Decision **26617-D02-2022**

Alberta Utilities Commission

ENMAX Power Corporation
EPCOR Distribution & Transmission Inc.

2023 Cost-of-Service Review – Reasons for Approval of Negotiated Settlements

July 28, 2022

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1 Decision summary

1. On June 20, 2022, the Alberta Utilities Commission issued a decision approving settlement agreements reached between ENMAX Power Corporation and the Office of the Utilities Consumer Advocate (UCA), and EPCOR Distribution & Transmission Inc. (referred to in this decision as EPCOR or EDTI) and the UCA (the Settlements or Settlement Agreements).[1] The Consumers' Coalition of Alberta (CCA) did not sign the Settlement Agreements. In its June 20, 2022, decision, the Commission found that the Settlements will result in just and reasonable 2023 rates for both ENMAX and EPCOR, and that approval of the Settlements is in the public interest. At the time it issued its approval, the Commission advised that written reasons would follow, which are set out in this decision.

2. In its consideration of any settlement, the Commission is ultimately guided by whether the settlement will result in just and reasonable rates, and is in the public interest. The evidence provided in this proceeding included:

(a) applications for settlement including the Settlement Agreements;

(b) written concerns of the CCA;

(c) oral submissions by counsel for ENMAX, EPCOR, the UCA and the CCA;

(d) oral evidence from witnesses representing ENMAX, EPCOR, the UCA and the CCA; and

(e) the record of Proceeding 26617.

3. The Commission has carefully considered the evidence and position of the CCA, which opposed both Settlements. The Commission was not convinced by the CCA's evidence regarding the Settlements. The Commission considered the evidence of the UCA to be more compelling, and finds that the UCA's evidence provided a solid foundation for acceptance of the Settlements.

4. This decision begins with a brief summary of the procedural history that led to the Settlement Agreements and the Commission's consideration of them. The law governing the Commission's approach to settlement agreements is then outlined, followed by the Commission's assessment of the evidence in respect of, and reasons for, approving the Settlements.

[1] Decision 26617-D01-2022: ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Review, Proceeding 26617, June 20, 2022.

2 Background

5. ENMAX and EPCOR operate under a performance-based regulation (PBR) framework, the current term of which was approved in Decision 20414-D01-2016 (Errata)[2] and expires at the end of this year. Each utility filed its 2023 cost-of-service (COS) review application with the Commission for approval, representing the rebasing of their respective revenue requirements through a COS framework.

6. In the course of this proceeding each utility requested, and received, the Commission's permission to pursue a negotiated settlement process in respect of their applications. Two separate negotiation processes were conducted in May 2022. The first negotiation process occurred among ENMAX, the UCA and the CCA. ENMAX reached a settlement agreement with the UCA, to which the CCA refused to be a signatory.[3] The second negotiation process occurred among EPCOR, the UCA and the CCA. EPCOR reached a settlement agreement with the UCA, to which the CCA also refused to be a signatory.[4]

7. The Commission established further process,[5] which included written submissions from the CCA,[6] as well as an oral hearing on June 17, 2022, to consider the CCA's concerns with the Settlement Agreements, any comments that the signatories wished to provide, and evidence from all parties. This process was conducted on an expedited timeframe, without change to the original process schedule that was established to consider the full COS applications.

8. Both Settlement Agreements were negotiated as packages, contingent on the Commission accepting the entire settlement.[7] Section 135 of the *Electric Utilities Act* therefore required the Commission in this case to either approve the entirety of each settlement or reject it.

3 Law governing negotiated settlements – Rule 018 and the public interest

9. The Commission established Rule 018: *Rules on Negotiated Settlements* pursuant to Section 132 of the *Electric Utilities Act.*[8] Section 6 of Rule 018 sets out requirements for the contents of a negotiated settlement application and provides that the onus is on the applicant to provide sufficient evidence to support it and enable the Commission to understand and assess the agreement. Section 7 includes requirements for the Commission's assessment of the settlement. The Commission structured this settlement process in accordance with Rule 018.

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2 Decision 20414-D01-2016 (Errata): 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, February 6, 2017.
3 Exhibit 26617-X0220 through 26617-X0224.
4 Exhibit 26617-X0228.01 through 26617-X0231.
5 Exhibit 26617-X0219, AUC letter - Process for the assessment of negotiated settlement agreement.
6 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, and Exhibit 26617-X0232, CCA Written Submission on EPCOR NSA – 26617.
7 ENMAX indicated that its negotiated settlement agreement (NSA) with the UCA was contingent on the Commission accepting the entire settlement in accordance with Section 135 of the *Electric Utilities Act.* However, ENMAX requested that if the Commission was considering rejecting the NSA out of concern with one or more provisions, the Commission indicate the provisions that were the source of its concern and provide the parties an opportunity to renegotiate: see Exhibit 26617-X0220, 2022-06-06-EPC Negotiated Settlement Application, paragraphs 19-20.
8 Section 132 of the *Electric Utilities Act* requires that the Commission recognize or establish rules, practices and procedures to facilitate the negotiated settlement of matters arising under the act.

