other words, all the "low-hanging fruit" has been harvested over the last decade as a result of being subjected to PBR.[191] The distribution utilities also claimed that the efficiencies that had been achieved during PBR2 are embedded into their actual costs, which formed the basis of their 2023 forecast revenue requirement under the COS rebasing approach. Accordingly, they indicated that savings have already been passed on to customers and it is unnecessary to include a stretch factor in the PBR3 plan.[192]

152. Considering the two-part rationale for the stretch factor that the Commission established in prior proceedings, Dr. Weisman suggested that an appropriate stretch factor (not including EPCOR's recommendation of an X factor premium discussed in Section 9.2.2) should be greater than zero per cent but less than 0.052 per cent.[193] EPCOR stated that because the TFP growth study conducted was based on a sample of utilities that were not subject to a pure price cap plan, a very small stretch factor would be justified if there were no changes in the PBR3 plan from PBR2.[194] However, EPCOR did not recommend that a stretch factor be included in the PBR3 plan and agreed with the other distribution utilities that there are no longer any easy-to-achieve efficiencies remaining for distribution utilities to realize.[195]

153. Parties representing customer groups argued that stretch factors should form part of the X factor in PBR3 plan. In its evidence for the CCA, PEG suggested that there is a strong argument for the continuation of a stretch factor, but that the Commission should reconsider its

185 Decision 2012-237, PDF pages 108-109, paragraph 482.
186 Decision 2012-237, PDF page 109, paragraph 483.
187 Decision 2012-237, PDF page 112, paragraph 499.
188 Decision 20414-D01-2016 (Errata), PDF pages 49-50, paragraphs 152-153.
189 Exhibit 27388-X0211, Fortis evidence, PDF pages 20-21, paragraph 48; Exhibit 27388-X0201, Apex evidence, paragraph 104, PDF page 34; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 36, paragraph 101; Exhibit 27388-X0197, ENMAX evidence, PDF page 27, paragraph 52.
190 Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 35-36, paragraph 100.
191 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 34, paragraph 94, and PDF page 36, paragraph 101.
192 Exhibit 27388-X0211, Fortis evidence, PDF page 21, paragraph 49.
193 Exhibit 27388-X0400, EDTI-AUC-2023FEB28-010(a), PDF page 27.
194 Exhibit 27388-X0212, EPCOR evidence, PDF page 17, paragraph 29.
195 Exhibit 27388-X0418, EDTI-UCA-2023FEB28-003(a), PDF page 7.

approach to setting a stretch factor and instead base it on statistical benchmarking studies, as is done in other jurisdictions.[196] As discussed in Section 7.4 of this decision, the Commission does not accept this recommendation at this time. PEG also stated that the low implicit stretch factor in PBR2 has been the cause of "chronic overearning" by the distribution utilities, and a low stretch factor should be considered as a reward where there is evidence of superior cost control. The UCA and J. Thygesen for the CCA did not agree with the distribution utilities that all "low-hanging fruit" has been harvested over the last two PBR terms.

154. Based on its expertise developed in administering the prior PBR plans and based on the record of this proceeding, the Commission agrees with Dr. Lowry's view[197] that at its most basic level, the stretch component of the X factor in a PBR plan reflects an expectation of how the productivity growth of a utility operating under that plan will differ from the industry historical productivity growth, as measured by the TFP growth study (or more technically, the average productivity trend of the group of utilities included in the TFP growth study). The Commission finds that it is reasonable to expect that productivity growth of the distribution utilities over the PBR3 term will differ from the industry historic productivity growth measured by the TFP growth studies and, therefore, a stretch factor is appropriate in PBR3.

155. First, the industry productivity growth determined through the TFP growth studies filed in this proceeding likely understates productivity growth that will be experienced by the distribution utilities over the PBR 3 term. These studies were largely based on utilities regulated under COS regulation. Dr. Makholm, Dr. Meitzen and Dr. Lowry confirmed that not all of the utilities in their respective TFP growth study samples were regulated under PBR. PEG confirmed only 18 per cent of the utilities in its sample were subject to some form of incentive regulation.[198] Dr. Meitzen could not partition firms between those regulated under COS and those regulated under PBR because his sample was made up of utilities on a continuum of regulatory regimes.[199] Dr. Makholm stated that most of the utilities in NERA's study were subject to COS, but this was based on his belief that "PBR is a relatively minor variation on a foundation of cost of service."[200]

156. Dr. Lowry, Dr. Meitzen and Dr. Weisman recognized that the form of regulation of utilities included in a TFP growth study could justify a stretch factor. Dr. Makholm disagreed that the form of regulation of the utilities in the TFP growth study sample is a salient reason for imposing a stretch factor. The Commission accepts the position of Dr. Lowry, Dr. Meitzen and Dr. Weisman on this point. The Commission agrees with its comments set out in Decision 2012-237 – a decision which Dr. Makholm heavily supported in his oral testimony – that it is reasonable to expect that utilities regulated under PBR will exceed the industry historic productivity growth because of the stronger cost containment incentives of PBR.

157. Second, the Commission considers that there continue to be opportunities for efficiency gains above the industry productivity growth rate resulting from the operation of the incentives and the proxy for competitive discipline found with PBR. In Decision 2012-237, the

196 Exhibit 27388-X0204.01, PEG evidence for the CCA-Electric, PDF page 135.
197 Exhibit 27388-X0231.01, PEG evidence for the CCA-Gas, PDF page 35.
198 Exhibit 27388-X0492.02, CCA-AUC-2023FEB28-028(a), PDF page 64.
199 Exhibit 27388-X0475, AllParties(NERA)-AUC-2023FEB28-010(e), PDF page 14; Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-010(e), PDF page 32; Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-010(e), PDF page 68.
200 Exhibit 27388-X0475, AllParties(NERA)-AUC-2023FEB28-010(e), PDF page 32.

Commission recognized that the transition from COS regulation to PBR provides an opportunity for distribution utilities to more easily realize achieved efficiency gains, referred to as the "low-hanging fruit." In the Commission's view, the distribution utilities in this proceeding (as they did in the PBR2 proceeding), and Dr. Makholm, focused on an unnecessarily narrow interpretation of this rationale for the stretch factor – namely, that the efficiency gains are only present when transitioning from COS to PBR. In Decision 20414-D01-2016 (Errata), the Commission cautioned against such a narrow interpretation.[201] The Commission agrees with Dr. Lowry's view that subsequent generations of PBR plans continue to provide incentives for higher productivity gains although these gains may be diminished as compared to earlier generations of PBR. In fact, Dr. Lowry's TFP growth calculations demonstrate that the distribution utilities were able to achieve higher productivity growth in PBR2 as compared to PBR1.[202]

158. While the distribution utilities have suggested that the supply of low-hanging fruit has been exhausted in the past two generations of PBR, the Commission observes that the distribution utilities provided a similar argument in both the PBR1 and PBR2 proceedings. In PBR1, the ATCO Utilities and Fortis argued that there would be no low-hanging fruit to pick during the transition to PBR because of their strong productivity performance under the COS regime.[203] In the PBR2 proceeding, the distribution utilities and their experts contended that the readily available efficiency gains had already been captured in the PBR1 term.[204] In both terms, the distribution utilities have found ways to become more efficient, consistent with the Commission's expectations based on the theory underlying PBR.[205]

159. As shown in Table 1 from Section 2.3 of this decision, the distribution utilities have achieved ROEs over the PBR1 and PBR2 terms that were greater, and in some instances significantly greater, than the approved ROEs. As was discussed in Section 2.3 and consistent with the determinations in the PBR rebasing decisions, while the Commission agrees with the distribution utilities that achieved ROEs may not be perfectly equated to a measurement of realized efficiencies (as there are other elements that affect the achieved ROE), they are nevertheless indicative of cost savings achieved through realized efficiencies. In the Commission's view, these ROEs indicate that the distribution utilities will still have considerable opportunity to achieve efficiencies in the upcoming term which justifies the up-front sharing of benefits prior to the next rebasing, even though the distribution utilities are going into their third generation of PBR.

160. In his rebuttal evidence, referring to his high-powered ESM soft cap proposal of 12.5 per cent (discussed in more detail in Section 9.6.1 below), Dr. Weisman stated that "Few, if any, of the companies are likely to achieve returns of this magnitude given that the preponderance of the low-hanging fruit has likely already been foraged in the first two PBR regimes."[206] Consistent with this logic, the Commission would have expected to see some decline in achieved returns as the potential for efficiency gains (the low-hanging fruit) was being depleted. However, as shown

201 Decision 20414-D01-2016 (Errata), PDF page 49, paragraph 151.
202 Transcript, Volume 7, pages 1333-1335.
203 Decision 2012-237, PDF page 107, paragraph 472 and PDF page 109, paragraph 484.
204 Decision 2012-237, PDF page 104, paragraph 484; Decision 20414-D01-2016 (Errata), PDF page 48, paragraph 147.
205 Decision 2012-237, PDF page 104, paragraph 484.
206 Exhibit 27388-X0567, D. Weisman rebuttal evidence for EPCOR, PDF page 32.

in Table 1, many distribution utilities achieved high ROEs during the last two years of the PBR2 term.

161. During the hearing, Dr. Weisman cautioned against inadvertently penalizing the distribution utilities for their successful performance in past PBR regimes with higher stretch factors in the next PBR plan (what is known in the academic literature as the "ratcheting effect").[207] While the Commission is mindful of this consideration, it is the Commission's view that ROEs that are consistently above the approved level for most distribution utilities in the PBR2 term are at least directionally indicative that there are available efficiencies remaining. Moreover, as discussed further in this section and throughout the decision, the Commission is confident that the approved PBR3 plan provides strong incentives to the distribution utilities to continue seeking efficiency gains and engaging in sustainable long-term cost-cutting behaviour. As such, the Commission finds the distribution utilities can reasonably be expected to achieve productivity growth above the growth identified in the TFP growth studies, justifying the inclusion of a stretch component in the X factor for PBR3.

162. Based on the above considerations, the Commission finds that it will include a stretch component in the X factor for the PBR3 plan. When it comes to the value of the stretch factor, parties in this proceeding reiterated the consensus captured in Decision 2012-237[208] that unlike the productivity component of the X factor, which has a definitive analytical source in the TFP growth study, the size of the stretch factor is, to a large degree, based on the regulator's judgment and regulatory precedent. From the various jurisdictional scans presented by parties, the Commission observes that stretch factors approved by other regulators range from zero per cent to 0.6 per cent.

163. The Commission has carefully considered and weighed the evidence on the record with respect to industry TFP growth considerations and the expert testimony related thereto, the decisions of other regulators, and parties' proposals. The Commission has applied its specialized expertise, regulatory experience, and judgement to this evidence, and finds that an X factor of 0.1 per cent, inclusive of industry TFP growth and a stretch factor, is reasonable for the PBR3 term, prior to the inclusion of any benefit-sharing provisions. As further discussed in Section 9, the Commission approves an X factor premium of 0.3 per cent as one of two additional benefit-sharing provisions introduced in the PBR3 plan. With the exception of the calculation of K-bar, the total X factor to be used in PBR3 is 0.4 per cent, inclusive of the benefit-sharing premium. For K-bar calculation purposes, an X factor of 0.1 per cent must be used.

7.4 PEG's benchmarking studies

164. In its evidence for the CCA, PEG benchmarked the non-energy/fuel O&M expenses, capital cost, and total cost of the Alberta distribution utilities using econometric models, which are based on estimating the costs incurred by a group of utilities in relation to the business conditions these utilities faced. PEG calculated benchmarking results for each year from 2013 to 2023 for ENMAX, from 2006 to 2023 for the other three electric distribution utilities, and from 2007 to 2023 for ATCO Gas. These benchmarks were based on econometric model parameter estimates and values for the business condition variables which, in PEG's view, were appropriate for each benchmarked distribution utility. Dr. Lowry further stated that the resultant benchmarks control for numerous business conditions that drive distributor costs, and also generate estimates

[207] Transcript, Volume 5, pages 769-770.
[208] Decision 2012-237, PDF page 112, paragraph 497.

of change in cost efficiency that are generally more accurate than those provided by productivity indexes.[209] He also stated that PEG adopted the estimation procedure that has been favoured by utility witnesses in Ontario.[210]

165. The results of Dr. Lowry's benchmarking studies indicated that:

- The forecast total cost of ENMAX in 2023 was 17 per cent below the econometric benchmark.
- The forecast total cost of EPCOR in 2023 was 25 per cent below the econometric benchmark.
- The forecast total cost of ATCO Electric in 2023 was 56 per cent above the econometric benchmark.
- The forecast total cost of Fortis in 2023 was 23 per cent below the econometric benchmark.
- The forecast total cost of ATCO Gas was 30 per cent below the econometric benchmark.

166. The distribution utilities expressed significant concerns with the validity of PEG's benchmarking studies, including, but not limited to the fact they were not sufficiently tested or validated and that the models are not able to address differences in the external environment in which the comparator utilities operate. In particular, they pointed to PEG's admission that the results for ATCO Electric bordered on the implausible. ENMAX also noted that PEG's study included a disclaimer that its benchmarking studies are first generation studies, that results may vary in future studies, and that limited discovery in this proceeding impacted the processing and interpretation of Alberta data.[211] Fortis expressed the same concern that these were first generation studies, and pointed to changes between the time PEG filed its evidence and the time it prepared its IR responses as an indicator of the questionable reliability of the benchmarking results.[212] EPCOR submitted that the translation of the benchmarking results into a defensible stretch factor is purely arbitrary, and that it makes little sense that EPCOR, with actual costs that are 25 per cent below predicted costs would still be assigned a stretch factor of between 0.15 per cent under the Ontario scorecard and 0.3 per cent under the Massachusetts scorecard.[213]

167. The Commission agrees that PEG's benchmarking studies in this proceeding are first generation and may not be entirely robust as demonstrated by the change in ATCO Gas's result through the course of the proceeding and the "implausible" result for ATCO Electric. Dr. Lowry acknowledged he had limited time to collect data and do the benchmarking analysis and the distribution utilities pointed out that they had limited ability to validate the analysis. Additionally, the translation of the benchmarking study results into a defensible stretch factor requires significant judgement and the Commission is not persuaded that such a method would

209 Exhibit 27388-X0204.01, PEG evidence for the CCA– Electric, PDF page 113.
210 Exhibit 27388-X0204.01, PEG evidence for the CCA– Electric, PDF page 144; Exhibit 27388-X0231.01, PEG evidence for the CCA– Gas, PDF page 50.
211 Transcript, Volume 9, page 1749, line 12 to page 1750 line 10.
212 Transcript, Volume 9, page 1782, lines 5-11.
213 Transcript, Volume 10, page 1921, lines 16-25.

improve upon the existing approach to setting a stretch factor in a PBR plan. However, the Commission considers that PEG's analysis, while not sufficient to rely upon in this proceeding, does provide a useful point of reference that suggests that most Alberta distribution utilities have superior performance as compared to the comparator group of U.S. distribution utilities.

168. The Commission encourages PEG to continue to refine its methodology, and to consider presenting benchmarking results for the next PBR term, which may be used to inform any stretch factor at that time. Further, the distribution utilities are encouraged to work with PEG to ensure PEG has the necessary information prior to any such filing. As well, in Section 11 of this decision, the Commission approves certain efficiency metrics for the distribution utilities and will monitor these metrics over the PBR3 plan. These metrics may further assist the Commission to determine, directionally, the need for one or more stretch factors in the next PBR plan.

8 Capital funding provisions

8.1 Approved capital funding

169. The Commission finds that supplemental capital funding, in addition to revenues provided under I-X and other available mechanisms (such as Y and Z factors) is required for the PBR3 term. This funding will consist of a K-bar and Type 1 capital tracker mechanisms, as well as alternative remuneration on a pilot basis.

170. K-bar funding will be based on the five-year average of the 2018-2022 actual capital additions and the calculation will include the customer growth escalator approved in PBR3 rebasing decisions in the place of the Q factor used in previous PBR terms and will use the X factor of 0.1 per cent. The Commission emphasizes that K-bar funding is not intended to provide funding for projects on a line-by-line basis, but rather is to supplement capital under the basic PBR I-X indexing mechanism as necessary to provide an envelope of funding for the management of business-as-usual activities with a reasonable opportunity to earn the approved rate of return.

171. The criteria for Type 1 capital tracker projects have been expanded from the criteria used in the PBR2 term to provide additional funding for expenditures directly caused by applicable law related to net-zero objectives and not otherwise funded by the PBR formula. The Commission additionally introduces an expanded accounting test to calculate the Type 1 capital tracker amount.

172. Applications will be accepted from distribution utilities to earn a return on operating solutions on a pilot basis when the operating solution is equally or more cost effective than a viable capital solution with similar outcomes.

173. This section relies extensively on the concepts and terminology used in setting supplemental capital provisions in the PBR1 and PBR2 plans. While this section provides some background, readers that are not familiar with capital funding provisions in prior generations of PBR in Alberta should refer to Appendixes 6 and 7 to this decision for an overview of capital funding mechanisms in PBR1 and PBR2 plans, definitions of relevant terms, and an explanation of calculation details for prior capital funding mechanisms.

174. The remainder of this section is organized as follows: in Section 8.2, the Commission confirms the need for supplemental capital funding in PBR3 and approves the continued use of K-bar funding and a Type 1 capital tracker mechanism, with some modifications to each. Section 8.3 discusses the K-bar mechanism for PBR3. Section 8.4 discusses the Type 1 capital tracker mechanism to be used in PBR3. Section 8.5 discusses a pilot alternative remuneration scheme approved by the Commission, and Section 8.6 discusses other capital funding proposals not adopted by the Commission.

8.2 Capital funding mechanisms to be used in PBR3

175. The Commission finds that supplemental capital funding is required for the PBR3 term when considering a number of factors, including jurisdictional comparisons and ensuring that the distribution utilities continue to have a reasonable opportunity to recover their prudent costs and earn a fair return.

176. In Decision 26356-D01-2021, the Commission concluded that capital funding provisions in PBR2, where all incremental funding was obtained through the K-bar mechanism, resulted in much stronger incentives to contain capital than in PBR1 because supplemental revenue was independent of utility costs. As well, these provisions resulted in significantly less regulatory burden because the amount of K-bar funding was developed formulaically each year and only required verification of certain assumptions and calculations. In this proceeding, parties generally supported this conclusion.[214]

177. With the exception of IPCAA, all parties pointed to the need for, and supported the continued use of, incremental capital funding mechanisms in PBR3. Parties generally supported the continued use of the Type 1 capital tracker mechanism for extraordinary capital additions and the K-bar mechanism for all other capital expenditures not qualifying for Y, Z or Type 1 treatment. However, parties differed in their proposals for the methodology to be used to set the amount of capital additions in K-bar and for the criteria used for Type 1 capital tracker funding.

178. The Commission heard in the past PBR proceedings that virtually every jurisdiction where PBR is in place has some form of supplemental capital provision due to the long-term, lumpy and cyclical nature of capital investments. Jurisdictional scans filed by parties in this proceeding confirm that this is still the case and that the funding mechanisms used by the Commission in prior PBR terms are consistent with mechanisms used in other jurisdictions.

179. The distribution utilities submitted that without K-bar funding in the PBR2 term, they would have generally struggled to achieve the approved rate of return of 8.5 per cent. Table 6 below shows distribution utility ROEs without K-bar funding in PBR2. In contrast, as shown in Table 1 from Section 2.3 of this decision, the actual ROEs (reflective of K-bar funding) were greater, and in some cases, significantly greater, than the approved return.

[214] Exhibit 27388-X0211, Fortis evidence, PDF page 25, paragraph 59; Exhibit 27388-X0212, EPCOR evidence, PDF page 18, paragraph 31; Exhibit 27388-X0570.01 PEG rebuttal evidence for the CCA, PDF page 61, paragraph 132.

Table 6. ROE without K-bar funding in PBR2[215]

Utility	2018	2019	2020	2021	2022F	PBR2 average
	(%)					
Fortis	4.41	4.89	4.87	1.50	0.44	3.22
ENMAX	4.51	6.18	6.21	3.67	2.14	4.54
ATCO Gas	8.04	7.59	7.09	6.46	8.83	7.60
ATCO Electric	7.74	9.53	7.63	8.36	6.78	8.01
EPCOR	7.86	7.45	6.64	4.50	2.09	5.71
Apex	3.66	4.89	2.30	2.30	0.88	2.81
Approved ROE	8.50	8.50	8.50	8.50	8.50	8.50

180. The Commission maintains the view, shared by parties in this proceeding, that although opportunities for improvement remained, capital funding provisions in PBR2 have worked reasonably well and placed the distribution utilities' capital expenditures under the high-powered incentives of K-bar and I-X, while allowing them a reasonable opportunity to recover prudent costs and earn the approved rate of return when considered in the context of the total PBR2 plan. Accordingly, the Commission agrees with the general view of parties in this proceeding that the PBR3 plan should continue to use the K-bar and Type 1 capital tracker funding mechanisms, with some adjustments as set out in the sections that follow.

181. Based on his comparison of net capital additions to depreciation expenses, D. Madsen for IPCAA suggested that incremental capital funding was not required for Fortis and ATCO Electric in PBR3.[216] The distribution utilities dismissed this analysis as inaccurate and too simplistic and argued that it did not account for multiple other parameters, such as retirements and net salvage, that are used in the calculation of revenue requirement for capital expenditures.[217] Dr. Brown pointed out that the K-bar calculation takes depreciation into account, along with other inputs; in other words, the K-bar calculation will ensure that the level of supplemental funding corresponds to the impact of the approved capital additions on the revenue requirement.[218]

182. The Commission agrees that the K-bar calculation will provide a more accurate assessment of each distribution utility's supplemental capital needs as the calculation considers all inputs to the revenue requirement calculation as compared to D. Madsen's simplified approach of comparing depreciation to net capital additions. If in fact, the funding from I-X applied to going-in rates is sufficient to cover the ongoing capital additions, this will result in a K-bar of zero, or possibly a negative K-bar amount, resulting in a reduction to revenue requirement and to customer rates.

215 Exhibit 27388-X0385, AllParties(EPC)-AUC2023FEB28-019(c), Attachment; Exhibit 27388-X0413, AllParties(EDTI)-AUC-2023FEB28-019(c), Attachment 1; Exhibit 27388-X0556, ATCO-AUC-2023APR11-005(d), Attachment 1; Exhibit 27388-X0506, AllParties(FAI)-AUC-2023FEB28-019(c), Attachment; Exhibit 27388-X0534, AllParties(Apex)-AUC-2023FEB28-019(c), Attachment.

216 Exhibit 27388-X0164, D. Madsen evidence for IPCAA, PDF pages 17-19.

217 Exhibit 27388-X0498, FAI-AUC-2023FEB28-003(a), PDF page 5; Exhibit 27388-X0587, ATCO Utilities rebuttal evidence, PDF pages 18-19, paragraphs 55-57.

218 Exhibit 27388-X0588, T. Brown rebuttal evidence for the ATCO Utilities and Apex, PDF page 45.

8.3 Funding for Type 2 capital in PBR3

8.3.1 Setting of K-bar

183. The Commission finds that in PBR3 K-bar should be calculated using a five-year average of 2018-2022 actual capital additions. The Commission further approves the use of a customer growth escalator in place of the Q factor and an X factor of 0.1 per cent in determining the K-bar amounts. In coming to these determinations, the Commission considered evidence on the use of historical averages versus forecasts of capital additions, the specific years to include in a historical average, and sufficiency of funding. Each of these considerations is discussed in further in this section.

184. In this proceeding, all parties generally supported the continued use of K-bar in PBR3. As well, subject to the discussion in Section 8.3.2, all parties were generally supportive of the mechanics of calculating the K-bar amount annually by means of the three-step accounting test employed in PBR2 (set out in Appendix 7 to this decision). However, parties differed in their preferred approaches to determining the amount of Type 2 capital additions on which K-bar is set.

185. By way of clarification, while K-bar is calculated based on net capital additions (net of retirements), for ease of reference, the Commission will simply refer to them as capital additions. Similarly, while approved groupings of capital projects were used for the purposes of capital tracker, K-bar and rebasing applications, in this section the Commission will simply use "capital projects" as a general term.

186. In the PBR2 plans, K-bar was set based on the four-year average of 2013-2016 actual capital additions (two-year average of 2015-2016 for ENMAX), converted to current year dollars using I-X and Q factors. In approving this formulaic approach to setting K-bar, the Commission indicated that it was aiming to reflect the years where PBR incentives were the strongest resulting in the greatest efficiencies and cost savings. As well, the Commission noted that reliance on a historical average is preferable to calculating incremental capital funding based on a distribution utility's capital forecast, because forecasts could be influenced by incentives inconsistent with those inherent to the PBR framework. Further, the Commission found that forecasts are less transparent, due to the asymmetric nature of the information available to parties and that there would be a significant regulatory burden in testing the forecasts.

8.3.1.1 Historical actuals versus forecasts

187. In this proceeding, EPCOR proposed that the K-bar funding in PBR3 should be based on five years of historical actual results, instead of four years as was done in the K-bar mechanism approved for PBR2.[219] The ATCO Utilities, Apex and Fortis proposed that K-bar should be set using forecasts, while ENMAX proposed that K-bar should be based on 2023 approved forecast capital additions. Interveners opposed these distribution utility proposals and argued in favor of continuing to set K-bar based on historical averages, as was proposed by EPCOR. Each of these proposals is discussed in more detail below.

188. The ATCO Utilities, Apex and Fortis proposed that distribution utilities should be allowed to forecast K-bar capital additions for projects where, in their view, a mechanistic escalation of historical actuals will not provide an adequate level of funding during the PBR3

219 Exhibit 27388-X0212, EPCOR evidence, PDF page 19.

term. These distribution utilities proposed a "hybrid K-bar" methodology that relies on a combination of mechanistic and non-mechanistic (i.e., traditional bottom-up) forecasts, similar to what was used in the 2023 COS rebasing proceedings.[220] [221]

189. All of the distribution utilities, except EPCOR, argued that relying exclusively on historical actuals to establish the capital additions for K-bar is a backward-looking approach that does not take into consideration the potential for projects within PBR3 for which historical actuals do not reasonably capture required additions. Further, these distribution utilities stated that this approach would not provide adequate funding for all projects approved in the 2023 COS rebasing proceedings. For example, Fortis stated that new projects approved in its 2023 forecasts will not be reflected in K-bar if it is based on historical capital additions. As a result, all distribution utilities other than EPCOR claimed that if the K-bar is based entirely on historical capital additions, it would leave the distribution utilities inadequately funded during the PBR3 term.

190. ENMAX proposed that K-bar be based on forecast capital additions approved in the 2023 COS rebasing proceedings as they "are more representative of anticipated capital additions for the PBR3 term." ENMAX added that these forecasts were tested and approved by the Commission.[222] Fortis and the ATCO Utilities similarly contended that if K-bar is based only on escalated historical capital additions, the K-bar funding in the PBR3 term will effectively ignore the non-mechanistic forecasts that were approved in the 2023 rebasing proceedings. In this regard, Fortis pointed out that several new projects received approval from the Commission to commence in 2023.[223] ENMAX pointed out that its five-year average of capital additions is $58 million less than forecast capital additions approved in the 2023 rebasing, and if K-bar is based on the average this will reduce available funding invalidating the objectives of rebasing to realign revenues and costs.[224]

191. On a related point, Fortis observed that in the rebasing proceedings, the Commission approved forecasts for a number of capital projects for which detailed business cases were provided that discussed an expenditure profile over the period from 2023 to 2028. This, in Fortis's view, provided support that the K-bar funding in 2024-2028 PBR3 plan should be based on these forecasts.[225] Similarly, the ATCO Utilities stated that because IPCAA did not object to ATCO Electric's multi-year grid modernization and wildfire protection programs in the rebasing proceeding, IPCAA should not object to the need for incremental funding in the present proceeding.[226]

192. Although EPCOR supported a K-bar set on historical actuals, it stated that K-bar provided adequate funding in PBR2 only "by happenstance," as it was only by chance that

[220] Under a mechanistic approach, the utilities forecast 2023 costs by calculating the average of actual 2018-2020 costs, and then restating that average in 2023 dollars by normalizing for inflation and system size using their I factor inflation and annual customer growth escalators. Under a non-mechanistic approach, the utilities forecast from the bottom up, which is the traditional way to forecast under COS regulation.

[221] Exhibit 27388-X0201, Apex evidence, PDF page 37, paragraph 117; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 39, paragraph 109; Exhibit 27388-X0211, Fortis evidence, PDF pages 25-26, paragraphs 61-63.

[222] Exhibit 27388-X0197, ENMAX evidence, PDF page 39, paragraph 69.

[223] Exhibit 27388-X0211, Fortis evidence, PDF pages 25-26, paragraph 63.

[224] Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-021(b), PDF pages 66-68.

[225] Exhibit 27388-X0211, Fortis evidence, PDF pages 25-26, paragraph 63.

[226] Transcript, Volume 11, page 2115, lines 1-11 (L. Smith).

