Alberta Utilities Commission

Direct Energy Regulated Services

2023 Default Rate Tariff and Regulated Rate Tariff

May 4, 2023

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Decision 27631-D01-2023
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Proceeding 27631

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1 Decision summary

1. This decision makes findings regarding Direct Energy Regulated Services' (DERS) default rate tariff (DRT) and regulated rate tariff (RRT) revenue requirements and non-energy charges for 2023. DERS' non-energy charges are shown as the fixed daily charge on its DRT and RRT customers' bills.

2. In its application, DERS set out a revenue requirement proposed to be collected through the daily charge for 2023. In this decision, the Alberta Utilities Commission will address matters identified by the Consumers' Coalition of Alberta (CCA), the Office of the Utilities Consumer Advocate (UCA), or the Commission that required specific consideration. Non-contentious matters that are not specifically addressed in this decision are approved as filed, unless they are affected by compliance filing directions.

3. In this proceeding, the regulated competitive split ratio of site counts was the most contentious matter. This ratio was an important element of DERS' application because it is used for allocation of costs to regulated customers who DERS serves under the DRT and RRT. The Commission has determined that a forward-looking methodology to forecast the regulated and competitive split is warranted given the significant recent changes in site counts. Based on this determination, the Commission referred to DERS' regulated and competitive site forecast to calculate a regulated competitive split of 60.1 per cent regulated.

4. DERS' application included the following proposals: a new method to forecast merchant fees; a budget increase to customer information operations; five per cent for labour inflation; an increase to staff full-time equivalents (FTEs); a bad debt deferral account; an expansion of the change management category and the addition of a deferral account for the ATCO System Change Project; and revised terms and conditions of service. During the proceeding, interveners also raised concerns over credit charges and the hearing cost reserve account. The Commission's decisions on these issues can be summarized as follows:

(a) The Commission approves DERS' new method to forecast merchant fees, which provides transparency between recurring and one-time payments forecast amounts.

(b) The Commission disallows DERS' customer information forecast of $224,047, and approves the amount of $84,000 for customer information consistent with the amounts approved for 2021 and 2022.

(c) The Commission denies DERS' proposed five per cent increase for labour inflation. Instead, the Commission approves three per cent to account for labour inflation.

(d) The Commission denies DERS' proposed increase of 2.4 FTEs for its Digital and Marketing team.

(e) The Commission denies DERS' bad debt expense forecast. Instead, the Commission directs DERS to recalculate its bad debt expense forecast according to the methodology set out in Section 4.6.1 below.

(f) The Commission denies DERS' proposed bad debt deferral account. Instead, the Commission approves a symmetrical deferral account such that if aggregate bad debt exceeds the revised forecast, 100 per cent of the difference will be deferred to the account of customers; and if aggregate debt is less than the revised forecast, 100 per cent of the difference will be credited to customers.

(g) The Commission approves the inclusion of the ATCO System Change Project into the change management category; a forecast of the project at $1.2 million; and a conventional deferral account for the project if the actual cost exceeds $1.2 million.

(h) The Commission approves the revised terms and conditions of service filed in exhibits 27631-X0030 and 27631-X0032 subject to the minor amendments in Section 5.1 below. The Commission directs DERS to incorporate the amendments in Section 5.1 and refile the documents in the compliance filing.

(i) The Commission approves the letter of credit charge at 225 basis points and the parental corporate guarantee charge at 40 basis points.

(j) The Commission denies DERS' hearing reserve of $0.453 million for 2023. Instead, the Commission directs DERS to update the hearing cost reserve and hearing cost recovery amounts in the compliance filing by updating the hearing costs to match DERS' cost claims in Proceeding 28082 in addition to excluding the costs for the 2024-2025 DRT and RRT application.

(k) For its 2023 non-energy DRT and RRT revenue requirements, DERS is required to submit a compliance filing to reflect the Commission's findings and directions, on or before July 7, 2023.

2 Introduction

5. DERS is a business unit of Direct Energy Marketing Limited and performs the DRT and RRT functions in the service territories of ATCO Gas and Pipelines Ltd. (ATCO Gas) and ATCO Electric Ltd., respectively.

6. ATCO Gas appointed DERS to perform the functions of the default supply provider under Section 28.1(2) of the *Gas Utilities Act* and Section 2 and Section 8 of the *Default Gas Supply Regulation*, beginning May 5, 2004. DERS was also appointed by ATCO Electric as the regulated rate provider under Section 104 of the *Electric Utilities Act*.

7. On September 9, 2022, DERS filed an application with the Commission, requesting approval of its 2023 DRT and RRT non-energy tariff application in accordance with sections 3 and 5 of the *Default Gas Supply Regulation*, Section 103 of the *Electric Utilities Act* and sections 2, 3 and 5 of the *Regulated Rate Option Regulation*.

8. The Commission issued notice of application on September 12, 2022, inviting interested parties to file a statement of intent to participate (SIP) by no later than September 23, 2022. The CCA and the UCA filed SIPs.

9. The Commission issued two rulings granting confidentiality orders. In a ruling dated October 3, 2022, the Commission granted DERS' request for confidential treatment of certain information in its contracts and associated documents pertaining to customer care and billing (CC&B) services. In a ruling dated January 18, 2023, the Commission granted DERS' request for confidential treatment of DERS' competitive, unregulated affiliate's site count information.

10. The application was processed through information requests (IRs), intervener evidence, IRs on intervener evidence, and oral argument and reply argument. Oral argument and reply argument was conducted on February 10, 2023, which is the close of record for this proceeding.

3 Requested approvals

11. For the 2023 test period, DERS originally[1] requested approval of:

- The DRT non-energy revenue requirement of $53.3 million.
- The DRT energy-related revenue requirement of $5.5 million.
- A DRT energy-related revenue requirement of $0.067 per gigajoule (GJ) to be included in the monthly gas cost flow-through rate (GCFR),[2]
- A DRT return margin of $0.066/GJ to be included in the monthly GCFR.[3]
- The RRT non-energy related revenue requirement of $16.9 million.
- The RRT energy related revenue requirement of $1.7 million.
- An annual cost of capital rate for DRT and RRT working capital of 3.02 per cent, plus taxes payable expense.
- The methodology used to allocate the DRT and RRT revenue requirements to the various rate classes.
- Continuation of the DRT and RRT hearing cost reserve accounts.
- Continuation of the bad debt deferral and late payment charge deferral accounts, which were approved in Decision 26207-D01-2021.[4]

[1] Exhibit 27631-X0001, application, PDF page 7. DERS provided some updates through its responses to IRs from the Commission. Further updates will be required as part of DERS' compliance filing.
[2] Exhibit 27631-X0001, application, Table 5.6.2-B, PDF page 91.
[3] Exhibit 27631-X0001, application, Table 6.1, PDF page 91.
[4] Decision 26207-D01-2021: Direct Energy Regulated Services, 2020-2022 Default Rate Tariff and Regulated Rate Tariff Application, Proceeding 26207, June 4, 2021.

12. Because the requested revenue requirement is collected through the daily charge, DERS also requires Commission approval of the daily charge in the following rate schedules and associated terms and conditions of service, effective January 1, 2023:

- The DRT and RRT rate schedules for 2023.[5]
- The amended DRT Terms and Conditions of Default Rate Service.[6]
- The amended RRT Terms and Conditions of Regulated Rate Service.[7]

4 Issues examined in this decision

13. The Commission will address matters with which either the CCA, the UCA or the Commission identified issues and that therefore require specific consideration.

14. In the application, there were a number of cost categories that comprise the applied-for DRT and RRT energy and non-energy revenue requirements. These cost categories are applicable to both the DRT and the RRT unless specifically noted. In this section of the decision, the Commission addresses issues on: (i) merchant fees; (ii) credit charges; (iii) customer information; (iv) labour; (v) bad debt; (vi) ATCO System Change (customer operations); and (vii) reserve accounts for hearing costs.