10. The Commission has considered negotiated settlements in rate cases where there has been unanimous agreement (unlike the case here) and has consistently indicated that the test requires consideration of three factors: (i) was the negotiation process fair, including with respect to notice and the conduct of the process itself; (ii) will the settlement result in just and reasonable rates; and (iii) are any of the settlement provisions, individually or collectively, patently against the public interest or contrary to law?[9]

11. The Commission may consider settlements that are not unanimous, and always retains its authority to accept or reject a settlement. As noted by the Alberta Court of Appeal in a leading decision:[10]

> [137] …What then is the Board's obligation when determining whether it will – or will not – approve a settlement? The first point is this. **Regardless of whether the settlement is unanimous (dissenting views are permitted), the Board retains the jurisdiction to conduct an independent review of the negotiated settlement to determine if it is in the "public interest"**….
>
> [138] The ultimate responsibility for approving negotiated settlements – and ensuring that the process operates in a fair and reasonable manner – must rest with an independent body. That body is the Board. The rationale for impressing this overriding supervisory authority on the Board is to ensure that the negotiated settlement process does not lead to abuse. Further, all consumers cannot be parties to negotiations conducted under the negotiated settlement process. One or more of the interested parties to the settlement may represent some consumers; but none will represent all. And even a broad range of Intervenors will not necessarily translate into a wide spectrum of positions since parties may make trade-offs which leave other issues unresolved, unaddressed or compromised.
>
> [139] Thus, as long as the distribution and transmission functions of electric utilities remain regulated, **the negotiated settlement process does not replace an appropriate and informed review by the Board as to what is in the overall public interest**. Otherwise, members of the consuming public may rightly ask: "Who's protecting our interest?" The answer, at the end of the day, is the Board. That is why negotiated settlements require Board approval. And it is also why **the Board's discretion in controlling rates as mandated by statute cannot be fettered by a negotiated settlement**: *Utilities Consumers' Group v. Yukon (Utilities Board)* 2001 YKCA 5, 35 Admin. L.R. (3d) 113. The overriding public interest demands no less. [emphasis added]

[9] 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, paragraph 29. The same test was recently set out in Decision 25726-D01-2021: ENMAX Power Corporation, 2021-2022 General Tariff Application Negotiated Settlement Agreement and Excluded Matters, Proceeding 25726, June 16, 2021, paragraph 23; and Decision 23966-D01-2020 (Corrigenda): ENMAX Power Corporation, 2018-2020 General Tariff Application Negotiated Settlement Agreement and Excluded Matters, Proceeding 23966, July 30, 2020. A similar test was set out recently in Decision 26207-D01-2021: Direct Energy Regulated Services, 2020-2022 Default Rate Tariff and Regulated Rate Tariff – Negotiated Settlement Agreement, Proceeding 26207, June 4, 2021, paragraph 18, wherein the Commission condensed the test (in the case of a unanimous settlement) into two parts: that the Commission "must consider the fairness and public interest factors with the objectives of determining: (i) if the process resulting in the settlement was fair, and (ii) if approval of the settlement will lead to rates that are just and reasonable. In making this determination, the Commission will consider if the settlement is patently contrary to the public interest or contrary to law."

[10] *ATCO Electric Limited v Alberta (Energy and Utilities Board),* 2004 ABCA 215.

12. In assessing a negotiated settlement, whether unanimous or non-unanimous, the Commission must therefore have regard to the requirements set out in Rule 018, including the fairness of the process. It must also remain focused on one critical question – will the proposed settlement lead to just and reasonable rates? The answer to this question is central to the determination of whether a settlement is in the public interest. The Commission's assessment of the evidence before it in the current proceeding with regard to fairness of the process, just and reasonable rates, and the public interest is set out in the section that follows.

4 The Commission's assessment of the negotiated settlements

4.1 Fairness of the settlement process

13. The Commission finds that the requirements of Section 6(3) of Rule 018 were satisfied by ENMAX[11] and EPCOR.[12] With regard to assessing the fairness of the Settlements, the Commission took into account the utilities' written submissions, but was also concerned with the short time frame that was provided to the parties for negotiating the Settlements. All parties advised that while the timelines were tight, and that more time could have been helpful to the negotiation process, they were nevertheless able to focus their time efficiently, and all parties viewed the process as fair.[13] The CCA further noted that the timing was not the reason that the CCA was unable to agree to a settlement.[14]

14. The Settlements were not unanimous, which led the Commission to ask the CCA to provide further detail regarding why it was not a signatory to the settlements.[15] The CCA initially stated with regard to the settlement between ENMAX and the UCA, that it "… was unable to agree to the amounts and terms of the settlement."[16] The CCA further specified that it was concerned with the "… magnitude of the agreed increases and that the settlement is still a substantial increase to the applied for revenue requirement over historical levels."[17]

15. With regard to the settlement reached between EPCOR and the UCA, the CCA initially submitted that it was "… not opposed to the outcome negotiated by the UCA and EDTI with respect to the settlement amount relative to the applied for revenue requirement over historical levels." Rather, the CCA clarified that it had "… an outstanding issue with efficiency sharing with customers based in part on the EDTI reported ROE's [return on equity] and requests the opportunity to address the issue of how EDTI's PBR2[[18]] efficiencies are shared with customers."[19]