EPCOR's circumstances in PBR2 reflected the historical data on which K-bar was set.[227] EPCOR stated that, with the exception of certain discrete categories of capital projects, circumstances in PBR3 would be similar to PBR2. Therefore, with an appropriately scoped Type 1 mechanism, EPCOR proposed that a K-bar mechanism based on historical data would provide sufficient funding in PBR3, and would result in reduced regulatory burden when compared to a K-bar that incorporates forecasts.[228]

193. Interveners argued against the use of forecasts. PEG for the CCA stated that if distribution utility forecasts are used when establishing the supplemental capital funding "utilities can use their superior understanding of the distribution utility business and their own operations to strategically exaggerate their capex needs."[229] PEG referenced decisions by regulators in California and Maine pointing to problems with relying on distribution utilities' forecasts in determining the amount of supplemental capital funding.[230] Both the CCA and the UCA took the position that if distribution utility forecasts are used to determine K-bar funding, it will allow the distribution utilities to leverage their information advantage and receive a capital funding envelope greater than what is actually needed.[231] The UCA added in argument that interveners can test and challenge the forecasts put forward by the distribution utilities, but the distribution utilities possess and maintain the underlying data that informs the forecasts and can decide how and when the data is presented.[232] IPCAA agreed with these concerns, stating that there was "significant risk where a distribution utility receives incremental capital funding based on a forecast"[233] and noted that this risk can be mitigated through the use of true-ups, or through restricting incremental capital funding to only extraordinary increases in capital needs.

194. In light of their concerns with over forecasting, the CCA and the UCA supported EPCOR's proposal for setting K-bar based on each distribution utility's average plant additions during PBR2.[234] Although IPCAA opposed the continued use of the K-bar mechanism, it indicated that if the Commission elects to continue to use K-bar in PBR3, it would prefer the use of historical averages as the K-bar inputs over the use of the 2023 forecast capital costs.[235]

195. The Commission shares the concerns of the representatives of customer groups regarding the introduction of forecasts to determine K-bar capital additions, especially those that rely on long-term forecasts over the entire PBR3 term and do not involve true-up. As discussed above, the use of forecasts introduces the risk of over-forecasting, and information asymmetry can make it difficult for the Commission to assess and test forecasts without significantly increasing regulatory burden. In Decision 20414-D01-2016 (Errata), the Commission expressly rejected calculating PBR2 K-bar capital additions based on distribution utility forecasts because it was concerned with creating problematic incentives contrary to the intent of PBR. The Commission continues to hold this view.

227 Exhibit 27388-X0212, EPCOR evidence, PDF page 29, paragraph 43.
228 Exhibit 27388-X0212, EPCOR evidence, PDF page 30, paragraph 46.
229 Exhibit 27388-X0231, PEG evidence for the CCA - Gas, PDF page 74.
230 Exhibit 27388-X0231, PEG evidence for the CCA - Gas, PDF pages 84-85.
231 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-020(a), PDF pages 55-56; Exhibit 27388-X0440, AllParties(UCA),-AUC-2023FEB18-020(a) and (b), PDF pages 44-45.
232 Transcript, Volume 10, page 1877, lines 4-9 (K. Rutherford).
233 Exhibit 27388-X0368, AllParties(IPCAA)-AUC-2023FEB28-020(a), PDF page 43.
234 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB 28-020(c), PDF page 56; Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-020(c), PDF Page 45.
235 Exhibit 27388-X0368, AllParties(IPCAA)-AUC-2023FEB28-020(c), PDF pages 43-44.

196. The distribution utilities' main response to the concerns raised by the interveners was that the Commission and interveners will have the opportunity to test the forecasts and the Commission can deny or adjust them if it finds that forecasts are not reasonable. Dr. Weisman, on behalf of EPCOR, suggested that distribution utilities would be incented to maintain credibility with their regulator, which would partially mitigate the challenges of information asymmetry.[236] The Commission agrees with the UCA's view that the ability to test a forecast does not fully mitigate the risk associated with the distribution utility's inherent information advantage. The effectiveness of the testing is hampered by this information advantage.[237] Furthermore, unlike in the COS proceeding where the forecasts are commonly approved for the period of one to two years, with three-year forecasts being less common, forecasting for K-bar purposes would be for a five-year term. As mentioned in PEG's evidence, other regulators have acknowledged the same hesitancies regarding the approval of long-term forecasts; for example, the Maine Public Utilities Commission was not persuaded that it should approve a six-year capital forecast as it introduced a level of predictive uncertainty into the ratemaking process that was found to be unacceptable.[238] The Commission shares this view.

197. Introducing a true-up, as suggested by the CCA,[239] may mitigate concerns with over-forecasting but would, in turn, result in additional regulatory burden to verify the prudence of actual costs. Equally concerning, forecasts with a true-up are imbued with COS incentives because in such a case the revenue provided under K-bar would reflect the actual incurred costs of the distribution utilities. This would significantly dampen the incentive for distribution utilities to pursue efficiencies given that the majority of capital will be subject to such K-bar.

198. In the PBR3 rebasing proceedings, the Commission approved capital forecasts that were developed for a single year. Although some of the business cases discussed expenditures for multi-year projects, the distribution utilities requested and received approval for a forecast revenue requirement only for the 2023 test year.[240] As such, the Commission does not share the view expressed by some distribution utilities that the approval of 2023 forecasts for certain multi-year projects extends to the approval of all years of forecast costs for those projects. Similarly, the Commission does not consider that the approval of a hybrid forecasting methodology (consisting of mechanistic and traditional forecasts) for the purposes of the PBR3 rebasing has any bearing to setting K-bar for the 2024-2028 term, as that forecast methodology was specific to the 2023 COS rebasing year.

199. The Commission acknowledges that ENMAX's proposal to use 2023 approved forecast capital additions for the K-bar calculation does not result in the same concerns as would be the case if it used the 2023 approved forecast, escalated to current year dollars, in each year of the PBR3 term, without any ability for a distribution utility to modify that forecast. However, this approach is inferior to EPCOR's approach of using a five-year average of actual capital additions because of the fluctuations and idiosyncrasies that could be embedded in any single year.

236 Transcript, Volume 5, page 787, lines 2-25 to page 788, line 1.
237 Transcript, Volume 10, page 1877 (K. Rutherford).
238 Exhibit 27388-X0231, PEG evidence for the CCA - Gas, PDF page 85.
239 Exhibit 27388-X0569, J. Thygesen rebuttal evidence for the CCA, PDF page 26, paragraph 96.
240 Proceeding 26615, Exhibit 26615-X0031, Fortis evidence, PDF page 6, paragraph 4; Proceeding 26615, Exhibit 26615-X0023, ATCO Electric evidence, PDF page 9, paragraph 7; Proceeding 26616, Exhibit 26616-X0018, ATCO Gas evidence, PDF page 9, paragraph 7, and Exhibit 26616-X0023, Apex evidence, PDF page 7, paragraph 5; Proceeding 26617, Exhibit 26617-X0022, ENMAX evidence, PDF page 14, paragraph 4, and Exhibit 26617-X0046.01, EPCOR evidence, PDF page 10, paragraph 2.

Further, since historical capital additions represent the actual costs that were incurred under the high-powered incentives of K-bar in PBR2, a five-year average of actual capital additions will ensure that the K-bar funding in PBR3 is reflective of the achieved efficiencies in PBR2.

200. For these reasons, the Commission rejects the proposals of the ATCO Utilities, Apex and Fortis to allow the distribution utilities to forecast capital additions for certain projects under K-bar. The Commission accepts the proposals of EPCOR, the CCA, the UCA and IPCAA to base the capital additions for the PBR3 K-bar on the five-year average of 2018-2022 actual capital additions made under the full incentives of the PBR2 plan. Doing so maximizes the incentive power of the PBR3 regime as any supplemental capital funding provided by the K-bar mechanism will provide an envelope of funding that is not dependent on distribution utilities' forecasts nor on their actual costs incurred in PBR3. If the distribution utilities incur capital additions at lower levels than the 2018-2022 historical average, and/or optimize their capital and O&M spend, all else being equal, they will be able to achieve higher earnings.

201. The Commission does not, however, subscribe to Dr. Weisman's view that K-bar can be equated to a mechanistic forecast which uses the past expenditures to forecast the future,[27] nor does it agree with the distribution utilities that a K-bar based on average historical expenditures is "backward looking" and will not allow them to engage in new activities. Rather, in the Commission's view, K-bar provides an envelope of funding that is based on the assumption that it is reasonable to expect that the distribution utilities will be able to manage their business-as-usual capital activities and have a reasonable opportunity to earn an approved rate of return, if they are provided with a level of supplemental capital commensurate with their actual experience during the prior PBR term. Based on the results of the PBR2 term, the Commission concludes that such assumption is reasonable. Further, as discussed in Section 8.4.2, the distribution utilities acknowledged that there is uncertainty regarding the timing required to respond to net-zero objectives. Should changes in regulation drive electrification faster than expected such that I-X and K-bar provide insufficient capital for these activities, funding may be available through the Type 1 capital tracker mechanism discussed below.

8.3.1.2 Years to include within historical actuals

202. Regarding the specific years that should be used in the K-bar calculation, EPCOR proposed that the K-bar funding in PBR3 should be based on five years of historical actual capital additions (i.e., 2018-2022) given that 2022 actual results will be available in time to be included in the K-bar calculation.[28] Dr. Lowry and R. Bell both agreed with this approach and R. Bell added that because capital additions can vary from year to year, it is best to use an average of the costs over the entire PBR term.[29] In their evidence, the ATCO Utilities suggested that the majority of capital costs in the PBR3 term could be forecast using a mechanistic approach and that a 2018-2020 escalated average of actual additions should be used, which is the same period that was used to establish the mechanistic forecasts in the 2023 COS year.[30]

203. For the same reasons of maximizing incentives, by reflecting the distribution utilities' actual performance over the PBR2 term, which smooths out any one-time expenditures specific to any given year, the Commission finds that using a five-year average is preferable to using a four-year average as was done in PBR2, and is also preferable to using the three-year average as proposed by some distribution utilities for projects with mechanistic forecasts under the hybrid K-bar proposal. As an additional note, the Commission did not include capital additions for 2017 (the fifth year of the PBR1 plan) in PBR2 K-bar because it was concerned that doing so may create an incentive for the distribution utilities to increase capital spending in that year, given

that Decision 20414-D01-2016 (Errata) on the parameters of PBR2 was issued prior to 2017. The same concern is not present here given that the PBR2 term ended in 2022.

204. The Commission has also considered whether to include the 2023 approved forecasts in the average capital additions on which K-bar is based but has decided against it for the same reason of maximizing the incentive properties of PBR by reflecting the distribution utilities' actual performance over the PBR2 term. Even though the 2023 rebasing was not a traditional full COS review because it relied on the mechanistic approach for many capital projects, it was conducted to realign revenues with costs. This involved a review of traditional forecasts for other capital projects. In the Commission's view, the incentives for the distribution utilities to find efficiencies in the single 2023 COS year will not be as strong as they were during the PBR2 term.

8.3.1.3 Sufficiency of funding

205. With regard to the distribution utilities' concern that a K-bar based on historical actuals will result in insufficient funding, the Commission notes that the 2023 capital costs approved in the PBR3 rebasing are reflected in the PBR3 going-in rates. K-bar provides supplemental capital funding *in addition* to the revenue provided under the going-in rates as escalated by I-X. It is, in fact, a relatively small component of the total revenue obtained under the PBR formula, with the majority of revenues coming from the going-in rates escalated by I-X in every year of the PBR term. For example, according to ENMAX's 2021 annual rates application, base PBR revenue amounted to $225 million, while K-bar amounted to only $27 million.[241] Furthermore, the distribution utilities agreed that, although not included in the five-year average, the 2023 approved forecast capital additions are present in the K-bar calculation as they are included in the going-in rate base. As well, as explained in Decision 22394-D01-2018, the annual K-bar calculation method ensures that the full-year capital additions approved in 2023 are captured in K-bar, with accurate associated depreciation.[242]

206. More importantly, however, K-bar funding is not intended to provide funding on a line-by-line basis for each individual project. As set out in Decision 20414-D01-2016 (Errata), in approving capital funding approach for the Type 2 capital, the Commission opted for a regulatory approach that was different from a COS-type project-by-project forecasting exercise. Instead, the approved K-bar approach provides the distribution utilities with a predetermined amount of incremental capital funding for the PBR term. The distribution utilities are expected to manage their capital programs within the capital funding constraints of the amounts provided.[243] Further, and consistent with the overall intent of PBR to manage costs on a holistic basis, the distribution utilities have the flexibility to use funding provided under K-bar for any capital project or even to divert it to O&M activities, as ATCO Electric did in PBR2.[244] The Commission expects that distribution utilities will continue to seek out ways to decrease costs through optimization of their existing assets, whether through implementation of non-wires solutions and operating solutions, and through modernization and automation of their systems.

[241] Proceeding 25865, Exhibit 25865-X0007, Appendix 5- Rate Schedules, Schedule 1.0.
[242] Decision 22394-D01-2018: Rebasing and Setting the Going-In Rates for the 2018-2022 PBR plans for Alberta Electric and Gas Distribution Utilities, First Compliance Proceeding, Proceeding 22394, February 5, 2020, PDF page 62, paragraphs 212-213.
[243] Decision 20414-D01-2016 (Errata), PDF page 59, paragraph 189.
[244] Proceeding 26615, Exhibit 26615-X0023, ATCO Electric Cost of Service Application, PDF page 12, paragraph 20.

207. In this regard, the Commission was not persuaded by Dr. Brown's view that the fair return standard applies at a project-by-project level such that each individual project undertaken by a utility would require funding to meet the fair return standard.[245] Dr. Brown's approach ignores that a PBR plan provides an overall funding envelope to the distribution utilities to operate their businesses and to allocate that funding as they see fit to meet their business needs.[246] Dr. Brown's approach also creates asymmetry such that a utility could retain the PBR benefits of decoupling of costs and revenues when revenues significantly exceed costs, but resile from that decoupling any time the reverse circumstance occurs. Finally, in his oral testimony Dr. Brown did not appear to have the correct understanding of the fair return standard, as that standard is applied on a total enterprise basis.[247]

208. While Fortis pointed out that there were new projects approved for 2023 that would not be reflected in the historical average, J. Thygesen noted that savings from previous PBR terms weren't considered in the calculation of supplemental capital.[248] In addition, the Commission is confident that the distribution utilities will continue to find cost-efficiencies due to the high-powered incentives of K-bar and will be able to offset any increased capital funding needs by realizing efficiencies in other areas, whether capital or O&M. From this perspective, the Commission does not agree with EPCOR that K-bar provided sufficient funding by happenstance. As EPCOR's own expert Dr. Weisman noted, "K-bar seems to have worked in precisely the way the Commission intended" by strengthening the incentives for capital cost management,[249] and it appears that EPCOR has responded to those incentives and managed its costs within the funding envelope provided by the PBR formula. Indeed, in PBR2, several distribution utilities spent less on capital than the average historical capital additions assumed in the K-bar mechanism. This behaviour is in line with expectations for efficient companies and reflects part of the competitive mindset that should result from the operation of PBR plans.

209. The Commission observes that for many distribution utilities, the actual spend was less than was provided under PBR formula (inclusive of I-X and K-bar). Further, as shown in Table 1 in Section 2.3 of this decision, with the exception of ENMAX, all distribution utilities were able to earn a return above, and in some cases, significantly above the approved ROE in almost all years of PBR2. This further demonstrates that the overall PBR2 plan provided sufficient funding to distribution utilities, including funding from K-bar based on escalated historical capital additions.

210. Even in ENMAX's case, its average return over the PBR2 term was 7.9 per cent. Experts in this proceeding agreed that it is normal for achieved returns to fluctuate around the approved level during the PBR term.[250] Further, as none of the distribution utilities have provided a quantification of the efficiencies realized in PBR2, the Commission finds that it is difficult to

245 Transcript, Volume 3, page 369, lines 11-14.

246 For example, utilities are able to shift funding from operations expenses to capital investment or vice versa as circumstances require.

247 The fair return standard analysis considers a fair return on the equity component of invested capital in a regulated utility, according to three well established factors – "comparable investments," "capital attraction" and "financial integrity,": *Northwestern Utilities Ltd. v. Edmonton (City)*, 1929 CanLII 39 (SCC), [1929] S.C.R.186.

248 Transcript, Volume 8, page 1463, lines 6-19 (J. Thygesen).

249 Exhibit 27388-X0567, D. Weisman rebuttal evidence for EPCOR, PDF page 24, paragraph 71.

250 Transcript, Volume 5, page 884, lines 18-15, page 903, lines 21-25 and page 904, lines 1-2 (Dr. Weisman); Transcript, Volume 10, page 2004, lines 6-11 (J. Wachowich); Transcript, Volume 4, page 709, lines 20-23 (A. Goulding); Transcript, Volume 8, page 1458, lines 5-16 (Dr. Lowry).

confirm whether ENMAX's comparatively lower earnings were a result of underfunding, or a result of a failure to respond to the incentives of PBR to realize business efficiencies.

211. Regarding ENMAX's concern that using a five-year average will once again leave it inadequately funded, the Commission reiterates the point it made earlier that the 2023 rebasing provided a re-set for all distribution utilities and ensured the 2023 approved rates recover the approved forecast costs and that all distribution utilities have a reasonable opportunity to earn the approved rate of return. These rates will also serve as going-in rates for the PBR3 term. Further, the K-bar capital funding in PBR3 will be based on five years of actual expenditures as compared to just two years (2015 and 2016) for ENMAX thus capturing the years where ENMAX may have spent more on capital than was provided under the I-X and K-bar. In the Commission's view, the rebasing reset, combined with K-bar based on five years of actual expenditures under PBR2, along with other elements of the PBR3 plan will provide all distribution utilities, including ENMAX, with a reasonable opportunity to recover prudent costs and earn the approved return in PBR3.

8.3.2 Other parameters of the K-bar calculation

212. For the reasons set out below, the Commission approves the use of a customer growth escalator in place of the Q factor in the K-bar calculation. The Commission also clarifies that an X factor of 0.1 per cent, not including the addition of the benefit-sharing premium, must be used in the K-bar accounting test.

213. Throughout the proceeding, the Commission explored changes to the K-bar calculation, such as (i) using the customer growth escalator instead of the Q factor in the K-bar calculation based on the assumption that the customer growth escalator better captures the change in the electric distribution utilities' required capital investment; (ii) reducing the K-bar funding by a predetermined percentage value; and (iii) excluding specific capital projects or programs that were included in the K-bar calculation in PBR2 to more closely align with the capital funding that is provided in other jurisdictions.[251] Each of these is addressed in turn below. An explanation of the K-bar calculation can be found in Appendix 7.

8.3.2.1 Customer growth or Q factor

214. The Q factor performs two distinct functions in the K-bar calculation also referred to as the "accounting test." In the first step of the K-bar calculation, the Q factor captures the effect on I-X revenue of changes in billing determinants. In the second step, the Q factor is used to escalate historical average capital additions to current year values. In the PBR2 term, the electric distribution utilities used a Q factor that was calculated as the year-over-year change in revenue due to overall changes in forecast billing determinants across all rate classes and components, including energy, demand and number of customers.[252] The gas distribution utilities used a Q factor that was based on the number of customers.[253]

215. The ATCO Utilities and Fortis proposed using the customer growth escalator that was approved in the rebasing proceedings (namely, the annual change in the average customer count

[251] Exhibit 27388-X0231, PEG evidence for the CCA, PDF page 110; Exhibit 27388-X0569, J. Thygesen rebuttal evidence for the CCA, PDF page 16, paragraph 54; Exhibit 27388-X0498, FAI-AUC-2023FEB28-001, PDF pages 1-2.

[252] Exhibit 27388-X0498, FAI-AUC-2023FEB28-001(b), PDF pages 1-2.

[253] Transcript, Volume 2, pages 244 and 336.

reduced by 15 per cent), rather than using the Q factor, for the purposes of calculating the K-bar capital additions in step 2 of the accounting test.[254] Fortis stated that since its capital revenue requirement is largely premised on the investment required to service new customer sites and the accompanying investment required for the overall customer base, customer growth is a better representation of the change in its required capital investments.[255] Fortis added that customer growth is a more accurate proxy for the expected growth in total costs noting that the Q factor value was negative twice during the PBR2 term, which was not consistent with its experienced growth in system capacity requirements.[256] While Fortis proposed that the Q factor be used in step one of the accounting test and the customer additions growth factor be used in step two, it recommended using only the customer growth escalator if the Commission preferred to use a single escalator in both steps of the accounting test.[257] Similarly, the ATCO Utilities suggested that using the customer growth escalator is a more principled approach to escalate K-bar additions in relation to the growth of the system.[258]

216. ENMAX and EPCOR agreed that there must be an escalation factor within the K-bar formula to account for the incremental revenue needed to address system growth; however, they were in favour of the continued use of the Q factor as it is a simple approach to account for the growth in the distribution system over time.[259] Dr. Lowry also agreed that the K-bar calculation should include a provision for the billing determinant or customer growth,[260] but added that the escalator used should match the PBR plan, meaning that if a utility is regulated under a price cap plan, that utility should use the Q factor, and if a utility is regulated under a revenue-per-customer cap, the customer growth escalator should be used.[261]

217. As mentioned previously in this section, the Q factor for gas distribution utilities under the revenue-per-customer cap plan was calculated based only on the number of customers and does not include other billing determinants.[262] The Commission finds merit in the proposal of the ATCO Utilities and Fortis to use the same approach for electric distribution utilities as well. This proposal was explored throughout the proceeding. In undertaking responses, each of the electric distribution utilities filed calculations demonstrating how the use of customer growth escalator approved in the PBR3 rebasing decisions in place of the Q factor would have impacted K-bar funding in PBR2.[263] While the undertakings showed that the use of customer growth escalator rather than the Q factor would have resulted in a relatively minor difference in K-bar over the entire PBR2 term,[264] the Commission finds that customer growth escalator is more indicative of changes in distribution utility costs as compared to the Q factor that captures changes in all billing determinants, including energy usage and customer demand. As was recognized in the rebasing decisions, utilities incur additional costs to connect new customers and changes in

254 Exhibit 27388-X0211, Fortis evidence, PDF pages 25-26, paragraph 62; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 39, paragraph 110; Exhibit 27388-X0438, ATCO-AUC-2023FEB28-012, PDF pages 40-41; Exhibit 27388-X0498, FAI-AUC-2023FEB28-001, PDF pages 1-2.
255 Exhibit 27388-X0498, FAI-AUC-2023FEB28-001(b), PDF pages 1-2.
256 Transcript, Volume 9, pages 1783-1784 (B. Hunter).
257 Transcript, Volume 6, page 1012 (A. Johnson).
258 Transcript, Volume 2, page 167 (J. Bagnall).
259 Transcript, Volume 4, pages 556-560; Transcript, Volume 5, page 794.
260 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-022.
261 Transcript, Volume 7, page 1353 (Dr. Lowry).
262 Transcript, Volume 2, pages 244 and 336.
263 Exhibit 27388-X0674, ATCO Utilities undertaking 3; Exhibit 27388-X0678, EPCOR undertaking 2; Exhibit 27388-X0691, ENMAX undertaking 3; Exhibit 27388-X0701, Fortis undertaking 2.
264 Exhibit 27388-X0675, ATCO Utilities undertaking 3 attachment 1.

energy throughput have little bearing on distribution utility costs; however, the relationship between customer growth and utility costs is not one-to-one, with economies of scale being one reason for this. As such, the Commission directs the distribution utilities (both electric and gas) to use customer growth, reduced by 15 per cent as per Decision 26615-D01-2022 and Decision 26616-D01-2022,[265] in place of the Q factor in the K-bar calculation.

218. The Commission recognizes that this change will result in a less precise calculation in Step 1 of the K-bar accounting test of the amount of revenue that electric distribution utilities receive from I-X under the price cap plan. However, in the Commission's view, this loss of precision is justified given the more accurate escalation of capital additions in Step 2 of the K-bar accounting test.

8.3.2.2 X factor in the accounting test

219. In its evidence for the CCA, PEG proposed that K-bar calculations should exclude the stretch factor.[266] The distribution utilities disagreed with such an adjustment noting that it would overstate the revenue provided under I-X in step 1 of the accounting test and that it would result in "an unjustified double-counting of stretch in the calculation of available K-bar funding."[267]

220. The Commission sees merit in PEG's proposal on a conceptual basis because mathematically, the addition of a stretch factor increases the overall value of the X factor, which in turn increases the K-bar amount due to the workings of the accounting test.[268] From that perspective, K-bar largely offsets the intention of a stretch factor (which is to restrain the rate at which customer rates increase over the PBR term). However, in the Commission's view, this reasoning can be equally applied to the X factor (both industry TFP growth and stretch). Yet, Dr. Lowry only recommended that the stretch component of the X factor be removed from the K-bar calculation.[269] Given that the Commission approved an X factor of 0.1 per cent consisting of both industry TFP growth and stretch, the Commission is not prepared, for the purposes of this decision, to remove an X factor of 0.1 per cent from the K-bar calculation.

221. However, the Commission wishes to clarify that an X factor of 0.1 per cent, exclusive of the benefit-sharing premium (i.e., the X factor premium), must be used in the K-bar accounting test. As explained in Section 9.2.2, although mechanically an X factor premium functions in similar fashion to a stretch factor, it has a different rationale, which is to share additional benefits with customers over the PBR3 term. If an X factor reflective of a benefit-sharing premium is included in the K-bar calculation, the workings of the accounting test would increase the K-bar amount with the paradoxical result that such increase to K-bar would, for the most part, offset the

265 Decision 26615-D01-2022, PDF pages 33-34, paragraph 124; Decision 26616-D01-2022, PDF page 32, paragraph 129.

266 Exhibit 27388-X0231.01, PEG evidence for the CCA - Gas, PDF page 109.

267 Exhibit 27388-X0531, AllParties(APEX)-AUC-2023FEB28-021(b)(iii); Exhibit 27388-X0500, AllParties(Fortis)-AUC-2023FEB28-021(b)(iii); Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-021(b)(iii); Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-021(b)(iii); Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-021(b)(iii).

268 Similar to the discussion on the effect of the Q value, an X factor performs two distinct functions in the K-bar accounting test. In the first step of the accounting test, an X factor determines the amount of revenue provided under I-X – that is, a higher X factor will result in lower revenue and a lower X factor will result in a higher revenue. In the second step, an X factor is used to escalate historical average capital additions to current year values. The effect of an X factor in the first step of the accounting test outweighs the effect of it in the second step by an order of magnitude.

269 Transcript, Volume 7, page 1350, lines 1-17.

rate reduction implied by the X factor premium benefit-sharing provision. As such, the distribution utilities are directed not to include the X factor premium in their K-bar calculations.

8.3.2.3 Removing projects from K-bar

222. In his evidence for the CCA, J. Thygesen proposed to remove certain capital projects from the K-bar calculation so that it more closely aligns with funding provided in other jurisdictions. The distribution utilities opposed the adoption of single elements from other jurisdictions' PBR plans explaining that "to adopt one component of another jurisdiction's PBR plan requires an understanding of the various other elements of that plan."[270] The Commission agrees with the distribution utilities that it is uncertain to what extent J. Thygesen ascertained the totality of capital funding in other PBR plans and rejects J. Thygesen's proposal.

8.4 Funding for Type 1 capital

223. The Commission finds that it will continue to use a Type 1 capital tracker mechanism for extraordinary expenditures. The Commission expands the criteria used in the PBR2 plan to provide for funding for capital directly caused by applicable law related to net-zero objectives. Further, the Commission introduces an expanded accounting test to calculate the Type 1 capital tracker amount.

224. In coming to these decisions the Commission considered the performance of the Type 1 capital tracker in past PBR plans, expenditures eligible for Type 1 funding, and funding for expenditures directly caused by applicable law related to net-zero objectives. Each of these considerations is discussed in the sections that follow.

225. With the exception of IPCAA,[271] all parties generally agreed with the continued use of Type 1 capital tracker funding in PBR3, although they differed on their proposals for the projects that should qualify for Type 1 funding and the corresponding criteria that should be used to determine eligibility.

226. All distribution utilities suggested that changes to the criteria for Type 1 capital were required for the PBR3 term. They argued that the Type 1 capital tracker criteria used in PBR2 were too strict and should be expanded. In addition, the distribution utilities stated that changes in policy related to net-zero objectives would drive the need for additional expenditures that would not be reflected in K-bar. In its evidence, ENMAX stated "there is no value in an incremental capital funding mechanism that is not attainable"[272] and pointed to the fact that no projects qualified for Type 1 funding during the PBR2 term as evidence that the existing Type 1 criteria should be modified for PBR3. The other distribution utilities and their experts put forward similar arguments.