15. Certain cost categories are affected by the ratio of regulated and competitive site counts that DERS uses to allocate costs. Some cost categories are unrelated to the regulated competitive split, and others are discretionary. The discrepancies in interpreting site count data from the Market Surveillance Administrator (MSA) retail statistics report raised in the CCA's evidence became a highly contested issue during the proceeding. Although information was incrementally added to the record and the matter was clarified before oral argument, the Commission identified the threshold adjustment and its associated site forecast to be a subissue examined within the context of the regulated and competitive split ratio issue.

4.1 Regulated and competitive split

16. DERS calculates a ratio, expressed as a percentage, between its regulated and competitive retail businesses to establish the percentage of costs for services shared between DERS and Direct Energy Partnership (DEP) that is allocated to DERS. This ratio, referred to as the regulated and competitive split in the application, allocates a portion of customer operations and labour costs to DERS. Within customer operations, DERS uses the regulated and competitive split to determine DERS' costs for the threshold adjustment, long distance costs, short message service costs, and change management costs.[8] For labour revenue requirements, certain staffing costs for FTEs are similarly impacted by the regulated and competitive split.[9]

5 Exhibits 27631-X0026, 27631-X0027, 27631-X0028 (DERS South DRT, North DRT, RRT).
6 Exhibits 27631-X0030 and 27631-X0031, DERS DRT Terms and Conditions of Default Rate Service, clean and blackline.
7 Exhibits 27631-X0032 and 27631-X0033, DERS RRT Terms and Conditions of Regulated Rate Service, clean and blackline.
8 Exhibit 27631-X0065, DERS-AUC-2022OCT19-002(c) and (d).
9 Exhibit 27631-X0065, DERS-AUC-2022OCT19-002(c) and (d).

17. DERS used the methodology established in the 2020-2022 non-energy Negotiated Settlement Agreement (NSA) that was approved in Decision 26207-D01-2021 to calculate the regulated and competitive split. The MSA retail statistics report, published quarterly, is the basis of this calculation. DERS submitted that this methodology continues to be a reasonable approach to determine the regulated and competitive split, but acknowledged that irrespective of the NSA between DERS, the UCA and the CCA regarding use of MSA data, the Commission is not obligated to accept its proposal.[10]

18. In its application, DERS applied for a split of 64.1 per cent regulated and 35.9 per cent competitive using the MSA December 2021 retail statistics report. Subsequently, in response to a CCA IR, DERS used the MSA June 2022 retail statistics report to update the split to 61.7 per cent regulated and 38.3 per cent competitive.[11]

19. The MSA data includes electricity and gas site counts for both DERS and DEP. The site counts are organized by residential, farm, commercial and industrial categories.

20. To produce the regulated and competitive split, DERS sums regulated gas and electricity site counts (numerator) and divides that by the sum of regulated and competitive gas and electricity site counts (denominator). In response to a Commission IR, DERS clarified that it excludes large commercial and industrial site counts from its competitive summation in the denominator.[12]

21. Jan Thygesen, on behalf of the CCA, contended that there are several issues with the regulated and competitive split methodology submitted by DERS.

22. According to J. Thygesen, the significant increase in competitive sites and the significant reduction in regulated rate option (RRO) sites over a short period is a reflection of strong trends underway.[13] J. Thygesen noted that in six months' time, DERS' regulated and competitive split calculation decreased from 64.1 per cent to 61.7 per cent.[14] J. Thygesen submitted that historical ratios are no longer appropriate due to the accelerated changes in regulated and competitive site counts. In his suggestion to move away from using historical ratios, J. Thygesen recommended that a forecast on the regulated and competitive split is required for 2023.[15]

23. J. Thygesen further submitted that DERS made errors in the regulated and competitive split calculation by including all residential, farm, commercial and gas industrial customers into the regulated site counts, but only included residential customers into the competitive site counts.[16] J. Thygesen submitted that this selective method of summing sites would result in an overstatement of the allocation percentage to the regulated portion of the regulated and competitive split. To remedy this inconsistency, J. Thygesen recommended using only MSA residential sites for both the regulated and competitive site counts in the calculation of the regulated and competitive split.[17] In his calculations, J. Thygesen advised that the regulated and

10 Exhibit 27631-X0065, DERS-AUC-2022OCT19-001.
11 Exhibit 27631-X0086, Attachment DERS-CCA-2022OCT28-002(a).
12 Exhibit 27631-X0065, DERS-AUC-2022OCT19-002(b).
13 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 47.
14 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 48.
15 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 47.
16 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 22.
17 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 31.

competitive split would be 58.55 per cent regulated based on the MSA June 2022 retail statistics report.

24. Given that the regulated and competitive split was corrected to 58.6 per cent based on the MSA June 2022 retail statistics report, and this is a drop of 250 basis points in six months compared to results using the MSA December 2021 retail statistics report, J. Thygesen submitted that this strong trend should be used for the 2023 forecast. To forecast the regulated and competitive split for 2023, J. Thygesen advised he projected this rate of change into mid-2023, and he calculated the regulated and competitive split to be 53.76 per cent regulated.[18]

25. J. Thygesen also identified the number of sites for threshold payments to be an issue based on his observations that the MSA data and DERS' actual site count data do not reconcile.[19] Due to this issue, J. Thygesen stated that he was unable to comment on whether the applied-for threshold payments and site accounts are reasonable.[20]

26. DERS disagreed with J. Thygesen's proposal to only include residential sites for regulated and competitive site counts to calculate its regulated and competitive split. DERS stated that it is the only regulated or default service provider within the ATCO Electric and ATCO Gas service territories, and therefore it must serve all regulated sites.[21] In respect to competitive site counts, DERS only considers residential sites.

27. DERS explained that competitive site count information reported by the MSA retail statistics report also includes large industrial and commercial sites served by Direct Energy Business (DEB), but DERS has reasons to remove DEB sites from the data set. DERS described DEB as an entity with its own separate CC&B system, which does not share staff that are allocated on the basis of site counts; and unlike DERS and DEP, DEB is not a party to the Direct Energy Marketing Limited-Direct Energy Limited Partnership nor the Direct Energy Marketing Limited-HCL master service agreements.[22] To accurately count competitive sites using the MSA data, DERS submitted that DEB sites must be removed, leaving only residential sites to be considered.

28. DERS also noted that the MSA data is provided by ATCO Gas and ATCO Electric, and DERS does not control the methodology selected by the distributors for their site count submissions to the MSA.[23]

29. DERS concluded by providing evidence that reconciles its internal site counts with the MSA retail statistics report.[24] The reconciliation produced variances between the data sets that DERS explained are due to MSA data excluding inactive sites, street lighting and Rural Electrification Association sites.[25] DERS submitted that this small difference is acceptable when establishing the regulated and competitive split.

18 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 48.
19 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 49.
20 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 50.
21 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 52.
22 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 48.
23 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 53.
24 Exhibit 27631-X0123-C, Attachment 3 – DEP versus MSA Comparison.
25 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 54.

30. In argument, the CCA raised a concern that the fair market value of the customer information system is likely distorted if DERS' consultant, Five Point, included competitive commercial and industrial customers into its benchmark study in an earlier proceeding. The CCA stated that if the fair market value and base cost charged to RRO customers were based on an assessment that all customers were included, then excluding large, competitive commercial and industrial sites from the regulated and competitive split allocation results in a higher per unit cost to customers.[26]

31. The CCA proposed that Desert Sky (a DERS consultant) and Five Point provide clarification to the effect that their benchmark work in Proceeding 2957 compensated, adjusted or otherwise took into account the fact that competitive commercial and industrial customers were excluded from the fair market value benchmarks.[27] Further, the CCA recommended that the Commission direct DERS to obtain affidavits from the benchmark consultants and to file the affidavits in the compliance filing.[28]

32. The CCA concluded that parties have gone through an extensive process to understand how DERS applied adjustments to the MSA data to calculate the regulated and competitive split, but it still did not have clarity on why DERS excluded all competitive commercial and industrial customers in the calculations rather than only large competitive commercial and industrial customers, as stated in DERS' rebuttal evidence.[29] Consequently, the CCA requested that going forward, it would still support the use of MSA data, but DERS should advise all parties on any adjustments to be made on the data and provide explanations on why the adjustments are required.[30]

33. For the reasons below, the Commission does not find that using the MSA retail statistics report is the best way to forecast the regulated and competitive split for DERS.