11 Evidence regarding the Rule 018, Section 6(3), requirements for ENMAX are set out in exhibits 26617-X0220 through 26617-X0224.
12 Evidence regarding the Rule 018, Section 6(3), requirements for EPCOR are set out in exhibits 26617-X0228.01 through 26617-X0231.
13 EPCOR spoke to the timing issue at Transcript, Volume 1, pages 51-53; page 96, lines 8-25 to page 97, lines 1-11. ENMAX submissions can be found at Transcript, Volume 1, page 76, lines 3-11. The UCA submissions can be found at Transcript, Volume 1, page 115, lines 24-25 to page 116, lines 1-13. The CCA submissions can be found at Transcript, Volume 1, page 141, lines 5-25 to page 42, line 1.
14 Transcript, Volume 1, page 141, lines 24-25 to page 142, line 1.
15 Exhibit 26617-X0214, Acknowledgement and direction to provide additional information.
16 Exhibit 26617-X0217, CCA response to AUC – Exhibit 214 – 26617, paragraph 3.
17 Exhibit 26617-X0217, CCA response to AUC – Exhibit 214 – 26617, paragraph 6.
18 PBR2 refers to the 2018-2022 PBR plans for Alberta electric and gas distribution utilities.
19 Exhibit 26617-X0217, CCA response to AUC – Exhibit 214 – 26617, paragraph 11.

16. Pursuant to sections 6(4), 6(5) and 7 of Rule 018, the Commission determined that it needed to further consider the proposed settlement applications and the CCA's dissenting views. It therefore took steps to obtain further information from the CCA and the parties to the Settlements. As noted above, the Commission set up a process that included written submissions from the CCA,[20] and convened an oral proceeding to hear submissions and evidence from all parties.

4.2 ENMAX settlement with the UCA

4.2.1 ENMAX distribution COS application

17. The ENMAX distribution COS application (DCOS Application) included a forecast 2023 revenue requirement of $299.8 million, which included an operations and maintenance (O&M) forecast of $105 million, a capital revenue requirement forecast of $199.1 million, and forecast revenue offsets decreasing the total revenue requirement forecast by $5.2 million.

18. ENMAX included the following table in its 2023 DCOS Application providing its actual revenue requirements between 2018 and 2020 and its forecast revenue requirements between 2021 and 2023:[21]

Table 1. ENMAX summary of revenue requirements 2018 to 2023

Revenue requirement	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast
	($ million)					
ROE	34.3	52.3	54.3	48.3	48.8	61.1
Interest on long-term debt	33.5	35.3	36.0	37.0	39.3	42.2
Operating & Maintenance	93.2	87.4	83.5	88.7	92.8	105.8
Revenue offsets	(6.7)	(6.2)	(5.7)	(5.2)	(5.2)	(5.2)
Depreciation	71.5	72.9	77.2	82.4	88.6	95.8
Total revenue requirement	**225.8**	**241.6**	**245.2**	**251.2**	**264.4**	**299.8**

Note: Figures subject to rounding.

19. ENMAX informed the Commission that the increase in capital-related revenue in the 2023 forecast (which include the rows labelled ROE, interest on long-term debt, and depreciation in the table above) included significant investment in the replacement of assets that are at, or near, end of life, and the accommodation of customer requests, as well as grid modernization and innovation investments.[22]

20. In its DCOS Application, ENMAX stated that it had struggled to earn its approved return under PBR, and began PBR2 in 2018 with an annual O&M shortfall of $9.5 million. It further noted that throughout PBR2, it had to invest approximately $142 million more capital in its distribution system than the funding provided by the PBR formula.[23]

20 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, and Exhibit 26617-X0228.01, CCA Written Submission on EDTI NSA – 26617.
21 Exhibit 26617-X0022, 2022-01-17 EPC 2023 Distribution Cost of Service Application, Table 1-1.
22 Exhibit 26617-X0022, EPC application, PDF page 2.
23 Exhibit 26617-X0022, EPC application, PDF page 5.

4.2.2 ENMAX and the UCA submissions regarding the settlement

21. The ENMAX settlement with the UCA includes a global reduction to O&M totalling $9.85 million, and a reduction to capital adjustments of $200,000[24], for a total of $10.05 million in reductions to the applied-for 2023 revenue requirement.[25] The ENMAX settlement also includes increases for inflation of $1.41 million and cost of debt of $2.3 million,[26] which reflected the most recent information available.[27]

22. ENMAX indicated that for the typical residential customer, the negotiated settlement agreement (NSA) would result in an increase of $2.65 per month, or a 1.8 per cent increase on a typical total monthly bill of $149.66. When adjusted for inflation and system growth,[28] the forecast 2023 O&M revised to reflect the NSA adjustments was $37.1 million lower than in 2014 (rebasing year for PBR1) and $16.3 million lower than in 2018 (the start of PBR2).[29]

23. The UCA stated that in agreeing to the ENMAX settlement, it was mindful of its previous submissions that O&M costs should be set at a level reflecting the lowest cost year in the second generation PBR term.[30] The UCA's witness, Russ Bell, had calculated O&M costs per customer from 2015 to 2023 using actual and forecast data. R. Bell determined that the lowest cost year was 2020, at $173.10 per customer, with the next lowest year being 2021 at $175.30. The UCA calculated that the ENMAX settlement would result in an O&M cost per customer of $174.70, higher only than 2020. Had the ENMAX application been approved as filed, the UCA calculated that the O&M cost per customer would have been $192.[31] The UCA considered that the agreed-upon O&M costs in the ENMAX settlement represented a reasonable compromise.[32]

24. The UCA was also of the view that using a lowest-cost year approach for O&M was a way to ensure that PBR benefits were captured and passed on to ENMAX's customers.[33]