227. IPCAA opposed the introduction of supplemental capital funding beyond K-bar for ATCO Electric and Fortis, on the basis that it would erode the incentive properties of PBR.[273] The UCA and the CCA supported continued use of the Type 1 funding mechanism, but opposed changing the eligibility criteria from the criteria used in PBR2. J. Thygesen for the CCA took the stance that there was little support for the need for additional funding, beyond K-bar, in PBR3

[270] Transcript, Volume 9, page 1637, lines 14-19.
[271] Transcript, Volume 9, page 1828, lines 13-22.
[272] Exhibit 27388-X0197, ENMAX evidence, PDF page 35, paragraph 84.
[273] Transcript, Volume 9, page 1828, lines 19-22.

and argued against any changes to the Type 1 eligibility criteria.[274] The UCA highlighted that the distribution utilities' claims that changes to the Type 1 funding mechanism are required for PBR3 are undermined by the fact that the majority of distribution utilities were able to earn above their approved rate of return in PBR2, without any Type 1 funding.[275]

228. The Commission does not find persuasive the distribution utilities' argument that the fact that no projects qualified for Type 1 funding in PBR2 should be taken as evidence that the funding mechanism is flawed. In the Commission's view, the mechanism worked as intended by restricting funding only to projects of an extraordinary nature as defined in Decision 20414-D01-2016 (Errata). The Commission extensively evaluated the two applications for Type 1 funding made during PBR2,[276] and determined that neither met the Type 1 criteria in place for PBR2, and therefore no Type 1 funding was awarded.

229. Given that the Type 1 capital tracker mechanism worked as intended in PBR2, and parties' general support for this safety mechanism to deal with capital additions of extraordinary nature, the Commission will continue the use of a Type 1 capital tracker funding mechanism in PBR3. The Commission acknowledges the interveners' concerns that capital funded under the Type 1 capital tracker mechanism does not have the same strong incentives as Type 2 capital funded under the general envelope of funding provided by I-X together with the supplemental K-bar funding. However, as stated in Decision 20414-D01-2016 (Errata), the Commission continues to be of the view that dividing capital into Type 1 and Type 2, with limited eligibility for extraordinary expenditures under Type 1 funding, strikes an optimal balance between maximizing the incentives of the plan and ensuring that an undue level of risk is not imposed on the distribution utilities.

230. Based on the considerations discussed further in this section, the Commission determines that it will expand the Type 1 criteria to provide additional funding for expenditures directly caused by applicable law related to net-zero objectives, and not otherwise funded by the PBR formula. Specifically, the Commission establishes the following criteria for Type 1 funding in PBR3:

(i) The project must be extraordinary and not previously included in the distribution utility's rate base.

(ii) The project must be required by a third party, or otherwise directly caused by applicable law related to net-zero objectives.

(iii) The project cost must have a material effect on the distribution utility.

231. To demonstrate how it arrived at these determinations, the Commission will first consider what types of expenditures will be eligible for Type 1 funding in PBR3, before discussing parties' recommendations regarding the criteria to be used.

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274 Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF page 50, paragraphs 137-139.
275 Transcript, Volume 10, page 1884, lines 8-14 (K. Rutherford).
276 Decision 26589-D01-2021, Type 1 Capital Tracker – Green Line Light Rail Transit Project, Proceeding 26589, November 24, 2021; Decision 25608-D01-2020, AltaGas Utilities Inc. Type 1 Capital tracker true-up – Etzikom Lateral Project, Proceeding 25608, October 16, 2020.

8.4.1 Expenditures not eligible for Type 1 funding

232. It is important to clarify the intent behind the Type 1 and Type 2 capital funding mechanisms established in Decision 20414-D01-2016 (Errata), in addition to other sources of funding available under the PBR formula. The majority of funding for capital additions is provided from base PBR rates indexed by I-X each year. The Z factor provides funding for both capital and O&M expenditures associated with exogenous events outside of the control of the distribution utility. Although Y factor funding is typically provided for expenses that are flowed through to customers, it can be used for capital additions incurred at the direction of the Commission, such as Apex's Natural Gas Settlement System Code (NGSSC) project.

233. With this general framework in mind, for purposes of establishing supplemental capital funding in PBR2, the Commission divided capital into two types. It approved the Type 1 capital tracker mechanism for extraordinary capital additions and the K-bar mechanism for all other capital expenditures not qualifying for Y, Z or Type 1 treatment, as further described in Appendix 6.

234. As stated in the previous section, parties differed in their views on what capital projects should be eligible for Type 1 funding in the PBR3 plan. The distribution utilities stated that changes in policy related to net-zero objectives would drive the need for additional expenditures that would not be reflected in K-bar. Many distribution utilities were also of the view that the criteria should be broadened to include more typical projects which were not extraordinary and were previously included in a distribution utility's rate base.

235. ENMAX specifically supported criteria that would require applicants to demonstrate why an investment is extraordinary,[277] while Fortis[278] and the ATCO Utilities[279] suggested that any project not included in K-bar should qualify for funding, provided the accounting test is used, and distribution utilities can demonstrate the need for the expenditure. The ATCO Utilities[280] and Apex[281] argued that Type 1 capital funding should be available for projects that are unknown at the time of setting PBR, or which have insufficient certainty on need, scope timing and/or cost at the outset of the plan to be included in K-bar. They later clarified that this would mean that any project not funded by K-bar would be eligible for Type 1 funding.[282] Fortis likewise proposed that any projects not incorporated into K-bar that have an established need should be eligible for Type 1 funding.[283] Fortis also proposed the introduction of a Major Projects Funding Supplement (MPFS),[284] which is discussed in Section 8.6 below.

236. The UCA highlighted that the vast majority of distribution utilities were able to earn at or above their allowed ROE in PBR2, without receiving Type 1 funding.[285] The UCA argued that this demonstrated the Type 1 criteria used in PBR2 were not too strict, but rather worked as intended. It argued that any revisions to Type 1 criteria should be strict enough to ensure that

277 Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-023(h)(iii), PDF page 80.
278 Exhibit 27388-X0500, AllParties(Fortis)-AUC-2023FEB28-023(h)(iii), PDF page 70.
279 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-023(h)(iii), PDF pages 123-124.
280 Exhibit 27388-X0221, ATCO Utilities evidence, PDF pages 36-37, paragraph 102.
281 Exhibit 27388-X0201, Apex evidence, PDF page 38, paragraph 122.
282 Transcript, Volume 1, page 164, lines 7-10 (T. Brown).
283 Exhibit 27388-X0211, Fortis evidence, PDF page 31, paragraph 81.
284 Exhibit 27388-X0211, Fortis evidence, PDF page 27, paragraphs 66-67.
285 Transcript, Volume 10, page 1884, lines 8-14 (K. Rutherford).

distribution utilities are incented to operate within the envelope of funding provided at the outset of PBR3.[286]

237. Similar to the conclusions in Decision 20414-D01-2016 (Errata), the Commission is not persuaded that there is a need to expand the criteria to provide additional funding for projects previously included in the distribution utility's rate base. As further discussed in this section, the fact that a particular project may not be funded under I-X and K-bar, does not automatically, in an of itself, qualify it as extraordinary. As also discussed in Section 8.3, the distribution utilities are expected to manage their total capital and O&M costs as a whole, rather than request incremental funding for individual projects. The distribution utilities demonstrated in PBR2 that they can successfully do so.

238. As was noted by the UCA, and as shown in Table 1, distribution utilities were generally able to earn above the approved rate of return in PBR2 in the absence of any Type 1 funding. Apart from the possibility of incurring additional expenditures directly caused by applicable law related to net-zero objectives, which will be addressed through expanded Type 1 criteria, the Commission is not persuaded that the distribution utilities' business activities will change significantly and in such a way as to require more funding in PBR3.

8.4.2 Funding for expenditures related to net-zero objectives

239. In this proceeding, the Commission sought input from parties on how to fund expenditures related to the integration of more renewable energy sources onto electric distribution systems, electrification, emissions reductions initiatives and hydrogen-related initiatives. In their submissions, parties also used the terms "greening of the grid," "decarbonisation" and "energy transition" to refer to these initiatives.

240. The UCA and the CCA argued that offering additional funding in PBR3 for net-zero objectives would be premature given uncertainties regarding the timing and impacts of net-zero and grid modernization initiatives.[287] J. Thygesen for the CCA suggested that net-zero objectives would not drive the need for additional capital funding in PBR3, arguing there are no explicit Commission-directed goals or targets for energy efficiency or renewable energy.[288] In addition, J. Thygesen argued that the distribution utilities had been completing grid modernization activities under the past PBR terms without additional funding, and the distribution utilities have not demonstrated that upcoming grid modernization activities will be a material departure from past practices.[289]

241. The distribution utilities took the stance that incremental funding would be required to support net-zero-related expenditures. Apex highlighted the potential for changes in legislation related to hydrogen blending,[290] while ENMAX[291] and Fortis[292] highlighted the potential grid impacts of electrification and the increasing adoption of Distributed Energy Resources (DERs).

[286] Transcript, Volume 10, page 1885, lines 5-10 (K. Rutherford).
[287] Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-023(c) and (d), PDF page 54.
[288] Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF page 50, paragraphs 137-138.
[289] Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF page 50, paragraph 137.
[290] Exhibit 27388-X0201, Apex evidence, PDF pages 40-41, paragraphs 130-131.
[291] Exhibit 27388-X0197, ENMAX evidence, PDF pages 40-46, paragraphs 103-116.
[292] Transcript, Volume 9, page 1795, lines 17-21 (B. Hunter).

ENMAX,[293] Apex,[294] Fortis[295] and EPCOR[296] suggested changes to the existing Type 1 criteria should be made to include funding for initiatives related to net-zero objectives.

242. The distribution utilities also acknowledged uncertainty regarding the timing and amount of expenditures required to respond to net-zero objectives. In response to Commission IRs, all distribution utilities except ENMAX agreed that expenditures related to net-zero objectives would have higher levels of uncertainty than traditional investments.[297] Although ENMAX stated it could not determine "if the forecast uncertainty related to expenditures to respond to net-zero policies would be higher than for traditional investments,"[298] it acknowledged that there is "considerable uncertainty" about the rate at which the transition to net-zero will occur.[299] ENMAX suggested that the distribution system must be ready ahead of mass-adoption of new technologies "so that customer adoption of technologies does not happen at a rate that exceeds [ENMAX's] ability to adapt its distribution system to accommodate them."[300]

243. The Commission agrees that there is the potential for net-zero objectives to drive the need for additional expenditures during the PBR3 term, and that the level of uncertainty and risk associated with the need for and timing of net-zero objectives makes capital investments required to respond to any such objectives unsuitable for funding through the Type 2 K-bar mechanism. At the same time, the Commission agrees with J. Thygesen that the distribution utilities were able to successfully implement multiple grid modernization initiatives in PBR2 while relying on the funding provided by I-X and K-bar. Furthermore, it is the Commission's view that some of these expenditures are part of the ongoing operations of a prudently managed distribution utility. Accordingly, the Commission finds it reasonable to expand the Type 1 mechanism criteria to provide additional funding only for expenditures that are clearly outside the types of expenditures already included within K-bar and are directly caused on an itemized basis by applicable law which may relate to net-zero objectives, with a clear requirement to begin work during the PBR3 term. Further, as discussed in Section 8.4, the Commission included a higher materiality criterion for Type 1 projects as compared to PBR2. These modified criteria will allow the Commission to complete a comprehensive review of any proposed Type 1 capital additions, and ensure that funding is provided only in very limited circumstances for select eligible projects.

244. In this regard, the Commission also agrees with intervener concerns regarding the need to avoid premature funding. As discussed in Section 5, distribution utilities have indicated they do not expect mass electrification to materially affect them within the PBR3 term. The Commission expects that industry and customer adoption is likely to follow from changes in applicable law, and that funding should therefore also be tied to such changes, in order to ensure that it is not provided prematurely. This tie to applicable law is reflected in the final criteria.

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293 Exhibit 27388-X0197, ENMAX evidence, PDF pages 35-36, paragraphs 83-88.
294 Exhibit 27388-X0201, Apex evidence, PDF page 38, paragraph 122.
295 Exhibit 27388-X0211, Fortis evidence, PDF page 31, paragraphs 78-80.
296 Exhibit 27388-X0212, EPCOR evidence, PDF pages 31-32, paragraphs 50-52.
297 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-023(f), PDF pages 120-121; Exhibit 27388-X0500, AllParties(Fortis)-AUC-2023FEB28-023(f), PDF page 70; Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-023(f), PDF page 125; Exhibit 27388-X0531, AllParties(APEX)-AUC-2023FEB-023(f), PDF page 71.
298 Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-023(f), PDF page 79.
299 Exhibit 27388-X0197, ENMAX evidence, PDF page 38. paragraph 99.
300 Exhibit 27388-X0197, ENMAX evidence, PDF page 38, paragraph 98.

8.4.3 Parties' recommendations on Type 1 criteria

245. In the previous section, the Commission determined that it will expand the Type 1 mechanism criteria to provide incremental funding for expenditures directly caused by applicable law related to net-zero objectives. The Commission now considers submissions regarding the specific criteria for Type 1 funding in PBR3.

246. In their evidence, the ATCO Utilities argued that the majority of projects should be funded under K-bar to incentivize cost control to the greatest extent possible,[301] while allowing for necessary and reasonable expenditures related to net-zero objectives or other external factors. The Commission agrees and is seeking to ensure that only truly extraordinary expenditures qualify for Type 1 funding, with the majority of funding to be provided through either I-X or K-bar. This ensures that the majority of capital funding under PBR3 is subject to the incentives of PBR.

247. The Commission questions whether the Type 1 criteria proposed by the distribution utilities are strict enough to ensure such an outcome. Criteria that fund any project not included in K-bar (as was proposed by Apex, the ATCO Utilities and Fortis) are overly broad. Likewise, the Commission finds the criteria requiring distribution utilities to demonstrate that a project offers a net benefit to customers or is led by customer needs (as proposed by ENMAX) would be meaningless because it applies to virtually all distribution utility projects.[302] The Commission agrees with the UCA's comments that "If the criteria for Type 1 capital funding is so broad that it can capture almost anything, then what work is there left for I minus X to do? And what incentives [are] there for a distribution utility to operate within the envelope of funding that I minus X provides?"[303]

248. The distribution utilities argued the vagueness of the proposed Type 1 criteria was a benefit, as it left opportunity for Commission discretion,[304] with distribution utilities bearing the onus of justifying the need for the project.[305] In the Commission's view such an approach would involve too much subjectivity and lack of certainty as opposed to setting objective eligibility criteria and clear expectations for Type 1 applications upfront.

249. While the Commission finds that the distribution utility proposals for modifications to the Type 1 criteria to be too broad, it is also not persuaded by the intervener argument that no changes to Type 1 criteria are required for PBR3. The Commission agrees with the UCA that there is significant uncertainty around if or when expenditures related to net-zero objectives will be required, but finds that this is not sufficient reason to refrain from implementing funding mechanisms to support such expenditures. Structured properly, the Commission believes that Type 1 funding could balance the potential need for funding for extraordinary expenditures and expenditures directly caused by applicable law related to net-zero objectives against the need to ensure that funding provided is not in excess of what is needed.

301 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 46, paragraph 138.
302 Transcript, Volume 4, page 574, lines 6-9.
303 Transcript, Volume 10, page 1885, lines 22-25 to page 1886, line 1.
304 Transcript, Volume 4, page 579, lines 13-23.
305 Transcript, Volume 9, page 1768, lines 12-15.

8.4.4 Approved Type 1 criteria

250. In this section, the Commission provides more information and further clarity on the approved Type 1 criteria.

8.4.4.1 Criterion 1: The project must be extraordinary and not previously included in the distribution utility's rate base

251. Under Criterion 1 for Type 1 projects, a distribution utility will be required to demonstrate that an applied-for project is "extraordinary."

252. In Decision 20414-D01-2016 (Errata), the Commission significantly restricted the eligibility for Type 1 capital tracker funding by introducing the qualitative requirements that the project be "extraordinary and not previously included in the distribution utility's rate base and required by a third party." At the same time, the Commission retained the use of the accounting test with a materiality threshold to demonstrate that the proposed project's revenue requirement was not adequately covered by I-X. Thus, for Type 1 capital tracker purposes, demonstrating that a project is extraordinary entailed the evaluation of both the qualitative characteristics of a project (such as uncertainty, magnitude, complexity, or third-party requirements) and a quantitative demonstration through the accounting test that the project's revenue requirement was not be adequately covered by I-X. This was a marked departure from the PBR1 capital tracker mechanism, where any project, regardless of its nature, could be considered outside the normal course of the distribution utility's ongoing operations if revenue provided under I-X was not sufficient to recover the entire revenue requirement associated with the approved capital additions for that project.[306]

253. The Commission considers that, in applying for Type 1 capital tracker treatment in PBR3, to demonstrate that a proposed project is extraordinary the distribution utilities should rely on the same conceptual combination of qualitative (through a business case) and quantitative (through the accounting test) characteristics used in PBR2. However, the Commission will impose an expanded accounting test and higher materiality threshold as further discussed below.

254. In this proceeding, the UCA,[307] the CCA[308] and IPCAA[309] indicated that they have concerns about overly broad Type 1 criteria leading to double counting. In particular, they contend that a distribution utility could receive additional Type 1 funding for a project which either offsets or eliminates the need for projects that were included in the K-bar funding envelope. This is a concern shared by the Commission. Introducing a broader Type 1 funding mechanism runs the risk that distribution utilities could pursue methods of shifting expenditures that would otherwise be funded through I-X and K-bar to Type 1 capital. Given that expenditures that qualify for Type 1 funding are recovered from customers essentially on a flow-through basis, this could allow distribution utilities to earn higher ROEs without finding efficiencies, and would result in higher prices for customers.

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306 Decision 2013-435: AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc., Distribution Performance-Based Regulation 2013 Capital Tracker Applications, PDF pages 45-46, paragraphs 149-150.
307 Transcript, Volume 10, page 1886, lines 21-25.
308 Transcript, Volume 10, page 1970, lines 8-15.
309 Transcript, Volume 9, page 1829, lines 19-25 to page 1830, lines 1-7 (R. Secord).

255. Two different proposals for accounting tests for supplemental capital tracker style funding mechanisms were put forward in this proceeding. EPCOR[310] and ENMAX[311] supported the use of the accounting test used for capital trackers in PBR1, while Fortis suggested the use of an expanded accounting test as part of its MPFS funding mechanism. Given that Fortis's MPFS funding mechanism is a capital tracker style funding mechanism, as is Type 1, the Commission finds it is reasonable to consider whether Fortis's proposal should be used for Type 1.

256. Fortis's expanded accounting test compares the revenues provided under both I-X and K-bar to the approved forecast revenue requirement for MPFS projects. Any portion of revenue requirement above the revenue provided by I-X and K-bar would be funded through the MPFS, provided such difference meets the materiality threshold.[312] The ATCO Utilities supported the use of such an expanded accounting test.[313]

257. The Commission considers that the expanded accounting test proposed by Fortis that includes revenues provided under both I-X and K-bar is an improvement over the previous accounting test that only accounts for revenues provided under I-X. Another important difference is that the accounting test used for capital trackers in PBR1 and PBR2 calculated the difference between the revenue requirement supported by I-X and the actual required revenue requirement on a project-by-project basis, while Fortis's proposed expanded accounting test is based on the total revenue requirement for all projects (i.e., capital additions included in K-bar and approved capital additions for Type 1 projects). This approach is conceptually similar to the K-bar calculation, which is also done on the basis of all capital projects.

258. EPCOR opposed the use of the expanded accounting test, arguing that it "does not consider the fact that there may be no funding provided under I-X and K-bar for new initiatives required to support net zero policy."[314] EPCOR's opposition appears to be based on the assumption that Type 1 incremental funding must be provided on an individual project basis in PBR3. In this regard, the Commission agrees with intervener concerns that there may be an interplay between projects proposed for Type 1 capital tracker treatment and projects included in K-bar. For example, while a utility may start a new project during PBR3, if doing so eliminates the need for an existing project funded by K-bar, then the new activity will not need incremental funding through a Type 1 capital tracker. The expanded accounting test accounts for such an interplay, although on a blanket basis. As such, in the Commission's view, Fortis's method better captures the Commission's intent that the parameters for capital funding in PBR3 should ensure that the overall envelope of funding available to distribution utilities is sufficient for their needs, and presents them with a reasonable opportunity to recover their prudently incurred costs and to earn the approved return.

259. Therefore, the Commission finds that all Type 1 applications must apply an expanded accounting test that compares the revenues provided under I-X and K-bar to the revenue requirement after incorporation of proposed costs (first on forecast and then on an actual basis) for projects requesting Type 1 funding. Any portion of revenue requirement above the revenue under I-X and K-bar would be funded through Type 1 capital tracker, subject to meeting the

310 Exhibit 27388-X0212, EPCOR evidence, PDF page 32, paragraph 51.
311 Exhibit 27388-X0197, ENMAX evidence, PDF page 36, paragraph 90.
312 Exhibit 27388-X0211, Fortis evidence, PDF page 28, paragraph 70.
313 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-023(h)(iii), PDF page 123-124.
314 Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-023(h)(iii), PDF page 126.

Type 1 criteria and the materiality threshold. For the purposes of such an expanded accounting test, the distribution utilities should use the assumptions consistent with K-bar calculation.

8.4.4.2 Criterion 2: The project must be required by a third party, or otherwise directly caused by applicable law related to net-zero objectives

260. In Decision 20414-D01-2016 (Errata), the Commission stated that Type 1 capital additions "might include capital additions required by new government programs not previously experienced but would not include types of expenditures required by governments in the normal course of expectations, such as moves required to accommodate road or interchange reconfigurations."[315]

261. The Commission considered the requirement that the project "must be required by a third party" in the two decisions dealing with the Type 1 capital tracker requests during the PBR2 term. As summarized in those decisions, the issue of whether the applied-for projects were required by a third party involved considerable debate and required thorough deliberation by the Commission.[316] Based on this experience, the distribution utilities must clearly address in their Type 1 applications the following two questions as part of Criterion 2: (i) what entity is requiring the project to be completed?; and (ii) is that entity a third party?[317]

262. With respect to the requirement that projects must be "otherwise directly caused by applicable law related to net-zero objectives," the Commission will assess whether there is a sufficiently direct chain of causation between the relevant legal obligation and the relevant project. For example, the Commission considers that to establish a sufficient degree of connection between the project and the applicable law, the distribution utility must be able to demonstrate the connection to the specific project in a reasonable level of detail on an itemized basis. As well, the distribution utility must be able to demonstrate that it is necessary to incur capital additions for the project during the PBR3 term.

8.4.4.3 Criterion 3: The project cost must have a material effect on the distribution utility

263. In prior PBR terms, the Commission applied the materiality threshold for supplemental capital funding not to the quantum of capital additions associated with the project, but to the portion of the revenue requirement not funded by I-X, as determined by the accounting test discussed in the previous section. Thus, the rationale was to exclude projects that can reasonably be expected to be undertaken under the general envelope of funds provided by I-X.

264. In PBR2, the materiality threshold for Type 1 capital projects was set equal to four basis points of each distribution utility's ROE, meaning that the portion of the revenue requirement not

[315] Decision 20414-D01-2016 (Errata), PDF page 62, paragraph 197.
[316] In Decision-26589-D01-2021, the Commission found that ENMAX's Green Line Project could be considered required by a third party because it was done at the request of the City of Calgary. At the same time, the Commission pointed to the dual role of the City as both the municipality and as a sole shareholder of ENMAX and stated that it is possible that depending on the circumstances, Calgary may or may not be considered a third party in the context of Criterion 2 when making a request of ENMAX (paragraph 48). In Decision 25608-D01-2020, the Commission was not persuaded that a third party required AltaGas's (now Apex) Etzikom lateral project as TC Energy, a regulated entity in itself, was not empowered to make the decision to abandon the Etzikom lateral and rather that authority was vested with the Canada Energy Regulator (paragraph 36).
[317] Decision 26589-D01-2021, PDF page 12, paragraph 42.

funded by I-X for each Type 1 project was required to be equal to, or greater than four basis points of the applicant distribution utility's ROE to be eligible for Type 1 capital funding.

265. ENMAX, EPCOR and Apex suggested that if Type 1 capital funding mechanism is modified, the four basis point materiality threshold should be maintained to accommodate funding for expenditures related to net-zero objectives.[318] The ATCO Utilities suggested there should be no materiality threshold for such projects; in their view, a high materiality threshold will blunt distribution utility responses to net-zero and other environmental objectives.[319] The UCA[320] and the CCA[321] supported increasing the materiality threshold, but did not provide any specific proposals as to what that threshold should be.

266. Fortis suggested that the materiality threshold remain unchanged for Type 1 capital and a materiality threshold of 10 basis points be implemented for its MPFS mechanism, discussed in Section 8.6.[322] In proposing the 10 basis point materiality threshold for the MPFS, Fortis indicated that it had proposed a high threshold to "facilitate the efficient and timely processing of MPFS applications."[323] In questioning, Fortis further clarified that the intent of the threshold was to ensure projects were "truly significant."[324]

267. The Commission is not persuaded by the ATCO Utilities' assertion that high materiality thresholds will blunt distribution utility responses. Distribution utilities have the ability to prioritize their capital expenditure as they see fit within the funding envelope provided in PBR. Materiality thresholds are intended to (i) ensure that only projects materially underfunded by I-X are considered for Type 1 funding, which ensures that the majority of funding is provided through I-X and K-bar and is therefore subject to the superior cost incentives of PBR; and (ii) avoid initiating proceedings for proposed projects with costs that are, for the most part, funded by I-X and K-bar, therefore decreasing regulatory burden. The Commission previously observed that decreased regulatory burden allows a utility to focus on the cost-efficient management of its business in the incentive environment created under PBR, ultimately achieving productivity improvements that benefit both the companies and customers.[325]

268. Given this intent, the Commission finds that a materiality threshold of 10 basis points of the applicable distribution utility's ROE is reasonable for the modified Type 1 funding mechanism to be used in PBR3. This will support the Commission's goal of ensuring that the majority of distribution utility expenditure is subject to the incentives of PBR, and reducing regulatory burden by ensuring only truly significant expenditures not otherwise or sufficiently covered by revenue provided under I-X and K-bar are brought to the Commission for consideration. The materiality threshold is to be applied to each individual capital category (at the grouping level approved in the rebasing decisions) proposed for Type 1 capital tracker treatment.

318 Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-023(h)(vii), PDF page 80; Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-023(h)(vii), PDF page 126-127; Exhibit 27388-X0531, AllParties(APEX)-AUC-2023FEB28-023(h)(vii), PDF page 74.
319 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-023(h)(vii), PDF page 124.
320 Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-023(h)[*sic*](vii), PDF page 55.
321 Transcript, Volume 10, page 1467.
322 Exhibit 27388-X0211, Fortis evidence, PDF pages 27-28, paragraph 68, and PDF page 31, paragraph 81.
323 Exhibit 27388-X0211, Fortis evidence, PDF pages 27-28, paragraph 68.
324 Transcript, Volume 6, page 1036, lines 11-18.
325 Decision 2013-435, PDF page 93, paragraph 374.

8.4.5 Minimum filing requirements for Type 1 projects

269. In addition to requiring the distribution utilities to demonstrate that the project proposed for Type 1 capital tracker treatment meets the established criteria, the Commission will continue to require distribution utilities to meet the minimum filing requirements (MFRs) to help the Commission in its determinations on whether it should approve funding for the proposed project. The Commission will use the same MFRs listed in Appendix 3 of Decision 3558-D01-2015[326] and adds the following requirements for Type 1 capital tracker applications in PBR3:

- Demonstration that all applicable external funding opportunities were pursued prior to submitting a Type 1 application.
- A cost-benefit analysis quantifying the overall costs and benefits of both the proposed project and the alternatives considered, including:
    - A description of the process used to identify alternatives.
    - An analysis that incorporates:
        - Consideration of non-wires solutions, including tariff-based solutions.
        - Justification of why utility investment in the project is appropriate.
        - Discussion of what market-based solutions were considered.
- A detailed description of how the project fits into the distribution utility's asset management and asset optimization strategy for grid modernization, including:
    - Identification of the criteria used to determine the safety or reliability risks addressed by the project.
    - A discussion of how the proposed project relates to ongoing initiatives funded through K-bar and other projects for which the distribution utility has sought or plans to seek Type 1 funding.
    - A discussion of how safety or reliability risks are being prioritized.
    - A discussion of how the project facilitates optimization of existing infrastructure.

270. The Commission will consider whether the information provided satisfies the above filing requirements in its decision on whether to grant Type 1 capital tracker funding. If amendments to the list of MFRs are necessary, then the Commission will consider such amendments as required, if there is sufficient evidence that the existing MFRs are not adequate. Unlike in PBR2, the Commission will accept Type 1 capital tracker applications based on distribution utility forecasts. These forecasts will be trued up to actual costs when they become available.