34. The Commission sets rates prospectively, and it finds that J. Thygesen's suggestion for a forecast regulated and competitive split has merit. However, the Commission does not agree with J. Thygesen that the forecast rate should be based on projecting a rate of change to mid-year of the test period because it is not clear how the projection is determined.

35. Currently, DERS' regulated and competitive split methodology is not forward looking. Instead, DERS uses data at a certain point in time as the basis for what site counts will be during the test period. DERS' reliance on the December 2021 MSA data and the June 2022 MSA data demonstrate that market conditions can result in significant shifts in the regulated and competitive split over a short period. Further, the MSA reports are based on data submitted by ATCO Gas and ATCO Electric, not DERS. ATCO Gas and ATCO Electric lack visibility into specific facts related to DERS' site counts.

36. During this proceeding, parties came to an understanding that the competitive counterpart to DERS serves competitive residential, and competitive commercial and industrial customers, on separate billing systems. The Commission therefore accepts DERS' explanations and agrees that adjustments have to be made on the MSA data to account for this nuance. However, even

[26] Transcript, Volume 1, page 85, lines 9-17.
[27] Transcript, Volume 1, page 87, lines 16-24.
[28] Transcript, Volume 1, page 101, lines 10-20.
[29] Transcript, Volume 1, page 80, lines 4-7.
[30] Transcript, Volume 1, page 102, lines 5-15.

when these adjustments were made, along with further adjustments to account for inactive sites, there are still differences between the MSA data and DERS' data.

37. Despite the agreement in the NSA to use the MSA data in the 2023 application and beyond, the Commission determines that DERS' internal site data is the most accurate and therefore, recognizes it as the primary source of data. The Commission therefore finds that using DERS' data best reflects market conditions and accurately allocates shared costs. Accordingly, the Commission will use DERS' internal data for this application. In addition, the Commission confirms that DERS can file the competitive DRT and RRT site counts without the need for a third-party audit in future applications.

38. To forecast the regulated and competitive split site counts, the Commission notes that the threshold adjustment calculations in Exhibit 27631-X0079 already provide regulated and competitive site counts forecasts for all of 2023. In the threshold adjustment calculations, DERS currently does not calculate the threshold adjustment using an allocation percentage to DERS based on its forecasted site counts, but rather on the allocation percentage calculated from the MSA retail statistics report. As outlined above, the Commission finds that calculating the regulated and competitive split based on the MSA retail statistics report leads to less accurate results for DERS, as compared to DERS' internal site data. This can be addressed as follows.

39. The Commission determines that DERS could update Excel cell AO29 in Exhibit 27631-X0079 such that DERS' allocation percentage is calculated by dividing DERS' annual site count by the combined annual site count.[31] The Commission has performed this calculation, and finds the regulated and competitive split to be 60.1 per cent regulated. Accordingly, the Commission directs DERS to apply the approved regulated and competitive split to all impacted revenue requirements in the compliance filing.

40. After considering the CCA's proposal to obtain clarification from Desert Sky and Five Point whether competitive commercial and industrial customers were excluded from the fair market value benchmarks, the Commission finds there would be little value in applying potential changes that will only apply for one more year given that the existing CC&B agreements expire at the end of 2024. There will be more value if DERS address the customer mix in its next application when it applies for a fair market value on its CC&B system. Accordingly, the Commission declines the CCA's request to obtain clarifications and affidavits from DERS' benchmark consultants. The Commission directs DERS to address the customer mix input in the next non-energy application.

4.2 Merchant fees

41. Merchant fees are the amounts charged by DERS' credit card service provider as well as the fees charged by the credit card companies. Customers use credit cards to make recurring payments and one-time payments. Currently, merchant fees are paid by all of DERS' regulated customers regardless of whether they use credit cards to pay, because merchant fees are built into the non-energy charge. DERS noted there has been a continued increase in the percentage of DERS customers who pay using credit cards and that the trend is forecast to continue.[32]

[31] Excel cell AO9 of 6,068,128 divided by Excel cell AO16 of 10,098,876 = 60.1%.
[32] Exhibit 27631-X0001, application, paragraph 93.

4.2.1 Revised merchant fee forecasting methodology

42. DERS currently forecasts merchant fees using a multiplier to account for the differences in average bill amounts between those who pay by credit card and those who pay via other methods. According to DERS, the average bill paid by customers using credit cards is higher compared to the average bill for all customers. In DERS' 2020-2022 non-energy tariff application, the Commission did not directly approve a multiplier because the application was settled through a mediated, negotiation settlement process.

43. In this application, DERS revised its forecast merchant fees formula to include five distinct components that were based on data over a 36-month period from June 2019 to May 2022. DERS stated that its revised methodology will provide a better forecast of merchant fees because there is visibility into the drivers of the merchant fee such that recurring and one-time payments are separately accounted for.[33] The formula for calculating the forecast Merchant Fees is:

> Forecast Merchant Fees = [Recurring Payment Credit Card Customers x Recurring Payment Average Monthly Bill x Average Merchant Fee] + [One-time Payment Credit Card Customers x One-Time Payment Average Monthly Bill x Average Merchant Fee][34]

44. The CCA and the UCA did not file IRs nor raise concerns in evidence with respect to DERS' revised methodology to forecast merchant fees. In IRs from the Commission, DERS was requested to provide details on what the resulting forecast merchant fees would have been for the months from January 2021 to August 2022 using the revised methodology, and what the resulting forecast merchant fees would have been using the methodology using a bill multiplier for the year 2023.[35] According to DERS, the variance comparing actuals with the backtest forecast from January 2021 to August 2022 was approximately $15,400,[36] and the variance comparing the current and proposed merchant fee methodology for 2023 was approximately $57,600.[37]

45. The Commission is satisfied that the revised methodology to forecast merchant fees offer similar results with DERS' current methodology, and that the forecast variances between the two methodologies are immaterial relative to the total merchant fee revenue requirement. The Commission agrees with DERS that the revised methodology provides better visibility into the drivers of the merchant fee when recurring and one-time payments are delinked. Accordingly, the Commission approves of DERS' revised methodology to forecast merchant fees.

4.2.2 Merchant fee responsibility

46. In IRs to DERS, the Commission and the UCA asked how DERS would be impacted if merchant fees were directly passed to customers who use credit cards to make bill payments. DERS indicated that it has not had the opportunity to thoroughly evaluate the impacts on its customers and its revenue requirements.[38] However, if the option to pay by credit card is eliminated, DERS identified an immediate negative impact to rates based on its analysis of bad

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[33] Exhibit 27631-X0065, DERS-AUC-2022OCT19-009.
[34] Exhibit 27631-X0001, application, paragraph 97.
[35] Exhibit 27631-X0065, DERS-AUC-2022OCT19-008(d) and DERS-AUC-2022OCT19-009.
[36] Exhibit 27631-X0069, Variance Explanation tab, Excel cell E7.
[37] Exhibit 27631-X0070, Comparison tab, Excel cell O14 – Excel cell O8 is $2,912.7-$2,970.3 (thousand) = $57.60 thousand.
[38] Exhibit 27631-X0080, DERS-UCA-2022OCT28-004(b).

debt. Referring to observations from its interactions with customers with past due amounts, DERS explained that customers who are in arrears often make use of a DERS' policy that permits friends or family to make credit card payments on their behalf. For this reason, DERS viewed that eliminating the ability to pay by credit card would have three main impacts: (i) a reduction in payments for customers with no other payment options; (ii) increased disconnections for non-payment; and (iii) increased bad debt write-offs.[39]

47. InterGroup Consultants Ltd., on behalf of the UCA, submitted that inclusion of merchant fees in the non-energy revenue requirement results in customers not paying by credit card subsidizing the service to customers who do pay by credit card. Rather than limiting credit card use, the UCA and InterGroup viewed that a more equitable approach would be to pass on the associated merchant fees to customers electing to pay by credit card.