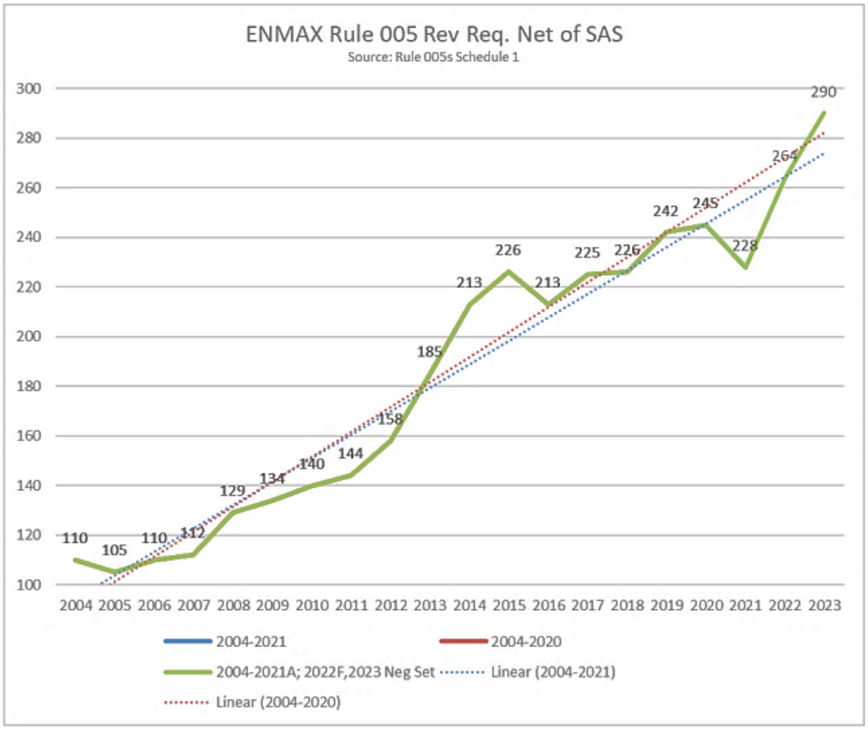
4.2.3 CCA submissions and ENMAX evidence in response

25. The CCA provided detailed written submissions explaining its opposition to the ENMAX settlement, with a focus on what it claimed was a significant increase in revenue requirement, particularly during rebasing years.[34] The CCA's evidence included two graphs with historical trend lines, together with amounts comprising ENMAX's revenue requirement.[35] The CCA argued that these graphs demonstrated a significant escalation in ENMAX's forecast revenue

[24] A reduction of $4.3 million in capital additions resulted in a reduction of $200,000 in capital adjustments.
[25] Exhibit 26617-X0220, EPC Negotiated Settlement Application, PDF pages 9-13, paragraphs 30-36.
[26] Exhibit 26617-X0220, EPC Negotiated Settlement Application, PDF pages 13-14, paragraphs 37-40.
[27] Exhibit 26617-X0221, Appendix C – NSA Continuity and Adjustment Calculations, tab Adjustment 6, line 7, and Adjustment 7, line 5.
[28] At paragraph 168 of its application, ENMAX stated that while its distribution system has grown, its O&M costs, when adjusted for inflation and the size of the system, have decreased or remained stable since 2014.
[29] Exhibit 26617-X0220, EPC Negotiated Settlement Application, PDF pages 13-14, paragraphs 45-46.
[30] Transcript, Volume 1, page 54, lines 19-24 (UCA submissions, T. Marriott).
[31] Transcript, Volume 1, page 55, lines 2-19 (UCA submissions, T. Marriott).
[32] Transcript, Volume 1, page 58, lines 8-14 (UCA submissions, T. Marriott).
[33] Transcript, Volume 1, page 100, lines 1-10 (S. McDonough), page 100, lines 13-25, page 101, lines 1-5 (R. Bell), page 102, lines 15-20.
[34] It was clear that this was the principal concern of the CCA. While the CCA raised other specific issues in its written evidence, in response to a question regarding where specific cuts could be made, the CCA's witness Jan Thygesen advised that the CCA's approach was to focus on the total dollars, and let the utility determine where to cut. See Transcript, Volume 1, page 126, lines 15-25 to page 127, lines 1-9 (J. Thygesen).
[35] Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, PDF pages 5 and 7.

requirement, well over the historical trend lines.[36] One of the CCA's graphs outlining the historical trends is set out below in Figure 1:[37]

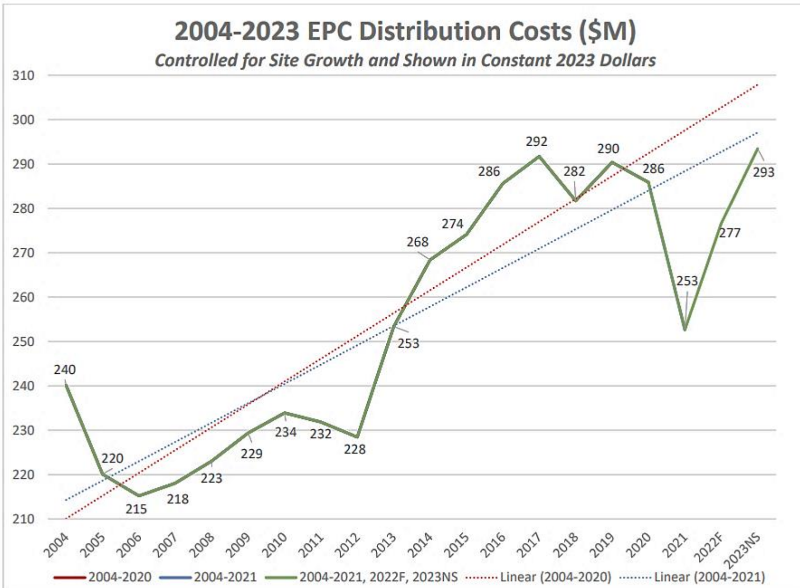
Figure 1. ENMAX Rule 005[38] revenue requirement, net of system access service