271. The reasoning behind these additional filing requirements is discussed below.

8.4.5.1 Exploration of external funding opportunities

272. During oral questioning, Commission counsel asked whether exploring the opportunities and applying for external funding could be a requirement of Type 1 funding.[327] While parties cautioned that not all changes in policy and regulation will be accompanied by funding opportunities,[328] they did not oppose the inclusion of this requirement. In argument, Fortis

[326] Decision 3558-D01-2015: Distribution Performance-Based Regulation Commission-initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications, Proceeding 3558, Application 1611054-1, April 8, 2015, Appendix 3.
[327] Transcript, Volume 2, pages 262-264; Transcript, Volume 3, pages 390-391.
[328] Transcript, Volume 2, page 262, lines 20-25 to page 263, lines 1-3.

provided an example of its Waterton Battery Project in which it used external funding to reduce the costs passed on to customers.[329]

273. In the interest of ensuring that only the necessary costs are passed on to customers, the Commission will therefore include the requirement that distribution utilities seek out external funding prior to submitting a Type 1 application. The Commission recognizes that external funding may not always be available, and that distribution utilities may not always be successful in obtaining funding where it is available. Nevertheless, the Commission expects distribution utilities to demonstrate they have completed a thorough review of available funding opportunities, and made an effort to pursue these opportunities at a level commensurate with how unregulated entities would pursue them.

8.4.5.2 Cost-benefit and alternative analysis

274. Inclusion of a cost-benefit analysis is standard practice in COS applications and capital tracker mechanisms. As was highlighted by ENMAX in its evidence, non-wires solutions may be more cost effective than traditional infrastructure investments.[330] Fortis echoed this, stating that "as a company, we view non-wire services as a good opportunity to … seek out lower cost alternatives … for the benefit of our customers."[331] EPCOR also agreed that it was reasonable to require an analysis of alternatives that includes consideration of non-wires solutions as part of any Type 1 application.[332]

275. During Commission questioning, the Commission also raised the question of whether the Type 1 criteria should require distribution utilities to demonstrate that they have explored competitive solutions. A. Goulding, on behalf of ENMAX, agreed with the Commission's concerns, stating that care must be taken to ensure that distribution utilities are not "crowding out something that would happen in the market holistically."[333]

276. Therefore, the Commission will require distribution utilities to explore non-wires and market-based solutions as part of their analysis of alternatives included in any applications for Type 1 funding.

8.4.5.3 Integration with asset management and asset optimization strategies

277. During questioning and in argument, Dr. Orans and Fortis suggested that distribution utilities should work with the Commission to develop five-year plans,[334] arguing that this could decrease the regulatory burden associated with reviewing Type 1 applications.[335] The Commission notes that requirements for electric distribution system plans are contemplated in the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act*. This legislation will come into force on proclamation, and will require distribution utilities to prepare electric distribution system plans in accordance with any regulations made by the Minister. The Commission therefore defers discussion of such a planning process until this legislation comes into force. However, the Commission agrees that there is merit in a more focused assessment of

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329 Transcript, Volume 9, page 1789, lines 24-25 to page 1790, line 1.
330 Exhibit 27388-X0187, ENMAX evidence, PDF page 39, paragraph 100.
331 Transcript, Volume 7, page 1213, lines 1-8.
332 Transcript, Volume 5, page 975, lines 3-20.
333 Transcript, Volume 4, page 718, lines 1-13.
334 Transcript, Volume 9, page 1768, lines 16-18.
335 Transcript, Volume 7, pages 1207-1209.

how Type 1 applications fit into the distribution utilities' overall asset management and asset optimization strategies over time. The Commission cannot be assured the distribution utilities are incurring the lowest cost to pass on to consumers over the long term without this more focused assessment. Therefore, in any application for Type 1 funding, the distribution utility must include a five-year Type 1 funding roadmap with respect to its distribution system. This roadmap should address:

(i) A description of existing infrastructure and the distribution utility's plans to optimize it.

(ii) A detailed overview of anticipated growth in the system.

(iii) Potential risks to safety or reliability, an assessment of each of these risks including mitigation strategies, and a prioritization of the mitigation strategies.

(iv) The status of ongoing or anticipated initiatives funded through K-bar or Type 1, including a discussion of how any newly proposed projects relate to ongoing projects.

(v) The best approach, whether through utility investment, non-wires solutions or competitive services, to achieve the lowest delivered cost to consumers.

278. The Commission will consider these roadmaps in assessing any Type 1 applications, including an analysis of how the proposed project relates to the roadmap filed as part of the application, and any relevant previously filed planning information or documents.

279. Finally, the Commission may revise this component of the PBR3 plan, based on the implementation and precise language of the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act* discussed above.

8.4.5.4 Forecast and true up of Type 1 capital additions

280. In response to Commission IRs,[336] all distribution utilities suggested that Type 1 funding should be prospective, and determined ahead of distribution utility investment. For example, Apex cited the "high level of uncertainty in scope, cost or timing" as the reason funding should be provided on a forecast basis. The UCA and the CCA[337] argued that funding should be based on actual costs, with the UCA stating that doing so "will result in a simpler regulatory process."[338]

281. The majority of parties, including the distribution utilities, also advocated for these forecast costs to be trued up to actuals. For example, Dr. Lowry for the CCA, and LEI for ENMAX, stated that a true-up would mitigate the risk that distribution utilities will exaggerate their capital funding needs.

282. Several parties, including LEI,[339] R. Bell[340] and Fortis[341] pointed to the regulatory burden associated with the capital tracker true-up process used in PBR1. Fortis and the ATCO Utilities

[336] Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-023(h)(vi), PDF page 81; Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-023(h)(vi), PDF pages 126-127; Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-023(h)(vi), PDF page 125; Exhibit 27388-X0500, AllParties(FAI)-AUC-2023FEB28-023(h)(vi), PDF page 70; Exhibit 27388-X0531, AllParties(APEX)-AUC-2023FEB28-023(h)(vi), PDF page 73.

[337] Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-023(h)(vi), PDF page 65.

[338] Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-023(h)[*sic*](vi), PDF page 55.

[339] Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 65.

[340] Exhibit 27388-X0582, R. Bell rebuttal evidence for the UCA, PDF page 14.

[341] Exhibit 27388-X0211, Fortis evidence, PDF page 33, paragraph 87.

suggested that rather than requiring annual true-ups, the requirement for and timing of true-ups could be determined on a case-by-case basis at the discretion of the Commission. Apex similarly suggested that the decision on whether a project should be trued up should "depend on the level of forecast certainty at the time of the Type 1 application."[342] While IPCAA supported the use of a true-up,[343] D. Madsen noted that true-ups diminish incentives to reduce capital spending.[344]

283. As was discussed above, the Commission recognizes the significant level of uncertainty associated with potential changes to government policy and regulation during the PBR3 term. As a result, the Commission finds it reasonable to approve Type 1 applications based on forecast capital additions, to give distribution utilities greater regulatory certainty and to better enable them to plan and prioritize their expenditures for any activities that may be new to them. Also to address potential uncertainty, and because of the concern that the absence of true-up creates unacceptable incentives to over forecast, the Commission finds that forecast costs for Type 1 projects should be trued up to actual capital additions when they become available. The Commission finds that mitigating the uncertainty associated with Type 1 capital-eligible investments outweighs any potential increase in regulatory burden associated with the true-up.

8.5 Alternative remuneration schemes

284. During the PBR3 term, the Commission will accept applications from distribution utilities to earn a return on operating solutions on a pilot basis. Through this pilot program, the Commission seeks to study the best way to incentivize operating solutions when they are equally or more cost effective than a viable capital solution with similar outcomes, and to understand the mechanism of how such a solution should work, including any proposals for the specific accounting treatment that should be afforded to these expenses. The Commission considered alternative remuneration schemes put before it, including TOTEX,[345] to come to its decision.

285. In Decision 26356-D01-2021, the Commission noted that the distribution utilities had expressed 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.[346] ENMAX, Apex and the ATCO Utilities each commented that the current proceeding should consider alternative remuneration schemes to address the bias towards capital.[347] The Commission included alternative remuneration schemes (e.g., TOTEX[348]) or funding for non-wires solutions (NWS) into the scope of this proceeding as it was interested in better understanding these issues.

342 Exhibit 27388-X0201, Apex evidence, PDF page 39, paragraph 126.

343 Transcript, Volume 9, page 1823, lines 20-23

344 Exhibit 27388-X0164, D. Madsen for IPCAA, PDF page 16.

345 TOTEX, or Total Expenditure, is an approach to incent utilities to seek out the most overall cost-effective solution. Under certain examples of a TOTEX funding approach, a pre-set capitalization rate is employed, irrespective of whether a utility's solutions involved operating or capital spending. A portion of utility capital and operating expenditures are combined into one regulatory asset that allows a rate of return on both.

346 Decision 26356-D01-2021, PDF page 22, paragraph 67.

347 Exhibit 27388-X0028, EPC submission for PBR3, PDF pages 13-16, paragraphs 45-59; Exhibit 27388-X0032, AUI comments on the preliminary issues list, PDF page 13, paragraph 30; Exhibit 27388-X0031, ATCO Utilities parameters of the PBR3 plans submission, PDF page 16, paragraphs 48-49.

348 TOTEX, or Total Expenditure, is an approach to incent utilities to seek out the most overall cost-effective solution. Under certain examples of a TOTEX funding approach, a pre-set capitalization rate is employed, irrespective of whether a utility's solutions involved operating or capital spending. A portion of utility capital and operating expenditures are combined into one regulatory asset that allows a rate of return on both.

286. In this proceeding, IPCAA and ENMAX proposed alternative remuneration schemes, although neither party identified how its proposal might be addressed on a pilot basis in the PBR3 term. IPCAA and ENMAX focused on capital bias and the need to provide incentives for operating solutions to overcome it.

287. IPCAA expressed a preference for a TOTEX form of regulation; however, it conceded that the complexity of such an approach may be administratively prohibitive, particularly if it was to be implemented in the way that the United Kingdom's regulator, Office of Gas and Electricity Markets (Ofgem),[349] has.[350]

288. To mitigate the complexity that a TOTEX solution such as that implemented by Ofgem would pose in Alberta, D. Madsen for IPCAA recommended a simplified TOTEX approach or a TOTEX incentive mechanism as a means to remove the incentive of a distribution utility to favor a capital solution. He laid out two alternatives: setting a TOTEX allowance for each distribution utility in the same manner as K-bar funding (using the I-X and Q parameters combined with an upfront efficiency adjustment), or directing the distribution utilities to provide a forecast for TOTEX in the 2024 test year.[351] Additionally, he recommended that either approach include an incentive mechanism that would allow for risks to be shared between the distribution utilities and customers. ENMAX argued that while IPCAA's proposal for TOTEX is intriguing, it is not feasible for implementation in the PBR3 term.

289. Regarding TOTEX, the Commission agrees that the version implemented by Ofgem would likely be prohibitively complex and administratively burdensome to implement in this PBR term as it would be a marked shift from the current regulatory paradigm that extends well beyond the design of PBR. While the Commission recognizes that simplified solutions such as those proposed by IPCAA would be more feasible, they would still involve fundamental changes to distribution utility regulation and the evidentiary record of this proceeding does not support a move to such a solution at this point.

290. IPCAA stated that if TOTEX is not adopted by the Commission for PBR3, other deemed capital solutions should be considered. To that end, D. Madsen proposed a solution in which specific operating costs that are incurred in place of capital costs are captured within a deferral account. The deferred costs would be recoverable through rates and would be applicable to each of the distribution utilities in the case that a cost-effective operating solution exists and can replace a more costly capital solution.[352] D. Madsen stated that this approach would act similarly to a management fee but would only be permitted when the distribution utility demonstrated that a necessary capital project can be avoided.

291. To address the instance that the return under the capital solution would still be greater than under an operating solution, D. Madsen proposed a modified clawback mechanism.[353] When

349 Exhibit 27388-X0164, D. Madsen evidence for IPCAA, PDF pages 31-34; Exhibit 27388-X0198, LEI evidence for ENMAX, PDF pages 77-78, Section 6.4.2.1. Ofgem is the United Kingdom's utility regulator and has implemented a TOTEX approach that separates price controls for electricity distribution, electricity and gas transmission and gas distribution. It distinguishes between recoverable expenditures within a one-year period and capitalizes the rest. The funding envelope is paired with targets and incentive mechanisms, including financial rewards, penalties and "reputational incentives."

350 Exhibit 27388-X0164, D. Madsen evidence for IPCAA, PDF pages 35 and 48.

351 Exhibit 27388-X0371, IPCAA-EPC-2023FEB28-004, PDF page 6.

352 Exhibit 27388-X0164, D. Madsen evidence for IPCAA, PDF page 45.

353 Exhibit 27388-X0164, D. Madsen evidence for IPCAA, PDF page 46.

a distribution utility adopts a more cost-effective operating solution, distribution utilities would be allowed to retain the earnings on capital that are already reflected in base rates, until rates are reset in the next rebasing year. D. Madsen identified, however, that the incentives provided by this solution would naturally weaken over the duration of a PBR term, which could be addressed by permitting the recovery of any forecast capital-related revenues net of operating costs over a full five-year period.

292. There was some support for a modified clawback approach, in responses to IRs; however, parties stated that it could dull incentives for distribution utilities to constrain their capital additions and in fact could incent an overspend on capital. Further, parties submitted that it would be uncertain and administratively burdensome. Parties generally agreed that if an ESM were to be implemented in the PBR3 plan, there would be no need for a modified clawback mechanism.[354]

293. The Commission will not implement the deferral account and clawback mechanism solutions proposed by D. Madsen. The record of this proceeding does not identify an appropriate return that could be used in the alternatives proposed for the deferral account solution. Regarding the modified clawback mechanism, the Commission agrees that it could result in undesirable incentives by creating a reward for overspend on capital. Further, as the Commission is implementing an ESM as described in Section 9, it does not see the need to further claw back earnings from capital.

294. ENMAX and its consultant, LEI, recommended a "deemed capital additions" approach that included variations on payment terms and recovery of costs. Under this approach, a distribution utility's capital bias would be reduced by providing a return on non-capital additions. The variations provided are outlined below:

Table 7. Options within LEI's "deemed capital additions" approach[355]

Approach	Payment terms	Return on expenditure	Amortization
Pre-paid or partially pre-paid	Contract pre-paid or partially pre-paid	Same return as rest of regulated asset base	At end of PBR term, unamortized part of contract would be included in subsequent PBR term's regulated asset base
Partial-amortization	Contract paid on annual basis	Same return as rest of regulated asset base	Amortization is enabled until the end of the contract
Margin-based	Contract paid on annual basis	Fixed adder	N/A

295. ENMAX identified a number of benefits that enabling capital treatment of operating solutions[356] could offer to distribution utilities and customers, including reduction of cost, increased choice, faster deployment, adaptability to variable demand, more frequent updates and

354 Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-024, PDF page 82; Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-024, PDF page 130; Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-024, PDF page 57; Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-024, PDF page 129.

355 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 72, Section 6.3.2.

356 LEI stated, "Examples of CaaS [capital as a service] include moving from use of company-owned data centers to cloud services, exploring use of non-wires alternative such as third-party owned batteries to defer or replace capital investment, or deploying energy efficiency and demand side management programs to manage load in a fashion that helps defer investment." (Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 72, Section 6.3.2).

the ability to implement new cloud-based business initiatives.[357] It further described the proposal as "in a sense … a step along the way to something like totex. [*sic*]"[358]

296. The CCA argued that methods used to encourage practices to improve performance, such as capitalizing any O&M expense, are a form of PBR and may merit consideration in PBR3. It did, however, express reservations with the strength of the evidentiary record in this proceeding to support such a solution for the PBR3 term.[359] D. Madsen for IPCAA was generally supportive of the LEI deemed capital solution although indicated that further clarification was needed to fully understand the proposal.[360] Fortis stated that it supported exploring LEI's proposed deemed capital and how it could be made consistent with the PBR3 framework.[361]

297. The Commission is interested in exploring elements of this solution over the PBR3 term on a pilot basis.

298. In considering the need to incentivize non-capital additions, or operating solutions, the starting point is that the distribution utility's decision-making must be reasonable. Customers are required to pay only for efficient distribution utility service[362] and nothing more. The Commission understands that IT service providers are moving towards cloud-based solutions, the cost of which may not be capitalized, and that these services are replacing traditional IT products that were previously eligible for capitalization. In such a case, the Commission considers that the distribution utility does not require an incentive, as it would be unreasonable for it to procure more expensive, non-cloud-based IT products simply because the costs of these products could be capitalized.

299. Nevertheless, the Commission wishes to remove barriers to cost-effective operating solutions to the extent that they exist, and continues to be interested in exploring solutions and understanding their applicability within the PBR regime in Alberta. Looking to the future, the Commission is interested in exploring ways to incentivize distribution utilities to act more like competitive companies driving towards least-cost solutions and to minimize any capital bias. The ultimate goal of incentivizing operating solutions is to provide long-term benefit to ratepayers by lowering costs in situations where operating solutions are more cost-effective than capital solutions.

300. To this effect, the Commission will consider applications from distribution utilities to earn a return on operating solutions on a pilot basis. A distribution utility must apply on a per-project basis and a proposal must relate to a scope of work that is not contemplated by an existing agreement or arrangement, and replaces a corresponding capital solution. Under this pilot, the distribution utility is required to demonstrate the reasonableness of the proposed

[357] ENMAX listed the following examples of non-wires solutions and other CaaS offerings: "cloud based servers, storage and application software solutions; an EV charging platform, enabling customers to share EV charging information and for utilities to administer and collect data for incentive programs, such as a customer rewards program for off-peak charging; and a DER [distributed energy resource] management platform, allowing the utility to control and monitor customer DER equipment and smart devices, such as batteries, thermostats, and EV chargers." (Exhibit 27388-X0197, ENMAX evidence, PDF page 56, paragraph 151.)

[358] Transcript, Volume 11, page 2086, lines 12-15 (D. Wood).

[359] Transcript, Volume 10, page 2006, lines 16-19 (J. Wachowich).

[360] Exhibit 27388-X0367, IPCAA-AUC-2023FEB28-008, PDF page 16.

[361] Transcript, Volume 9, page 1796, lines 4-9 (B. Hunter).

[362] *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2015 SCC 45, paragraph 7 [ATCO Pensions].

operating costs. For example, a distribution utility may choose to present the results of a bid solicitation or contract for the operating solution as support for its proposal.

8.6 Capital funding mechanisms not accepted by the Commission

301. In this section, the Commission discusses other capital funding proposals that it does not accept. As discussed in the sections that follow, in the Commission's view these proposals can be accommodated under the general envelope of funding provided by the PBR3 formula, including the K-bar and Type 1 capital tracker mechanisms approved in prior sections of this decision.

8.6.1 Funding for Fortis system transfers

302. In the PBR3 rebasing Decision 26615-D01-2022, the Commission denied Fortis's request for approval of $15 million in capital additions for potential system transfer costs, but granted Fortis deferral account treatment for any actual system purchase costs in 2023.[363] In this proceeding, Fortis confirmed that no system transfers have taken place to date in 2023.[364] Fortis proposed that system transfers occurring during PBR3 should be funded through the Y factor mechanism, as there are no amounts associated with system transfers in its 2023 going-in rates, and because of the uncertainty of the cost and timing of system transfers.[365]

303. In Decision 24405-D01-2019,[366] where the Commission considered the treatment of distribution system acquisition costs under PBR, it found that "absent a Commission direction, the costs associated with the acquisition of a distribution system or assets are not eligible for Y factor treatment."[367] In Decision 26615-D01-2022, the Commission stated, "Consistent with the determinations in Decision 24405-D01-2019, any system purchase transactions during the PBR3 term should be funded in accordance with the PBR3 framework."[368]

304. The Commission does not find any reasons to deviate from its past determinations. Although the Commission agrees that the timing and cost of system transfers is uncertain, as argued by Fortis, this uncertainty also existed for past system transfers, and was considered by the Commission in making its determinations in Decision 24405-D01-2019. The Commission also does not agree with Fortis's characterization that system transfer costs are not reflected in the going-rates. Even though there are no such costs in the 2023 approved forecasts, Fortis's going-in rate base contains the undepreciated amounts of historical capital additions for past system transfers. In response to UCA IRs, Fortis indicated that it had completed system transfers in 2018 and 2019.[369] Furthermore, the Commission is currently processing Fortis's request for a system transfer,[370] the costs of which will presumably be accrued in 2023. Given the Commission's decision to set K-bar based on a five-year average of historical actual capital additions, the undepreciated cost of these system transfers would also be captured in K-bar.

363 Decision 26615-D01-2022, PDF page 72, paragraph 296.
364 Transcript, Volume 6, pages 1045-1046 (B. Henderson).
365 Exhibit 27388-X0211, Fortis evidence, PDF page 35, paragraphs 93-94.
366 Decision 24405-D01-2019: Generic Proceeding to Review Rate Treatment of Distribution System Acquisition Costs Under Performance-Based Regulation, Proceeding 24405, September 6, 2019,
367 Decision 24405-D01-2019, PDF page 4, paragraph 2.
368 Decision 26615-D01-2022, PDF page 72, paragraph 296.
369 Exhibit 27388-X0516, FAI-UCA-2023FEB28-010(a), PDF page 17.
370 Proceeding 28358, Fortis Application for Direction to Pay Compensation Related to Site Transfers.

8.6.2 Fortis proposal for a Major Projects Funding Supplement

305. In addition to suggesting changes to the criteria for Type 1 capital funding, Fortis also suggested the introduction of a new capital funding mechanism, which it called the Major Project Funding Supplement or MPFS for short.[371] The MPFS would provide funding for "capital projects that may experience significant changes in capital additions that were not reasonably predictable at the outset of the PBR term." MPFS would only be available to projects that were already funded by K-bar, and experienced a material increase in capital need above what was included in K-bar.[372] As mentioned in Section 8.4.4.3, Fortis proposed a materiality threshold of 10 basis points for the MPFS.

306. The Commission finds that the MPFS as proposed by Fortis is similar to the Type 1 proposals put forward by Apex and the ATCO Utilities because it relies on uncertainty to determine whether a project is eligible for incremental funding. Therefore, Fortis's proposal comes with the same risks of double-counting and dilution of incentives as discussed in Section 8.4 above. The fact that the MPFS is specific to projects already funded by I-X and K-bar only compounds this issue, as it would drastically reduce the incentive to manage costs under I-X and K-bar by offering a mechanism through which distribution utilities could seek additional funding. Given these incentives, in the Commission's assessment, the high materiality threshold could further incent distribution utilities to increase expenditures to become eligible for MPFS funding.

307. The Commission is not persuaded of the need for the MPFS and sees considerable risk in implementing such a mechanism. As such, the Commission denies Fortis's request to include the separate MPFS funding mechanism in PBR3 in addition to the approved K-bar and Type 1 capital tracker funding provisions.

8.6.3 The ATCO Utilities Y factor proposal

308. The ATCO Utilities suggested that "capital programs driven by government policy initiatives or legislative changes (including both net-zero policies, hydrogen and Bill 22)"[373] should be funded through the Y factor. The ATCO Utilities argued that if the Commission agreed with its proposal, such expenditures could be considered to be "incurred in compliance with the direction of the Commission," and therefore be granted an exemption from the existing Y factor criteria.[374] They argued that Y factor treatment is warranted because "neither K-bar nor a modified Type 1 capital mechanism will provide funding for incremental O&M costs related to government initiatives and legislation changes."[375]

309. The Commission does not accept the ATCO Utilities' proposal that all expenditures related to net-zero objectives be granted blanket Y factor treatment. As noted in Section 8.4.1, the Commission has the ability to direct the recovery of costs incurred at its direction through the Y factor and to test these costs, as was done for Apex's NGSSC project. However, it is not clear to the Commission that any of the expenditures related to net-zero objectives will require Commission direction to implement. In any event, the Commission considers Type 1 capital tracker mechanism to be a more targeted tool to deal with these capital additions as it accounts

371 Exhibit 27388-X0211, Fortis evidence, PDF page 27, paragraphs 66-67.
372 Exhibit 27388-X0211, Fortis evidence, PDF page 27, paragraph 66.
373 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 46, paragraph 137.
374 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 43, paragraph 125.
375 Exhibit 27388-X0438, ATCO-AUC-FEB28-013(c), PDF page 45.

for funding that may already be provided under I-X and K-bar (as was discussed in Section 8.4). The Commission also disagrees with the ATCO Utilities' assertion that Y factor treatment is the only funding mechanism that can fund both capital and O&M costs. As noted in Section 8.3.1.3, ATCO Electric confirmed that it used K-bar funding to support O&M expenditures during the PBR2 term.[376] The Commission expects that given the total envelope of funding provided under the PBR3 plan, distribution utilities should have the flexibility to support both capital and O&M expenditures.

8.6.4 EPCOR requests for a deferral account

310. EPCOR proposed to implement a deferral account that would capture operating and capital additions incurred during PBR3 associated with the analytical and assessment work to support net-zero objectives, grid modernization and non-wires solutions.[377] It deemed much of this work to be cost effective or cost minimizing. EPCOR stated its proposal meets the Commission's criteria for approving deferral accounts. It also stated that the proposed deferral account would create symmetry in terms of the costs and benefits for both EPCOR and its customers by addressing incentives that might otherwise discourage such cost-minimizing activities from being undertaken.

311. The Commission finds that in the current industry environment, the analytical and assessment work to support net-zero objectives, grid modernization and non-wires solutions is an expected part of normal course distribution utility business as part of prudent management of its operations. The Commission expects the distribution utilities to manage their business under the overall envelope of funding provided by the Commission without seeking funding for each individual project or initiative. In Decision 2012-237, the Commission indicated the proliferation of deferral accounts and flow-though items that reconnect costs and revenues detract from the incentives of PBR and removed a number of deferral accounts in transitioning to PBR. For these reasons, the Commission rejects EPCOR's proposed deferral account.

9 Benefit-sharing provisions

9.1 Approved benefit-sharing provisions

312. AUC PBR Principle 5 states that customers and the regulated companies should share the benefits of a PBR plan. When previously evaluating the impact of PBR in Alberta, the Commission found that ultimately customers have experienced lower rates under PBR than would be expected under COS regulation.[378] However, the Commission also found that there may be advantages to sharing the benefits of PBR among customers and the utilities *during* a PBR term (i.e., before rebasing), especially during challenging economic conditions such as those experienced during PBR2.[379] The Commission concluded that:

> 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

[376] Proceeding 26615, Exhibit 26615-X0023, ATCO Electric evidence, PDF page 12, paragraph 20.
[377] Exhibit 27388-X0212, EPCOR evidence, PDF pages 33-38, paragraphs 56-63.
[378] Decision 26356-D01-2021, PDF page 23, paragraph 76.
[379] Decision 26356-D01-2021, PDF page 25, paragraph 81.

plans, rates continued to increase during an economic downturn in Alberta and utility earnings during this same period were characterized by the interveners as excessive.[380]

313. Based on the record of this proceeding, the Commission will increase the sharing of benefits with customers during PBR3, by including two additional benefit-sharing provisions in the plan: (i) an asymmetric, two-tiered ESM; and (ii) an X factor premium of 0.3 per cent. The approved asymmetric ESM requires the distribution utilities to share any earnings above the approved ROE with a deadband of 200 basis points. Beyond the deadband there will be two tiers of sharing. Between 200 and 400 basis points above the approved ROE, the sharing ratio will be 60 per cent for distribution utilities and 40 per cent for customers. At earnings 400 basis points above the approved ROE or greater, the sharing ratio will be 20 per cent for distribution utilities and 80 per cent for customers. The elements of the ESM are explained in Section 9.3 and further details on the ESM sharing calculations are found in Section 9.4. Additionally, given the structure of the ESM, the Commission finds that it is no longer necessary to trigger the reopener review when an achieved ROE exceeds the approved ROE by 300 basis points in two consecutive years during the PBR3 term. This is explained further in Section 9.5.

314. The benefits of PBR, such as reductions in costs due to realized efficiencies, can be shared with customers in several ways. During a PBR term, customers benefit from lower rates through the X factor (which may include a stretch and premium portion). Customers may also benefit through an ESM, where a utility earns more than the approved rate of return and a portion of the achieved earnings are shared with customers. Further, to the extent the utility was successful in achieving efficiencies that resulted in cost savings during a PBR plan, the new going-in rates that result from rebasing at the end of a term should reflect these realized savings, thereby benefiting customers throughout the next PBR term.[381]

315. In certain circumstances a regulator may opt to include in a PBR plan additional provisions to share with customers benefits of PBR in excess of the rate reductions from the X factor and/or sooner and at more frequent intervals than at rebasing; or as Dr. Weisman quoted in his evidence, share benefits with customers "in direct, visible ways precisely when the regulated firm benefits."[382] The most widely used benefit-sharing mechanism is an ESM, explained in the following section.

316. Depending on the particular mechanism used, sharing of benefits can also address the potential that a regulated utility could earn a return significantly different than the approved ROE during the PBR term. However, some benefit-sharing mechanisms may diminish the incentives of a PBR plan. By requiring the utility to share with customers a portion of earnings, benefit-sharing provisions serve to at least partially reconnect revenues with costs during the plan. As well, the regulated utility may not invest as much effort in seeking cost-reducing innovations if less than 100 per cent of the earnings/avoided costs realized as a result of such innovations are retained by the utility.