48. InterGroup provided examples of other utilities who accept credit card payments through a third-party service that charges a service fee for each payment customers make.[40] InterGroup proposed that if merchant fees cannot be charged directly to customers paying by credit card, then the merchant fees should be recovered from the energy-related revenue requirement.[41]

49. In order to fully assess the feasibility of routing credit card payments through a third-party service provider, DERS indicated that it would need to undertake an analysis and consider the following items: (i) a need for a clear communication plan to provide customers on recurring credit card payments the ability to adapt their payment preferences; (ii) a review of the service options before potentially engaging with an appropriate credit card third-party service provider; (iii) a need to determine its forecast to incorporate its future plans regarding credit payments and merchant fees including impacts to bad debt, late payment charges, customer satisfaction, customer attrition, customer escalations and complaints, and change management forecasts; and (iv) a need to work with its billing and customer care system support team to determine costs, capabilities, and timelines for system changes.[42]

50. DERS further remarked that only the DRT provides a mechanism for incorporating a portion of merchant fees into the commodity charge whereas the RRT does not. DERS explained that the RRT commodity rate is set strictly based on its energy price setting plan (EPSP), which is determined in accordance with the *Regulated Rate Option Regulation*. Additionally, DERS asserted that none of the EPSPs in effect for the three RRO providers contemplate the inclusion of merchant fee costs in the energy charge.[43]

51. The Commission finds that there is merit in the proposal to have merchant fees allocated to customers paying by credit cards. Making this change would require DERS to adopt a user-pay model where it would potentially contract a third-party provider to process credit card bill payments. The Commission is not convinced that there is an urgency to direct DERS to exclude merchant fees from the 2023 non-energy requirement nor to shift the recovery of merchant fees on the energy-related revenue requirement of the DRT. In addition, the Commission recognizes

39 Exhibit 27631-X0065, DERS-AUC-2022OCT19-010(c).
40 Transcript, Volume 1, page 126, lines 9-12.
41 Exhibit 27631-X0098, InterGroup evidence, PDF page 12.
42 Exhibit 27631-X0122, DERS' rebuttal evidence, paragraph 94.
43 Exhibit 27631-X0122, DERS' rebuttal evidence, paragraph 96.

that DERS should fully understand the risks and benefits of using a third-party provider for credit card payments, as well as the impact on DERS' customers and revenue requirements.

52. The RRT energy revenue requirement is determined in accordance with the *Regulated Rate Option Regulation*, and the Commission agrees with DERS that none of the EPSPs from regulated service providers incorporate merchant fees. Historically, RRO service providers have adopted standardized cost and risk component names and descriptions for the purpose of filing energy and non-energy applications. This practice is a result of the outcome of RRT consultation between the Commission, the three main RRO service providers, the CCA and the UCA.[44] In review of the final results of the RRT consultation, merchant fees are classified as non-operating costs under the category of non-energy costs.[45] These two documents are attached to this decision as Appendix 3 and Appendix 4.

53. The UCA's recommendation to shift the RRT merchant fees onto the energy-related revenue requirement requires broader discussions with the same participants involved in the aforementioned RRT consultations. Therefore, the Commission is not prepared to make a decision on this matter in this proceeding.

54. Accordingly, the Commission directs DERS to investigate the feasibility of passing on the associated merchant fees to customers electing to pay by credit card for the DRT in its next non-energy application.

4.3 Credit charges

55. Credit charges are included as a forecast of DRT energy-related credit costs. NRG Energy Inc., the parent company of DERS, provides DERS credit support to ensure that it maintains the ability to procure gas. Customers pay for credit support through DERS' monthly GCFR filings as a component of the energy-related charges on a per GJ basis. On January 5, 2021, the day the sale transaction from Centrica to NRG was completed, DERS started receiving credit support from NRG.[46]

56. The UCA and InterGroup submitted that the credit charges increase from the approved $0.250 million in 2021 and 2022 to the $0.791 million forecast for 2023 is excessive. Specifically, InterGroup noted that the higher letter of credit (LC) charge of 225 basis points, as well as the inclusion of the parental company guarantee (PCG) charge of 40 basis points were inconsistent with DERS' previous applications where the LC was set at 70 basis points absent any PCG charges.[47] In InterGroup's view, the credit charges should only consist of LC charges, set at 70 basis points, which it calculated to be $0.356 million.

57. DERS admitted that the omission of the PCG charge on the DRT energy charge spreadsheet on proceedings prior to Proceeding 26207 was an oversight.[48] However, DERS disputed that PCG charges were historically excluded from credit charges. In rebuttal, DERS provided a table of historical DRT credit charges, which identified a consistent PCG charge of 40 basis points since 2012.[49] Further, DERS provided a reference to its 2012-2016 DRT and RRT

44 Appendix 3, Commission-initiated consultation on the regulated rate tariff, November 22, 2013, letter.
45 Appendix 4, RRT consultation final results, November 21, 2013.
46 Proceeding 26207, Exhibit 26207-X0001, application, paragraph 135.
47 Exhibit 27631-X0098, InterGroup evidence, PDF page 13.
48 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 103.
49 Exhibit 27631-X0122, DERS rebuttal evidence, Table 6.2, PDF page 42.

application, where it clarified in a IR response that NGX purchases are supported by a LC and a parental guarantee.[50]

58. DERS argued that there is no reason to deny the increase in credit costs given that the cost of credit reflects actual LC and PCG charges. It explained that a change in corporate parent naturally results in a change in actual cost incurred by DERS.[51]

59. The UCA is concerned that DERS did not explain how the LC rate available through NRG compares to the rate that would be available to DERS as a stand-alone entity.[52] The UCA argued that DERS has failed to meet its onus to justify its proposed LC rate of 225 basis points,[53] and it continued to support InterGroup's recommendation to set DERS' credit cost at $0.356 million.[54]

60. The Commission recognizes that DERS requires proper credit support to procure gas in order to fulfil its obligation to serve default gas supply customers, and that a change to DERS' parent company has resulted in a change to the LC offered to DERS. The Commission also finds that DERS provided helpful historical context where the LC and PCG charges are included in credit costs for the DRT. Based on these reasons, the Commission approves the LC and PCG charge of 225 basis points and 40 basis points, respectively.

61. Notwithstanding the approval of the LC and PCG charges for the 2023 test year, the Commission agrees with the UCA that there is merit in exploring whether DERS, as a stand-alone entity, would be able to secure a more favourable credit rate. Accordingly, the Commission directs DERS to provide the Commission, in its next non-energy application, the LC rate from NRG, the best rate that would be available to DERS as a stand-alone entity, and the PCG charge.

4.4 Customer information

62. DERS incurs customer information costs from providing and gathering information to and from customers. Information provided to customers may include information regarding rates, billing, market or government policy updates, changes to services, or other targeted information regarding emergent topics or issues. Feedback from customers may potentially identify service improvements and help develop DERS' change management agenda.

63. In its application, DERS indicated that it expects to carry out a higher level of customer information activities. For 2023, DERS forecasts $224,097 for customer information activities including bill inserts, online surveys and digital information. It intends to focus its customer information on distribution charges, the unknown customer process, and how regulated rates are determined.

64. DERS explained that the need for bill inserts and general communication with customers has increased due to market developments and other customer service related needs in recent years.[55] It added that there was value to undertaking regular customer surveys because it provided a measure of customer satisfaction, which it reports to the Commission as part of

50 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 103.
51 Transcript, Volume 1, page 55, lines 2-12.
52 Transcript, Volume 1, page 128, lines 16-20.
53 Transcript, Volume 1, page 128, lines 20-22.
54 Transcript, Volume 1, page 130, lines 2-8.
55 Exhibit 27631-X0098, InterGroup evidence, PDF page 44.

Rule 003*: Service Quality Reporting for Energy Service Providers*. For digital information, DERS proposed to continue further production of digital information tools, including videos, bill calculators, and other digital projects to better inform customers regarding their energy service.

65. The UCA and InterGroup oppose the customer information forecast for 2023. InterGroup submitted that DERS had not explained the rationale for the bill inserts nor justified the high distribution costs, especially given that the information is already posted on DERS' existing website.[56] Additionally, InterGroup submitted that DERS has not substantiated the survey costs and digital information tools.[57] Due to these concerns, InterGroup recommended that customer information cost for 2023 be approved at the 2020-2022 level of $84,000, in the face of the continuing decline of RRO sites.