26. In response to the CCA's evidence, ENMAX provided a similar graph,[39] the underlying data for which controlled for site growth, and was shown in constant 2023 dollars. Controlling for site growth and inflation produced a significantly different graphical representation of ENMAX's revenue requirement over time:

36 Transcript, Volume 1, page 125, line 25 to page 126, lines 1-3 (J. Thygesen).
37 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, PDF page 5.
38 Rule 005: *Annual Reporting Requirements of Financial and Operational Results.*
39 Exhibit 26617-X0236, EPC 2004-2023 Distribution Costs Chart Controlled for Growth and Constant.

Figure 2. ENMAX 2004-2023 distribution costs controlled for site growth, in constant 2023 dollars



27. In response to Commission questions, ENMAX explained that it produced the above graph in response to the CCA evidence. ENMAX pointed out that the CCA's graph and data did not adjust for inflation, or the large increase in site counts, from 2004 to 2023.[40] ENMAX later filed the underlying data on inflation and site counts it used to produce the graph. The Commission notes that the site counts increased from 367,365 in 2003 to 532,927 in 2021, with a projected increase to 551,210 in 2023 – a 50 per cent increase compared to 2003.[41]

4.3 EPCOR settlement with the UCA

4.3.1 EPCOR DCOS

28. EPCOR applied for approval of a forecast 2023 revenue requirement of $275.14 million in EPCOR's 2023 DCOS Application. This amount included a 23.8 per cent increase in mid-year capital rate base since 2020; a $16.55 million increase in operating costs relative to the 2018-2020 average, driven in part by increased municipal franchise fees and the expensing of the Alberta Electric System Operator (AESO) contributions in 2023;[42] and a $13.92 million increase in deferral account costs, which primarily reflected the amortization of deferral costs associated with AESO contributions.[43]

29. The EPCOR DCOS Application also incorporated approximately $11.87 million of what it asserted were realized and quantifiable cost reductions achieved by EPCOR during the PBR1 and PBR2 terms. These included reductions resulting from automation initiatives, optimization of processes, and restructuring or consolidating groups within EPCOR.[44]

40 Transcript, Volume 1, page 77, lines 12-22 (R. Lottermoser) and page 78, lines 2-15.
41 Exhibit 26617-X0238, EPC-AUC-2022JUN17-001 Undertaking, Chart Data.
42 The expensing of AESO contributions was directed by the Commission in Decision 26521-D01-2021: Revised Regulatory Accounting Treatment for Alberta Electric System Operator Customer Contributions, Proceeding 26521, October 6, 2021.
43 Exhibit 26617-X0228.01, PDF page 9, paragraph 21.
44 Exhibit 26617-X0228.01, PDF page 10, paragraph 22.

30. EPCOR stated that the applied-for revenue requirement reflected a 2.08 per cent decrease in net operating costs and a 22.3 per cent reduction in operating costs per customer since 2012. It also included a forecast full-time-equivalent level that was 8.9 per cent below 2012 levels, notwithstanding an increase of 26 per cent in the number of customer sites over that period.[45]

4.3.2 EPCOR and the UCA submissions regarding the settlement

31. The EPCOR settlement with the UCA includes a $6.179 million reduction to EPCOR's applied-for revenue requirement.[46] This includes a $4.691 million reduction in EPCOR's operating costs; a further $0.688 million decrease in capital-related revenue requirement resulting from a $15 million reduction to EPCOR's forecast capital additions; and a $0.8 million reduction to correct for errors and omissions in the DCOS Application.[47]

32. The UCA submitted that in agreeing to the EPCOR settlement, it had again focused on O&M costs and the lowest cost year during the second PBR term. The UCA's witness, R. Bell, calculated EPCOR O&M costs using actuals and forecasts between 2015 and 2023. He determined that 2020 was the lowest cost year at $167.30 per customer, and the next lowest year was 2018 at $168.50. The UCA calculated that if the EPCOR NSA was approved, this would lead to a 2023 O&M cost per customer of $168.10, higher only than 2020. If EPCOR's DCOS Application was approved as filed, the 2023 cost per customer would be $181.40.[48] The UCA considered that the agreed-upon O&M costs in the EPCOR settlement represented a reasonable compromise.[49]

33. The UCA was also of the view that using a lowest-cost year approach for O&M was a way to ensure that PBR benefits were captured and passed on to EPCOR customers.[50]

34. In response to questions about the CCA's concerns regarding EPCOR's capital expenditures, the UCA's witness noted that capturing efficiencies through measurement of O&M is more straightforward because these costs are somewhat repetitive or continuous.[51] R. Bell explained that in looking at capital, if there was a ramp-up near the end of the PBR term or forecast for the next term, that may be a sign that capital was not needed or deferred, and further deferral could be possible.[52] He added, however, that assessing the reasonableness of the quantum and timing of capital expenditures is much more difficult because of the lumpy nature of the work involved and "… projects may be discrete and change from year to year."[53]