317. In his evidence for EPCOR, Dr. Weisman emphasized that when considering the need for additional benefit-sharing provisions in PBR3 plan, the issue is not whether consumers have benefitted from PBR as compared to COS regulation, because they clearly have. Rather, the question is whether, to better meet AUC PBR Principle 5, the share of benefits passed on to

380 Decision 26356-D01-2021, PDF pages 24-25, paragraph 79.
381 Decision 20414-D01-2016 (Errata), PDF page 16, paragraph 26.
382 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 14, paragraph 33.

customers under PBR should be increased to make the sharing between customers and the distribution utilities more equitable.[383] The Commission agrees with Dr. Weisman's characterization of the impetus behind consideration of a benefit-sharing provision. This is consistent with the Commission's findings in Decision 26356-D01-2021, which evaluated the PBR1 and PBR2 plans.

318. R. Bell for the UCA and J. Thygesen for the CCA pointed to high returns achieved by the distribution utilities during the prior PBR terms and advocated for the inclusion of an ESM. Fortis and its expert Dr. Orans included an ESM in their PBR3 plan proposal. LEI also supported the inclusion of an ESM; however, its client ENMAX argued against it.

319. Parties in support of an ESM submitted that it would provide more timely sharing of benefits with ratepayers, it is consistent with AUC PBR Principle 5 and it would ensure utility earnings remain within acceptable limits. LEI also argued that an ESM could help to avoid unscheduled regulatory interventions, such as imposing windfall profit taxes that distort patterns of investment and returns, and it could increase the overall social acceptability of a PBR plan.[384] The last point was also highlighted by Dr. Weisman, who observed in his evidence for EPCOR that consumer buy-in is important to the sustainability of any regulatory regime, especially PBR, that can result in high achieved ROEs for regulated utilities.[385]

320. With the exception of Fortis, all other distribution utilities did not support the inclusion of additional benefit-sharing provisions in PBR3 plan. In general, they cited similar reasons to those of the Commission in the PBR1 and PBR2 decisions that such provisions result in blunting or weakening of incentives for the utilities to find efficiencies and the potential for increased regulatory burden. They also argued that the reopeners currently in place offer comparable safeguards to an ESM without the associated disincentives.[386]

321. Ultimately, most parties in this proceeding agreed that there are valid arguments both for and against including additional benefit-sharing provisions in PBR plans and conceded that there is a trade-off between maximizing the incentives for efficiency under the plan and sharing realized efficiencies during the plan term.[387] The Commission agrees with this assessment. The Commission included an ESM in the ENMAX 2007-2013 FBR plan, despite agreeing with parties that it dampened incentives.[388] In the PBR1 and PBR2 plans, the Commission relied on the X factor and rebasing to ensure that customers shared in the benefits of PBR and did not include additional benefit-sharing provisions.

[383] Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 8, paragraph 19.
[384] Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 84.
[385] Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF pages 13-14 and 23, paragraphs 32-33 and 58-59.
[386] Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF pages 59, 62-63; Exhibit 27388-X0197, ENMAX evidence, PDF page 58, paragraph 155; Exhibit 27388-X0212, EPCOR evidence, PDF page 51, paragraph 89; Exhibit 27388-X0201, Apex evidence, PDF pages 45-47, paragraphs 146-155; Exhibit 27388-X0221, ATCO evidence, PDF pages 49-51, paragraphs 148-162.
[387] Exhibit 27388-X0194, R. Bell evidence for the UCA, PDF page 7; Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 84; Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF pages 5-6, paragraph 10; Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF pages 57-58; Exhibit 27388-X0210, R. Orans evidence for ENMAX, PDF page 22.
[388] Decision 2009-035, PDF page 68, paragraphs 280-281.

322. Based on the record of this proceeding, the Commission continues to be of the view, previously expressed in Decision 26356-D01-2021, that when it comes to the sharing of benefits among customers and the utilities envisioned in AUC PBR Principle 5, the proper balance is yet to be found.

323. The distribution utilities have strongly and successfully responded to the incentives provided to them in the previous two PBR plans. As previously noted throughout this decision and shown in Table 1, the majority of the distribution utilities achieved actual ROEs that were greater, and in some cases, significantly greater, than the approved return in almost all years of the PBR1 and PBR2 terms. While representatives of customer groups agreed that some sharing of benefits occurred at the time of rebasing, they submitted that the amount of sharing was not commensurate with utility earnings above the approved ROE. This concern is especially relevant for the COS-type rebasing, where any cost reductions achieved in the past PBR term may be masked by utility forecasts used for setting the going-in rates.

324. In the PBR1 decision, the Commission was also concerned with the effect on ESM and customer rates that would result in the event a utility earned above the approved return in one year and below the approved return in the following year (or vice versa). The Commission observes that except for ENMAX,[389] this concern did not materialize for the distribution utilities as their returns were consistently above the approved ROE over the PBR1 and PBR2 terms.[390]

325. In previous PBR plans the Commission focused on maximizing the incentive properties of the plan for the distribution utilities. For PBR3 the Commission is prepared to accept a marginal loss of incentive power in favour of more equitable and timely sharing of benefits with customers. The Commission will observe the distribution utilities' responses to the incentives created by the PBR3 plan and may make further adjustments in future PBR plans to maintain an optimal balance of incentives and sharing of benefits.

326. At the same time, in making these determinations, the Commission agrees with Dr. Weisman's view that in designing a PBR plan, it is necessary to consider the totality of customer benefits which consist of (i) efficiencies shared upfront through formulaic limits on allowed rate increases; (ii) efficiencies shared during the plan by way of shared earnings; and (iii) efficiencies shared after the plan ends through the rebasing process. Representatives of customer groups tend to focus extensively on earnings shared during the plan because forgone innovation that increases future rates is less visible to them than high utility earnings. However, if sharing of efficiencies during a PBR plan results in a significant weakening of the incentives of the plan, customers may in fact end up worse off because their share of PBR benefits can grow larger at the same time that total PBR benefits become smaller, or as Dr. Weisman put it, customers "may be getting a larger slice of a smaller pie."[391] Dr. Weisman added to this thought in his rebuttal evidence:

> The regulated firm under a well-designed PBR plan is like the goose that lays the gold egg. The "golden egg" being cost-reducing innovation. When regulators tamp down too

389 Between the years 2013 and 2021, ENMAX earned less than the approved ROE in 5 out of 9 fiscal years, as shown in Exhibit 27388-X0194 UCA evidence, PDF page 18, A17 and as calculated by the UCA, between 2013 and 2021 ENMAX's average ROE was 7.88 per cent.

390 As shown in Table 1, over 10 years, not including ENMAX and treating ATCO Gas North and South as two separate utilities, the distribution utilities earned below the approved ROE only four times out of the 60 reported returns.

391 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 32, paragraph 84.

> stringently on the regulated firm's earnings, say with a standard ESM, they are de facto killing the goose that lays the golden egg. This is a lose-lose scenario in that it is bad for the goose (the regulated firm) and bad for consumers.[392]

327. Therefore, as discussed in the sections that follow, in implementing the ESM and X factor premium provisions, the Commission wishes to preserve, to the greatest extent possible, the incentive power of the PBR3 plan. Again, in the Commission's view, the purpose of introducing these provisions is to secure better sharing of total benefits of PBR between utilities and their customers, while preventing the muting of the incentives of PBR as much as possible.

9.2 Approved additional benefit-sharing provisions

328. In this proceeding, all parties presented some form of additional benefit-sharing provision either in their primary submission or as an alternative. Specifically, parties proposed: (i) traditional ESM, with different recommendations as to the parameters such as a deadband and sharing ratios; (ii) high-powered ESM (HP-ESM); (iii) X factor premium approach; and (iv) a menu approach that would offer distribution utilities a choice among some of these mechanisms. The Commission accepts the ESM and X factor premium provisions and discusses them below. The Commission does not accept the HP-ESM and a menu approach for the reasons discussed in Section 9.6.

9.2.1 ESM

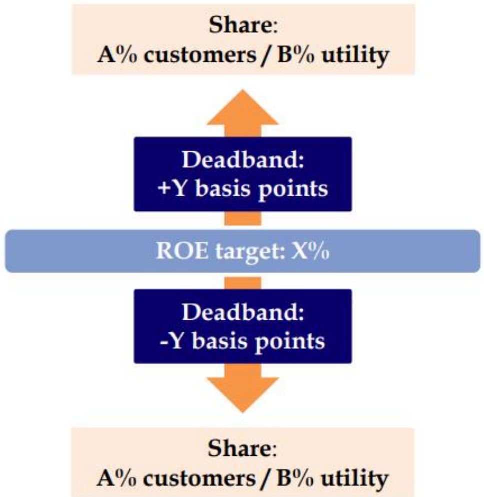
329. As noted in the previous section, ESMs are historically the most widely used benefit-sharing mechanism included in PBR plans. In the current proceeding, the majority of parties, including most distribution utilities, recommended the use of an ESM in PBR3 in the event that the Commission opted to include additional benefit-sharing provisions.

330. An ESM shares a portion of the utility's earnings above a certain threshold or "deadband" with the utility's customers. An ESM may be symmetric which means that the utility shares with customers earnings above the approved return (earning surplus) and collects from customers a share of earnings below the approved return (earnings deficit). Under an asymmetric ESM, normally only achieved returns above the upper limit of the deadband are shared with customers. The utility bears the risk if its achieved return is below the approved ROE. The implementation of an ESM generally requires annual filings of the utility's achieved ROE and sharing calculations as well as some form of verification of these filings, particularly if any ROE adjustments (such as normalization or accounting for the effects of true-ups or other regulatory decisions) are permitted.

331. LEI provided a useful illustration of how a simple ESM (in this example, a symmetric ESM) generally works:

[392] Exhibit 27388-X0567, D. Weisman rebuttal evidence for EPCOR, PDF page 12.

Figure 1. Illustration of ESM design elements (symmetric ESM example)[393]



332. For the reasons set out below, the Commission will include an ESM in the PBR3 plan as one of the additional benefit-sharing provisions.

333. First, typically the amount of sharing under an ESM is proportionate to the utility earnings: that is, the more the utility earns above or below the deadband, the more is shared with customers (in dollar terms). This effect may be further amplified if a tiered ESM sharing structure is implemented with higher sharing percentages (i.e., a greater proportion of utility earnings required to be shared with customers) in each tier. Dr. Weisman observed that in this case the ESM would resemble a "progressive tax" in that sharing increases with utility returns.[394] While the Commission acknowledges that this aspect of an ESM results in some loss of incentives (i.e., by restricting the company's earnings, an ESM can limit a utility's incentive to minimize costs), it has an offsetting benefit of ensuring that customers benefit "at precisely the same time that the regulated firm's earnings are more pronounced."[395] As mentioned in Decision 26356-D01-2021, this proportionate sharing of benefits (and the resulting reduction in customer rates) may become very useful during economic downturns, especially if regulated utilities post higher returns during adverse economic conditions.

334. Second, as Dr. Weisman observed, an ESM provides for a certain degree of self-correction and therefore guards against revenues and costs moving too far out of balance.[396] This may mitigate the need for reopening the plan. The Commission recognizes this relationship in Section 9.5 of this decision where it removes the 300 basis points reopener provision for returns above the approved ROE.

393 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 83, Figure 34.

394 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 32, paragraph 28.

395 Exhibit 27388-X0567, D. Weisman rebuttal evidence for EPCOR, PDF page 12, footnote 10, David E. M. Sappington and Dennis L. Weisman, "Seven Myths About Incentive Regulation," in Michael A. Crew, ed., *Pricing* and *Regulatory Innovations Under Increasing Competition* and *Other Essays*, Boston: Kluwer Academic Publishers, 1996, page 10: "The value of incentive regulation stems in large part from its potential to secure gains for all parties simultaneously. The welfare of consumers can be higher at precisely the same time that the regulated firm's earnings are more pronounced. The gains for any one party do not necessarily come at the expense of another party."

396 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 13, paragraph 30.

335. Third, the Commission also agrees with the views of LEI and Dr. Weisman that because an ESM returns a share of earnings in excess of the approved ROE to customers, it can increase the overall social acceptability of a PBR plan. The submissions of customer groups in this and other proceedings support the point that, "When the utility's returns are unduly high, it may be difficult to convince consumers that economic regulation is providing adequate rate discipline."[397] Conversely, if an ESM is instituted, customers may be less likely to view the distribution utilities' earning above the approved return as a signal that their rates are too high because the earnings are shared, which will serve to reduce rates.

336. The Commission also agrees with the view advanced by the distribution utilities that if not carefully designed, PBR with earnings sharing can result in a significant loss of incentives. As further discussed in Section 9.3, the Commission selected ESM features that preserve the incentives of PBR to the largest degree possible.

9.2.2 X factor premium

337. EPCOR proposed an X factor premium that would work in a similar fashion to a stretch factor and would ensure that customers receive a guaranteed benefit upfront instead of linking customer benefits to the achieved returns of the distribution utilities and waiting until rebasing at the end of the PBR term to share these benefits. EPCOR proposed an X factor premium of 0.3 per cent (without an ESM in the PBR3 plan) which it stated would translate into approximately $0.8 million in guaranteed annual benefits flowing to EPCOR's customers during the PBR3 term. Alternatively, EPCOR was also prepared to adopt an X factor premium of 0.24 per cent coupled with the HP-ESM proposed by Dr. Weisman.[398]

338. Dr. Weisman explained that mechanically, an X factor premium would function in similar fashion to a stretch factor, but it would have a different rationale.[399] The stretch factor is grounded in PBR Principle 1. Namely, by adjusting the industry historical TFP growth, a stretch factor helps to arrive at a reasonable expectation of utility productivity; this, in turn, results in a better emulation of the incentives of competitive market. In contrast, the X factor premium is grounded in PBR Principle 5, which states that customers and the regulated utilities should share in the benefits of PBR. Apex and Dr. Lowry commented that the X factor premium is in effect a stretch factor acting as a benefit-sharing mechanism.[400] The X factor premium is a mechanism with the sole purpose of sharing the benefits of PBR with customers.[401]

339. IPCAA, and both PEG and J. Thygesen on behalf of the CCA, supported an X factor premium or stretch factor as part of PBR3. PEG noted its general preference for stretch factors over earnings sharing. In addition Dr. Lowry indicated that EPCOR's proposed X factor premium is in line with the stretch factors arising from his power distribution benchmarking results.[402] J. Thygesen stated that if the breadth of capital support is narrowed to be in line with what is provided in other jurisdictions, then a higher stretch factor might be sufficient in lieu of earnings sharing. However, J. Thygesen continued, it may still be reasonable to have an ESM

397 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 23, paragraph 58.
398 Exhibit 27388-X0212, EPCOR evidence, PDF page 52, paragraphs 92-93.
399 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 24, paragraph 60.
400 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 12; Transcript, Volume 9, page 1642, (D. Langen); Transcript, Volume 10, page 1995 (J. Wachowich); Transcript, Volume 7, page 1358 (M. Lowry).
401 Transcript, Volume 10, pages 1903-1904 (J. Liteplo).
402 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-029(b), PDF page 72.

with broad deadbands as a safety mechanism.[403] Other parties agreed that X factor and ESM are related as both play a role in sharing the benefits of PBR with customers. LEI proposed coupling the X factor with an ESM.[404]

340. The distribution utilities, other than EPCOR, did not support the X factor premium approach. The ATCO Utilities objected to the upfront nature of benefit sharing independent of achieved results and stated that it "seems punitive to impose a stretch factor which rather than sharing achieved efficiencies somewhat arbitrarily reduces the reasonable costs a utility requires to furnish an essential public service."[405] ENMAX stated that the X factor premium does not share benefits with customers in the same direct way as ESM.[406] Fortis stated there were no inherent advantages or desirable properties with the X factor premium as compared to a symmetric ESM.[407]

341. The Commission finds that it will include an X factor premium of 0.3 per cent in the PBR3 plan to provide additional benefit sharing in PBR3 by way of a predetermined, guaranteed reduction to customer rates in each year during the term of the plan. Similar to the workings of the stretch factor, the X factor premium benefits customers because it provides the expected gains of PBR to them, by means of lower rates, from the start of the PBR plan rather than the alternative of waiting until rebasing. Further, by sharing the benefits of PBR, independent of the actual performance of the utilities, the X factor premium continues to support the strong incentives of the plan. These desirable properties align with the Commission's stated objectives for the PBR3 plan to include more equitable customer sharing going forward.

342. The Commission finds it reasonable to set the X factor premium at 0.3 per cent. In making its determination, the Commission exercised its judgement and expertise informed by EPCOR's analysis that this premium equates to $0.8 million in guaranteed annual benefits flowing to EPCOR's customers during the PBR3 term and similar analyses performed by other distribution utilities in response to Commission IRs. As shown in the table below, the addition of the X factor premium of 0.3 per cent would not reduce the distribution utilities earnings substantially. In performing this analysis, the Commission is mindful of the distribution utilities' submissions that this back-casting exercise has limited use because it assumes no change in utility behaviour, which could be different under different parameters of the alternative plan and associated incentives. However, given the relatively insubstantial amount of the X factor premium of 0.3 per cent relative to past distribution utility returns, the Commission considers such analysis can be used as a general reasonableness check of the approved value.

403 Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-029(b), PDF page 73.
404 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 12.
405 Exhibit 27388-X0221, ATCO evidence, PDF page 50, paragraph 157.
406 Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-029(b), PDF page 96.
407 Exhibit 27388-X0500, FAI-AUC-ALL-2023FEB28-029(a), PDF page 87.

Table 8. Hypothetical amounts associated with a 0.3% X factor premium if one existed in years 2018-2021[408]

Utility	2018	2019	2020	2021
	($ million)			
Apex	0.12	0.23	0.37	0.53
ATCO Gas	0.60	1.20	1.90	2.50
ATCO Electric	0.26	0.67	0.97	1.27
ENMAX	0.24	0.50	0.76	0.99
EPCOR	0.22	0.49	0.80	1.15
Fortis	0.37	0.74	1.13	1.51

343. The Commission acknowledges the distribution utilities' concerns that the sharing mandated by the X factor premium may not correspond with their actual performance and that setting the value of such a premium involves regulatory judgement. In weighing these concerns, the Commission has determined that it would not rely exclusively on an X factor premium to ensure the sharing of benefits with customers in PBR3. Rather it has combined upfront sharing through an X factor premium with an ESM so not all customer benefits rely on either earnings above a deadband or are guaranteed as part of the X factor. In so doing, the Commission has considered the interplay between the X factor (including the premium), the inclusion and parameters of an ESM, as well as other elements of the PBR3 plan in setting the specific values and characteristics of each of the plan elements, including the benefit-sharing provisions. Had only one of the benefit-sharing provisions been relied up in PBR3 to provide customer benefits, either the customer sharing ratios would have been greater under ESM or the X factor premium percentage would have been greater. Instead, the Commission sought to achieve the most equitable balance for both customers and distribution utilities using the two benefit-sharing provisions: one containing more timely sharing, and the other targeting actual ROEs significantly exceeding the approved ROE.

9.3 Features of the approved ESM

344. As previously stated, the Commission has determined that it will require the distribution utilities to implement an asymmetric, two-tiered ESM as part of the PBR3 plan, which will contain a 200 basis point (two per cent) deadband in excess of the approved ROE within which the utility retains all earnings. This section explains how the Commission arrived at these determinations.

9.3.1 Symmetric vs asymmetric

345. Under a symmetric ESM, achieved returns both above and below the approved ROE are shared with customers, subject to any deadband. Under an asymmetric ESM, normally only achieved returns above the upper limit of the deadband around the approved ROE are shared with customers.

346. Regarding the prevalence of asymmetric ESMs, PEG for the CCA stated that many ESMs are designed to share earnings both above and below the approved ROE, but a growing number

[408] Exhibit 27388-X0531, AllParties(Apex)-AUC-2023FEB28-031(c), PDF page 92; Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-031(c), PDF page 155; Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-031(c), PDF page 174; Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-031(c), PDF page 99; Exhibit 27388-X0500, AllParties(Fortis)-AUC-2023FEB28-031(c), PDF page 91.

are asymmetric ESMs, sharing only earnings in excess of the approved ROE.[409] Dr. Orans noted that of the eight jurisdictions and utility examples he reviewed, five included asymmetric ESMs, while the remaining three included symmetric ESMs.[410] Based on the case studies it reviewed, LEI noted an emerging trend that 77 per cent of the ESMs it reviewed are asymmetric.[411]

347. The majority of parties preferred a symmetric ESM design because it reduces utility business risk relative to an asymmetric ESM.[412] In contrast, the CCA and ENMAX (in agreement with LEI's recommendations) preferred an asymmetric ESM design based on their view that utilities have control over significant portions of their costs and associated timing.[413] Although Dr. Orans on behalf of Fortis stated that a symmetric ESM can potentially create a more robust structure during times when costs are highly variable and uncertain, he also noted that many jurisdictions have adopted asymmetric ESMs which maintain strong efficiency incentives and share gains with customers.[414]

348. The Commission agrees with Dr. Oran's view that an asymmetric ESM can provide stronger incentives to avoid particularly low earnings as compared to symmetric ESM plans because a utility cannot collect any portion of earnings below the approved ROE from customers. Consistent with its findings in the PBR2 decision, the Commission also finds that utilities have control over significant portions of their costs and associated timing. Overall, based on the examination of the actual returns over the past two PBR plans set out in Table 1, the Commission is of the view that, in designing the ESM provision for PBR3, it is reasonable to expect that there is a greater need for an ESM to ensure that customers share in the gains above the approved return than for an ESM to protect the utilities in the event earnings below the approved ROE.

349. In approving the asymmetric ESM, the Commission nevertheless considers that other elements of the PBR3 plan ensure that the plan provide strong incentives to the distribution utilities to engage efficiency-seeking behaviour and adequately protects them from downside business risks. Specifically, as set out in the next section, the ESM design includes a wide deadband above the approved ROE before any sharing of earnings is triggered. As well, in Section 9.5, the Commission modifies the reopener provision of the plan to allow the distribution utilities to earn higher returns before any reopener is triggered, while keeping the lower reopener bound at the same level as in PBR1 and PBR2 to protect the distribution utilities from significant downside risks. Other provisions of the plan, such as Z factors, provide to the distribution utilities additional security and protection from unexpected events that could potentially have negative economic impacts.

9.3.2 Deadband and sharing ratios

350. A deadband is a range around the approved ROE within which the utility does not share realized earnings. Earnings above or below the deadband are shared with customers at a

[409] Exhibit 27388-X0231, PEG evidence for the CCA, PDF page 112.
[410] Exhibit 27388-X0500, FAI-AUC-ALL-2023FEB28-034, PDF page 96.
[411] Exhibit 27388-X0198, LEI evidence for ENMAX, PDF page 87.
[412] Exhibit 27388-X0194, R. Bell evidence for the UCA, PDF page 23. Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 41, paragraph 115.
[413] Transcript, Volume 10, pages 1999-2000.
[414] Exhibit 27388-X0210, R. Orans evidence for ENMAX, PDF page 23.

specified sharing ratio or ratios (percentage sharing). There may be several tiers of sharing, each with a distinct sharing ratio.

351. The general rationale behind implementing a deadband in an ESM is to preserve, to the greatest extent possible, the incentives of the PBR plan.[415] Within the approved deadband range, the separation of costs and revenues is preserved and the utility retains all earnings that it generates in excess of the approved ROE. From this perspective, many parties stated that a wider deadband would better preserve the incentive properties of the PBR, while a narrow deadband would have the opposite effect as it reconnects a utility's revenues to its costs sooner.[416]

352. The Commission was presented with a wide range of deadband alternatives from J. Thygesen's proposal of 59 basis points[417] at the low end to the ATCO Utilities' 300 basis points at the high end.[418] There was also a mix of tiered and non-tiered sharing ratios in parties' proposals presented in evidence, as discussed below.

353. J. Thygesen of the CCA and Dr. Orans on behalf of Fortis, proposed narrow deadbands of 59 basis points (asymmetric)[419] and 75 basis points (symmetric), respectively.[420] J. Thygesen recommended that above the deadband, the sharing between customers and the utility would be 50/50 in the first tier and 75/25 in the second tier, commencing at 150 basis points above the approved ROE.[421] Dr. Orans stated that if the Commission were to adopt an asymmetric ESM, then he recommended a wider deadband between 150 to 200 basis points to preserve the existing strong management incentives already present in PBR2, with a secondary goal of equitable sharing of benefits with customers.

354. All other parties proposed a wider deadband for the ESM design. Fortis recommended a deadband at 125 basis points symmetrically around the approved ROE.[422] Dr. Weisman recommended the deadband at 200 basis points,[423] which was also the deadband recommended by R. Bell of the UCA, after which sharing would be 50/50 between customers and the utility.[424] R. Bell also added that if the X factor falls lower than the PBR2 X factor rate of 0.3 per cent, then the deadband should be narrower and set at 100 basis points.[425]

415 For example, in Exhibit 27388-X0213, D. Weisman evidence for EPCOR, at PDF page 41, pararaph114, D. Weisman explained with reference to academic literature that "There should be a deadband around the approved ROE to (i) take into account the natural variability in earnings; (ii) provide strong incentives for investment in cost-reducing innovation; and (iii) recognize the 'high transaction costs associated with rate reviews and allow these costs to be avoided when the benefits of price adjustments are small."

416 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF pages 89-90; Exhibit 27388-X0221, ATCO evidence, PDF page 51, paragraph 159; Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF page 62; Exhibit 27388-X0201, Apex evidence, PDF page 46, paragraph 149; Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 41, paragraph 114.

417 Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF page 59, paragraph 165.

418 Exhibit 27388-X0221, ATCO evidence, PDF page 52, paragraph 162.

419 Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF page 59, paragraph 165.

420 Exhibit 27388-X0210, E3 evidence for Fortis, PDF pages 23-24.

421 Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF page 59, paragraph 169.

422 Exhibit 27388-X0211, Fortis evidence, PDF page 45, paragraph 126.

423 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 42, paragraph 117.

424 Exhibit 27388-X0194, R. Bell evidence for the UCA, PDF page 3.

425 Exhibit 27388-X0194, R. Bell evidence for the UCA, PDF page 3.

355. LEI stated that sharing ratios are typically set at 50/50 between customers and the utility. LEI, supported by ENMAX,[426] recommended implementing an asymmetric ESM for PBR3, with a 300 basis point deadband above the target ROE, with 50/50 sharing between customers and the utility outside of the deadband.[427]

356. The ATCO Utilities recommended a 300 basis points deadband above and below the approved ROE; which it said was sufficiently wide to lessen the blunting of efficiency incentives that an ESM would cause and set similar to the existing reopener thresholds.[428] Beyond the 300 basis point deadband, the next 200 basis points would be shared at 25/75 between customers and the utility, and then for any ROE that exceeds beyond 500 basis points above the approved ROE, sharing should be 90/10 between customers and the utility.[429]

357. Having considered the evidence, including the written and oral testimony of the experts in this proceeding, the Commission has determined that a wider deadband balances the need to ensure more equitable customer sharing during the PBR term with the need to preserve the incentives of PBR. As Dr. Weisman described it, "the regulated firm is the residual claimant for its efficiency gains in this range of financial returns just as it is under pure PBR."[430] From this perspective, the Commission considers that implementing a sufficiently wide ESM deadband will ensure that the PBR3 plan provides strong efficiency incentives.

358. In the Commission's view, a deadband in the range of 100 basis points or narrower around the approved ROE would result in significant blunting of incentives as this would reconnect utility costs and revenues sooner and transfer most of the risks and rewards from a utility to its customers. From the Commission's experience, it is not uncommon for utilities under COS regulation to exceed their approved ROE by more than that range. At the other end of the spectrum, a deadband closer to 300 basis points would not result in meaningful sharing of benefits based on historical experience, as none of the distribution utilities, except for the ATCO Utilities, reached that level of returns in PBR1 and PBR2. In the Commission's view, a deadband of 200 basis points above the approved ROE which is in the mid-point of the range of deadbands proposed by the parties as discussed above adequately balances these objectives.

359. In considering the sharing ratios, the Commission was assisted by Dr. Weisman's view that:

> As the company's financial returns move progressively above (below) the upper (lower) bounds of the deadband, it becomes less likely that the company's innovation and business acumen (or lack thereof) explain these outcomes and more likely that they are explained by various exogenous effects (e.g., a systemic problem with the structure of the PBR plan, the PBR parameters or the going-in rates for the PBR plan).[35] This observation has implications for how returns in these ranges should be treated.
>
> [35.] In other words, it is increasingly less likely that the regulated firm is that "proficient" or that "deficient."[431]

426 Exhibit 27388-X0197, ENMAX evidence, PDF page 4.
427 Exhibit 27388-X0198, Evidence of LEI on behalf of ENMAX, PDF page 88.
428 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 52, paragraph 159.
429 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 52, paragraph 162.
430 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 21, paragraph 51.
431 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 22, paragraph 54.

360. From this perspective, the Commission agrees with those parties who proposed tiered sharing ratios[432] and finds that by implementing a 200 basis point deadband and two tiers of progressively decreasing proportional sharing between distribution utilities and their customers, distribution utilities will continue to be incented to seek out efficiencies.

361. Based on the above, the Commission approves the following provisions of the ESM for PBR3:

(i) An asymmetric deadband of 200 basis points above the approved ROE for a given year, within which no sharing with customers occurs. As well, no sharing with customers by way of an ESM occurs below the approved ROE.