66. The Commission views that customer information costs are discretionary, and it is not persuaded that a higher level of customer information activities is warranted given that DERS forecasted declining regulated sites for 2023. Particularly, DERS indicated it has forecast an annual reduction in DRT customer sites of 5.9 per cent and a reduction of 5.7 per cent in RRT customer sites for 2023.[58] In the absence of any submissions that the current level of customer information activities is inadequate to meet service quality standards, the Commission views that the current level of funding to provide and gather information to and from customers is adequate. Accordingly, the Commission approves customer information costs at $84,000 for 2023, consistent with the levels approved for 2020-2022.

4.5 Labour

67. Labour costs are based on the forecast FTEs allocated to DERS and on the forecast labour cost for each position providing direct support to DERS. The forecast labour cost for each position is based on 2022 labour costs inflated by a proposed labour inflation of five per cent.

68. DERS forecast an increase of 2.4 FTEs in 2023 to support its digital functions and customer communication roles.[59] Specifically, DERS indicated that in 2021, a team within the Marketing and Digital department was developed to support website, digital and communications functions.[60] Previously, these types of support were provided by U.S.-based teams when DERS was owned by Centrica, but the cost for those services had never been allocated to DERS. Subsequently in 2021, the acquisition of Direct Energy by NRG triggered a change to DERS' staffing structure, and DERS no longer had access to U.S.-based support for website, digital and communications functions. DERS submitted that it had to develop such support through third-party contractors or internal teams, and ultimately it decided it was more fiscally prudent to staff the roles internally.

4.5.1 Labour inflation

69. DERS indicated that it applied NRG's 2023 forecast labour inflation of five per cent to 2022 base salaries for employees in positions that directly support DERS. It deviated from its traditional methodology of using a three-year average of actual labour increase because including

56 Exhibit 27631-X0098, InterGroup evidence, PDF page 23.
57 Exhibit 27631-X0098, InterGroup evidence, PDF page 23.
58 Exhibit 27631-X0001, application, paragraph 30.
59 Exhibit 27631-X0001, application, paragraph 175. DERS described that it required 45.0 FTEs in 2022 and is forecasting 47.4 FTEs in 2023.
60 Exhibit 27631-X0001, application, Table 5.5.11.1-A: FTEs and Variances 2020 Decision/Actual-2023 Forecast.

the unprecedented zero per cent wage increase from 2020 would result in a value much lower than the expectations for 2023. As part of its application, DERS included independent labour increase forecasts to support the proposed five per cent labour inflation.

70. J. Thygesen provided evidence that criticized the mix of independent labour increase forecasts from Alberta and U.S. sources that DERS put forward. J. Thygesen stated that the Alberta Government's Average Weekly Earnings and wage increases as reported by Statistics Canada that DERS cited are problematic because this data includes variations in hours and positions whereas DERS operates in an environment with regular hours and classifications.[61] J. Thygesen added that these sources are irrelevant as occupational, and upmarket job move increases are incomparable to fixed positions and job compositions.[62] The following passage from Statistics Canada is reproduced from J. Thygesen's evidence:

> Gains in average hourly wages are the result of multiple factors, including wage growth and **changes in the composition of employment by industry and occupation**. In September, wage gains were boosted by year-over year growth in the number of employees **in relatively high-paying industries**, including construction (+109,000; +10.0%) and professional, scientific and technical services (+56,000; +4.4%). Average wages were up 7.5% (+$2.36 to $33.79) in construction and 9.1% in professional, scientific and technical services (+$3.42 to $40.98) in September, with gains in the latter industry exceeding 7% in six provinces (not seasonally adjusted).[63] [emphasis in original]

71. J. Thygesen stated that DERS provided minimal evidence demonstrating the mix of its labour force was changing, and therefore, the factors leading to the high increases that are the drivers of the comparators do not apply.[64]

72. As an alternative option, J. Thygesen proposed using actual negotiated wage settlements in Alberta. These settlements averaged two per cent in 2023 and 1.07 per cent in 2024 based on finalized settlements. According to J. Thygesen, two per cent for labour inflation increases is the appropriate labour inflation rate for DERS.

73. In rebuttal, DERS submitted that J. Thygesen's evidence relied on wage settlements for unionized employees, which is not applicable because DERS does not have unionized employees. In contrast to J. Thygesen, DERS considered the cited passage from Statistics Canada to be on point because the "professional, scientific and technical services" industry classification is a classification within which DERS competes for talent. DERS maintained that while wage growth in Alberta has been lower than the national average, as suggested by J. Thygesen, the Business Council of Alberta highlighted that "professional, scientific and technical services, have been industries where strong wage growth kept pace with the national average."[65]

74. DERS referred to remarks from sources including the Royal Bank of Canada and the Business Council of Alberta,[66] whose consensus was that Alberta will continue to see economic growth in 2023. DERS argued that in addition to increasing wage pressures, the annual inflation

61 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 56.
62 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 58.
63 Exhibit 27631-X0099.01, Thygesen evidence, paragraph 57.
64 Exhibit 27631-X0099.01, paragraph 58.
65 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 81.
66 Exhibit 27631-X0122, DERS rebuttal evidence, paragraphs 77-78.

rate in Alberta in 2022 was 6.5 per cent, and that mortgage qualification challenges and house prices in Calgary are on the rise.[67]

75. The Commission agrees with DERS that it is not sensible to use the traditional methodology of using a three-year average of actual labour increase to forecast labour increase for 2023 because the zero per cent wage increase in 2020 would skew the average.

76. The Commission notes that DERS provided references to support a labour increase,[68] but it did not answer the UCA's IR to fully explain how NRG's forecast labour inflation was derived.[69] Without understanding how NRG's forecast labour inflation was calculated, the Commission determines that there is insufficient support for a five per cent labour increase.

77. The Commission is not convinced that proposed labour inflation increases from the CCA are reasonable either given that unionized wage settlements, even in the Alberta context, are not practical comparators for DERS. The Commission is of the view that local, non-union comparisons should be used for DERS. Therefore, it gives weight to Alberta sources. From the list of salary headlines and sources that DERS provided,[70] the Commission considers the Average Weekly Earnings and ATB's summary of 2022 increases relevant to the calculation of the labour increase for DERS.

78. Taking the average of the rest of the data from the Average Weekly Earnings and ATB,[71] the Commission calculates three per cent for labour increase. Accordingly, the Commission directs DERS to incorporate a three per cent labour inflation into its labour forecast in its compliance filing.

4.5.2 Digital and Marketing team

79. DERS' Digital and Marketing department is a new department that started in 2021 with FTEs allocated to two positions, namely Digital Management managers and Digital Management analysts.[72] The team grew to include FTEs for other positions in 2022, and DERS requested to expand its team to approximately 6.1 FTEs for 2023.

80. DERS indicated that approximately six FTEs from the U.S. provided support to DERS prior to the transition to NRG.[73] Further, DERS confirmed that there was no increase in workload leading to the incremental increase in FTEs, and that the FTE increase is to continue the gradual transition of FTEs to the Direct Energy Alberta team for allocation to DERS.[74]

81. J. Thygesen objected to the incremental FTE increase by presenting evidence that detailed that DERS had already applied for two manager positions for marketing and digital

67 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 82.
68 Exhibit 27631-X0016, Attachment 15 - References for salary increases, and Exhibit 27631-X0081, Attachment DERS-UCA-2022OCT28-002
69 Exhibit 27631-X0080, DERS-UCA-2022OCT28-002(d).
70 Exhibit 27631-X0016, Attachment 15 - References for salary increases, and Exhibit 27631-X0081, Attachment DERS-UCA-2022OCT28-002.
71 Average of 3.2% (March 2022), 3.7% (June 2022), 2.2% (August 2022) from the Average Weekly Earnings and 3% (August 2022) from ATB = 3.0%.
72 Exhibit 27631-X0003.01, worksheet 5.2.9 FTE Detail (DRT & RRT), Excel cells E23 and E24.
73 Exhibit 27631-X0065, DERS-AUC-2022OCT19-032(a).
74 Exhibit 27631-X0065, DERS-AUC-2022OCT19-032(b) and (c).