4.3.3 CCA submissions and EPCOR evidence in response

35. The CCA initially submitted that it did not take issue with the numbers at which EPCOR and the UCA settled, but instead remained concerned that consumers were not receiving the

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45 Exhibit 26617-X0228.01, PDF page 10, paragraph 24.
46 Exhibit 26617-X0228.01, PDF page 6, paragraph 11(e).
47 Exhibit 26617-X0228.01, paragraph 25. The Commission notes that the $0.8 million reduction for the correction of errors and omissions would have had to occur in any event, bringing the settlement number to $5.379 million in overall reductions.
48 Transcript, Volume 1, page 57, lines 1-25 (UCA submissions, T. Marriott).
49 Transcript, Volume 1, page 58, lines 8-14 (UCA submissions, T. Marriott).
50 Transcript, Volume 1, page 100, lines 1-10 (S. McDonough); page 100, lines 13-25, page 101, lines 1-5 (R. Bell); page 103, lines 5-16; page 106, lines 5-18 (S. McDonough).
51 Transcript, Volume 1, page 107, lines 12-14 (R. Bell).
52 Transcript, Volume 1, page 107, lines 20-25, to page 108, lines 1-2 (R. Bell).
53 Transcript, Volume 1, page 108, lines 3-5 (R. Bell).

benefit of realized efficiencies, particularly given EPCOR's reported returns above Commission-approved ROEs.[54]

36. However, in its further written evidence, the CCA appeared to reverse its position regarding the EPCOR and the UCA settlement numbers, noting that:

> … the CCA has a growing sentiment of disagreement with the "number at which the UCA and EPC [*sic*] settled". This disagreement is based on a further understanding of how EDTI presented the forecast revenue requirement to give the appearance of future forecast costs having a closer alignment with overall cost trends …[55]

37. In its written evidence, the CCA witness Jan Thygesen raised concerns about EPCOR overforecasting capital expenditures, but ultimately spending far less. J. Thygesen submitted that EPCOR's actual capital additions for PBR2 have been $163 million in nominal dollars annually on average between 2018 and 2021, as opposed to the $180 to $190 million annual commitment made by EPCOR witnesses in the last rebasing proceeding.[56] J. Thygesen suggested that EPCOR pocketed the difference between its overforecast and underspend on capital, and attributed EPCOR's higher than approved ROE returns to this practice.[57] He further submitted that this amounted to a double-billing of customers, with EPCOR claiming to need capital in PBR2, not spending the capital, and then claiming the money was needed again.[58]

38. In the oral proceeding, EPCOR's witness Saqib Chaudhary was asked to respond to these allegations. S. Chaudhary referenced a table in the CCA evidence[59] that was drawn from an EPCOR response to a CCA information request. The table demonstrated that over the PBR period (including 2022 forecast additions), EPCOR would spend $8 million more than it had received in funding. EPCOR's witness confirmed that the capital funding in the table represented the total capital funding EPCOR received during PBR2, including both K-bar funding and capital funding provided under the I-X base rate (despite the relevant table row being labelled as "K-bar Funded Capital Additions"), and that 2022 capital expenditures were on target for spending over the amount forecast.[60]

39. During the oral proceeding, the CCA's J. Thygesen was questioned after EPCOR's S. Chaudhary. Notwithstanding the written submissions referenced above at paragraphs 36 and 37, which indicated the CCA had issues with the EPCOR revenue requirement, in oral evidence, J. Thygesen stated that the CCA was not opposed to the settlement, and that his recommendation would be to accept the revenue requirement, or the EPCOR NSA.[61]

40. J. Thygesen then elaborated on the CCA's position regarding efficiencies. When asked about the lowered metering costs in EPCOR's Advanced Metering Infrastructure (AMI) Program, he confirmed that the CCA's position was that all efficiencies achieved from that

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54 Exhibit 26617-X0217, CCA Response to AUC – Exhibit 214 – 26617.
55 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF page 15, paragraph 34.
56 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF page 6, paragraph 20.
57 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF page 14, paragraphs 28-31.
58 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF pages 21-22, paragraphs 54-57.
59 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF page 19, table below paragraph 47.
60 Transcript, Volume 1, page 88, lines 15-25, pages 89-91, page 92, lines 1-5 (S. Chaudhary questioned by L. Berg).
61 Transcript, Volume 1, page 128, lines 18-25, page 129 (J. Thygesen questioned by L. Berg).

EPCOR program during PBR2 should be returned to customers, and that starting the process of doing so only at the beginning of the next PBR term was not sufficient. He noted that this was particularly the case as the AMI program had been put in place in 2018, meaning that although benefits had been realized starting several years ago, they had yet to be shared with customers.[62]

4.4 Commission findings

4.4.1 Assessment of evidence from the UCA and the CCA

41. In assessing the evidence regarding the Settlement Agreements, the Commission considered that the UCA has a statutory responsibility that includes the following:

> … to represent the interests of Alberta residential, farm and small business consumers of electricity and natural gas before proceedings of the Alberta Utilities Commission and other bodies whose decisions may affect the interests of those consumers …[63]

42. "Consumer" is broadly defined in the *Government Organization Act* as it pertains to the UCA, and includes an eligible customer[64] as defined in the *Regulated Rate Option Regulation;* a consumer[65] as defined in the *Energy Marketing and Residential Heat Sub-metering Regulation;* a person who purchases fewer than 2,500 gigajoules of natural gas per year, or a person who receives water from a provider for residential purposes, small business purposes, or agricultural purposes other than irrigation.[66]

43. The CCA represents a subset of these consumers through its work for the Alberta Consumers Association and the Alberta Council on Aging.