(ii) A first tier of sharing between 200 basis points and 400 basis points above the approved ROE for that year where the distribution utility retains 60 per cent of the incremental earnings and customers receive 40 per cent of the incremental earnings in this range.

(iii) A second tier of sharing at 400 basis points above the approved ROE for that year where the distribution utility retains 20 per cent of the incremental earnings and customers receive 80 per cent of incremental earnings in this range.

362. In the Commission's view, the above ESM provisions reasonably balance the objectives of ensuring that (i) the efficiency incentives of the plan are maintained to the greatest extent possible; and (ii) customers and the distribution utilities share the benefits of the PBR plan. As discussed throughout this section, in developing the elements of the ESM, the Commission took into account the inclusion of an X factor premium provision, which is another benefit-sharing provision in the PBR3 plan, as well as the other parameters of the PBR3 plan.

9.4 ESM sharing calculations

363. In this proceeding, the distribution utilities and R. Bell for the UCA provided some illustrative ESM calculations using past returns.[433] These calculations are consistent with the Commission's understanding of how sharing amounts for an ESM should be calculated, as provided below:

(i) Calculate the difference between the distribution utility achieved ROE percentage from Rule 005 (after any approved ROE adjustments) for a given year less the approved ROE percentage for that year.

(ii) If the difference from part (i) is less than 200 basis points, no sharing will take place.

(iii) If the difference from part (i) is between 200 and 400 basis points, the amount above 200 basis points will be multiplied by the applicable customer sharing ratio of 40 per cent for the first ESM tier and the equity portion of the mid-year rate base for that year to determine the dollar amount to be shared with customers in the following year.

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[432] Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 52, paragraph 162; Exhibit 27388-X0169, J. Thygesen evidence for the CCA, PDF pages 58-59, paragraph 165.

[433] Exhibit 27388-X0379; Exhibit 27388-X0402; Exhibit 27388-X0457; Exhibit 27388-X0500; Exhibit 27388-X0531, Distribution utilities' responses to AllParties-AUC-2023FEB28-031; Exhibit 27388-X0194, R. Bell evidence for the UCA, PDF pages 23-24.

(iv) If the difference from part (i) is greater than 400 basis points, the amount above 400 basis points will be multiplied by the applicable customer sharing ratio percentage for the second tier of 80 per cent and the equity portion of the mid-year rate base for that year. This second tier sharing amount is then added to the first tier sharing amount from part (iii) to determine the total amount to be shared with customers in the following year.

364. The parties generally agreed that the annual Rule 005 actual ROE results should be the starting point for ESM calculations, and distribution utilities put forward their recommendations for adjustments to the Rule 005 actual ROE prior to any sharing calculations being performed.

365. Parties were also generally in agreement that if too many adjustments to the ROEs reported in Rule 005 are permitted, this could trigger a debate of what portion of earnings should count for ESM purposes, thereby turning the calculation of ESM sharing amounts into a burdensome fully litigated cost of service review of the entirety of a distribution utility costs, not dissimilar to a rebasing or a reopener proceeding. In his evidence for the ATCO Utilities, Dr. Brown captured this concern:

> In addition, an ESM may create additional burden and undermine incentives in a different way: it must be very clear that the operation of the ESM should be automatic, based solely on the existing financial reporting (Rule 005). If there is the possibility that the ESM calculation will not be automatic, that could trigger a burdensome debate over whether certain recorded spending should or should not "count" for ESM purposes. If this were to happen then the ESM would create administrative burden and would also undermine incentives through uncertainty over how expenditures (and savings) will be treated—effectively, the annual ESM filing could take on characteristics of a reopener proceeding, with argument over whether all costs should be taken into account, and whether earnings are due to savings or external factors.[434]

366. Fortis requested the following adjustments be made in determining the ROE amount to be shared:[435]

(i) Rider E[436] assets and associated costs are recovered through a special facilities charge attributable to specific customers. As such, any calculation should exclude the assets and costs associated with Rider E;

(ii) To avoid double counting of ESM amounts in a given year, any amounts recognized in Rule 005 results associated with the true-up of a prior year's ESM need to be excluded from the calculation of the current year's ESM amounts; and

(iii) Any amounts collected in 2024 on account of the approved ECM amounts from PBR2 should be excluded from the determination of ESM as this amount is related to efficiencies achieved by the utilities at the end of the previous PBR term.

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434 Exhibit 27388-X0222, T. Brown evidence for the ATCO Utilities and Apex, PDF page 59, Q/As 111.
435 Exhibit 27388-X0500, FAI-AUC-ALL-2023FEB28-027(a), PDF page 85.
436 Rider E is designed for the distribution utility to recover costs for facilities constructed by the utility on a customer owned or leased property, as requested by the customer.

367. The ATCO Utilities agreed with the recommendations by Fortis and stated it currently excludes Rider E from utility earnings.[437] EPCOR agreed with the Fortis recommendations for ROE adjustments, and stated other adjustments it believed should be included are the impacts of rider true up, and impacts of K-bar true ups for weighted average cost of capital (WACC) and base rate adjustments.[438]

368. Apex stated that in addition to adjustments for the ESM and ECM, the actual ROE for ESM purposes should reflect necessary adjustments for Commission decisions and rulings not known or available at the time of Rule 005 filings.[439] Apex provided examples of this, such as rulings on depreciation studies and generic cost of capital proceedings that are not available until after the completion of the year to which they relate and may be accounted for in a subsequent year. Apex stated that utilities should be allowed to reflect necessary adjustments to the Rule 005 ROE to ensure proper matching of revenues and expenses to reflect the appropriate ROE for ESM purposes. Apex also stated that its starting point for ESM calculations should be its weather-normalized actual ROE.[440]

369. ENMAX also agreed that ECM and ESM amounts should be excluded. In addition, ENMAX advocated for adjusting the reported ROE for "anomalous entries impacting the Rule 005 ROE" such as ENMAX's accounting omission related to its transmission access charge deferral account true-up. In argument, ENMAX's counsel stated, "The circumstances in which the Rule 5 ROE should be adjusted for earnings sharing purposes should be very narrow, but in ENMAX's view, it is reasonable to keep the door open to account for instances where exceptional circumstances make it unfair either to customers or the utility to base earnings sharing on the Rule 5 ROE alone."[441]

370. The UCA and the CCA stated that just as there were no adjustments to the Rule 005 ROE for purposes of the ECM calculations, there should not be any adjustments for calculating the ESM amounts.[442] As such, the only adjustment to the Rule 005 ROE the UCA and CCA supported was to exclude any earnings related to the ECM.

371. The Commission agrees that adjustments to the actual ROE for ESM calculation purposes must be minimized to avoid creating undesirable incentives for all parties in terms of reporting or scrutinizing costs as well as the resulting regulatory burden associated with the proposed adjustments to the ROE.

372. For these reasons, the Commission will generally only consider the following pre-determined, objective adjustments to achieved ROEs reported in Rule 005 that are similar to the adjustments to ROEs for reopener purposes:

(i) Amounts related to ESMs and ECMs from prior periods must be excluded.

437 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-027(b), PDF page 146.
438 Exhibit 27388-X0402.01, AllParties(EDTI)-AUC-2023FEB28-027(a) and (b), PDF page 163.
439 Exhibit 27388-X0531, AllParties(Apex)-AUC-2023FEB28-027(b), PDF page 85.
440 Exhibit 27388-X0531, AllParties(Apex)-AUC-2023FEB28-027(a), PDF page 84.
441 Transcript, Volume 9, page 1756, lines 4-10.
442 Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-027(b), PDF page 64. Exhibit 27388-X0494, AllParties(CCA)-AUC-2023FEB28-027(b), PDF page 71.

(ii) Any costs or revenues related to Rider E assets for ATCO Electric and Fortis must be excluded.

(iii) Amounts related to I factor and K-bar true-ups must be accounted for; however, the Commission will not permit adjustments for other small true-ups (e.g., Y factors, various rider true-ups, transmission access charge deferral account true-ups, etc.).[443]

(iv) Weather normalized ROEs for gas distribution utilities must be used.

373. Given that all of these adjustments should be available by the time of the annual PBR rate adjustment filings due September 10 each year, the distribution utilities are directed to calculate any earnings to be shared with customers under the approved ESM provisions as part of those applications. Detailed calculations must be provided by distribution utilities to show how they determined the sharing amount including support for any adjustments to the Rule 005 reported ROE, subject to the limitations on adjustments noted below.

9.5 Reopener provision

374. In the PBR1 and PBR2 plans, the Commission approved an ROE-based reopener provision as a safeguard against unexpected results that could signal that there is a problem with the design or operation of the plan that makes its continued operation untenable.[444] Specifically, the Commission indicated that an earned ROE that is 500 basis points above or below the approved ROE in a single year or 300 basis points above or below the approved ROE in two consecutive years may warrant a reopening and review of the plan.

375. In developing the scope of this proceeding, the Commission indicated that it would not review that reopener provision in the PBR3 plan. However, the Commission stated that changes to the reopener provision could be required if an ESM is included within the PBR3 plan.[445]

376. Most parties in this proceeding agreed that an ESM and reopener provisions are not mutually exclusive and can both be present in a PBR plan as they serve different purposes. The Commission agrees. However, because the Commission has determined that a two-tiered asymmetric ESM with a wide deadband and tiered sharing will be included in PBR3, the Commission finds that it is no longer reasonable to trigger the reopener review when an achieved ROE exceeds the approved ROE by 300 basis points in two consecutive years. In the Commission's view, the established ESM sharing tiers will sufficiently mitigate the need for reopening the plan at these earnings levels.

377. Other reopener provisions will remain the same as in the first two PBR terms. The Commission retains the reopener trigger of 500 basis points above the approved ROE in a single year. The Commission may also consider reopening the plan if the achieved returns are 300 basis points below the approved ROE in two consecutive years or 500 basis points below the approved ROE in a single year. Given the asymmetric ESM, retaining the 300 basis points reopener

443 With the exception of Commission-directed adjustments related to true-ups, the achieved ROE will not be adjusted for true-ups for prior period accruals or future Commission decisions that relate to prior periods as these occur in the normal course of utility operations.

444 Decision 2012-237, PDF page 164, paragraph 723.

445 Exhibit 27388-X0046 AUC Letter, Ruling on final list of issues, footnote 3: "Another example is that the introduction of an ESM may impact the reopener provision."

provision in relation to achieved returns below the approved ROE will continue to protect distribution utilities from downside risks.

378. For simplicity and to avoid the duplication of work associated with the calculation of prior period adjustments, the Commission finds that consideration of a reopener may be triggered on the basis of the same restated ROE used for ESM purposes, as reported in the PBR annual rate adjustment in September of each year. However, unlike for ESM purposes, the Commission may consider further normalizing the reported ROE in assessing the need for a reopener, as discussed in Decision 20414-D01-2016 (Errata).[446] To clarify, the Commission will consider the need for a reopener if the adjusted achieved ROE is 500 basis points above the approved ROE even though there will be current year ESM amounts expected to be paid in the following year.

9.6 Other customer sharing proposals

9.6.1 High-powered ESM

379. To address the dulling of incentives typically associated with an ESM, Dr. Weisman in his evidence for EPCOR proposed, what he termed, an HP-ESM. Similar to a standard ESM, HP-ESM has a deadband around the approved ROE (200 basis points as per Dr. Weisman's proposal) within which there is no sharing. However, under Dr. Weisman's HP-ESM proposal, the first 100 basis points of returns above the upper bound of the deadband accrue entirely to customers. The second 100 basis points above the upper bound of the deadband accrue entirely to the regulated firm.[447]

380. Because of this structure, explains Dr. Weisman, once a utility earns a return outside the upper bound of a deadband, the HP-ESM is intended to appear to the utility as an unavoidable, lumpsum tax and it will be motivated to continue innovating and reducing its costs to minimize the effect of such a lump-sum tax.[448] Thus, HP-ESM may not diminish the utility's incentives for efficiency because, once outside of the first 100 basis points above the deadband, the utility will retain the full amount of earnings just as under a PBR plan with no ESM.[449]

381. Other features of Dr. Weisman's HP-ESM are similar to a traditional ESM. The proposed HP-ESM is symmetric, with customers paying additional funds to the utility if its returns are less than the approved ROE and outside the 200 basis points deadband. Dr. Weisman also proposed to have either a "soft cap" or a "hard cap" on earnings significantly above or below the approved ROE, in his proposal 400 basis points. Under a soft cap approach, earnings would be examined as they would under a reopener to determine if they were a result of the expected workings of a PBR plan or arose because as a result of a flaw in the plan. Depending on the outcome of such review, the utility may be permitted to retain (or collect if below the approved ROE) a portion, or the full amount of such earnings. Under a hard cap, any earnings in excess of the 400 basis points above (or below) the approved ROE would accrue to (or be collected from) customers.[450]

382. For the reasons set out below, the Commission will not adopt the HP-ESM as proposed by Dr. Weisman for EPCOR.

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446 Decision 20414-D01-2016 (Errata), PDF pages 82-84.
447 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 19.
448 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 21.
449 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 21
450 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 20.

383. The HP-ESM approach is a novel idea, and Dr. Weisman admitted in an IR response that he was not aware of any jurisdiction that has adopted the HP-ESM approach discussed in his evidence.[451] Other than EPCOR, no party in this proceeding supported the adoption of HP-ESM. Parties' main concerns with this approach were that it was overly complex and difficult to understand,[452] it would not function in the way it was intended and could in fact chill innovation,[453] and it would not result in stronger incentives than a simple symmetric ESM.[454] R. Bell for the UCA stated that the HP-ESM provides limited protection to customers if the utility experiences windfall gains.[455]

384. In setting the scope of this proceeding, the Commission recognized the potential for a traditional ESM to diminish the incentives of PBR and asked parties to provide evidence on alternative mechanisms to share the benefits of PBR between customers and distribution utilities. The Commission finds that Dr. Weisman's HP-ESM proposal is an interesting and thoughtful alternative to a traditional ESM. At least from a theoretical perspective, a HP-ESM may have better incentive properties as it permits the utility to keep all its earnings once it clears the initial threshold or "lump sum tax."

385. In designing a one-size-fits-all benefit-sharing provision for all distribution utilities in Alberta, the Commission considers that the progressive nature of a traditional ESM is preferred to strike a reasonable balance between greater sharing of benefits with customers and mitigating any blunting of PBR incentives for the distribution utilities.

386. Unlike a traditional ESM, the proposed HP-ESM was not supported by the interveners, who submitted that it would not prevent the distribution utilities from achieving high returns and that such returns would not be shared with customers proportionately, or progressively (i.e., increasing sharing percentage with higher achieved returns).All distribution utilities, except EPCOR, preferred a traditional ESM to the proposed HP-ESM if the Commission opted for additional benefit-sharing provisions.

387. Overall, the Commission finds that a more traditional ESM that ensures that benefits are shared with customers "in direct, visible ways precisely when the regulated firm benefits,"[456] coupled with an X factor premium, better meets the Commission's objectives for benefit sharing in PBR3.

9.6.2 Menu option

388. Dr. Weisman indicated that the Commission may offer the distribution utilities a choice among various benefit-sharing provisions, such as a choice between a standard ESM and a complete buy-out of an ESM through an X factor premium. He explained that by doing so, the Commission may be able to secure benefits for customers by inducing utilities to select plans that are tailored to their capabilities and to the environments in which they operate.

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451 Exhibit 27388-X0400, EDTI-AUC-2023FEB28-013(b), PDF page 39.
452 Exhibit 27388-X0457, AllParties(ATCO)-AUC-2023FEB28-030(a), PDF page 152.
453 Exhibit 27388-X0379, AllParties(EPC)-AUC-2023FEB28-028(a), PDF page 97.
454 Exhibit 27388-X0500, AllParties(Fortis)-AUC-2023FEB28-028(a)(i), PDF page 86.
455 Exhibit 27388-X0440, AllParties(UCA)-AUC-2023FEB28-028(a), PDF page 68.
456 Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF page 14, paragraph 33.

389. Dr. Weisman explained in his evidence that EPCOR had chosen not to pursue the menu approach. Its reasons for not pursuing it were:[457]

(i) The Commission considered but subsequently rejected the menu approach in both the first and second-generation PBR proceedings.

(ii) The menu approach to PBR is not common and a number of regulatory commissions that experimented with it would later abandon it.

(iii) Regulators may have a difficult time explaining to their constituencies precisely why they are offering the companies a choice of PBR regimes under which to operate.

(iv) The Commission has repeatedly underscored the importance of reducing "red tape" and streamlining the regulatory process and this approach may work at cross purposes with those stated objectives.

390. Parties were not supportive of the menu approach to benefit sharing because, in addition to the reasons Dr. Weisman provided, they were uncertain how the various options would be determined and how they could be assured that the options would provide equitable choices.[458]

391. The Commission finds that for the purposes of the PBR3 plan, the complexities associated with the menu approach are likely to outweigh the potential benefits. The Commission will not offer the distribution utilities a choice of benefit-sharing parameters. The Commission will continue to evaluate the distribution utilities' responses to the incentives provided by the PBR3 plan and may consider offering a choice among benefit-sharing provisions in future PBR plans.

10 Discontinuation of the ECM

392. The Commission has previously accepted that a utility's incentive to find efficiencies weakens as the end of the PBR term approaches because there is less time remaining for a utility to benefit from any efficiency gains before authorized revenues are reset to match costs. The Commission approved the inclusion of the ECM to address this weakening of incentives by permitting the distribution utilities to carry a portion of earnings in excess of the approved ROE from the prior PBR term to the following years. The ECM was approved for both the PBR1 and PBR2 plans.

393. Specifically, the approved ECM allowed the distribution utilities to carry a portion of earnings in excess of the approved ROE from the prior PBR term to the following years. The ECM ROE add-on was calculated as 50 per cent of the difference between the average approved and average actual ROEs over the course of the PBR term, with an upper limit of 0.5 percentage points.[459] This ROE add-on applied for two years after the end of each PBR term and was collected by way of a Y factor.

[457] Exhibit 27388-X0213, D. Weisman evidence for EPCOR, PDF pages 30-31, paragraphs 79-81.
[458] Transcript, Volume 4, page 616, lines 4-9; Transcript, Volume 9, page 1643, line 17 to page 1644, line 3; Transcript, Volume 10, page 1914, line 4 to page 1915, line 22.
[459] Decision 2012-237, PDF page 175, paragraph 766, as clarified in Decision 20414-D01-2016 (Errata), PDF page 30, paragraph 79.

394. In this proceeding, the Commission explored whether the ECM achieved its intended purpose and whether it should be included in the PBR3 plan, especially if the ESM is approved. In general the distribution utilities supported including an ECM in PBR3 and the representatives of customer groups did not. Some of the parties also provided adjustments that could be made to the current ECM if the Commission were to decide to continue with this mechanism.

395. Parties generally agreed that ESM and ECM serve different purposes and are not mutually exclusive. In their evidence, the ATCO Utilities stated that the ESM and ECM deal with separate and different issues and as such both could be included in the plan.[460] Similarly, Fortis stated that both an ESM and ECM can be included as they have distinct and separate purposes within the plan.[461]

396. In its evidence for ENMAX, LEI recommended to continue including the ECM provision but in a modified form. It proposed calculating the ECM as 50 per cent of the difference between the average approved and average actual ROEs achieved during the final three years of the PBR term.[462] LEI explained that in the absence of an ECM, the incentive properties weaken as the term progresses resulting in the deferral of late-in-term productivity investments to early in a subsequent term. LEI further explained that its modification to the ECM calculation which reduces the test period for the differential from five years to the final three years of the PBR term is intended to better target the mechanism towards late-in-term initiatives.[463]

397. Similarly, Dr. Brown's evidence for the ATCO Utilities and Apex stated that an ECM should be included as the strength of the cost control incentive weakens towards the end of the plan term, and in later PBR generations an ECM is more important because the "low-hanging fruit" has already been collected. Dr. Brown suggested that the current ECM effectively provides a multiplier of about 20 per cent to the strength of the cost-control incentive in each of the plan years. Dr. Brown also stated that the incentive could be strengthened in the later years of the plan. As a result both the ATCO Utilities and Apex suggested using a weighted five-year average instead of the existing simple five-year average ROE be used in the ECM calculation with greater weights placed on the ROEs achieved in the later years of the PBR plan.[464]

398. In his evidence on behalf of the CCA, J. Thygesen stated that the ECM should be discontinued in the PBR3 plan because it does not differentiate between efficiencies at the start of the term and the end of the term. Therefore, there is a mismatch between the stated objective of the ECM and the way the actual mechanism works.[465] The CCA also stated that while Dr. Brown's proposed revision would constitute an improvement as it attaches more weight to the end of the term, the weightings towards the end of term could provide incentives to game or strategically defer costs until the first year of the next plan.[466] The CCA also argued the utilities are already rewarded via ROE for efficiency savings.[467]

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460 Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 53, paragraph 165.
461 Exhibit 27388-X0211, FortisAlberta Evidence, PDF page 48, paragraph 136.
462 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF pages 100-101.
463 Exhibit 27388-X0198, LEI evidence for ENMAX, PDF pages 100-102.
464 Exhibit 27388-X0201, Apex evidence, PDF page 51, paragraphs 171-173; Exhibit 27388-X0221, ATCO Utilities evidence, PDF page 48, paragraph 147.
465 Exhibit 27388-X0169, J. Thygesen CCA evidence for the CCA, PDF page 61, paragraph 176.
466 Exhibit 27388-X0494, AllParties(CCA)-2023FEB28-035(d) to (e), PDF pages 85-86.
467 Transcript, Volume 10, page 1992, lines 19-21 (J. Wachowich).

399. In its evidence for the CCA, PEG explained that an ECM can offer several potential benefits. It can discourage opportunistic cost deferrals and encourage utilities to achieve long-term performance gains. PEG suggested that if the ECM were to be continued, an alternative ECM should be considered such as a stretch factor linked to statistical benchmarking. Alternatively, the ECM could be based on a comparison of the revenue requirement in the first year of the plan to that resulting from a one-year extension of the expiring plan.[468]

400. The Commission asked each distribution utility to list any specific cost reducing initiatives that were undertaken in the last two years of PBR2 that would not have been undertaken in the absence of the ECM. In general the distribution utilities could not point to specific cost initiatives that that would not been undertaken in the absence of an ECM with some stating that such decisions were taken in context of the PBR2 plan as a whole.[469]

401. In argument, Apex referenced the statements of the CCA's expert Dr. Lowry that it would be hard for him to confirm that the ECM had no effect in past PBR terms. Apex argued that in order to strengthen the incentive provided by the ECM in PBR3 and to discourage what Dr. Lowry referred to as "strategic deferrals," the ECM should be modified to strengthen the incentive in the later years of the PBR term, as was recommended by each of Apex, the ATCO Utilities and ENMAX.[470] Similarly, the ATCO Utilities argued that if the Commission were to remove the ECM from the PBR3 plan, it will be incenting the strategic deferrals described by Dr. Lowry and would as a result reduce customer savings in the next rebasing.[471]

402. The UCA acknowledged the view of LEI that a deferral of purely discretionary projects "would not be a terrible thing;"[472] however, the UCA argued that the impact will be relatively short-lived and such outcome would be a better alternative than keeping the ECM with the uncertainty regarding whether it is actually useful. The UCA argued that as long as safety and reliability measures are not impacted, it questions the need for an ECM to encourage efficiencies during the final years of the term.[473]

403. The Commission is not persuaded, based on the evidence in this proceeding, that the ROE-based ECM in the form approved for PBR1 and PBR2 plans, achieves its intended purpose of addressing the weakening of incentives towards the end of the PBR term. It appears from the IR responses and discussion during the oral hearing that the presence of an ECM is not a determining factor in a distribution utility's decision making with respect to any cost-saving or efficiency initiatives that are being considered. Multiple distribution utilities stated that they consider the PBR plan as a whole when deciding whether or not to implement such initiatives.[474] Four out of six utilities indicated that the ECM should be modified to focus on the ROEs in the

[468] Exhibit 27388-X0231-01, PEG evidence for the CCA, PDF pages 119-120.
[469] Exhibit 27388-X0379, AllParties(EPC)-2023FEB28-035(c), PDF page 106; Exhibit 27388-X0402, AllParties(EDTI)-2023FEB28-035(c), PDF page 187; Exhibit 27388-X0457, AllParties(ATCO)-2023FEB28-035(c), PDF pages 168-169; Exhibit 27388-X0500, AllParties(Fortis)-2023FEB28-035(c), PDF page 99; Exhibit 27388-X0531, AllParties(Apex)-2023FEB28-035(c), PDF page 100.
[470] Transcript, Volume 9, page 1648, lines 22-25 to page 1649, lines 1-6 (D. Langen).
[471] Transcript, Volume 9, page 1720, lines 11-21 (L. Smith).
[472] Transcript, Volume 4, page 727, line 25 to page 728, line 10.
[473] Transcript, Volume 10, page 1892, lines 6-25 to page 1893, lines 1-5 (K. Rutherford).
[474] Transcript, Volume 2, page 274, lines 8-16 (M. Stock); Transcript, Volume 3, page 381, lines 6-17 (L. Radke); Transcript, Volume 4, page 620, lines 21-25 to page 621, lines 1-7 (J. Taylor); Transcript, Volume 5, page 827, lines 13-25 to page 828, lines 1-7 (S. Chaudhary); Transcript, Volume 5, page 1073, lines 20-23 (B. Henderson); Transcript, Volume 6, page 1363, lines 3-6 (M. Lowry).

last three years of the plan to better achieve its intended purpose. Although the Commission acknowledges this proposal may be an improvement over the ECM methodology used in PBR1 and PBR2, it is not persuaded that even with this adjustment, the incentive properties of the ECM would be augmented such that distribution utilities would make different decisions and pursue greater efficiencies in the later years of the PBR3 plan than they otherwise would. Further, the distribution utilities did not demonstrate that the benefits of incremental efficiencies or cost reductions achieved through the use of an ECM outweighed the costs to consumers of the incremental earnings paid to utilities to incent those incremental efficiencies.

404. While the Commission acknowledges that there is a theoretical risk that the distribution utilities could strategically defer projects that could otherwise be completed in the later years at the end of the plan, there was no evidence on the record of this proceeding to suggest that the ECM had directly mitigated this risk through changed distribution utility behaviour over PBR1 and PBR2. Ultimately, the Commission is not persuaded that the ECM is necessary to address such risk given the other incentive properties of the PBR3 plan.

405. For the reasons above, the Commission will not include an ROE-based ECM in the PBR3. However, as stated earlier, the Commission recognizes that a utility's incentive to find efficiencies weakens as the end of the PBR term approaches because there is less time remaining for a utility to benefit from any efficiency gains before authorized revenues are reset to match costs. In the future, the Commission may consider alternative remedies to enhance efficiencies at the end of the term, including alternative forms of ECM.

11 Quantification and tracking of efficiencies

406. One of the guiding PBR principles used by the Commission is that "customers and the regulated companies should share the benefits of a PBR plan."[475] In the absence of an ESM in prior PBR plans, this sharing of benefits with customers was done by means of an X factor during the plan (i.e., through lower rates) and at rebasing at the end of the plans. This is why in the PBR3 rebasing proceedings, the Commission directed the distribution utilities to quantify and clearly demonstrate how the efficiencies realized, and cost reductions achieved, during the PBR2 term were reflected in their 2023 forecast revenue requirement, and would be passed on to customers.[476]

407. Ultimately, while the Commission determined that the proposed 2023 forecast revenue requirements were reasonable, the Commission found that the utilities were not able to adequately link projected efficiencies and costs savings to particular initiatives. To avoid similar problems at the next rebasing, the Commission directed the utilities to present proposals in this proceeding on how efficiencies can be effectively quantified and tracked over time.[477]

408. In this proceeding, parties proposed a wide range of options, ranging from no implementation of metrics, as suggested by Apex, to the implementation of several metrics, as suggested by ENMAX. Apex and the ATCO Utilities stated that achieved efficiencies are reflected in their actual results, and incurring costs and diverting management attention away

475 Decision 2012-237, PDF page 15, paragraph 28.
476 Decision 26354-D01-2021, PDF page 14, paragraph 40.
477 Decision 26615-D01-2022, PDF page 26, paragraph 91; Decision 26616-D01-2022, PDF page 26, paragraph 103.

from the pursuit of future cost savings in order to track metrics would be counterproductive.[478] As a result of the wide range of proposals, parties were asked in a Commission IR to choose what they believe are the three most relevant metrics from a list compiled by the Commission, which included the metrics proposed by each party. The parties provided the following submissions, with controllable O&M per customer and controllable O&M per km of line (pipe) being the top two suggested metrics.

Table 9. Suggested metrics from All Parties IR-015[479]

All Parties IR-015 suggested metrics								
Metric	**ATCO**	**EPCOR**	**Fortis**	**ENMAX**	**Apex**	**UCA**	**IPCAA**	**Total count**
Total Cost per Rate Base	X				X			2
Controllable O&M per Customer	X	X*	X		X		X	5
Controllable O&M per km of line (Pipe)	X		X	X	X			4
Rate Base per FTE		X						1
Reconciliation of Approved ROE to Actual ROE		X						1
Distribution Service Price Index (DSPI)			X					1
Capex per customer				X			X	2
Capex per km of line				X				1
Capital addition per new customer by rate class						X		1
Capital additions per unit of additional peak capacity						X		1
Capital additions per km of new lines built						X		1
Total capital expenditures and controllable operating costs per customer.							X	1

*EPCOR suggested Operating cost per customer and mentioned it is similar to controllable O&M per customer.