functions in the revenue requirement for 2021 and 2022.[75] According to J. Thygesen, the FTE increase for 2023 has already been captured as part of negotiations from the previous non-energy application for DERS' Regulated Commercial department. J. Thygesen inferred that there is a minimum of $400,000 overstatement of labour costs in the current application.[76]

82. InterGroup submitted that DERS failed to provide the requisite background on why digital and marketing functions are required for the DRT and RRT, nor why these functions were provided without a cost allocation to DERS from its previous U.S.-based parent company.[77] InterGroup expressed concerns that the Digital and Marketing team is the largest driver of the resulting labour costs, and that it is highly questionable whether the 6.1 FTE positions are primarily involved in the marketing tied to competitive functions rather than regulated services.[78] Meanwhile, the UCA noted that the expert report on NRG Corporate Shared Services already list website services as one of the items provided by NRG IT.[79]

83. DERS refuted J. Thygesen's evidence and stated that the increase to the Digital and Marketing team has been partially offset by other reductions.[80] DERS explained that one of the manager positions was previously part of the Alberta Regulated Business team, and that the position was included as part of the Digital and Marketing group in the 2021 actuals. DERS argued that any pre-existing FTEs in the Digital and Marketing group would not be reflected as incremental nor would there be an overstatement of labour costs.[81]

84. Similarly, DERS rebutted InterGroup's evidence and submitted that the UCA and its expert were too focused on the word "marketing" and was likely conflating the term "marketing" with "advertising."[82] DERS adopted the definition of " 'marketing research' to include using information to define opportunities and problems; generate, refine and evaluate actions; monitor performance; and improve understanding of it as a process."[83] To illustrate that development of information or communication content is constant and dynamic, DERS identified areas of focus from 2021 and 2022 to include managing communication regarding policy changes, development of bill inserts, website updates, emails and mail to DERS' customers, and internal communication management.[84]

85. Additionally, DERS presented evidence to demonstrate that the website services provided by the IT DEH Digital[85] cost centre are unrelated to the functions provided by DERS' Digital and Marketing FTEs.[86]

86. The UCA argued that DERS provided inconsistent explanations for the increase in FTEs. The UCA added that while DERS suggested the increase in FTEs is driven by functions previously performed by its parents, at the same time, DERS also suggested that the Digital and

75 Exhibit 27631-X0099.01, Thygesen evidence, paragraphs 64-67.
76 Exhibit 27631-X0099.01, Thygesen evidence, paragraphs 68-69.
77 Exhibit 27631-X0098, Intergroup evidence, PDF page 21.
78 Exhibit 27631-X0098, Intergroup evidence, PDF pages 21 and 23.
79 Exhibit 27631-X0098, Intergroup evidence, PDF page 21.
80 Exhibit 27631-X0001, application, paragraph 178.
81 Exhibit 27631-X0122, Thygesen evidence, paragraphs 66-67.
82 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 85.
83 Exhibit 27631- X0122, DERS rebuttal evidence, paragraph 85.
84 Exhibit 27631- X0122, DERS rebuttal evidence, paragraph 87(i) to (v).
85 The Commission understands DEH to be Direct Energy US Holdings Inc.
86 Exhibit 27631-X0122, DERS rebuttal evidence, paragraph 89-90.

Marketing team will provide new communications and functionality.[87] More importantly, the UCA and InterGroup questioned the prudence of an internal marketing team for a regulated service provider under the backdrop of declining RRO customer sites. Notwithstanding its concerns on the utilization of digital and marketing functions for the RRO, the UCA recommended a range of FTEs for the Commission to consider. The UCA stated that either zero or at most a nominal allocation of the 6.1 FTEs in the digital and marketing functions should be allocated to DERS.[88]

87. For the reasons below, the Commission denies a net increase of 2.4 FTEs to DERS.

88. Without a comparable Digital and Marketing group in DERS' 2020-2022 non-energy decision the Commission finds it difficult to ascertain how much of the digital and marketing support functions were embedded into the Alberta Regulated Business team. In general, DERS' application lacks a clear explanation of FTEs shifts and department changes. However, the more important question for the Commission is whether incremental resources are necessary to provide default service to regulated customers.

89. The Commission is unconvinced that DERS' parent company would provide approximately six FTEs to support digital and marketing functions without a cost allocation to DERS. Given that DERS is projecting continued decreases in both the DRT and RRT regulated sites for 2023, the Commission views that DERS has adequate support in the Digital and Marketing team to carry on the duties described in DERS' application. Accordingly, the Commission denies the request for 2.4 incremental FTEs to support the Digital and Marketing team.

90. Further, the Commission notes that there is a causal link between increased customer information activities and growth of the marketing and digital functions team. Maintaining the same level of customer information activities would not justify further growth in the marketing and digital functions. As the Commission noted earlier, a continuous decline of regulated sites is expected in 2023. Coupled with the effects of high inflation and affordability concerns, pausing the growth of digital and marking functions in a regulated environment is prudent particularly given that these supports were previously provided at no cost to DERS.

4.5.3 Analysis of salary actuals

91. In a response to a Commission IR, DERS provided total remuneration details and components of labour costs including base salaries, benefits and short-term incentives.[89] The Commission finds the details of the composition of total remuneration to be helpful in understanding year-to-year labour variances. For the compliance and future non-energy applications, the Commission directs DERS to file similar total remuneration details.

4.6 Bad debt

92. In this proceeding, there are two significant issues to address with respect to bad debt. First, the Commission needs to decide what methodology should be used to determine the 2023 forecasts for the two components that comprise the total bad debt expense for the DRT and the RRT. Second, it needs to decide whether a deferral account should be established, and if it

[87] Transcript, Volume 1, page 131, lines 23-25, and page 132, lines 1-4.
[88] Transcript, Volume 1, page 132, lines 5-25.
[89] Exhibit 27631-X0066, Attachment to DERS-AUC-2022OCT19-005.

determines that a deferral account should be established, what the mechanism is for how the deferral account will function.

4.6.1 Total bad debt expense

93. DERS' total bad debt expense for the DRT and the RRT consists of two components: (i) bad debt relating to billed amounts that are not collected from customers (bad debt); and (ii) the cost of commissions paid to external collection agencies (collection agency costs).

94. DERS forecast the bad debt component for 2023 as a percentage of total revenue, with the percentages used in calculating the forecast amounts for the DRT and the RRT being are the average of the corresponding percentages for the 2020 and 2021 actuals, and for the year-to-date actuals to July 2022.[90] DERS forecast the collection agency costs component for 2023 as a percentage of total revenue, with the percentage used in calculating the forecast amounts being the average of the corresponding percentages for the 2017, 2018 and 2019 actuals.[91]

95. DERS' total bad debt expense forecast amounts for 2023 are $14.131 million for the DRT[92] and $6.349 million for the RRT,[93] which results in a combined DRT/RRT total of $20.48 million. The resulting percentages of total revenues used for the bed debt component are 1.09 per cent for the DRT and 2.09 per cent for the RRT.[94] The resulting percentages of total revenues used for the collection agency costs component are 0.17 per cent for the DRT and 0.16 per cent for the RRT.[95]

96. J. Thygesen presented an analysis described as "Bad Debt as a Percentage of Revenue Table" for the DRT and the RRT, for 2012 to September 2022.[96] He submitted that there is a downtrend in averages in that the most recent one-year experience is lower than the average for 2019-September 2022. J. Thygesen stated that this suggests that the bad debt experience may be reverting to long-term norms.[97] J. Thygesen recalculated his analysis based on feedback from DERS.[98] The recalculated forecast percentages for 2023 are 0.92 per cent for the DRT and 1.71 per cent for the RRT, for a resulting total bad debt expense forecast of $10.340 million[99] for

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90 Exhibit 27631-X0065, IR response to DERS-AUC-2022OCT19-029(a), and Exhibit 27631-X0077, Attachment DERS-AUC-2022OCT19-029 - BD LPC RO [bad debt, late payment charge, revenue offsets].