44. The Commission has carefully considered the evidence of both of these parties, having regard to the guidance from the Court of Appeal of Alberta that in any settlement, the Commission can assume that the utility's revenue requirement will be satisfied, and that the Commission only needs to have regard for whether the settlement will result in just and reasonable rates for consumers, and is in the public interest.[67]

45. The Commission accepts the evidence of the UCA regarding the ENMAX and EPCOR Settlements, and finds that the Settlements represent a reasonable compromise of contested issues in the larger ENMAX and EPCOR rebasing applications.

46. In assessing the CCA's evidence regarding ENMAX, the Commission was concerned with the CCA's decision to include an "anomalous year" in its trend line analysis. More specifically, the year 2021 was an anomalous year for ENMAX from an ROE perspective. In

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62 Transcript, Volume 1, page 135, lines 7-25, to page 136, lines 1-8 (J. Thygesen questioned by L. Berg).
63 *Government Organization Act*, Schedule 13.1, Section 3(a).
64 In the *Regulated Rate Option Regulation*, an "eligible customer" means (i) a rate classification customer, and (ii) any other customer, if the owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site. Furthermore, a "rate classification customer" means (i) a residential rate classification customer, (ii) a farm rate classification customer, or (iii) an irrigation rate classification customer as defined in a regulated rate tariff.
65 The *Energy Marketing and Residential Heat Sub-metering Regulation* defines "consumer" as a person who enters into a marketing contract to purchase less than 2,500 gigajoules of gas per year or 250 megawatt hours of electricity per year.
66 *Government Organization Act*, Schedule 13.1, Section 1(a).
67 *ATCO Electric Limited v Alberta (Energy and Utilities Board),* 2004 ABCA 215, paragraphs 145-146.

2021, ENMAX had to absorb significant losses that occurred in previous years, which drove down its ROE for that year considerably. While the CCA acknowledged the impact of the anomalous year,[68] it nevertheless included it in its trendline analysis, arguing that the trendline reflecting the anomalous year showed that the ENMAX revenue requirement was up to $15 million higher than the historical trend.[69]

47. The CCA purported to remove the impact of the anomalous year by subtracting the ENMAX ROE requirement from each year, and plotting the resulting calculations on a graph.[70] The CCA argued that this demonstrated a spending gap above historical trends of $18 to $20 million.[71] However, in producing this graphical evidence, the CCA did not address the fact that:

(a) the ROE is an integral part of the revenue requirement that must be considered by the Commission;

(b) removing the ROE had the effect of flattening the trendlines and thereby increasing the differential between the trendline and forecast spend; and

(c) on average, ENMAX has not achieved its approved ROE over time.[72]

48. The Commission further notes that the CCA did not take the basic step of converting the data to constant 2023 dollars, further exaggerating the differences between forecast spend and historical trendlines.

49. Finally, while the Commission does not agree (nor was there evidence to support the proposition) that costs increase on a one-to-one basis with increases in site counts, it recognizes that large increases in site counts will add to the overall costs of the distribution system. The Commission therefore finds the ENMAX graph reproduced in Figure 2 above, and which accounts for an increase in sites, to be, on balance, more persuasive than the evidence submitted by the CCA.[73] In particular, the CCA's evidence made no provision for changes in total costs attributable to the increase in the size of the ENMAX customer base and system over time.

50. The Commission also has concerns with the CCA's evidence on EPCOR. As previously noted, J. Thygesen suggested that EPCOR pocketed the difference between what the CCA alleged EPCOR overforecast and underspent on capital, and attributed EPCOR's returns in excess of approved ROE to this alleged practice.[74] He further submitted that this amounted to a double-billing of customers, with EPCOR claiming to need capital in PBR2, not spending the capital, and then claiming the money was needed again.[75]

68 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, PDF page 6.
69 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, PDF page 6.
70 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, PDF page 7.
71 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, PDF page 8, paragraph 16.
72 Exhibit 26617-X0226, CCA Written Submission on ENMAX NSA – 26617, PDF page 10.
73 Exhibit 26617-X0236, EPC 2004-2023 Distribution Costs Chart Controlled for Growth and Constant.
74 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF page 14, paragraphs 28-31.
75 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF pages 21-22, paragraphs 54-57.

51. This was not the case, however. As EPCOR pointed out, a table reproduced in the CCA's own evidence[76] demonstrated that over the PBR period (including 2022 forecast additions), EPCOR would spend $8 million more than it received in funding.

52. The CCA also submitted that all cost savings realized through EPCOR programs in PBR2 should be transferred to customers in PBR3.[77] The CCA took issue with the fact that EPCOR could benefit from a PBR2 program that saved money beginning in 2018, while consumers would not see that benefit until the (ongoing) annual savings were reflected in future rates as part of PBR3.[78]

53. The CCA is a sophisticated intervener, and should be well aware that PBR is designed to incent utilities to seek efficiencies by enabling them to benefit directly from achieving such efficiencies during a PBR period. Under the current PBR framework, the savings from these efficiencies are passed on to consumers through lower rates in the next PBR period. Retroactively confiscating all of the benefits of such efficiencies during a prior PBR period with no prior notice would undermine PBR incentives and the credibility of the regulator.