409. Generally, parties agreed that any selected metric must be clearly defined, especially if the metric measures "controllable" costs, where a clear definition of controllable would be required. When asked how they would define "controllable," parties generally agreed that in the context of O&M, this would include all O&M except for any items that are not in the utility's direct control, such as flowthroughs,[480] transmission expenses and franchise fees,[481] and that the definition of controllable should be consistent across all utilities.

410. The parties differed on whether any metric using total costs (O&M plus capital additions) per km of line (pipe) or total costs per customer would be a suitable metric. Apex stated that the drivers of capital costs and O&M expenses differ, that as a result, any trends may not be meaningful, and that the volatility of capital additions is also a factor.[482] The ATCO Utilities agreed with Apex and explained that a significant amount of capital expenditures may not be driven by an increase in customers, but is required to be done to upgrade the system and deal

[478] Transcript, Volume 9, page 1681, lines 8-15, and page 1721, lines 2-24.

[479] Adapted from responses to All Parties-AUC-2023FEB28-015, Exhibit 27388-X0379; Exhibit 27388-X0402; Exhibit 27388-X0440; Exhibit 27388-X0457; Exhibit 27388-X0494; Exhibit 27388-X0500; Exhibit 27388-X0531.

[480] Transcript, Volume 2, page 276, lines 2-7.

[481] Transcript, Volume 3, page 383, lines 9-21, and page 384, lines 1-11.

[482] Transcript, Volume 2, page 278, lines 5-18.

with age constraints. The ATCO Utilities stated that, as a result, the lack of a linkage between capital costs and number of customers, or km of pipe/line the metric may cause an inference that the utility is inefficient when it is not.[483] While ENMAX did not object to combining O&M and capex, it stated that separating them would allow for more visibility and a meaningful narrative.[484] EPCOR also did not object, but cautioned against using the combined metric in isolation.[485]

411. D. Madsen, on behalf of IPCAA, stated that the volatility of capital should not be a concern for total cost metrics, as this volatility should be explainable by the utilities, that it is important to assess all utility costs and this information helps to inform differences that might exist on a per customer, per km of line or other basis.[486] R. Bell, on behalf of the UCA, also suggested that looking at both O&M and capital is important, using the example of advanced metering infrastructure (AMI), where a large improvement in O&M costs can be seen, but the associated cost increase in capital expenditures is substantial. R. Bell therefore suggested that looking at only one component would be misleading.[487]

412. For the reasons that follow, the Commission directs the utilities to track efficiencies using the following metrics:

(i) Controllable O&M per customer.

(ii) Controllable O&M per km of line (pipe).

(iii) Total cost per customer, broken out by Total O&M per customer and Total capital additions per customer separately.

(iv) Total cost per km of line (pipe), broken out by Total O&M per km of line (pipe) and Total capital additions per km of line (pipe) separately reported.

413. The Commission believes that using these metrics will help quantify and clearly demonstrate how efficiencies are realized, and cost reductions are achieved. In the Commission’s view, this will help avoid the challenges in identifying the achieved efficiencies and calculating realized savings at the next rebasing.

414. There was wide agreement in the proceeding from most parties that tracking controllable O&M both per customer and per km of line or pipe are suitable measures to track changes in costs over time and in so doing, to track efficiencies gained by the distribution utilities in their overall O&M spend over time. The Commission agrees. For the purposes of these metrics, controllable O&M shall be defined as the expenditures reported in Rule 005, adjusted for any items that are not in the utility’s direct control, such as flowthroughs, transmission expenses and franchise fees. These adjustments must be itemized.

415. The Commission also sees value in requiring the distribution utilities to report and track total costs. While the Commission acknowledges that capital drivers may differ from the drivers of O&M, there is still value in tracking and quantifying how efficiencies are realized and how

483 Transcript, Volume 3, page 385, lines 8-25.
484 Transcript, Volume 4, page 624, lines 17-25.
485 Transcript, Volume 5, page 832, lines 10-16.
486 Transcript, Volume 7, page 1237, lines 21-25.
487 Transcript, Volume 8, page 1546, lines 18-25.

cost reductions are achieved from the perspective of capital expenditures. While the number of customers and km of line (pipe) may not always be a primary driver of capital additions, when compared against each other, especially over longer terms, the use of these metrics will allow for some level of comparability over time. The Commission also believes that separating total cost into O&M and capital will ensure greater visibility and allow the distribution utilities to provide a meaningful narrative explanation of the various costs and associated drivers of those costs, which mitigates the concerns expressed about total costs not being indicative of efficiency gains over time.

416. The Commission does not agree that using metrics to quantify and track efficiencies introduces substantial regulatory burden or diverts attention away from cost-saving efforts as suggested by the ATCO Utilities. The data to be used in these metrics is already collected by the distribution utilities for use in their Rule 005 submissions. Consequently, the calculation of these metrics will not be burdensome. Furthermore, as mentioned above, the tracking of these metrics may address some of the challenges in identifying the achieved efficiencies and calculating realized savings at the next rebasing, which should lead to a more efficient rebasing process. However, the reporting of these metrics should not necessarily prevent the distribution utilities from providing more detailed information about specific projects or programs that they have undertook to optimize their systems, become more efficient and reduce costs. The Commission directs the distribution utilities to calculate and present the above metrics annually, at the time of the annual PBR rate adjustment filing.

12 Other issues – EPCOR customer-specific rates

417. In Decision 27018-D01-2022,[488] the Commission observed that EPCOR is currently the only distribution utility in Alberta to offer customer-specific (CS) rates to its largest customers that have a forecast peak demand greater than 5,000 kilovolt ampere (kVA) and are supplied at primary voltage. EPCOR currently has 26 customers under CS rate. Each CS rate can be thought of as a separate rate class but with only one customer.

418. In EPCOR's PBR1 and PBR2 plans, CS rates were treated the same as all other rates, meaning the rate for the year was made up of the base rate plus the class's share of the Y factor and capital funding mechanism in place (K factor in PBR1 and K-bar in PBR2). However, because each CS rate class only includes one customer with a relatively small number of assets, if there is no or little asset replacement, this may create a growing gap between the costs for service and revenue recovered through PBR rates, leading to windfall gains or losses.[489]

419. In Decision 27018-D01-2022, the Commission directed EPCOR to consider exploring other alternatives to its CS rate design in the PBR3 term, and to explore discontinuing CS rates to reduce regulatory burden and achieve greater consistency with other distribution utilities. EPCOR did not support the option of discontinuing the CS class, as doing so would result in large rate variations for existing CS customers and unknown impacts to other customer classes.

488 Decision 27018-D01-2022, PDF page 19, paragraph 83.

489 Exhibit 27388-X0212, EPCOR evidence, PDF page 58, paragraph 113. EPCOR further explained that this is not an issue for other rate classes with many customers as only some of the assets used to provide service to the class are replaced during the PBR term.

420. Instead, EPCOR identified the alternatives below for potential treatment of CS rates in the PBR3 plan and developed recommendations to address the concerns expressed by the Commission in Decision 27018-D01-2022:

(i) Status quo.

(ii) Remove the CS rates from the PBR plan.

(iii) Do not index CS rates during PBR.

(iv) Modify the method to allocate the capital funding mechanism amount and the Y factor amount.

421. Among the alternatives considered, EPCOR preferred option (iv) to modify the allocation method for capital funding and Y factor amounts because it would improve upon the method of allocating the capital funding and the Y factor amounts to the CS rate class. EPCOR also stated it would modify the method used to allocate the additional capital funding amount to each individual CS rate and it would better reflect the specific assets used by each CS customer.

422. EPCOR explained that in PBR1 and PBR2, the additional capital funding amount was allocated using a simplified allocation method reflecting each rate class's share of total revenue requirement. EPCOR stated that the drawback of this method is that certain costs were allocated to the CS class that may or may not reflect the asset types used to provide service to the CS class. As such, EPCOR proposed to update the allocation method for its additional capital funding amount to use the capital plant in service for each rate class in its COS study. In EPCOR's view, using the allocators from its most recently approved Phase 2 application will not add significant regulatory burden and aligns with the Commission's direction from Decision 2012-237 to allocate the additional capital funding amount using COS principles.

423. EPCOR recommended the following changes to the CS rate class commencing January 1, 2024:

(i) Close the CS class to all new customers.

(ii) Remove the upper demand limit from the Time of Use Primary (TOUP) class; this way, all new customers with demand above 150 kVA that require primary voltage will be added to the TOUP class.

(iii) Update the method used to allocate the additional capital funding mechanism and Y factor to use the COS method.

424. EPCOR submitted that its proposal will generally result in a lower allocation of the additional capital funding to its CS rates customers compared to allocations based on the simplified allocation method. EPCOR also believed this would result in an improved allocation methodology based on cost of service principles to all rate classes, thereby properly reducing the escalation of CS rates through the PBR3 term as the customers' value of assets in service declines as expected over the years through depreciation. This new capital funding allocation method will result in changes to other rate classes, but no other class is expected to see a change

in the allocation of greater than plus or minus 4 per cent.[490] EPCOR anticipated the greatest impacts for this allocation change will be to the Residential class (-3.42 per cent) and to the Time of Use class (+3.86 per cent) and the Commission finds these changes to be reasonable in light of greater adherence to cost causation principles. To be clear, the numbers quoted do not represent changes in rates, but rather are the percentage of additional or less capital funding being allocated to those classes.

425. EPCOR offered to allow existing customers with CS rates to remain in the CS class. If any of these customers request a change in service, EPCOR would move them to the TOUP class if the move results in a lower cost to the customer. CS rate applications would still have to be filed for customers that request a change in service requirement that does not result in lower costs to the customer under the TOUP class.

426. EPCOR stated it will commit to reviewing the TOUP class rate design and the CS rate design as part of its next Phase 2 application.

427. Overall, EPCOR recommended that the existing CS rates be included in the PBR3 plan, and treated in the same way as the other rate classes, subject to the following two conditions:

(i) the 2023 COS CS rates as approved by the Commission in Decision 27653-D01-2022[491] be used as the basis for the going-in rates for the PBR plan; and

(ii) EPCOR's proposed revised method to allocate the capital funding mechanism and the Y factor amounts be approved for use in PBR3.

428. The Commission finds that EPCOR's recommended changes are reasonable and the proposed CS rate design is an improvement over how these rates were calculated in prior PBR plans. The Commission will also require that EPCOR stop offering any new CS rates as of January 1, 2024, and instead offer TOUP rates to new qualifying customers, or in instances when existing CS rate customer service needs change. Overall, EPCOR's recommendations for the CS rate class align with the Commission's intent to reduce regulatory and administrative burden.

429. As such, effective January 1, 2024, the Commission directs EPCOR to:

(i) Close the CS rate class to any new customers.

(ii) Remove the upper demand limit from the TOUP class so that any new customers with demand requirements above 150 kVA that require primary voltage are able to be added to the TOUP class.

(iii) Allow existing CS customers to remain in the CS class if they elect to do so; however, should the customer service needs change and a move to TOUP would result in lower rates and the customer wishes to transition to the TOUP class, EPCOR must allow the customer to do so.

[490] Exhibit 27388-X0212, EPCOR evidence, PDF page 69, Table 8.4.5-1.
[491] Decision 27653-D01-2022: EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates, Proceeding 27653, Applications 27653-A001 and 27653-A002, December 13, 2022.

(iv) Use the updated COS-based method to allocate the Y factor and capital funding amounts (in lieu of the simplified allocation method used in prior PBR plans).

(v) Continue to include and index CS rates in the PBR3 plan in a similar fashion to the other rate classes. EPCOR will use the 2023 COS CS rates as approved by the Commission in Decision 27653-D01-2022 as the basis for the going-in rates for PBR3.

430. The Commission also directs EPCOR, in its next Phase 2 application, to review the TOUP class rate design and the CS rate design and bring forward any recommendations as a result of the CS class changes in this decision, recognizing the CS rate class changes may impact the TOUP class.

13 Conclusion

431. For the reasons that follow, the Commission concludes that the rates established by PBR3 plans approved in this decision, when viewed in their entirety, will be just and reasonable and provide the distribution utilities with a reasonable opportunity to recover their prudently incurred costs and earn the approved rate of return over the term of the plan.

432. The Supreme Court of Canada provided guidance in *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)* regarding what constitutes just and reasonable rates under both the *Electric Utilities Act* and the *Gas Utilities Act*. There, Justice Rothstein writing for a unanimous court stated:

> In Canadian law, "just and reasonable" rates or tariffs are those that are fair to both consumers and the utility: *Edmonton (City) v. Northwestern Utilities Ltd*., [1929] S.C.R. 186 (S.C.C.), at pp. 192-93, per Lamont J. Under a cost of service model, rates must allow the utility the opportunity to recover, over the long run, its operating and capital costs. Recovering these costs ensures that the utility can continue to operate and can earn its cost of capital in order to attract and retain investment in the utility: OEB, at para. 16. Consumers must pay what the Commission "expects it to cost to efficiently provide the services they receive" such that, "overall, they are paying no more than what is necessary for the service they receive": *OEB*, at para. 20.[492]

433. There are several noteworthy characteristics of this excerpt. First, the court emphasizes that just and reasonable rates strike a balance between the interests of consumers and utilities. Second, the court includes a temporal parameter on the reasonable opportunity principle, stating that it applies to capital and operating costs "over the long run." Third, the court explains that the rates are required to include what the Commission expects it will cost the utility to provide its services efficiently, such that no more than necessary is paid by consumers. Fourth, the court emphasizes that the reason an opportunity to recover costs is required, is to ensure that the utility can continue to attract and retain investment.

434. The Commission's assessment that the plan will result in just and reasonable rates and that the distribution utilities will be afforded a reasonable opportunity to recover their prudently incurred costs and earn a fair return was made considering the PBR3 plan as a whole over the course of the full plan term. Also fundamental to the Commission's analysis is a recognition that

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[492] ATCO Pensions, paragraph 7. This approach is also consistent with Commission precedent: Decision 2012-237, paragraph 35, and Decision 20414-D01-2016 (Errata), PDF page 87, paragraph 287.

during the plan term, the distribution utilities are required to conduct their business in a way that meets their obligations and to actively and continuously seek out opportunities to find efficiencies in the way that they conduct their business, which will benefit their customers and contribute to their own success.[493] The I-X mechanism, among other plan components, encourages the distribution utilities to make decisions and achieve outcomes that would mimic the outcome in a competitive market[494] and by implication provide efficient service.

435. Examining the plans in their entirety recognizes the high degree of interdependency among PBR plan components such that they are all considered in determining whether the rates resulting from the plans will be just and reasonable. The Commission carefully considered and set the parameters of each plan component in balance with the parameters of all other plan components. The parameters of each of the PBR 3 plan components should therefore not be viewed in isolation from other plan components because of these significant interdependencies. It is with this understanding in mind that the Commission analyzes major components of the plan in the following paragraphs.

436. The Commission considers that the PBR3 plan will be more reflective of ongoing economic conditions for both utilities and customers. In maintaining the revenue-per-customer cap plan for gas utilities and the price cap plan for electric utilities, the Commission recognizes the continued decline in usage per customer for the low use rate class for gas utilities and the continuation of stable customer consumption for electric utilities, expected to persist for the duration of the PBR3 term. In setting the I factor, the Commission recognizes that because the inflation environment has become more uncertain in recent years, it may no longer be reasonable to rely on inflation averaging out over the PBR3 term as was assumed in prior plans. The Commission has therefore implemented a forecast and true-up approach under which distribution rates will be ultimately indexed by the actual province-wide inflation experienced in a given year to more closely reflect the economic conditions in that year so that neither the distribution utilities nor customers are detrimentally affected if inflation forecasts turn out to be inaccurate.

437. In selecting the X factor value, the Commission considered the latest productivity trends in electric and gas distribution industries, including updated assumptions used in the TFP growth studies to accurately capture the productivity trends in the industry. The Commission used its expertise to adjust industry historic TFP growth by applying a stretch factor.

438. To allow for a more equitable sharing of PBR benefits among the distribution utilities and customers, the Commission introduced two additional benefit-sharing provisions in the PBR3 plan that ensure sharing upfront rather than waiting until rebasing: an ESM and an X factor premium. The ESM will provide more certain and timely sharing of benefits with customers on a prospective basis without unduly limiting the utilities’ efficiency incentives. Since the ESM applies asymmetrically to earnings in excess of the approved ROE, but not earnings below the approved ROE, the Commission modified the reopener provision to narrow the circumstances in which overearning could trigger a reopener. This modification recognizes the accelerated sharing with customers that the utilities will be subject to, and provides them a correspondingly greater opportunity to earn in excess of the ROE without a reopener being triggered. The X factor premium ensures that customers receive an annual guaranteed benefit upfront regardless of the actual performance of the utilities.

493 Decision 20414-D01-2016 (Errata), PDF page 87, paragraph 287.
494 Decision 20414-D01-2016 (Errata), PDF page 38, paragraph 109.

439. As in past PBR proceedings, the distribution utilities raised concerns about whether the plan would provide them with a reasonable opportunity to earn their approved rate of return, although in this proceeding they did so mostly in the context of requesting supplemental funding for capital projects in addition to revenue provided under I-X.

440. With regard to these concerns, the PBR3 plan includes Type 1 capital tracker and K-bar capital funding provisions to provide funding for capital projects in addition to the revenue provided under I-X. K-bar will provide funding during the PBR3 plan that will allow the distribution utilities to make investments in their systems consistent with the historical levels of capital investment. At these levels, the utilities have generally demonstrated that they can provide safe and reliable service to their customers, without detriment to their opportunity to recover their costs and earn a fair return. The distribution utilities have historically demonstrated high levels of reliability and service quality. The Commission is confident that the distribution utilities will be able to maintain high levels of reliability and service quality over the course of the PBR3 term with the funding that is provided by the plan.

441. Type 1 capital tracker funding will be available for extraordinary expenditures, including costs connected with governmental net-zero objectives, where laws cause the distribution utilities to incur costs. The Commission has also implemented a new alternative remuneration scheme on a pilot basis, which allows distribution utilities to earn a return on certain operating costs to displace more costly capital solutions.

442. In balancing the elements of the plan and assessing the reasonability the plan as a whole, the Commission also considered plan parameters that did not need to be changed. For example, the PBR3 plan continues to have a Z factor provision to account for a significant financial impact (either positive or negative) resulting from an exogenous event outside of the control of the distribution utility and for which the distribution utility has no other reasonable opportunity to recover the costs within the PBR formula. The Y factor provision, which allows certain Commission-approved costs (such as costs of accessing a gas or electric transmission system) to be flowed through to customers, is also unchanged in the PBR3 plan.

443. The Commission notes that the PBR3 plan continues to have a reopener based on ROE considerations which "serves as a safeguard against unexpected results in the event that there is a problem with the design or operation of the plan that makes its continued operation untenable."[495] The reopener is a further safeguard to ensure that the PBR3 plan results in just and reasonable rates, as it provides a mechanism for the Commission to ensure that both utilities and consumers are protected if the PBR3 plan has unexpected results.

444. Ultimately, the Commission considers that the resulting PBR3 plan is fair and balances the economic incentives inherent in each of the interrelated parameters in a manner that encourages cost-effective and efficient provision by the distribution utilities of safe and reliable service. In other words, the Commission considers that the whole of the PBR3 plan is greater than the sum of its parts, and it has determined that the whole of the plan will result in just and reasonable rates that will be fair to both Alberta consumers and Alberta distribution utilities.

[495] Decision 2012-237, PDF page 164, paragraph 723.

14 Compliance filings and 2024 rates

445. As was stated in the rebasing decisions, the rates approved for 2023 on a forecast cost basis for each distribution utility as part of the rebasing process will also serve as going-in rates for the PBR3 plan that will commence on January 1, 2024.

446. Each of the distribution utilities is directed to submit a compliance filing to apply for 2024 rates that reflect the PBR3 plan parameters and all pertinent directions set out in this decision, by November 3, 2023. In addition to updating rates and to responding to the Commission's directions, the distribution utilities must include, in their respective compliance filings all information that typically accompanies the calculation of rates in annual PBR rate adjustment filings, including the following:

(i) 2024 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.

(ii) Customer bill impact analysis of proposed rates.

(iii) Terms and conditions of service for 2024.

(iv) True-up of the prior approved deferral accounts such as the amounts included in the Y factor and 2022 Transmission Access Charge Deferral Account (as applicable).

(v) Currently approved deferral accounts and rate riders, which shall continue to be applied in 2024. The differences between forecast and actual costs for amounts in these accounts will subsequently be trued up in the annual PBR rate adjustment filings.

(vi) Any other items required to support the proposed 2024 distribution tariff.

447. The Commission directs all distribution utilities to support their proposed 2024 rates with accompanying Excel schedules, with formulas intact. Any hard-coded numbers must be accompanied by an explanation of where these numbers come from.

448. To ensure that PBR rates are approved in time and on a prospective basis, the Commission may consider approving the applied-for rates on an interim basis effective January 1, 2024. Any directed adjustments to such interim rates will be dealt with following the Commission's final approvals in 2024.

15 Order

449. It is hereby ordered that:

(1) Each of Apex Utilities Inc., ATCO Electric Ltd. (distribution), ATCO Gas and Pipelines Ltd. (distribution), ENMAX Power Corporation (distribution), EPCOR Distribution & Transmission Inc. (distribution) and FortisAlberta Inc. shall file a compliance filing by way of an application in accordance with the findings and directions set out in this decision by November 3, 2023.

Dated on October 4, 2023.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Kristi Sebalj
Vice-Chair

(original signed by)

Michael Arthur
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Alberta Federation of Rural Electrification Associations Shores Jardine LLP
Apex Utilities Inc. (Apex) Stikeman Elliott LLP
ATCO Electric Ltd.
ATCO Gas Bennett Jones LLP Toby Brown
City of Grande Prairie
Consumers' Coalition of Alberta
Direct Energy Marketing Limited
ENMAX Power Corporation (ENMAX) Torys LLP London Economics International LLC
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden Ladner Gervais LLP Nicholas Crowley Dennis Weisman Mark Meitzen
FortisAlberta Inc. (Fortis) Fasken Martineau DuMoulin LLP Tara Katamay-Smith Ren Orans Energy and Environmental Economics
Independent System Operator
Industrial Power Consumers Association of Alberta (IPCAA) Ackroyd LLP
NERA Economic Consulting (NERA) Lawson Lundell Barristers & Solicitors

Name of organization (abbreviation) **Company name of counsel or representative**
NOVA Gas Transmission Ltd.
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP Russ Bell & Associates Inc.
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair K. Sebalj, Vice-Chair M. Arthur, Commission Member Commission staff P. Khan (Commission counsel) P. Schembri (Commission counsel) L. Fukuda B. Edwards F. Alonso E. Deryabina M. Logan N. Morter C. Robertshaw S. Sharma A. Spurrell V. Wang C. Young O. Vasetsky D. Sappington, PhD

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
Apex Utilities Inc. and ATCO Gas and ATCO Electric Ltd. S. Assie	T. Brown
Apex Utilities Inc. D. Langen	T. Brown D. Makarenko M. Stock A. Tan
ATCO Gas and ATCO Electric Ltd. L. Smith S. Assie	J. Bagnall L. Brennand T. Brown K. Burgemeister L. Radke
Consumers' Coalition of Alberta (CCA) J. Wachowich	R. Kavan M. Lowry J. Thygesen
ENMAX Power Corporation D. Wood T. Campbell	M. Fagan A. Goulding A. Grogan D. Stanghetta J. Taylor
EPCOR Distribution & Transmission Inc. J. Liteplo B. Willms	B. Chan S. Chaudhary N. Crowley M. Meitzen D. Weisman
FortisAlberta Inc. B. Hunter	B. Henderson A. Johnson K. Noble R. Orans M. Stroh
Industrial Power Consumers Association of Alberta R. Secord	D. Madsen
NERA Economic Consulting S. Dhalla L. Manning	J. Makholm
Office of the Utilities Consumer Advocate (UCA) K. Rutherford	R. Bell

Alberta Utilities Commission

Commission panel
C. Dahl Rees, Chair
K. Sebalj, Vice-Chair
M. Arthur, Commission Member

Commission staff
P. Khan (Commission counsel)
P. Schembri (Commission counsel)
L. Fukuda
B. Edwards
F. Alonso
E. Deryabina
M. Logan
N. Morter
C. Robertshaw
S. Sharma
A. Spurrell
V. Wang
C. Young
O. Vasetsky

Appendix 3 – Procedural summary

On May 26, 2022, the Commission issued Bulletin 2022-06 and a notice of proceeding and established Proceeding 27388 to set the parameters of the PBR3 plan. The Commission stated that its first step would be to determine the scope of the proceeding and that it intended to conduct a roundtable in September 2022 to discuss best practices and areas for improvement that can be addressed in designing the PBR3 plan, including examining parameters used in other jurisdictions that have implemented PBR.

The Commission invited interested parties to participate in this proceeding by filing a statement of intent to participate (SIP) in the Commission's eFiling System by June 9, 2022. SIPs were received from ENMAX, EPCOR, the Alberta Federation of Rural Electrification Associations, Fortis, IPCAA, Direct Energy Marketing Limited, the UCA, ATCO Gas, and ATCO Electric Ltd. (the ATCO Utilities), the AESO, NOVA Gas Transmission Ltd., Apex, The City of Calgary and the CCA.

On June 17, 2022, the Commission issued a preliminary list of issues and directions on procedure and invited parties to file comments on this list of issues. The Commission set out a process schedule for the remainder of the proceeding that included comments on the preliminary list of issues, the industry roundtable, IRs and responses, rebuttal evidence from parties and an oral hearing, if required.

On June 30, 2022, ENMAX filed a letter[496] on behalf of the distribution utilities and customer groups[497] (the proceeding participants) in response to the Commission's process schedule. The proceeding participants stated that they have concerns with the proposed roundtable, that the current process schedule does not allocate sufficient time to develop the evidentiary record and that the overall schedule is unnecessarily compressed. The proceeding participants stated that they did not believe that a roundtable was an efficient or appropriate mechanism for setting the scope of the proceeding. However, they indicated general support for a roundtable, or technical session, after the evidence has been submitted to identify areas or issues of agreement and determine the scope of, or rounds of, IRs, and the scope of an oral hearing, if required.

In response, on June 17, 2022, the Commission accepted the request that the scope of the proceeding be determined through a written process and removed the roundtable from the process schedule. The Commission directed that parties identify areas or issues of agreement in their responses to submissions on the issues list to help narrow the scope for this proceeding.

The Commission received comments on the preliminary list of issues from Direct Energy Marketing Limited, the AESO, the CCA, ENMAX, the customer group (the CCA, Calgary, IPCAA and the UCA), EPCOR, the ATCO Utilities, Apex and Fortis.

Taking the comments of the participants into account, the Commission developed its final list of issues and issued it on September 16, 2022.

496 Exhibit 27388-X0022.
497 Apex, the ATCO Utilities, ENMAX, EPCOR, Fortis, Calgary, the CCA, IPCAA, the UCA.

Each of the distribution utilities, the CCA and the UCA retained an independent expert or consultant. A list of the participants who retained parties is set out below along with the names of the retained parties.

Proceeding participant	Independent expert or consultant
Apex and ATCO	The Brattle Group (Dr. Toby Brown)
ENMAX	London Economics International LLC (A.J. Goulding, Dr. Marie N Fagan)
EPCOR	Weisman Associates, LLC (Dr. Dennis Weisman) Christensen Associates Energy Consulting (Dr. Mark Meitzen, Nicholas Crowley)
Fortis	Energy and Environmental Economics (E3) (Dr. Ren Orans)
CCA	Icarus Regulatory Services Ltd. (Jan Thygesen) Pacific Economics Group (PEG) (Dr. Mark Lowry, Rebecca Kavan) PEG's area of focus: inflation and productivity research for US electric power distributors, Alberta benchmarking and productivity research for electric distribution utilities
The City of Calgary*	Pacific Economics Group Research LLC (Dr. Mark Lowry, Rebecca Kavan) PEG's area of focus: X factor; capital funding provisions; consideration of introducing an earnings sharing mechanism and the need for an efficiency carry-over mechanism; quantification and tracking of efficiencies, all focused on ATCO Gas and/or Alberta's gas distribution utilities
IPCAA	Emrydia Consulting Corporation (Dustin Madsen)
UCA	Russ Bell & Associates Inc. (Russ Bell)

*The City of Calgary ultimately withdrew from the proceeding, and the work it had retained PEG to complete was then sponsored by the CCA.

Additionally, the Commission hired NERA to obtain a total factor productivity study and Dr. David Sappington to provide expert assistance to Commission staff and panel.