91 Exhibit 27631-X0001, application, paragraph 138. Exhibit 27631-X0002.01, 2023 DRT revenue requirements, worksheet "5.1.12 DRT BD PR RO," Excel cell O33. Exhibit 27631-X0003.01, 2023 RRT revenue requirements, worksheet "5.2.12 RRT BD PR RO," Excel cell O30.

92 This consists of $12.238 million of bad debt and $1.893 million for collection agency costs, as included in Exhibit 27631-X0002.01, 2023 DRT revenue requirements, worksheet "5.1.12 DRT BD PR RO," Excel cells O21 and O27.

93 This consists of $5.886 million of bad debt and $0.463 million for collection agency costs, as included in Exhibit 27631-X0003.01, 2023 RRT revenue requirements, worksheet "5.2.12 RRT BD PR RO," Excel cells O21 and O25.

94 Exhibit 27631-X0002.01, 2023 DRT revenue requirements, worksheet "5.1.12 DRT BD PR RO," Excel cell O32. Exhibit 27631-X0003.01, 2023 RRT revenue requirements, worksheet "5.2.12 RRT BD PR RO," Excel cell O29.

95 Exhibit 27631-X0002.01, 2023 DRT revenue requirements, worksheet '5.1.12 DRT BD PR RO', Excel cell O33. Exhibit 27631-X0003.01, 2023 RRT revenue requirements, worksheet '5.2.12 RRT BD PR RO', Excel cell O30.

96 Exhibit 27631-X0100, attachment to evidence of Jan Thygesen.

97 Exhibit 27631-X0099.01, evidence of Jan Thygesen, PDF page 7, paragraph 18.

98 Exhibit 27631-X0110, response to CCA-DERS-2022DEC21-006(a), PDF page 16.

99 Based on forecast DRT revenues of $1,120.562 million, as shown in Exhibit 27631-X0110, response to CCA-DERS-2022DEC21-006(a), PDF page 16.

the DRT and $4.826 million[100] for the RRT, with a combined total of $15.167 million.[101] DERS analyzed J. Thygesen's revised bad debt percentages of revenue for the DRT and the RRT, and identified additional errors and inconsistencies.[102]

97. InterGroup noted that DERS' total bad debt expense forecasts for 2021 and 2022 in the 2020-2022 DRT and RRT application in Proceeding 26207 were $32.710 million and $25.970 million, respectively, and there was no deferral account requested. InterGroup indicated that during the interrogatory process for Proceeding 26207, DERS provided an updated forecast for 2021 and 2022 to incorporate the 2020 actuals, and the resulting forecasts prior to negotiations were $25.072 million and $21.062 million, respectively, with no deferral account requested. It noted that in the NSA, the agreed-upon forecasts for 2021 and 2022 were $18.572 million and $14.562 million, respectively, that these amounts were $6.5 million less than the updated forecasts of $25.072 million and $21.062 million, and that a deferral account mechanism had been agreed upon.[103]

98. InterGroup recommended that the combined DRT/RRT total bad debt expense forecast amount for 2023 be set at $13.98 million, which is $6.5 million less than DERS' forecast of $20.48 million.[104]

99. DERS indicated that it had not incorporated additional risk into the 2023 bad debt forecast as it had in the preparation of the 2020-2022 bad debt forecast, because DERS was fully aware that it would be proposing the continuation of the deferral account in the 2023 application. DERS submitted that the $6.5 million reduction identified by InterGroup as an improvement for 2021 and 2022 was solely a product of the NSA and was only part of the agreement that was approved by the Commission as an entire package.[105]

100. The Commission agrees with the analysis put forward by DERS[106] that J. Thygesen's revised forecast included additional errors and inconsistencies. Therefore, the Commission finds that the revised forecast percentages and associated total bad debt expense forecasts provided by J. Thygesen in Exhibit 27631-X0110[107] are not helpful in establishing the forecast percentages of revenue for bad debt and collection agency costs, and are also not helpful in establishing the associated total bad debt expense forecasts.

101. InterGroup, in its evidence, did not present an analysis of the percentage of revenue methodology used by DERS. It recommended that the combined DRT/RRT total bad debt expense forecast of $20.48 million be reduced by $6.5 million, to $13.98 million. The Commission notes that the recommended $6.5 million reduction was drawn from the reduction agreed to as part of the 2020-2022 NSA. While DERS may have agreed to a $6.5 million reduction as part of the 2020-2022 NSA, this was part of an overall settlement package.

100 Based on forecast RRT revenues of $282.026 million, as shown in Exhibit 27631-X0110, response to CCA-DERS-2022DEC21-006(a), PDF page 16.
101 Exhibit 27631-X0110, response to CCA-DERS-2022DEC21-006(a), PDF page 16. The combined total is different than the sum of the two numbers preceding it because of rounding.
102 The analysis is included in Exhibit 27631-X0122, DERS' rebuttal evidence, PDF pages 9-15, paragraphs 10-22.
103 Exhibit 27631-X0098, UCA's evidence, PDF page 17.
104 Exhibit 27631-X0098, UCA's evidence, PDF page 19.
105 Exhibit 27631-X0122, DERS' rebuttal evidence, PDF page 16, paragraph 25.
106 Exhibit 27631-X0122, DERS' rebuttal evidence, PDF pages 9-15, paragraphs 10-22.
107 In the response to CCA-DERS-2022DEC21-006(a), PDF page 16.

The Commission finds that Intergroup's recommended $6.5 million reduction therefore lacks evidentiary support.

102. InterGroup did comment on DERS' percentage of revenue methodology for the bad debt component, as part of its information responses. It stated that the percentage of revenue for 2020 should not be used in the calculation of the percentage for 2023, because it was not a normal year. InterGroup noted that when the bad debt component for 2023 is forecast using the average of the percentages of revenue for the 2018, 2019 and 2021 actuals, the resulting combined DRT/RRT total bad debt expense forecast for 2023 would be $14.100 million.[108]

103. Considering the Commission's rejections above of J. Thygesen's and InterGroup's recommendations for the combined DRT/RRT total bad debt expense forecast for 2023, the Commission finds that the percentage of revenue methodology is the only viable methodology presented during the proceeding to forecast the bad debt component.[109] What is clear from the evidence is that the economic volatility associated with the COVID-19 pandemic also created significant volatility in the 2020 and 2021 yearly numbers for bad debt expense. Consequently, the Commission rejects the use of any percentage of revenue figures for 2020 and 2021 in determining the forecast bad debt expense component for 2023.

104. DERS used the average of the actual 2020, 2021 and year to date July 2022 bad debt expense as a percentage of the revenues for those years to arrive at the 1.09 per cent forecast percentage for the DRT and the 2.09 per cent forecast percentage for the RRT. It explained why it chose to use this data.[110]

105. The Commission finds that the use of the averages for 2020, 2021 and year to date July 2022 do not form an acceptable basis upon which to base the forecast percentages for the 2023 bad debt component for the DRT and the RRT. The Commission considers that over the course of 2020 and 2021, the COVID-19 pandemic, the subsequent implementation of the utility payment deferral program, the disallowance of the charging of late payment penalties and its subsequent reinstatement, and the suspension of disconnection activities and its later reinstatement, resulted in the bad debt data for these years not being a reasonable predictor of what the bad debt expense will be for 2023,.[111] While actual year to date percentages may be reflective of what the actual full year percentages will be, no analysis has been presented which demonstrates that this is the case. In addition, year to date actuals may not reflect the bad debt activities that take place at different times during a year, such as an increase in collection activity in advance of the seasonal ban on disconnections. Consequently, the Commission considers that full year actual percentages should be used as the basis for the forecasts.