54. In assessing the evidence presented by the CCA and the UCA, the Commission finds the UCA evidence more persuasive.

5 2023 closing rate base and PBR3 going-in rates

55. In the Notice issued on January 18, 2022,[79] the Commission indicated that the rates approved for 2023 under this COS review proceeding would be used as going-in rates for the future PBR term that will commence in 2024. In Decision 26354-D01-2021, the Commission determined that the actual 2023 opening rate base will be used to fix the 2023 rates.[80]

56. Opening and closing rate base are required due to the mid-year convention for setting rates. The mid-year convention is the accepted method for approximating the cost of capital investments in the year, and for the purposes of calculating other capital related costs. The mid-year convention uses an arithmetical average of a utility's investments to account for capital related costs uniformly over the entire year, recognizing that assets are added to rate base throughout the year. It is commonly used in regulatory jurisdictions in North America.

57. The Commission will use the forecast 2023 closing rate base reflected in the Settlement Agreements (that is, 2022 actual closing rate base plus the forecast capital additions for 2023 approved by the Commission in this decision and Decision 26617-D01-2022) to fix ENMAX's and EPCOR's going-in rates for PBR3 in 2024.

76 Exhibit 26617-X0232, CCA Written Submission on EDTI NSA – 26617, PDF page 19, table below paragraph 47.
77 Transcript, Volume 1, page 134, lines 14-25 to page 135, lines 1-6 (J. Thygesen). PBR3 refers to PBR plans that will start in 2024 for Alberta electric and gas distribution utilities.
78 Transcript, Volume 1, page 135, lines 11-25 to page 136, lines 1-8 (J. Thygesen).
79 Exhibit 26617-X0071, Notice of application, 2023 Cost-of-Service review.
80 Decision 26354-D01-2021: Process to Establish 2023 Rates for Alberta Electric and Gas Distribution Utilities, Proceeding 26354, June 18, 2021, paragraph 25.

58. This finding is subject to the following two considerations to be resolved in Proceeding 27388 where the parameters of the PBR3 plans will be established.

59. The first consideration relates to the fact that in setting the PBR3 plans, the Commission expressed interest in implementing PBR rate adjustments on July 1 of each year rather than January 1 as is the current practice. If such a change is made, it will necessitate consideration of how to set rates for the January 1 to June 30, 2024 period.

60. The second consideration is that the actual closing 2023 rate base may be used for any approved capital funding mechanism in PBR3, subject to the decision of the Commission in respect of its examination of the parameters of PBR3 in Proceeding 27388. The Commission notes that all supplemental capital funding mechanisms used in both the PBR1 and PBR2 plans relied on the actual closing rate base in the rebasing year, even though the going-in rates for those plans were set on a different basis (forecast rate base was used for PBR1 and notional rate base for PBR2).

6 Decision

61. The Commission finds that accepting the Settlement Agreements is in the public interest because they will lead to just and reasonable rates and provide certainty, plus savings in costs, resources and time that all parties would have otherwise expended in a fully litigated proceeding.

62. As previously held in Decision 26617-D01-2022, the Commission has decided to approve the settlement agreement between ENMAX and the UCA as filed, in its entirety. The Commission has also decided to approve the settlement agreement between EPCOR and the UCA as filed, in its entirety.

7 Compliance filings to this decision

63. ENMAX and EPCOR shall each file a compliance application and include in their respective compliance applications all information that typically accompanies the calculation of rates, including the following:

- A 2023 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.
- A 2023 distribution tariff based on the approved revenue requirement and the associated bill impact analysis.
- Terms and conditions of service for 2023 for approval.
- A true-up of the prior approved deferral accounts such as the amounts included in the Y factor and 2021 Transmission Access Charge Deferral Account true-up.
- All currently approved deferral accounts and rate riders, which shall continue to be applied in 2023. The differences between forecast and actual costs for amounts in these accounts will subsequently be trued up in the annual PBR rate adjustment filings.
- Any other items required to support the proposed 2023 distribution tariff.

8 Order

64. It is hereby ordered that:

(1) Each of ENMAX Power Corporation and EPCOR Distribution & Transmission Inc. shall file a compliance filing in accordance with the directions set out in this decision by September 16, 2022.

Dated on July 28, 2022

Alberta Utilities Commission

(original signed by)

Kristi Sebalj
Vice-Chair

(original signed by)

Cairns Price
Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
ENMAX Power Corporation (ENMAX or EPC)
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden, Ladner Gervais LLP
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP Russ Bell & Associates Inc.

Alberta Utilities Commission Commission panel K. Sebalj, Vice-Chair C. Price, Commission Member B. Romaniuk, Acting Commission Member Commission staff L.-M. Berg (Commission counsel) K. Macnab (Commission counsel) C. Robertshaw A. Jukov

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
ENMAX Power Corporation (ENMAX or EPC) D. Wood and T. Campbell	J. Taylor D. Stanghetta M. Bartek R. Lottermoser
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo	S. Chaudhary
Consumers' Coalition of Alberta (CCA) J. Wachowich, QC	J. Thygesen
Office of the Utilities Consumer Advocate (UCA) T. Marriott, QC	S. McDonough R. Bell