On the request of Calgary and the CCA, and supported by the UCA, the Commission established a limited preliminary pre-evidence discovery process in which specific parties could file IRs with the Commission for response from the utilities to inform the preparation of evidence by those parties. IRs were filed by the UCA, the CCA and Calgary between November 29 and December 1, 2022. The relevant utilities filed their responses on January 6, 2023.

On January 12, 2023, in response to a request for a time extension from Calgary and the CCA, the Commission set a deadline of January 20, 2023, for parties' evidence.[498] On January 19, 2023, the day before the evidence deadline, Calgary notified the Commission that it was withdrawing from the proceeding.[499] The CCA subsequently filed a letter on this same date noting that this withdrawal was not expected and is somewhat unprecedented. The CCA referenced Calgary's sponsored evidence under preparation by PEG and stated that it was

498 Exhibit 27388-X0106, AUC letter ruling on Calgary and the CCA's motion for extension.
499 Exhibit 27388-X0118, City of Calgary Letter re Withdrawal from Proceeding.

seeking client instruction with respect to the CCA's ability to sponsor this evidence.[500] On January 20, 2023, the Commission temporarily suspended the deadline for parties to file evidence in the proceeding.[501] On January 26, 2023, the Commission reinstated a deadline of January 27, 2023.[502]

The CCA stated that it was still in the process of reviewing the evidence prepared by PEG for Calgary and indicated that it could be unable to meet the January 27 deadline.[503] All parties filed evidence on January 27, and the CCA filed remaining portions of evidence initially sponsored by Calgary on January 30. The Commission stated that it accepted the CCA's late filing on this occasion and found that no party would be prejudiced by the late filing.[504]

On February 2, 2023, the Commission established a new schedule for the remaining process steps until the oral hearing.[505] On February 22, 2023, the Commission set the dates for oral argument and reply based on scheduling constraints received from parties.[506]

Parties and the Commission filed IRs on February 28, 2023, and parties filed responses to IRs on March 28, 2023.

On April 5, 2023, the Commission issued a letter[507] identifying instances in the responses to IRs where it required further information. On April 11 and 13, 2023, parties provided the requested additional information.

Parties filed rebuttal evidence on April 28, 2023. The CCA filed additional rebuttal evidence on May 5, 2023.

On May 4, 2023, the Commission established the scope of the oral hearing. In the same letter, the Commission confirmed that since Rule 005: *Annual Reporting Requirements of Financial and Operational Results* 2022 annual reports would be available during the oral hearing, parties could refer to this data for the remainder of the proceeding to the extent it was relevant to the parameters of the PBR3 plan.[508]

The oral hearing was held virtually on June 5-9 and June 12-14, with oral argument and reply argument held virtually on July 4-6, 2023. The Commission considers the record for this proceeding to have closed on July 6, 2023, when oral reply argument was concluded.

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500 Exhibit 27388-X0119, CCA letter re Calgary withdrawal.
501 Exhibit 27388-X0130, AUC letter Temporary evidence filing deadline suspension.
502 Exhibit 27388-X0140, AUC letter ruling regarding evidence deadlines.
503 Exhibit 27388-X0143, CCA Comments on process.
504 Exhibit 27388-X0292 AUC letter rulings and revised process schedule.
505 Exhibit 27388-X0292 AUC letter rulings and revised process schedule.
506 Exhibit 27388-X0314, AUC letter schedule for oral argument and reply.
507 Exhibit 27388-X0539, AUC letter request for further information and process items.
508 Exhibit 27388-X0606, AUC letter – Scope of virtual hearing and time estimates.

Appendix 4 – The PBR1 and PBR2 plans

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PBR1

Using the approved 2012 COS rates as going-in rates, the PBR1 framework in Decision 2012-237 approved a price cap plan for electric distribution utilities and revenue-per-customer cap plan for gas distribution utilities. Under these plans, rates (under price cap plans) or revenue-per-customer class (under revenue-per-customer cap plans) were adjusted annually by means of an I-X indexing mechanism.

Additionally, the PBR1 plan provided for certain rate adjustments to enable the recovery of specific costs where it could be demonstrated that those costs cannot be recovered under the I-X mechanism and where certain other criteria have been satisfied. Specifically, Y factor provided for rate adjustments for certain flow-through costs that should be recovered from, or refunded to, customers directly. Z factor provided for rate adjustments to account for the effect of exogenous and material events outside of the control of the distribution utility and for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan. The Commission also determined that a rate adjustment mechanism to fund certain capital-related costs was required under the approved PBR plans in some circumstances. A capital funding mechanism referred to as a "capital tracker" was established and the revenue requirement associated with approved amounts was collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. To be eligible for capital tracker funding, a utility needed to demonstrate that a capital project meets the established criteria.

The Commission did not include an ESM in the PBR1 plan; however, it approved the inclusion of an ECM to address the weakening of incentives towards the end of the PBR term. The Commission included in the PBR1 plan a reopener provision as a safeguard in the event that there is a problem with the design or operation of the plan that makes its continued operation untenable.[509] Specifically, the Commission opted for an ROE-based reopener, and indicated that an earned ROE that is above or below the approved ROE by 500 basis points in a single year or by 300 basis points in two consecutive years may warrant consideration of a reopening and review of the plan. Finally, in that decision, the Commission implemented reopener provisions, service quality monitoring and enforcement, as well as annual rate adjustment filing requirements.

PBR2

The PBR2 plans approved in Decision 20414-D01-2016 (Errata) retained many of the elements of the PBR1 plan. The differences were limited to:

(1) rebasing methodology to set going-in rates

(2) updating the X factor value

(3) changing the capital funding provisions

[509] Decision 2012-237, PDF page 164, paragraph 723.

(4) altering the calculation of ROE for reopener purposes

With regard to the rebasing to set going-in rates for PBR2, the Commission did not rely on a COS-type review of utility forecast costs. Rather, it set going-in rates on the basis of a notional 2017 revenue requirement, rooted in actual costs experienced by each distribution utility during the PBR1 term. This notional revenue requirement was intended to reflect the notional costs each distribution utility would have incurred in 2017 if operating under the full incentives of the PBR framework.[510]

To determine the X factor value, the Commission considered multiple industry TFP growth studies. The Commission approved an X factor, inclusive of a stretch factor, of 0.3 per cent for the PBR2 plan.

Regarding capital provisions, in Decision 20414-D01-2016 (Errata), the Commission discontinued the capital tracker mechanism used in PBR1. Instead, the Commission divided capital into two types and approved two different capital funding mechanisms. Type 1 capital included projects that could not be fully funded under the I-X mechanism and did not qualify for Y factor or Z factor treatment. For these projects, the Commission approved the Type 1 capital tracker mechanism with much stricter eligibility criteria than in PBR1. Any capital projects that did not qualify for funding under Type 1 capital trackers, Y factor or Z factor, would qualify under Type 2 capital. For this capital, the Commission approved funding by way of a K-bar mechanism, which was based on average historical capital additions incurred in PBR1. The Commission stated that as much incremental capital funding as possible should be managed under the Type 2 capital funding mechanism.

With respect to the ROE for reopener purposes, the Commission determined that consideration of a reopener may be triggered by either the initially reported ROE filed in the Rule 005 filing, or by a subsequent restated ROE, which reflects the final approved amounts pertaining to the reporting year. The Commission also determined that the calculation of the ROE for assessing reopeners should not include the ECM amounts from a prior PBR plan. Accordingly, the Commission directed the distribution utilities to include as part of their annual PBR rate filings an ROE adjustment schedule and provide a detailed description of each adjustment, with references to Commission decisions or rules approving the final amounts from which the adjustment arises.

[510] Decision 20414-D01-2016 (Errata), Section 4.2.

Appendix 5 – Parameters of the 2018-2022 PBR plans that continue into and form part of the next generation PBR plan

(return to text)

The Commission has included this appendix for information purposes to summarize previous Commission PBR plan directions that remain in place for the next generation PBR term. To the extent that discrepancies exist between this appendix and previous AUC decisions, the directions from previous AUC decisions will prevail unless they have been specifically overridden elsewhere in this decision.

(1) Price cap or revenue-per-customer-cap

The Commission will continue to employ a price cap for electric distribution utilities (ATCO Electric, ENMAX, EPCOR and Fortis) and a revenue-per-customer cap for natural gas distribution utilities (Apex and ATCO Gas).

(2) Y factor

Y factor costs are costs that are flowed through to customers. For costs to be eligible for Y factor treatment, all of the following criteria must be met:

(i) The costs must be attributable to events outside management's control.

(ii) The costs must be material. They must have a significant influence on the operation of the distribution utility; otherwise the costs should be expensed or recognized as income, in the normal course of business.

(iii) The costs should not have a significant influence on the inflation factor in the PBR formulas.

(iv) The costs must be prudently incurred.

(v) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

In addition to those Y factors that meet the above criteria, the Commission will allow the distribution utilities to recover, as Y factor rate adjustments, specific costs incurred at the direction of the Commission and flow-through costs that have been approved for continued flow-through treatment under the distribution utilities' PBR plans.

The following types of costs have been determined by the Commission to satisfy the Y factor criteria enumerated above:

(a) AESO flow-through items.

(b) Farm transmission costs.

(c) Accounts that are a result of Commission directions (e.g., AUC assessment fees, intervener hearing costs, UCA assessment fees, AUC tariff billing and load settlement initiatives, Commission-directed Rural Electrification Associations acquisitions, effects of regulatory decisions).

(d) Income tax impacts other than tax rate changes.

(e) Municipal fees.

(f) Load balancing deferral accounts.

(g) Weather deferral account (ATCO Gas only).

(h) Production abandonment costs.

(3) Service quality

The Commission will continue to rely on the legislative provisions, including the imposition of penalties, to address enforcement issues should service quality degrade. The mechanism to monitor service quality will continue to be defined by Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

(4) Term

The Commission considered that a five-year fixed term for the distribution utilities' PBR plan is reasonable.

(5) Z factor

The Commission continues to consider it necessary to include the Z factor in the PBR plan to allow for an adjustment to a distribution utility's rates to account for a significant financial impact (either positive or negative) of an exogenous event outside of the control of the distribution utility and for which the distribution utility has no other reasonable opportunity to recover the costs within the PBR formula.

The Commission considers that the following criteria will apply when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

(i) The impact must be attributable to some event outside management's control.

(ii) The impact of the event must be material. It must have a significant influence on the operation of the distribution utility; otherwise the impact should be expensed or recognized as income, in the normal course of business.

(iii) The impact of the event should not have a significant influence on the inflation factor in the PBR formula.

(iv) All costs claimed as an exogenous adjustment must be prudently incurred.

(v) The impact of the event was unforeseen.

The Commission considers that all of the above criteria must be met in order for an item to qualify for a Z factor rate adjustment. The Commission considers that Z factors should be symmetrical in that they should apply to exogenous events with both additional costs that the distribution utility needs to recover and also reductions to costs that need to be refunded to customers.

The Commission establishes the threshold for use in part (ii) above as the dollar value of a 40 basis point change in ROE on an after-tax basis calculated on the distribution utility's equity used to determine the final approved revenue requirement on which going-in rates were established (2023). This dollar amount threshold is to be escalated by I-X annually.

Z factor rate adjustment applications are generally to be filed as part of the annual PBR rate adjustment filing. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis.

(6) Financial reporting requirements

In its annual PBR rate adjustment filing, each distribution utility shall continue to provide:

(a) A copy of its Rule 005 filing.

(b) A schedule showing disallowed costs, excluded from a distribution utility's ROE.

(c) Attestations and certifications signed by a senior officer of the distribution utility.

Although the distribution utilities are not required to file a complete set of MFRs and general rate application (GRA) schedules annually, the distribution utilities must continue to maintain the ability to file a complete set of MFRs and GRA schedules with actual results for all years within the term of the PBR plans, unless otherwise directed or exempted by the Commission.

(7) Annual PBR rate adjustment filing

The Commission determines that the effective date for annual PBR rate changes will be January 1 each year. As such, the annual PBR rate adjustment filing is to be made by September 10 of each year.

The following items must be included in the annual PBR rate adjustment:

- Z factors approved during the previous 12 months.
- K factor and K-bar factor adjustments related to approved Type 1 and Type 2 capital.
- Y factor adjustment to collect Y factors that are not collected through separate riders.
- Billing determinants for each rate class.
- Backup showing the application of the formula by rate class and resulting rate schedules
- A copy of the Rule 005 filing filed in the current year as well as the ROE adjustment schedules for prior years.
- Any other material relevant to the establishment of current year rates
- For the electric distribution facility owners, the annual Transmission Access Charge Deferral Account filing and the Balancing Pool Adjustment Rider.

Applications related to flow-through items may be submitted throughout the year.

The distribution utilities will provide a revised forecast of their billing determinants annually as part of the September 10 annual PBR rate adjustment filings. Distribution utilities should utilize consistent billing determinant forecasting methodologies during the PBR term unless the Commission orders otherwise. Distribution utilities will describe the methodology they plan to use for the duration of the PBR term as part of their compliance filings to this decision. These billing determinants will generally be used to allocate K, K-bar, Y and Z factors to rate classes and to calculate the resulting rate adjustments, and will also be used in performing the annual use-per-customer adjustments for gas distribution utilities. In Decision 2012-237 the Commission stated that this billing determinant information along with the Phase 2 methodologies in place for each distribution utility would be the method used for allocating these factors.[511] However, in Decision 2013-072 the Commission also granted permission for distribution utilities to use a simplified approach to calculating rate adjustments that did not require the use of approved Phase II methodologies.[512] In addition, in Decision 2013-270 the Commission clarified that these rate adjustments would be calculated using forecast billing determinants, and that there would be no subsequent true-up to account for differences between the forecast billing determinants and actual billing determinants.[513]

511 Decision 2012-237, PDF pages 215, 217, 977 and 982, paragraph 971.
512 Decision 2013-072, PDF page 18, paragraph 65.
513 Decision 2013-270, PDF page 8, paragraph 21.

Appendix 6 – Capital funding mechanisms used in past PBR terms

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In setting the PBR1 and PBR2 terms, the Commission found that supplemental capital funding, in addition to revenues provided under the I-X mechanism, was required to provide for necessary capital additions.

PBR1

In PBR1, the Commission adopted a capital tracker funding mechanism that permitted recovery of specific types of capital expenditure outside of the I-X mechanism. The Commission implemented a criteria-based approach to assess whether capital projects would qualify for capital tracker treatment. The three criteria were:

(i) Criterion 1: the project must be outside of the normal course of the company's ongoing operations

(ii) Criterion 2: ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

(iii) Criterion 3: the project must have a material effect on the company's finances.

The Commission determined that a project would satisfy Criterion 1 if it satisfied the requirements of the project assessment and passed the accounting test based on the use of the "project net cost approach":

- The purpose of the project assessment was to demonstrate that a project proposed for capital tracker treatment was (i) required to provide utility service at adequate levels and, if so, (ii) the scope, level and timing of the project were prudent, and the forecast or actual costs of the project were reasonable. To that end, the Commission relied on a business case and an engineering study to aid it in conducting project assessment under Criterion 1.[514]

- Under the project net cost approach the revenue generated under the I-X mechanism for each capital project, capital program or project category, was compared to the approved forecast revenue requirement associated with that capital project, capital program or project category in a PBR1 year. This analysis demonstrated a lack of double-counting on a project-by-project basis. The sum of these individual project-by-project revenue shortfalls was to be recovered by way of capital trackers through a K factor adjustment in the PBR formula.[515]

With respect to the accounting test and to determine the amount of K factor funding, the utility had to demonstrate that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project. The accounting test, as it relates to revenue calculations, consisted of two components:

[514] Decision 2013-435, PDF page 74, paragraphs 278-279.
[515] Decision 2013-435, PDF page 51, paragraph 174.

- The revenue provided under the I-X mechanism for a project proposed for capital tracker treatment. This component utilizes the WACC rate embedded in a utility's approved going-in rates and requires assumptions regarding the values for the I-X index and Q for each year.[516]

- The revenue requirement calculations based on the forecast or actual capital additions for a project for a given PBR year. This component requires assumptions regarding the current year's WACC rate, approved ROE and capital structure including preferred shares.[517]

A project would satisfy Criterion 2 if it was for the replacement of existing capital assets or was required by an external party. In addition, a growth-related project would satisfy Criterion 2 when it could be demonstrated that the customer contributions together with incremental revenue allocated to the project on some reasonable basis, when added to the revenue provided under the I-X mechanism, were insufficient to offset the revenue requirement associated with the project in a PBR1 year.[518]

Finally, each project had to satisfy the first tier of the materiality test of Criterion 3 on an individual basis (the four basis point threshold), and all approved capital trackers collectively had to satisfy the second tier of the materiality test of Criterion 3 (the 40 basis point threshold).

- The four basis point threshold for individual projects: The Commission found that applying a materiality threshold to the portion of revenue requirement for a project not funded under the I-X mechanism was warranted. This materiality threshold for individual projects was calculated as a four basis point change in the company's ROE on an after-tax basis.[519]

- The 40 basis point threshold for all approved capital trackers: the Commission found that the 40 basis point threshold adopted for Y factors and Z factors (the dollar value of a 40 basis point change in ROE, on an after tax basis, calculated on the company's equity used to determine the revenue requirement on which going-in rates were established) would apply to the annual revenue requirement to be recovered by way of all capital trackers in aggregate, escalated by I-X each year.[520]

PBR2

In PBR2, the Commission divided capital into two types: Type 1 and Type 2. Extraordinary expenditures outside of management's control was considered to be Type 1 capital, while all other capital not qualifying for Y or Z factor treatment would be considered Type 2 capital. The Commission approved separate capital funding mechanisms for Type 1 and Type 2 capital, capital trackers for Type 1 capital and K-bar for Type 2 capital.

Type 1 capital tracker programs included programs that could not be fully funded under the I-X mechanism and did not qualify for Y factor or Z factor treatment, similar to the capital tracker

516 Decision 20497-D01-2016: FortisAlberta Inc., 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast, Proceeding 20497, February 20, 2016, paragraph 344.
517 Decision 20497-D01-2016, paragraph 345.
518 Decision 2013-435, PDF page 230, paragraph 1098.
519 Decision 2013-435, PDF page 95, paragraphs 382-384.
520 Decision 2013-435, PDF page 94, paragraphs 375-378.

mechanism approved in PBR1. The Commission established the following two criteria for Type 1 capital trackers, which replaced the original capital tracker criteria listed above. To qualify for Type 1 funding, distribution utilities were required to demonstrate that both criteria listed below were satisfied:

(i) The project must be of a type that is extraordinary and not previously included in the distribution utility's rate base.

(ii) The project must be required by a third party.[521]

The Type 1 capital tracker mechanism in PBR2 also relied on the accounting test, similar to the accounting test utilized by companies during PBR1 to determine the amount of K factor funding. The Commission eliminated the 40 basis point materiality threshold and maintained the four basis point materiality threshold at the program level for Type 1 capital trackers in PBR2.[522]

To reduce regulatory burden in PBR2, the Commission also replaced capital tracker forecast applications with a placeholder amount for Type 1 capital tracker programs based on untested internal forecasts. The Commission required distribution utilities to file applications each year seeking approval of the prior year capital tracker true-up after prior year actuals were known.[523]

Any capital programs that did not qualify for funding under Type 1 capital trackers, Y factor or Z factor, would qualify under Type 2 capital for K-bar funding, which was a predetermined amount of incremental capital funding for the duration of the PBR2 plans.

The base K-bar amount for 2018[524] (the first year of PBR2) was calculated using an accounting test similar to the accounting test used during the first generation PBR plans but applied to all Type 2 capital programs. The test was calculated on a projected amount of rate base for 2018 for Type 2 capital, which determined the capital funding shortfall or surplus for all Type 2 capital programs. The accounting test results for Type 2 capital in 2018 were then aggregated to determine the 2018 base K-bar amount. For 2019-2022, K-bar funding was calculated using very similar steps to those used to arrive at the 2018 base K-bar amount, with adjustments to account for the effects of inflation (the I factor), productivity (the X factor), the growth in billing determinants (the Q factor) and changes to the weighted average cost of capital.[525] These updated parameters were used in the accounting test to calculate the amount of incremental capital funding for a given year.

The Commission considered that the use of K-bar funding offers advantages over capital tracker treatment as it is advantageous to give utilities flexibility in dealing with the timing of their capital programs and the ability to discover and pursue efficiencies related to capital expenditures through a mechanistic funding mechanism. Additionally, using a formulaic capital funding mechanism reduced the regulatory burden and dealt with the issue of information asymmetry that arises when capital funding is based on forecasts provided by the utilities. Under capital trackers, the Commission was required to examine detailed business cases for the capital funding requests of each utility and, because of the information asymmetry, it was difficult and resource-intensive for the Commission and interveners to test the applications. This added to the

521 Decision 20414-D01-2016 (Errata), PDF page 62, paragraphs 197-199.
522 Decision 20414-D01-2016 (Errata), PDF page 70, paragraph 228.
523 Decision 20414-D01-2016 (Errata), PDF pages 71 and 73, paragraphs 233 and 239.
524 Decision 20414-D01-2016 (Errata), PDF page 77, paragraph 254.
525 Decision 22394-D01-2018, PDF page 68, paragraph 226.

regulatory burden and went against PBR Principle 3, which states that a PBR plan should reduce the regulatory burden over time. The Commission found that the separation of capital into Type 1 capital trackers and Type 2 capital would increase regulatory efficiency by reducing the number of regulatory proceedings to approve and true up capital tracker programs.[526]

The Commission was of the view that as much incremental capital funding as possible should be managed under the Type 2 capital mechanism because distribution utilities had flexibility in dealing with the timing of their capital programs and were capable of accommodating many changes in circumstances without immediate concerns about service quality, while discovering and pursuing efficiencies throughout the second generation of PBR plans.

[526] Decision 20414-D01-2016 (Errata), PDF pages 61 and 67, paragraphs 196 and 214.

Appendix 7 – K-bar calculation

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The accounting test that will determine the K-bar capital funding in PBR3 will be nearly identical to the accounting test that was used to determine the K-bar funding in PBR2, with the exceptions that the capital inputs will consist of a five-year average of actual capital additions from 2018-2022 and customer growth, discounted by 15 per cent, will be used instead of the Q factor. Further, an X factor of 0.1 per cent, not including the addition of the benefit-sharing premium, must be used in the K-bar accounting test.

To the extent that discrepancies exist between this appendix and previous AUC decisions, the directions from previous AUC decisions will prevail unless they have been specifically overridden elsewhere in this decision. The K-bar calculation is set out below.

The 2024 base K-bar amount will be calculated as follows:

Step 1: Calculate the revenue requirement that is recovered in rates for Type 2 K-bar projects or programs for 2024. Using the 2023 going-in capital-related revenue requirement, calculate the amount of revenue requirement by program or project that is recovered in base rates under the I-X escalation mechanism for 2024.

(i) The amount of revenue requirement by program or project recovered in base rates under the I-X mechanism for 2024 should be determined in a manner consistent with the assumptions and use the same capital additions, retirements, depreciation parameters, and any other parameters utilized in the calculation of the going-in revenue requirement and going-in rates. Therefore, when identifying the portion of the rate base associated with the going-in rates for each Type 2 capital expenditure category, the mid-year rate base for the first component of the K-bar test should be the same as the mid-year rate base used to establish going-in rates. The revenue that is provided under I-X for Type 2 projects in 2024 is then calculated as the 2023 going in rates for each Type 2 capital expenditure category escalated by the approved I-X and customer growth escalator.

Step 2: Calculate the notional revenue requirement for Type 2 K-bar projects or programs for 2024.

(i) As inputs into the K-bar formula, the distribution utilities will determine the actual capital additions for each K-bar project from 2018-2022 and convert the capital additions to 2023 dollars using the approved I-X index and customer growth escalator for each year.[527]

(ii) Calculate the average K-bar capital additions, by program or project, in 2023 dollars for the 2018-2022 period.

(iii) Inflate the average K-bar capital additions by project to 2024 dollars using the I-X index and the customer growth escalator approved for 2024.

[527] As set out in Section 8.3, the distribution utilities must use the year-over-year change in average customer count reduced by 15 per cent for their customer growth escalator.

(iv) Calculate the amount of K-bar capital for 2024, by project or program, based on the capital additions from Step 2(iii) and the 2023 mid-year rate base using the method for calculating incurred capital costs from the capital tracker accounting test approved in Decision 2013-435. The distribution utilities should use a five-year average of inflation-adjusted retirements from 2018-2022 as an assumption in the accounting test.

Step 3: Calculate the K-bar by subtracting the recovered capital revenue requirement (Step 1) from the notional revenue requirement (Step 2).

(i) Calculate the difference between the 2024 K-bar capital-related revenue requirement required on a projected basis by program or project (from Step 2) and the 2024 K-bar capital-related revenue requirement recovered in the base rates by program or project (from Step 1). The result is the capital funding shortfall or surplus amount for each program or project for 2024.

(ii) Sum the capital funding shortfall and surplus amounts, including both negative accounting test results and positive accounting test results without any materiality considerations, for all Type 2 projects and programs from Step 3(i) to get the total interim base K-bar for 2024.

For 2025 through 2028, the K-bar annual parameter adjustments use very similar steps to those described above, with adjustments made to account for the effects of inflation and productivity represented by I-X, customer growth, and changes to the WACC. These updated parameters will be used in the K-bar accounting test to calculate the amount of incremental capital funding for a given year.

Following the same three steps as above, use the K-bar accounting test to calculate K-bar funding in each of the years 2025 through 2028 is described below.

Step 1: Calculate the revenue requirement that is recovered in the base rates under the I-X mechanism for Type 2 K-bar projects or programs for each of the years 2025 through 2028.

(i) Using the going-in revenue from Step 1 of the 2024 K-bar calculation as the starting point, calculate the amount of capital-related revenue that is generated under the going-in revenue by escalating it by the I-X index and the customer growth escalator approved for each year.

Step 2: Calculate the notional revenue requirement for Type 2 K-bar projects or programs for each of the years 2025 through 2028.

(i) Using the notional K-bar additions calculated in Step 2, part (iii) of the 2024 K-bar calculation as the starting point, calculate the amount of notional additions for each year from 2025 through 2028 by escalating the average capital additions to that year's dollars by applying the I-X and the customer growth escalator approved for that year. Similarly, calculate the notional amount for retirements in each year, by using the approved I factor to convert the average retirements to that year's dollars.

(ii) Calculate the depreciation expense and resulting accumulated depreciation that results from applying the most recent Commission-approved depreciation parameters to the notional rate base that results from adding the 2025 to 2028 notional additions and subtracting the notional retirements from the 2024 notional rate base captured in Step 2(iv) of the 2024 calculation.

(iii) Calculate the capital-related revenue requirement for each year from 2025 to 2028 using the 2024 notional rate base from Step 2(iv) of the 2024 calculation, notional annual capital additions and retirements from Step 2(i) and depreciation from Step 2(ii). The WACC to be used in the calculation will be based on the ROE and capital structure approved for that year, as well as the actual embedded cost of debt for that year. Any required income tax calculation should be consistent with the findings of Section 6.3 of Decision 22394-D01-2018.

Step 3: Calculate the K-bar.

(i) Calculate the difference between the K-bar capital-related revenue requirement required on a projected basis by program or project (from Step 2) and the capital-related revenue recovered in the base rates by program or project (from Step 1) for each year from 2025 to 2028. The result is the capital funding shortfall or surplus amount for each program or project for 2025 to 2028.

(ii) Sum the capital funding shortfall and surplus amounts, including both negative accounting test results and positive accounting test results without any materiality considerations, for all Type 2 projects and programs from Step 3(i) to get the total K-bar for each of 2025 through 2028.

Appendix 8 – Abbreviations

Abbreviation	Name in full
AESO	Alberta Electric System Operator
AWE	average weekly earnings
CANSIM	Canadian Socio-Economic Information Management System
COS	cost of service
COSR	cost-of-service regulation
CPI	consumer price index
CS rate	customer-specific rate (or class)
ECM	efficiency carryover mechanism
ESM	earnings shared mechanism
FBR	formula-based regulation
FWI	fixed weighted index
HP-ESM	high-powered earnings shared mechanism
I factor	inflation factor
IR	information request
K-bar	A mechanism to provide capital funding for the management of business as usual activities.
km	kilometres
kVA	kilovolt ampere
KWh	kilowatt hour
LEI	London Economics International LLC
MPFS	Major Projects Funding Supplement
MW	megawatt
NERA	NERA Economic Consulting
O&M	operation and maintenance
OEB	Ontario Energy Board
PEG	Pacific Economics Group
PBR	performance-based regulation: The number after “PBR” refers to the generation of AUC PBR plan, i.e., PBR1 refers to the first generation PBR plan (2013-2017); PBR2 refers to the second generation PBR plan (2018-2022); PBR3 refers to the third generation PBR plan (2024-2028).
Q factor	An adjustment for change in all billing determinants (for electric distribution utilities) and in customer growth (for gas distribution utilities).
ROE	return on equity

Abbreviation	Name in full
RRO	regulated rate option
TFP	total factor productivity
TOUP	Time of Use Primary
WACC	weighted average cost of capital
X factor	productivity offset
Y factor	An adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly.
Z factor	An adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan.