Alberta Utilities Commission

EPCOR Distribution & Transmission Inc.

Phase 2 Distribution Tariff Application

July 11, 2022

Alberta Utilities Commission
Decision 27018-D01-2022
EPCOR Distribution & Transmission Inc.
Phase 2 Distribution Tariff Application
Proceeding 27018

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Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

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

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1 Decision summary

1. This decision provides the Alberta Utilities Commission's determinations on EPCOR Distribution & Transmission Inc.'s (EPCOR or EDTI) Phase 2 application. Subject to certain modifications as explained in this decision, the Commission approves EDTI's proposals effective January 1, 2023, on the following:

- cost-of-service study (COSS)
- rate design
- terms and conditions for distribution access service and for distribution connection services
- distribution tariff policies

2. The Commission also directs certain changes to take effect in EDTI's next Phase 2 proceeding; including to revise the allocation methodology of Federal Energy Regulatory Commission (FERC) Account 367 to make the methodology simpler and more transparent, and to provide the results of a demand-metering billing feasibility study.

3. EDTI is directed to submit a compliance filing to reflect the determinations in this decision on or before August 15, 2022.

2 Introduction and procedural summary

4. Rate-setting under traditional cost-of-service regulation involves two phases. Phase 1 sets the revenue requirement of a utility for a given year or years, and is typically approved by the Commission on a forecast basis. Under the performance-based regulation (PBR) plans approved for EDTI and three other Alberta electric distribution utilities for the 2018-2022 term,[1] a utility's revenue requirement is established by indexing its prior year's rates by an inflation factor less a productivity factor, subject to certain other adjustments, such as a mechanism for capital funding and adjustments for costs or events outside of management's control.

5. Phase 2 primarily designs rates and establishes rate class cost allocations used in determining how much of the revenue requirement should be recovered from each customer class and the billing determinants that will apply to each class. A billing determinant refers to a unit of measure required to determine a customer's bill. For example, for the residential customer, a utility needs the number of days it served a customer and the amount of energy a customer consumed during that period. These two elements, the number of days of service and

[1] Decision 20414-D01-2016 (Errata): 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, February 6, 2017, amending the decision issued December 16, 2016.

energy consumed in kilowatt hours (kWh), are the two billing determinants for the residential class.

6. On November 30, 2021, EDTI filed its Phase 2 application requesting Commission approval of its proposed distribution tariff, terms and conditions[2] of service and distribution tariff policies, supported by the COSS and rate design. This was the first Phase 2 application for EDTI since its 2010-2011 Phase 2 was determined in Decision 2011-375.[3] EDTI also requested approval of revisions to the method of calculating new and updated customer specific (CS) rates (outside of the Phase 2 tariff approval process) and calculation of billing determinants.

7. To consider EDTI's application, the Commission commenced this proceeding by issuing a notice of application on December 2, 2021, requiring interested parties to submit a statement of intent to participate (SIP). SIPs were received from the Office of the Utilities Consumer Advocate (UCA) and the Consumers' Coalition of Alberta (CCA).

8. The main process steps for this proceeding included a round of information requests (IRs) to EDTI, responses to IRs from EDTI, intervener evidence, IRs to interveners, responses to IRs from interveners, rebuttal evidence, oral argument and reply argument. The Commission considers the record of this proceeding to have closed on May 2, 2022, upon completion of oral argument and reply argument.

3 Commission directions from previous decisions

9. The Commission has reviewed EDTI's responses to prior Commission directions in EDTI's Phase 2 application. The Commission notes that no party objected to any of EDTI's prior direction responses. The Commissions finds that EDTI has fully complied with all past Commission directions related to Phase 2 matters.[4]

4 COSS

10. EDTI retained Black & Veatch Canada Company (B&V) to develop EDTI's COSS and rate design method. The Commission approves for the most part the COSS filed by EDTI with the exception of some changes to be completed in EDTI's compliance filing as recommended by the UCA and agreed to by EDTI in the course of the proceeding. The objective of the COSS was to ensure that the costs that form EDTI's revenue requirement are allocated among rate classes in a fair and transparent manner.[5] Broadly, the COSS is made up of the following three steps:

(i) Functionalization – Functional groups are organized using the uniform system of accounts (USA), into the seven functions of Distribution Substation, Primary,

[2] Terms and conditions of service govern the relationship between the owner of the electric distribution system and its eligible customers for electricity service. The Commission approves the terms and conditions of service periodically in rate proceedings dealing with tariffs.

[3] Decision 2011-375: EPCOR Distribution & Transmission Inc., 2010-2011 Phase II Distribution Tariff Application, Proceeding 980, September 15, 2011.

[4] Decision 2011-375, and Decision 23842-D01-2018: EPCOR Distribution & Transmission Inc., 2018 Customer Specific Distribution Access Service Rate for a New Customer (CS46), Proceeding 23842, September 21, 2018.

[5] Exhibit 27018-X0001, application, paragraph 67.

Transformer, Secondary, Service Connection, Meter, Wholesale Billing, and Lighting;

(ii) Classification – functionalized costs are classified as customer, energy or demand; and

(iii) Allocation – classified costs are allocated to each rate class using function and class-specific allocators.

4.1 Allocation of general operations and maintenance costs

11. In Decision 2011-375,[6] the Commission directed the following:

> The Commission considers that EPCOR's proposed allocator is an improvement over the previous return based allocator and therefore approves the proposed general O&M [operations and maintenance] allocator as filed. However, the Commission directs EPCOR to conduct a review of the allocation of its general O&M costs and the common overhead allocator and submit this review along with the justification for the chosen method of allocating general O&M costs, as part of EPCOR's next Phase II application. In particular, EPCOR is directed to address the concerns expressed by the UCA regarding current capital expenditures impacting the allocation of general O&M to rate class in its review.

12. EDTI noted that its COSS proposed in this proceeding used revised allocators for general operations and maintenance (O&M) costs. General O&M was allocated using internal allocation methods following methodology aligned with the allocation guidelines in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual.[7] General O&M related to plant was allocated proportionally to distribution plant while general O&M related to labour was allocated using an internal labour allocator related to distribution plant.[8]

13. In light of the COSS and the updated methodology, the revenue requirement allocation changed for many of EDTI's rate classes. The most material changes in the revenue requirement allocation were to the Residential class (from 47.3 per cent to 54.9 per cent), Medium Commercial class (from 8.9 per cent to 11.1 per cent) and Time-of-Use class (from 22.3 per cent to 17.8 per cent).[9]

14. Other aspects of the COSS will be discussed further in the decision. The changes required to be made in EDTI's compliance filing are discussed in Section 4.3.

4.2 EDTI COSS proposals supported by the UCA

15. In the UCA's evidence, provided by its consultant InterGroup Consultants Ltd., six recommendations were made regarding the methodology that should be implemented by EDTI as part of its current application and future cost-of-service studies. Some of these recommendations aligned with what EDTI had proposed for its COSS in its application, while others were

[6] Decision 2011-375, paragraph 100.
[7] https://pubs.naruc.org/pub.cfm?id=53A3986F-2354-D714-51BD-23412BCFEDFD
[8] Exhibit 27018-X0001, application, paragraph 18.
[9] Exhibit 27018-X0001, application, paragraph 74.

recommendations that EDTI accepted during the course of the proceeding. For simplicity, the discussion below is structured using InterGroup's recommendations.

4.2.1 COSS allocation method

16. InterGroup stated:[10]

> EDTI's proposal to move from a Capital Asset Review ("CAR") approach to COSS, and not adopt a GIS [Geographic Information System]-based approach, but instead to move to the broad approach based on the Uniform System of Accounts ("USA") as set out in the Black & Veatch COSS Report, is appropriate (subject to the more detailed comments below).

17. EDTI made some key changes to the COSS in this application as compared to the COSS relied upon in EDTI's last Phase 2 that was filed December 6, 2010.[11] The methodology used in the 2011 application assigned power system assets using the Capital Asset Review (CAR)-based direct cost method. The significant difference between the CAR methodology and the methodology EDTI applied to use in this proceeding is that the applied-for method uses the USA accounting system to functionalize, classify and allocate costs. EDTI explained that the previously approved CAR-based direct cost allocation method used CAR costs from 2004 to allocate costs in EDTI's ATS (Asset Tracking System) accounts to asset subtypes.[12] EDTI further explained in its application that the costs allocated to these asset subtypes were then assigned to rate classes primarily based on its judgment. The underlying differences in the two different methods (CAR and USA) result in some differences in the assignment of assets and costs to functional groups.

18. EDTI explained that the CAR-based COSS was overly complex and difficult to update, requiring extensive manual record keeping as well as the application of a significant amount of expert knowledge and experience with respect to asset usage across its system.[13]

19. EDTI's COSS relied upon in this application utilizes USA costs as inputs, thereby avoiding the use and updating of the CAR-based costs. Further, EDTI stated its current COSS uses industry-accepted and NARUC Cost Allocation Manual based methods to functionalize, classify and allocate costs, thereby avoiding the judgment-based allocations inherent in the CAR-based direct cost method.[14]

20. No parties objected to EDTI's change to the USA-based methodology from the CAR-based methodology to allocate costs in its COSS. The Commission finds that EDTI's USA-based methodology for its COSS is reasonable and is approved.

4.2.2 Minimum system study

21. InterGroup submitted the following on the minimum system study:[15]

[10] Exhibit 27018-X0039, UCA evidence, PDF page 5.
[11] Proceeding 980, EPCOR 2010-2011 Phase II distribution tariff application.
[12] Exhibit 27018-X0001, application, paragraph 73.
[13] Exhibit 27018-X0001, application, paragraph 37.
[14] Exhibit 27018-X0001, application, paragraph 73.
[15] Exhibit 27018-X0039, UCA evidence, PDF page 5.

> The EDTI and Black & Veatch recommendation to not use the results of the minimum system study, and instead use a 100% demand classification for poles, conductors and transformers is reasonable for this proceeding and should be approved.

22. The Commission previously directed EDTI in its last Phase 2 decision to conduct a minimum system and/or zero intercept studies for the poles, towers and fixtures and transformer asset types within its secondary distribution system, and to submit those studies in its next Phase 2 distribution tariff application, and to also provide the pros and cons of using those studies to classify costs instead of the current approach.[16]

23. Concurrent with the COSS, EDTI's consultant B&V completed a minimum plant study and it was discussed in Appendix A of B&V's COSS. B&V elected not to use the results of the minimum plant study in the COSS, as B&V determined that, "Typically, Black & Veatch supports the partial classification of primary and secondary costs to customers. However, in EDTI's case, we do not recommend using the minimum system method due to the data challenges explained above."[17]

24. No parties objected to EDTI's position that the minimum system study should not be relied upon for its COSS, and the Commission agrees with B&V's position that it would not be appropriate to use due to the uncertainty with EDTI's historical asset data. The Commission finds that EDTI has complied with the direction and no further action is required.

4.2.3 Functionalizing FERC 365 - Overhead Conductors and Devices

25. InterGroup wrote about FERC 365 as follows:[18]

> The Black & Veatch approach to functionalizing FERC 365 should be accepted for this proceeding, subject to EDTI confirming due diligence has been performed to confirm the average unit costs for primary versus secondary conductors (and, in particular, that the average cost of primary overhead conductor is below that for secondary overhead conductor).

26. Regarding the due diligence, the UCA explained:[19]

> One curiosity may be the unusual nature of having unit costs for primary distribution assets be below the average unit costs for secondary system assets. In the case of EDTI, however, this appears to primarily reflect the differing types of conductors used (ACSR [aluminium conductor steel-reinforced cable] versus weatherproof) and if so, the cost differential, though unexpected, may be justified.

27. EDTI in its rebuttal evidence confirmed that the unit costs provided in its application are correct.[20] EDTI further confirmed the UCA's belief that the weatherproof conductors it utilized for overhead secondary systems typically have similar or slightly higher unit costs compared to the ACSR conductors utilized for overhead primary systems. This accounted for the difference

16 Decision 2011-375, paragraph 83.
17 Exhibit 27018-X0002, B&V COSS, PDF page 19.
18 Exhibit 27018-X0039, UCA evidence, PDF page 5.
19 Exhibit 27018-X0039, UCA evidence, PDF page 15.
20 Exhibit 27018-X0046, EPCOR rebuttal evidence, PDF page 8.

between the unit cost of the secondary conductors compared to the unit costs of similarly sized primary conductors.

28. In its summary of oral argument, the UCA stated it accepted EDTI's explanation of the unit cost difference, and requested that the Commission direct EDTI to use the B&V approach to functionalizing FERC Account 365.

29. No other concerns were raised by parties, and the Commission also accepts EDTI's explanations for the unit cost differences. The Commission approves EDTI's functionalization of FERC Account 365 as filed.

4.3 UCA COSS recommendations accepted by EDTI

30. As mentioned earlier, certain UCA recommendations for changes to EDTI's COSS were subsequently agreed to by EDTI during the proceeding. These are discussed below.

4.3.1 Demand allocator

31. In its evidence provided on behalf of the UCA, InterGroup stated that: [21]

> EDTI should move to using a 6-year average of loads for the purposes of developing the I-NCP 50-50 allocator and the 12-NCP allocator. This approach should be retained until such time as a more stable load regime becomes present in the data. At that time, EDTI may propose to move back to a 3-year average, if EDTI determines that the 3-year approach better represents expected go-forward conditions.

32. In the context of ratemaking, generally, demand refers to the amount of energy consumed at one time, and demand costs are costs that vary with the kilowatt (kW) demand imposed by the customer.[22] Demand determinants are used in the COSS to allocate functionalized and classified costs to rate classes. Consistent with EDTI's last Phase 2 application, EDTI proposed to continue to use a three-year average to calculate what it terms as the Integrated Non-Coincident Peak 50/50 (I-NCP 50/50) and 12 Non-Coincident Peak (12-NCP) allocators to determine rate class demand. In this application, EDTI updated the demand allocation calculations using 2018 to 2020 actual data.

33. These allocators are further defined below:

- The I-NCP 50/50 allocator is used to allocate costs that are functionalized as primary. The allocation determinant is based on each rate class's proportionate share of the 50/50 weighting of on-peak energy and I-NCP. EDTI defines on-peak energy as the energy between the eighth and 20th hour of each weekday, excluding statutory holidays.[23]

- The I-NCP allocation determinant represents the contribution to substation peak load by rate class, and was calculated using peak loads at each substation. The peak load at a substation is defined as the substation's hourly loads during which load is greater than or equal to 90 per cent of the annual peak at the substation. The annual load coincident

[21] Exhibit 27018-X0039, UCA evidence, PDF page 5.
[22] NARUC Cost Allocation Manual, PDF page 29: https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD
[23] Exhibit 27018-X0001, application, paragraphs 58-59.

to substation peak load for each rate class was calculated (referred to as "coincident load") and the rate class percentage of total coincident load was calculated.

- The 12-NCP allocator is used to allocate costs that are functionalized as secondary. Secondary assets include poles and conductors that transmit power at secondary voltage from the transformer to the service connection at customer sites. The 12-NCP allocator is the rate class's proportionate share of the NCP demand of the subject rate classes. This determinant is calculated by adding each rate class's share of total load during the top-12 system peak hours within a year.

34. InterGroup recommended the use of a six-year average to calculate the demand allocators in place of the three-year average to mute the effects of unusual demand changes to the residential and medium commercial rate classes, likely brought on by the COVID-19 pandemic in 2020 and 2021. InterGroup further explained that much fewer hours were assessed by EDTI in its calculation support for 2020, 323 hours assessed for 2020 versus a historical 2015 to 2019 five-year average of 892 hours per year, which further pointed to 2020 being an anomalous year.[24] The CCA also supported the use of a six-year average.[25]

35. EDTI agreed with the use of the six-year average method and provided updated tables. The updated tables showed that the results of the six-year averages fall nearer to the 2018-2020 three-year averages, which indicated that the impacts of the recent actuals and trends from 2020 and 2021 are muted if the six-year averages are used.[26] EDTI further noted that it will review the calculation of its demand allocators in its next Phase 2 proceeding.[27]

36. The Commission agrees with the consensus of the parties and finds that the six-year average method to measure demand is more representative of actual rate class demand. The Commission directs EDTI in its compliance filing to use in its COSS a six-year average calculation as the demand allocator, in place of the three-year average period used in its application, for the calculation of the I-NCP 50/50 and 12-NCP demand allocators. The Commission further directs EDTI to review the calculation of its demand allocators in its next Phase 2 application.

4.3.2 Functionalization of FERC 364 - Poles, Towers and Fixtures

37. Regarding the functionalization of FERC Account 364, InterGroup recommended that:[28]

> The Black & Veatch approach to functionalizing FERC 364 Poles, Towers and Fixtures should be adjusted such that poles which serve a shared function (primary/secondary) should be functionalized based on the relative overall length of conductors, not on the new build costs of the conductors.

38. InterGroup explained in its evidence that EDTI had used an allocation ratio for the costs of poles with shared roles in both primary and secondary functions by comparing the new build costs of the conductors. InterGroup further stated that, "There is no reason to expect that the pole function is driven by the relative value of the conductor that is strung thereon, but rather simply

24 Exhibit 27018-X0043, UCA evidence, PDF page 10.
25 Transcript, Volume 1, page 65, lines 9-23.
26 Exhibit 27018-X0046, EPCOR rebuttal evidence, PDF page 6.
27 Exhibit 27018-X0046, EPCOR rebuttal evidence, PDF page 6.
28 Exhibit 27018-X0039, UCA evidence, PDF pages 5-6.

the quantity – each metre of secondary conductors, and each metre of primary conductor, requires the support of poles."[29]

39. EDTI agreed with InterGroup's proposal that the functionalization of FERC 364 poles, towers and fixtures should be adjusted such that poles serving a shared function be functionalized based on the relative overall length of conductors, not on the new build costs of the conductors.[30] The Commission agrees with InterGroup that basing the FERC 364 allocation on the conductor length is a superior methodology to new build costs as conductor length is connected to the number of poles used to support the conductor, which is a better indicator of the related costs. The Commission thereby directs EDTI to update its COSS in its compliance filing to functionalize shared poles using overall conductor length for purposes of calculating the 2023 rates.

4.3.3 Functionalization of FERC 367 – Underground Conductors and Devices

40. InterGroup's final recommendation, regarding the allocation of FERC Account 367, was as follows:[31]

> In future EDTI COSSs, the approach to FERC 367 Underground Conductors and Devices should be revised to improve simplicity and transparency. Specifically, the portions of the account that are only of relevance to individual or small subsets of classes (notably, 367-URD and 367-UID) should instead be directly assigned to those classes, rather than the complicated functionalization/allocation approach used by Black & Veatch.

41. InterGroup stated that due to the material changes involved in making this revision, this approach need not be adopted today, but should be reviewed for potential application in future EDTI COS studies.[32]

42. Both EDTI and its consultant, B&V, agreed with InterGroup's recommendation regarding FERC 367.[33] EDTI stated that it would review and revise the method as necessary in its next Phase 2 application, which it expects to file during the third PBR term. The Commission agrees with InterGroup's recommendations above regarding FERC 367 and directs EDTI in its next Phase 2 application to revise the allocation methodology of FERC 367 to make it methodology simpler and more transparent. The Commission endorses the filing of EDTI's next Phase 2 application during the third PBR term.

5 Rate design

5.1 Overview

43. The next step in a Phase 2 application following an updated COSS is to design and determine just and reasonable rates for the utility's customer classes that reflect the COSS findings while enabling the utility to collect its approved revenue requirement. EDTI stated it followed an approach to design rates that was consistent with Bonbright's principles of rate

[29] Exhibit 27018-X0039, UCA evidence, PDF page 16.
[30] Exhibit 27018-X0046, EPCOR rebuttal evidence, PDF page 8.
[31] Exhibit 27018-X0039, UCA evidence, PDF page 6.
[32] Exhibit 27018-X0039, UCA evidence, PDF page 17.
[33] Exhibit 27018-X0051, B&V rebuttal evidence, PDF page 4.

design, and that EDTI's rate design objective was to calculate rates for each rate class in a fair and transparent manner.[34]

44. EDTI stated that after unit rates were first calculated using the classified and allocated costs and the billing determinants, they were then adjusted to limit bill impacts while still achieving revenue-to-cost ratios as near to 1:1 as reasonably possible.[35] EDTI stated that it had considered the Commission's comments in a recent FortisAlberta Inc. Phase 2 distribution tariff decision that the Commission was mindful of the COVID-19 pandemic and economic challenges that customers faced when assessing bill impacts.[36] Further, the Commission said that it may be an opportunity for Fortis to keep its bill impacts at or near zero for 2022, and then to adjust its rates for 2023 to move closer to the usual targeted revenue-to-cost ratios range of 95 per cent to 105 per cent.

45. With those comments from the Commission in mind, EDTI proposed to limit rate increases to a maximum of five per cent and to have no lower limit to the rate adjustment decreases. No party to this proceeding took any issues with EDTI's general approach to setting its rates and limiting rate increases for its customer classes, even if it meant some customer classes may not receive rate reductions as large as they would have been otherwise due to this rate smoothing.

46. The Commission has a long-standing practice, as part of balancing the rate design principles, to strive for rates that have a revenue-to-cost ratio of 100 per cent while not exceeding a 10 per cent bill impact for any customer rate class. The revenue-to-cost ratio is the proportion of costs collected from customers compared to the costs allocated to customers. Even though the goal is a 100 per cent revenue-to-cost ratio, practically speaking, it may not be possible to achieve that without causing unacceptable bill impacts. As a result, the Commission generally targets a revenue-to-cost ratio range of 95 per cent to 105 per cent.

47. The Commission agrees with EDTI's overarching rate design methodology and finds that EDTI has taken a prudent and reasonable approach to minimizing rate impacts to ratepayers during this economically difficult time for many Albertans.

48. The Commission notes that no customer class was anticipated to receive a rate increase greater than five per cent; however, staying under a total bill impact increase of five per cent as calculated by EDTI[37] is dependent on other non-distribution bill components such as transmission charge decreases to provide offsets to distribution-related bill increases. The Commission approves EDTI's proposed rate design for this Phase 2 application, with the exception of the residential customer rate design regarding the fixed and variable bill components, as discussed below.

5.2 Residential fixed/variable billing ratio

49. EDTI proposed maintaining residential customer rates at a proportion of 80 per cent fixed billing, where customers are billed a daily charge for being connected to the distribution system, and 20 per cent variable, where customers are billed by the kWh consumed. This was the only

[34] Exhibit 27018-X0001, application, paragraph 87.
[35] Exhibit 27018-X0001, application, paragraph 89.
[36] Decision 25916-D01-2021: FortisAlberta Inc., 2022 Phase II Distribution Tariff Application, Proceeding 25916, July 8, 2021, paragraphs 114-119.
[37] Exhibit 27018-X0001, application, Table 7.0-1.

instance where EDTI diverged from the findings of its consultant's COSS, where the B&V COSS determined that residential customer rates should have a lower fixed billing component of 41.6 per cent.

50. EDTI stated that a higher fixed (customer $/month) charge of 80 per cent is appropriate given that the current metering infrastructure for residential sites can only rely on a customer's energy (kWh) consumed for billing. Until residential demand meters can be made available for customer billing purposes, EDTI argued that continuing the current fixed and variable rate structure provides a practical alternative with a larger proportion of the revenue recovered through a fixed (customer) charge. EDTI defended its position of maintaining the current 80 per cent fixed ratio by referring to the four experts quoted in the Distribution System Inquiry Final Report who advocated for shifting from rate structures that emphasize variable rate components to those that recover a larger portion of distribution utility costs through corresponding fixed or demand charges.[38]

51. The 80 per cent fixed residential customer ratio was last approved by the Commission in EDTI's 2010-2011 Phase 2 distribution tariff;[39] however, the residential fixed versus variable billing proportion was not specifically discussed, but rather, was approved as a part of approving all of EDTI's customers' rates under that application.

52. EDTI further defended the 80 per cent fixed proportion by referring to the increasing adoption of distribution-system connected generation (DCG), such as roof-mounted solar panels, which EDTI explained is expected to result in energy consumption declines for those customers with DCG. EDTI stated that maintaining the current level of fixed distribution charges will avoid any potential cross-subsidization between customers with DCG and customers without DCG. EDTI further explained that the best way to ensure the accuracy of price signals to distribution customers and equity between customers with and without DCG, is to maintain the relative magnitude of the fixed (customer $/month) component (the 80 per cent) of the distribution rate.

53. Finally, EDTI stated that the proposed residential and small commercial rates with a higher customer (fixed $/month) charge and a lower energy (variable $/kWh) charge will reduce the risk of revenue deficiencies should residential consumption decrease.

54. When asked in a Commission IR whether a 20 per cent variable portion will provide a sufficient price signal, EDTI responded that the cost of electricity (the commodity, as charged through retail rates) is sufficient to provide an appropriate price signal to customers with respect to the volume of energy they consume. For recovery of distribution system related costs, EDTI believes the use of energy-based rates should be minimized as they send a distorted or misleading price signal.

55. EDTI explained that the fixed charges as identified in the COSS are customer charges, such as metering, billing, the costs incurred by being a customer, and the variable costs were the demand-related costs. EDTI noted that the COSS did not classify any costs as energy but rather only as demand or customer. In the absence of the ability to bill residential customers using demand, EDTI submitted that it is appropriate to allocate some of the demand-related costs to the

[38] Proceeding 24116, Distribution System Inquiry – Final Report, February 19, 2021, Section 5.2.1.3, paragraph 307.

[39] Decision 2011-375, Section 5.2.4.

customer.[40] In another IR response to the Commission, EDTI said that the residential rates as proposed recover approximately one-third of the demand component of rates as a variable (energy) charge, and two-thirds of the demand component as a fixed charge.[41]

56. The UCA agreed with EDTI's reasoning for the residential customer fixed proportion and accepted the 80 per cent fixed ratio,[42] while the CCA disagreed and believed EDTI should respect the findings of the COSS and lower the fixed charge proportion to 41.6 per cent.[43] Both interveners to this proceeding (the UCA and the CCA) agreed that EDTI should pursue demand metering as soon as possible so a fixed/variable rate structure could be determined in order to best reflect residential customer demand in its rates.

57. The Commission asked in an IR if the consultant preparing EDTI's COSS, B&V, supported EDTI deviating from the COSS-determined fixed/variable ratio for residential customers.[44] EDTI responded that B&V supported EDTI's findings to resume the 80 per cent level of residential fixed charges due to the inability of EDTI's meters to measure demand for the residential customer class; therefore, the 80 per cent fixed customer charge for residential customers chosen by EDTI was not contrary to its COSS findings.

58. The Commission notes that translating a demand component of customer bills into a fixed or variable charge is one that requires some degree of judgment, acknowledging that customer demand and consumption are not the same. Until a utility has a metering system that measures and tracks individual customer demand, the ideal rate design to reflect demand-related costs cannot be attained and, in the meantime, judgment is required. This is reflected by the widely varying fixed/variable ratios that have currently been requested and approved for the major Alberta electric distribution utilities as shown in the table below:[45]

Table 1. Electric utility residential fixed/variable distribution tariff billing ratios

Utility	Proposed fixed	Proposed variable	Approved fixed	Approved variable
	(%)			
ENMAX[46]	87	13	74	26
ATCO Electric[47]	33	67	33	67
Fortis[48]	67	33	67	33
EPCOR	80	20	TBD	TBD

59. As shown above, EPCOR currently has the highest approved residential fixed rate component among the utilities. The UCA was asked in an IR whether there should be more consistency among the utilities and the UCA responded that it was not imperative each utility

40 Exhibit 27018-X0030, EDTI-AUC-2022FEB02-011(c).
41 Exhibit 27018-X0030, EDTI-AUC-2022FEB02-012(b).
42 Transcript, Volume 1, page 82, lines 23-24.
43 Exhibit 27018-X0044, CCA-AUC-2022MAR28-001 (b).
44 Exhibit 27018-X0030, EDTI-AUC-2022FEB02-011(b).
45 Exhibit 27018-X0040, CCA-AUC-2022MAR28-002, and Exhibit 27018-X0041 UCA-AUC-2022MAR28-002.
46 Decision 24820-D01-2020: ENMAX Power Corporation, 2019 Distribution Tariff Phase II Application, Proceeding 24820, August 28, 2020, paragraph 59. Note: ENMAX proposed to eventually increase the fixed component to 100 per cent fixed.
47 Proceeding 24747, ATCO Electric 2019 Distribution Tariff Phase II Application, Exhibit 24747-X0140, ATCO rebuttal, paragraph 43.
48 Proceeding 25916, FortisAlberta 2022 Phase II Distribution Tariff Application, Exhibit 25916-X0028, Schedule 5.1 – 2021 Base Revenue and Rate Design, Tab 5.1-A5 Detailed Dist. RC, Fixed = cell V15 (Residential Customer Service/REA) / Z15 (Total Revenue).

have identical fixed and variable cost recovery components, since each utility will have different underlying cost structures.[49] The UCA also stated in its IR response to the Commission that Patrick Bowman, the UCA's consultant from InterGroup, held the view that the preferred rate design approach is to implement variable demand charges as soon as feasible. The CCA was asked a similar IR by the Commission,[50] and the CCA responded that there does not appear to be any reason to have such variability between the utilities because while there may be differences in operation, they are dwarfed by the similarities. The CCA further explained that the technologies and structures used by the utilities are basically the same (substations, cables, overhead lines, meters, etc.); therefore, the fixed/variable ratios should be largely the same.

60. The UCA agreed with the reasoning for EDTI's 80 per cent fixed billing ratio for residential customers while the CCA believed it should follow the COSS findings and be set to 41.6 per cent. The Commission finds that arbitrarily assigning two-thirds of the demand allocation of customer costs to the fixed billing ratio is too high, and this is reinforced by comparing EDTI to the other utilities' residential fixed/variable billing ratios in Table 1 above. As mentioned earlier, this 80:20 fixed/variable ratio was set by EDTI in its last Phase 2 over 10 years ago, and EDTI provided no empirical support for the fixed/variable split due to the inability to measure demand for these residential customers.

61. A higher fixed charge ratio means all customers are closer to paying the same amount per month for their distribution service. The Commission has concerns about lower-consuming customers residing in smaller homes or apartments, likely with lower demand requirements, subsidizing higher-consuming customers residing in larger homes that the Commission believes are more likely to have higher demand requirements.

62. While there may be no perfect solution at this time due to the subjectivity that must be applied in order to determine the demand-related fixed/variable billing ratio, EDTI stated in an IR response that reallocating 50 per cent of the demand charge to customers and 50 per cent to energy would result in a customer charge (fixed billing) of approximately 71 per cent and an energy charge (variable billing) of approximately 29 per cent.[51] The Commission finds this to be a reasonable compromise given the evidence on record and lack of empirical evidence supporting the 80 per cent fixed ratio. A 71 per cent fixed ratio also aligns EDTI more closely with the two other distribution utilities that currently have a higher residential customer fixed billing ratio than variable (ENMAX and Fortis), with ATCO Electric Ltd. being an outlier with a higher variable proportion.

63. EDTI is directed in its compliance filing to this proceeding to revise its residential billing ratio in its rate design to 71 per cent fixed and 29 per cent variable to reflect a 50/50 split of demand-allocated costs as determined by the COSS to the customer and energy components.

5.3 Demand metering feasibility study

64. The Commission understands that it is a difficult proposition for utilities to assign the appropriate fixed and variable ratio to costs that are deemed to be demand related or driven when there is no way to measure the demand, and a significant amount of judgment must be applied to arrive at the fixed/variable billing ratio. This difficulty was highlighted during the Distribution

49 Exhibit 27018-X0041, UCA-AUC-2022MAR28-002.
50 Exhibit 27018-X0044, CCA-AUC-2022MAR28-001(e).
51 Exhibit 27018-X0030, EDTI-AUC-2022FEB02-011(c).

System Inquiry, as experts provided somewhat mixed signals as to the nature of distribution costs being fixed or variable, stating, "… while distribution costs are mostly fixed in the short term, they are variable in the long term."[52] The experts did agree, however, that distribution rates must contain a variable component to provide a forward-looking price signal to customers.

65. Ideally, the way to address the fixed/variable billing ratio issue is to have a demand metering system in place to appropriately assign demand-related costs based on customer demand instead of consumption, as recommended by all parties in this proceeding.

66. The Commission understands EDTI's current advanced metering infrastructure (AMI) meters already have the capability to measure demand, and anticipates the bulk of the costs to implement this billing change will be driven primarily by the supporting systems to measure and store the data reported by the AMI meters, along with the commensurate changes to the billing systems that will be required to bill residential and small commercial customers based on demand. The Commission is interested in seeing different options (if any), with each option's incremental costs in terms of additional functionality from a customer's perspective.

67. In the Distribution System Inquiry, EDTI estimated that the costs of collecting interval data for energy and demand billing required at least a $10 million investment.[53]

68. The CCA recommended that a move to more variable rates would be desirable, and that EDTI should be directed in a future application to provide a more developed and refined cost estimate for interval data metering and provided a detailed list of questions that it felt should be answered in the study.[54]

69. In the UCA's argument in support of demand metering and billing, it stated that the preferred rate design approach is to implement variable demand charges as soon as feasible.[55] The UCA asked the Commission to direct EDTI in its next Phase 2 proceeding to cover several objectives and topics in the scope of a study.[56] The UCA also stated that it wished to avoid any situation where the feasibility study only leads to the need for more studies on practical implication, and the actual change is thereby excessively delayed further.

70. To that end, the Commission directs EDTI to commence a feasibility study to determine the scope and cost to build and implement a metering system that is able to measure demand for residential and small commercial customers. The Commission has considered the feasibility study items as recommended by the CCA and the UCA. The Commission directs EDTI to include in the feasibility study the information requested in and/or responses to the following:

- Identify the objectives of moving to demand based billing.
- Assess the capabilities of EDTI's existing meters and related systems.
- Identify all possible alternatives to provide demand-based billing with detailed preliminary cost estimates and timelines for implementation, including investigating and

52 Proceeding 24116, Distribution System Inquiry – Final Report, Section 5.2.1.3, paragraph 311.
53 Exhibit 27018-X0038, CCA evidence, paragraph 31.
54 Exhibit 27018-X0038, CCA evidence, paragraph 32.
55 Transcript, Volume 1, page 84, lines 12-15.
56 Transcript, Volume 1, page 84, line 17 to page 85, line 14.

reporting on all of the options as to how EDTI should recover the variable demand-related costs, the pros and cons with each option, including but not limited to conducting practical testing within the feasibility study, using a small number of demand metered customers of various classes. This should include the costs of any modifications that would be required to EPCOR's current communication systems.

- The current capital and operating costs incurred by EDTI to support time-of-use (TOU) rates for interval rate classes, and the incremental costs that would be incurred to the other non-TOU rate classes if TOU rates were to be implemented for them. This should include a discussion of whether there are any thresholds that result in a step function of cost increases for the non-TOU classes to measure interval data.

- Whether hourly or subhour interval data (i.e., 15 minutes) will be required, including a discussion of the pros and cons of hourly versus subhourly data, and whether these requirements differ by rate class or type of customer (for example, whether industrial customers may need 15-minute interval data but hourly or less frequent measurements would be sufficient for residential and small commercial customers).

- Whether operating costs for residential customers could be reduced by only collecting interval data for energy and demand during residential peak periods and, if so, the pros and cons of doing so, including the expected loss in billing accuracy.

- If the Alberta Electric System Operator (AESO) had TOU rates, would it enable the potential flow-through of AESO's tariffs to distribution facility owner customers and enable them to be able to see and respond to AESO price signals?

- Whether demand billing and/or TOU rates would assist in price signalling for electric vehicle owners and incent them to charge vehicles outside of peak hours.

71. EDTI is directed to complete this demand-metering billing feasibility study, including in its scope the items for discussion as listed above, and to bring forward the results as well as the costs to complete the study in its next Phase 2 application.

5.4 Calculation of CS rates for new customers

72. EDTI has a customer class referred to as the CS rate class, which EDTI describes as typically representing customers with loads over five megawatts (MW) served by dedicated primary feeders, occasionally with some sharing of backup resources.[57]

73. EDTI calculates each CS rate using a method that is based on EDTI's COSS and rate design method, which can also be applied to create a CS customer's rate outside of a Phase 2 application. The method currently used by EDTI was last approved by the Commission in Decision 26619-D01-2021.[58] The previously approved method directly assigns power system assets used by each CS customer to be charged to that customer, and operations, maintenance

[57] Exhibit 27018-X0001, application, paragraph 136.
[58] Decision 26619-D01-2021: EPCOR Distribution & Transmission Inc., 2021 Customer Specific Distribution Access Service Rate Update for an Existing Customer (CS40), Proceeding 26619, July 13, 2021.

and general (OM&G) costs are assigned using a factor applied to a power system revenue requirement.

74. A prior Commission decision directed EDTI to examine the relevancy of using capital costs to allocate OM&G costs in its next Phase 2 application, and if the allocator remains relevant, to recalculate the ratio as required.[59] In the current Phase 2 application, EDTI proposed a revised method to calculate CS rates when a new CS rate class customer applies for service or when existing CS customers apply for a change to their forecast peak demand.

5.4.1 Proposed rate design method for new CS customers

75. In a response to a Commission IR,[60] EDTI provided the following table to summarize the changes in the proposed rate design (column A) versus the previously approved and currently used rate design (column B):

Table 2. New CS rate design comparison

	Cost category	A Proposed rate design	B Current rate design
1	Direct capital (return and depreciation)	Direct assigned	Direct assigned
2	Wholesale billing	Fixed daily rate per customer ($1.95 per day)	OM&G factor (ratio 1.851 of capital costs)
3	O&M, General Capital & Administrative	Multiple of direct capital (ratio of 0.0319 of direct capital)	
4	Distribution to transmission contribution (Account 303)	Customer's demand ($0.3141 per MW)	Not included

Source: Exhibit 27018-X0030, EDTI-AUC-2022FEB02-010-01, PDF page 33.

76. As shown in Table 2 above, the direct assigned capital costs do not change between the current and proposed methods; the changes occur in how EDTI charges CS customers for wholesale billing and OM&G (rows 2 and 3) and distribution to transmission contributions based on demand (row 4).

Wholesale billing and OM&G CS rate design changes

77. In the proposed CS billing changes, EDTI is breaking out the wholesale billing category (row 2 of Table 2 above) and distribution to transmission contributions (row 4 of Table 2) as this approach aligns with how these costs are assigned and recovered in EDTI's COSS. Wholesale billing is recovered as a fixed cost ($/day); distribution to transmission contribution cost is recovered based on demand ($/MW); and the OM&G is recovered as a multiple of the direct capital charge, which EDTI stated is reflective of how the costs are incurred.[61]

78. The proposed change to OM&G CS rate design also addresses a prior Commission direction that EDTI consider whether the use of a static OM&G allocation ratio that is unchanged during the PBR term results in the efficient and fair allocation of OM&G costs across all of EDTI's customers as new customers are added to (or removed from) the CS rate class.[62]

59 Decision 23842-D01-2018, Direction 3.
60 Exhibit 27018-X0030, EDTI-AUC-2022FEB02-010.
61 Exhibit 27018-X0030, EDTI-AUC-2022FEB02-015.
62 Decision 23842-D01-2018, Direction 4.

79. EDTI stated in its application that within a PBR plan, OM&G costs should be added to each new CS customer using a method based on the method that was used to allocate OM&G costs to rate classes in the most recently approved COSS. In this way, CS customers added within the PBR plan will be treated in the same way in respect of OM&G costs as customers in all other rate classes.[63] EDTI also stated that its proposed method is consistent with how OMG&A and general plant costs are assigned in the COSS and with the allocation methods for these cost categories described in chapters 6 and 8 in the NARUC Cost Allocation Manual.[64]

Distribution to transmission contributions (Account 303) CS rate design changes

80. EDTI also made a change regarding distribution to transmission contributions. EDTI proposes to assign distribution to transmission contribution costs using a factor applied to the contract demand of the CS customer. The factor is calculated as the ratio of the total distribution to transmission contributions allocated to the CS class in the COSS divided by the total billing demand of the CS class.

CS rate reduction

81. Calculations of the CS design factors and rates as described above were provided in B&V's Rate Design Report.[65] EDTI acknowledged the prior CS class rate design may have resulted in over-recovery of costs during the PBR term, and as a result CS customers were proposed by B&V to receive a 33.9 per cent rate reduction in its Rate Design Report.[66]

82. EDTI explained this prior over-recovery was caused because a CS rate that is calculated using cost-of-service principles at the start of a PBR term and then converted to a PBR rate will increase each year by the I-X and capital factors. However, if the assets used to provide service to the CS customer remain unchanged, the actual costs will likely decrease as the depreciation expense remains unchanged, and the capital costs decrease as the net book value of the assets decrease. EDTI stated it is exploring further alternatives to CS rates for its third PBR term.[67]

Commission findings

83. No parties presented any concerns with the proposed CS rate design. The Commission finds that the proposed CS rate design is an improvement over the prior approved methodology, as the proposed CS rate design better aligns with the method costs are assigned and recovered in B&V's COSS. The Commission approves the proposed CS rate design as filed. However, the Commission directs EDTI, while it is considering alternatives to CS rate design for its third PBR term, to also explore discontinuing CS rates. CS rates are relatively burdensome to administer and regulate for the benefit of relatively few EDTI customers. The Commission notes that EDTI's CS rate class is a unique rate structure among the Alberta distribution utilities, and other utilities have evidently found ways to arrive at a more generic rate structure for their larger customers rather than providing them each with their own individual rate. The Commission directs EDTI to report, as part of its proposal to address CS rates for its third PBR term, whether there is an opportunity to move future large customers who would be CS rate class candidates and possibly existing CS rate class customers (which the Commission understands could be more

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[63] Exhibit 27018-X0001, application, paragraph 33.
[64] Exhibit 27018-X0001, application, paragraph 139.
[65] Exhibit 27018-X0005 B&V EDTI Electric Rate Design Report, Appendix B – CS Rate Design for New Customer Additions, PDF page 19.
[66] Exhibit 27018-X0005, B&V EDTI Electric Rate Design Report, PDF pages 13-14, column H, rows 22-48.
[67] Exhibit 27018-X0030, EDTI-AUC-2022FEB02-009(b).

difficult) to either a new rate class, or existing rate classes to reduce regulatory burden and achieve greater consistency with distribution service provided in other service areas.

5.5 Revised billing determinant forecast method

84. As part of its application, EDTI filed a report from B&V proposing an update to EDTI's billing determinant forecast methodology. B&V stated that the current methodology is very formulaic, which presents a number of advantages, especially in a PBR construct. B&V further stated that although the formulaic methodology is simple to understand, objective, not subject to an analyst's judgment and easily repeatable, there are several shortcomings that require an update of the methodology.[68] The updated methodology employs a regression model and updates the input variables used by EDTI to more closely track the various factors or events that could impact forecast usage and customer site counts.

85. The following data and assumptions were incorporated by B&V:

- Variables designed to capture the effect of the COVID-19 pandemic, in order to more accurately predict demand going forward.

- A proposed forecasting methodology that separates the impacts of load growth and consumption behaviour on a customer basis, thus providing mechanisms allowing for the separation of changes in sales triggered by customer growth versus behavioural changes triggered by influences such as the adoption of energy efficiency measures.

- A weather normalizing factor was added so customer classes were weather normalized and adopted binary variables for the time of year, capturing consumption behaviour that varies by season but is not temperature related.[69]

86. No party objected to the changes in the B&V-proposed forecasting methodology. The Commission finds the updates to be reasonable and approves the updated forecasting methodology as filed.

6 Terms and conditions for electric distribution service

87. As part of its application, EDTI also sought approval of certain revisions to the distribution connection services terms and conditions (Schedule DT-A-2). EDTI informed the Commission that the majority of the proposed revisions were intended to improve clarity of terms and conditions, and to address current industry practices, such as the growing adoption of DCG and energy storage. Some updates were also aimed at reducing the administrative burden on EDTI and its customers. Overall, these changes were reflected in detail in Section 8 of EDTI's application.

88. Based on the Commission's review of the revised terms and conditions in the course of the proceeding, and EDTI's ensuing willingness to refine them in response to the Commission IRs,[70] the Commission is satisfied with EDTI's requested revisions to its distribution connection

68 Exhibit 27018-X0009, B&V billing determinants forecast, PDF page 9.
69 Exhibit 27018-X0009, B&V billing determinants forecast, PDF page 9.
70 Exhibit 27018-X0030, EDTI-AUC-2022FEB02-016, EDTI-AUC-2022FEB02-017, EDTI-AUC-2022FEB02-019, EDTI-AUC-2022FEB02-020.

services terms and conditions. Accordingly, the Commission directs EDTI to update its distribution connection services terms and conditions, as provided in the EDTI Phase 2 application as Schedule DT-A-2,[71] while reflecting the revised draft language as proposed by EDTI in its responses to IRs EDTI-AUC-2022FEB02-016(b), EDTI-AUC-2022FEB02-017(a) and EDTI-AUC-2022FEB02-020, as part of its compliance filing to this decision.

89. As EDTI's other terms and conditions schedules – Terms and Conditions for Distribution Access Service (Schedule DT-A-1); Distribution Tariff Policies (Schedule DT-A-3); and EDTI Investment Eligibility (Schedule A) – had no other changes to the previously approved versions other than an update to their effective dates as of 2023, they are all approved by the Commission as filed.

7 Mitigating the risk of stranded assets

90. In Decision 2012-155,[72] the Commission directed EDTI to explore the merits of possible additional means of mitigating the risk of stranded asset costs resulting from default or bankruptcy on the part of its larger customers (i.e., CS rate class) and present proposals regarding same when it files its next Phase 2 or PBR rebasing applications. As part of that decision, the Commission offered mitigation measures for EDTI's consideration in conjunction with the results of EDTI's own investigation.[73]

91. In this proceeding, EDTI confirmed that it explored alternatives to mitigating stranded asset risk, and in particular, the risk arising from default or bankruptcy by large customers. EDTI discussed its consideration of each potential measure in Section 2.2 of its application. Ultimately, EDTI concluded that it remains confident that the risk of stranded assets is reasonably and sufficiently mitigated through its terms and conditions, albeit recognizing that the risk cannot be eliminated in its entirety.[74] In EDTI's view, no additional mitigation steps are required over and above the measures currently provided for in its terms and conditions.[75]

92. In the CCA's evidence, provided by its consultant Jan Thygesen of Icarus Regulatory Services Ltd., J. Thygesen questioned the adequacy of EDTI's mitigation measures, which, in his view, protect EDTI and leave customers with residual risk.[76] J. Thygesen recommended that any assets no longer required to provide service to customers should to be moved to plant held for future use or removed from rate base.[77] EDTI dismissed J. Thygesen's recommendation for having no reasonable basis. In EDTI's view, the Commission's recent Decision 27187-D01-2022[78] appropriately balances customer protection from the risk of stranded assets related to the CS rate class, wherein in the event of a CS customer default, EDTI was directed to bring any

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71 Exhibit 27018-X0016, Schedule DT-A-2, EPCOR terms and conditions for distribution connection services.
72 Decision 2012-155: EPCOR Distribution & Transmission Inc., Customer Specific Distribution Access Service Rate for New Customer, Proceeding 1731, June 8, 2012.
73 Decision 2012-155, paragraph 33.
74 Transcript, Volume 1, page 27, lines 3-13.
75 Exhibit 27018-X0001, application, paragraph 20.
76 Exhibit 27018-X0038, paragraph 38.
77 Exhibit 27018-X0038, paragraph 41.
78 Decision 27187-D01-2022: EPCOR Distribution & Transmission Inc., 2022 Customer Specific Distribution Access Service Rate for New Customer CS48, Proceeding 27187, April 6, 2022.

unpaid amount to the Commission's attention, at which time the Commission will determine the regulatory treatment of the outstanding amount(s).[79]

93. The Commission has reviewed EDTI's response to each potential mitigation measure and considered J. Thygesen's position. At this time, the Commission finds that the measures currently provided in EDTI's terms and conditions, in conjunction with the aforementioned direction from Decision 27187-D01-2022, strike a reasonable framework for ensuring that a risk of stranded asset costs resulting from default or bankruptcy on the part of EDTI's larger customers is acceptably mitigated. Should new evidence arise that requires reconsideration of this matter, the Commission may revisit this decision and the approach taken for stranded asset cost mitigation.

8 Order

94. It is hereby ordered that:

(1) EPCOR Distribution & Transmission Inc. submit, by August 15, 2022, a Phase 2 compliance filing incorporating all the relevant findings and directions in this decision.

(2) EPCOR Distribution & Transmission Inc. to provide in its next Phase 2 application:

(i) a revised allocation methodology of Federal Energy Regulatory Commission (FERC) Account 367 to make the methodology more simple and transparent;

(ii) the results of a demand-metering billing feasibility study including all items in its scope as directed in this decision; and

(iii) a review of the calculation of its demand allocators.

(3) EPCOR Distribution & Transmission Inc. to provide as part of its proposal to address CS rates for its third PBR term a discussion as to whether there is an opportunity to discontinue the CS rate class and move future large customers who currently would be CS rate class candidates and possibly existing CS rate class customers to either a new rate class or existing rate classes.

Dated on July 11, 2022.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

[79] Decision 27187-D01-2022, paragraph 16.

(original signed by)

Douglas A. Larder, QC
Vice-Chair

(original signed by)

Vera Slawinski
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden, Ladner Gervais LLP
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair D.A. Larder, QC, Vice-Chair V. Slawinski, Commission Member Commission staff P. Khan (Commission counsel) C. Robertshaw A. Jukov B. Edwards

Appendix 2 – Oral argument and reply argument – registered appearances

Name of organization (abbreviation) **Name of counsel or representative**	**Witnesses**
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden, Ladner Gervais LLP	Jonathan Liteplo Bradon Willms
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP	Randall McCreary, QC Breanne Schwanak
Consumers' Coalition of Alberta (CCA)	James Wachowich, QC

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Commission also directs certain changes to take effect in EDTI's next Phase 2 proceeding; including to revise the allocation methodology of Federal Energy Regulatory Commission (FERC) Account 367 to make the methodology simpler and more transparent, and to provide the results of a demand-metering billing feasibility study. .... paragraph 2
2. EDTI is directed to submit a compliance filing to reflect the determinations in this decision on or before August 15, 2022. .... paragraph 3
3. The Commission agrees with the consensus of the parties and finds that the six-year average method to measure demand is more representative of actual rate class demand. The Commission directs EDTI in its compliance filing to use in its COSS a six-year average calculation as the demand allocator, in place of the three-year average period used in its application, for the calculation of the I-NCP 50/50 and 12-NCP demand allocators. The Commission further directs EDTI to review the calculation of its demand allocators in its next Phase 2 application. .... paragraph 36
4. EDTI agreed with InterGroup's proposal that the functionalization of FERC 364 poles, towers and fixtures should be adjusted such that poles serving a shared function be functionalized based on the relative overall length of conductors, not on the new build costs of the conductors. The Commission agrees with InterGroup that basing the FERC 364 allocation on the conductor length is a superior methodology to new build costs as conductor length is connected to the number of poles used to support the conductor, which is a better indicator of the related costs. The Commission thereby directs EDTI to update its COSS in its compliance filing to functionalize shared poles using overall conductor length for purposes of calculating the 2023 rates. .... paragraph 39
5. Both EDTI and its consultant, B&V, agreed with InterGroup's recommendation regarding FERC 367. EDTI stated that it would review and revise the method as necessary in its next Phase 2 application, which it expects to file during the third PBR term. The Commission agrees with InterGroup's recommendations above regarding FERC 367 and directs EDTI in its next Phase 2 application to revise the allocation methodology of FERC 367 to make it methodology simpler and more transparent. The Commission endorses the filing of EDTI's next Phase 2 application during the third PBR term. .... paragraph 42
6. EDTI is directed in its compliance filing to this proceeding to revise its residential billing ratio in its rate design to 71 per cent fixed and 29 per cent variable to reflect a 50/50 split of demand-allocated costs as determined by the COSS to the customer and energy components. .... paragraph 63
7. To that end, the Commission directs EDTI to commence a feasibility study to determine the scope and cost to build and implement a metering system that is able to measure demand for residential and small commercial customers. The Commission has considered the feasibility study items as recommended by the CCA and the UCA. The Commission

directs EDTI to include in the feasibility study the information requested in and/or responses to the following:

- Identify the objectives of moving to demand based billing.
- Assess the capabilities of EDTI's existing meters and related systems.
- Identify all possible alternatives to provide demand-based billing with detailed preliminary cost estimates and timelines for implementation, including investigating and reporting on all of the options as to how EDTI should recover the variable demand-related costs, the pros and cons with each option, including but not limited to conducting practical testing within the feasibility study, using a small number of demand metered customers of various classes. This should include the costs of any modifications that would be required to EPCOR's current communication systems.
- The current capital and operating costs incurred by EDTI to support time-of-use (TOU) rates for interval rate classes, and the incremental costs that would be incurred to the other non-TOU rate classes if TOU rates were to be implemented for them. This should include a discussion of whether there are any thresholds that result in a step function of cost increases for the non-TOU classes to measure interval data.
- Whether hourly or subhour interval data (i.e., 15 minutes) will be required, including a discussion of the pros and cons of hourly versus subhourly data, and whether these requirements differ by rate class or type of customer (for example, whether industrial customers may need 15-minute interval data but hourly or less frequent measurements would be sufficient for residential and small commercial customers).
- Whether operating costs for residential customers could be reduced by only collecting interval data for energy and demand during residential peak periods and, if so, the pros and cons of doing so, including the expected loss in billing accuracy.
- If the Alberta Electric System Operator (AESO) had TOU rates, would it enable the potential flow-through of AESO's tariffs to distribution facility owner customers and enable them to be able to see and respond to AESO price signals?
- Whether demand billing and/or TOU rates would assist in price signalling for electric vehicle owners and incent them to charge vehicles outside of peak hours.....................

8. EDTI is directed to complete this demand-metering billing feasibility study, including in its scope the items for discussion as listed above, and to bring forward the results as well as the costs to complete the study in its next Phase 2 application.

9. No parties presented any concerns with the proposed CS rate design. The Commission finds that the proposed CS rate design is an improvement over the prior approved methodology, as the proposed CS rate design better aligns with the method costs are assigned and recovered in B&V's COSS. The Commission approves the proposed CS rate design as filed. However, the Commission directs EDTI, while it is considering alternatives to CS rate design for its third PBR term, to also explore discontinuing CS rates. CS rates are relatively burdensome to administer and regulate for the benefit of relatively few EDTI customers. The Commission notes that EDTI's CS rate class is a unique rate structure among the Alberta distribution utilities, and other utilities have evidently found ways to arrive at a more generic rate structure for their larger customers rather than providing them each with their own individual rate. The Commission directs

EDTI to report, as part of its proposal to address CS rates for its third PBR term, whether there is an opportunity to move future large customers who would be CS rate class candidates and possibly existing CS rate class customers (which the Commission understands could be more difficult) to either a new rate class, or existing rate classes to reduce regulatory burden and achieve greater consistency with distribution service provided in other service areas. .... paragraph 83

10. Based on the Commission's review of the revised terms and conditions in the course of the proceeding, and EDTI's ensuing willingness to refine them in response to the Commission IRs, the Commission is satisfied with EDTI's requested revisions to its distribution connection services terms and conditions. Accordingly, the Commission directs EDTI to update its distribution connection services terms and conditions, as provided in the EDTI Phase 2 application as Schedule DT-A-2, while reflecting the revised draft language as proposed by EDTI in its responses to IRs EDTI-AUC-2022FEB02-016(b), EDTI-AUC-2022FEB02-017(a) and EDTI-AUC-2022FEB02-020, as part of its compliance filing to this decision.. paragraph 88