106. It is evident that the resulting actual bad debt percentages of revenue for 2020 and 2021 for the DRT of 1.76 per cent and 0.39 per cent, respectively, are outliers when compared to the 2017-2019 actual percentages of 1.12 per cent, 0.92 per cent and 0.74 per cent respectively.[112] The same situation holds true for the RRT, where the actual 2020 and 2021 percentages were

108 Exhibit 27631-X0114, response to UCA-DERS-2022DEC21-004(e), PDF pages 14-15.
109 As outlined below, while the Commission accepts this methodology, it disagreed with DERS' submissions regarding the years that should be used to calculate the percentage of revenue.
110 Exhibit 27631-X0001, application, PDF pages 58-61, paragraphs 128-135.
111 Exhibit 27631-X0001, application, PDF pages 58-60, paragraphs 128-131.
112 Exhibit 27631-X0002.01, 2023 DRT revenue requirements, worksheet "5.1.12 DRT BD PR RO."

3.26 per cent and 0.96 per cent, respectively, compared to the 2017-2019 actual percentages of 2.34 per cent, 1.76 per cent and 1.62 per cent, respectively.[113]

107. The Commission finds that the average of the corresponding actual bad debt expense as a percentage of revenue for the years 2017-2019 should be used to forecast the bad debt component for the DRT and the RRT for 2023. Using the percentages reported above,[114] this results in an average of 0.93 per cent for the DRT and 1.91 per cent for the RRT, and the Commission directs DERS to use these percentages in the compliance filing when forecasting the bad debt component of the total bad debt expenses for 2023.

108. With regard to collection agency costs, DERS used the average of the actual 2017, 2018 and 2019 collection agency costs as a percentage of the revenues for those years to arrive at the 0.17 per cent forecast percentage for the DRT and the 0.16 per cent forecast percentage for the RRT. It explained why it chose to use these three years and not use information for 2020 and 2021.[115] The Commission considers that the explanation provided by DERS, which describes that collection actions were suspended or limited for periods in 2020 and 2021, justifies why the percentages for 2020 and 2021 should not be used. The Commission approves the 0.17 per cent of revenues forecast percentage for the DRT for 2023, for forecasting the collection agency costs component of the total bad debt expense forecast, and the Commission directs DERS to use this percentage in its compliance filing. The Commission also approves the 0.16 per cent of revenues forecast percentage for the RRT for 2023, for forecasting the collection agency costs component of the total bad debt expense forecast, and the Commission directs DERS to use this percentage in its compliance filing.

4.6.2 Bad debt deferral account

109. DERS submitted that bad debt forecasts are always somewhat uncertain given the significant impact that factors outside of DERS' control can have on bad debt results, and that the potential for actuals that are vastly different than the forecast continue to pose risks to DERS and to customers. Accordingly, DERS requested that the DRT and RRT total bad debt expense forecasts for 2023 be subject to asymmetrical deferral treatment.[116] DERS indicated that this request to continue with asymmetrical deferral account treatment for bad debt in 2023 is similar to what was approved as part of the 2020-2022 NSA in Decision 26207-D01-2021.[117]

110. The specifics of DERS' requested bad debt deferral account are as follows: (i) If the actual combined DRT/RRT total bad debt expense for 2023 is greater than the Commission-approved forecast, 100 per cent of the difference is captured in the deferral account and will be subsequently recovered from customers. (ii) If the actual combined DRT/RRT total bad debt expense for 2023 is less than the Commission-approved forecast, 75 per cent of the difference is captured in the deferral account and will be subsequently refunded to customers.[118]

111. The CCA submitted that if the Commission does approve the total bad debt expense forecast amounts requested by DERS, it would support a bad debt deferral account with no

113 Exhibit 27631-X0003.01, 2023 RRT revenue requirements, worksheet "5.2.12 RRT BD PR RO."
114 For the DRT: 1.12 per cent for 2017, 0.92 per cent for 2018 and 0.74 per cent for 2019. For the RRT: 2.34 per cent for 2017, 1.76 per cent for 2018 and 1.62 per cent for 2019.
115 Exhibit 27631-X0001, application, PDF page 62, paragraph 138.
116 Exhibit 27631-X0001, application, PDF page 56, paragraph 123.
117 Exhibit 27631-X0001, application, PDF page 56, paragraph 123.
118 Exhibit 27631-X0001, application, PDF page 57, paragraph 125.

asymmetrical customer impact. The CCA stated that if the Commission approves the revised $15.2 million forecast calculated by J. Thygesen, or the UCA's forecast for bad debts, then the CCA would accept the asymmetrical sharing deferral account proposed by DERS.[119]

112. InterGroup submitted that the bad debt deferral account requested by DERS in this proceeding does not function exactly the same as the bad debt deferral account for 2021 and 2022 approved as part of the 2020-2022 NSA in Decision 26207-D01-2021.[120]

113. InterGroup stated that the bad debt deferral account for 2023 requested by DERS should be expressly rejected. It submitted that there is no reduction incorporated into DERS' combined total bad debt expense forecast amount of $20.48 million, unlike the $6.5 million reduction incorporated into the forecasts for 2021 and 2022. InterGroup indicated that DERS has eliminated any cost sharing when the actual total bad debt expense exceeds the forecast of $20.48 million. It noted that it appears DERS intends to apply the incentives individually to the DRT and the RRT, and this could benefit DERS. It explained that, as an example, if the combined DRT/RRT total bad debt expense actuals for 2023 was $20.48 million, being the same as the forecast, with the total actual DRT expense being lower by a million and the total actual RRT expense being greater by a million, DERS would receive 25 per cent of the million dollar savings on the DRT side, and would collect 100 per cent of the million dollar excess on the RRT side from customers.[121]

114. InterGroup recommended that the bad debt deferral account mechanism adopted in the 2020-2022 NSA be continued for 2023, with the following parameters: (i) set the combined DRT/RRT total bad debt expense forecast amount for 2023 at $13.98 million, which is $6.5 million less than DERS' forecast of $20.48 million; (ii) establish the upper bound of the full deferral zone at $20.48 million; and (iii) maintain the 25 per cent/75 per cent DERS/customer sharing for actual bad debt below the forecast of $13.98 million and maintain the equal sharing for the difference between actual bad debts and the upper bound of $20.48 million.[122]

115. In response to InterGroup's comment that DERS intends to apply the incentives in the bad debt deferral account individually to the DRT and the RRT, DERS pointed out that the illustrative bad debt deferral account model presented in Exhibit 27631-X0021.01 is the same format and design as the existing bad debt deferral account agreed to in the NSA, and is consistent with DERS' approach to submit separate revenue requirements and rates for the DRT and RRT businesses.[123]

116. The Commission finds that a deferral account should be established; however, it rejects the deferral account mechanism proposed by DERS and the deferral account mechanism proposed by the UCA.

117. Having regard to the evidence in this proceeding, the Commission finds that for the 2023 year, the fairest deferral account mechanism for the total bad debt expense for the DRT and the RRT is the traditional deferral account mechanism. If the actual costs exceed the approved forecast, the difference is collected from customers; if the actual costs are less than the approved

119 Transcript, Volume 1, page 96, lines 7-14.
120 Exhibit 27631-X0098, UCA's evidence, PDF pages 17-19.
121 Exhibit 27631-X0098, UCA's evidence, PDF pages 18-19.
122 Exhibit 27631-X0098, UCA's evidence, PDF page 19.
123 Exhibit 27631-X0122, DERS' rebuttal evidence, PDF page 17, paragraphs 28-29.

forecast, the difference is refunded to customers. This is commonly referred to as a symmetrical deferral account. The Commission directs that in order to prevent any cross-subsidies between DRT and RRT customers, separate total bad debt expense deferral accounts be established; one for the DRT and one for the RRT, and each one be accounted for separately. The balance in the DRT total bad debt expense deferral account will be settled with DRT customers and the balance in the RRT total bad debt expense deferral account will be settled with RRT customers.

118. The Commission considers that the traditional deferral account is fair to both DERS and its customers, particularly in circumstances where there has been recent volatility in bad debt expenses, and where there is some uncertainty regarding these expenses going forward. While it eliminates any additional incentive for DERS to manage its bad debt expenses, the Commission notes DERS' submission that in any year, its bad debt results are mainly driven by the willingness and ability of its customers to pay their bills, and that while DERS has some influence over customers' willingness to pay, it has little or no influence over customers' ability to pay.[124]

119. The Commission considers that commodity prices will ultimately have an impact on bad debt expenses. If actual commodity costs are much lower than the forecast commodity costs used to establish the forecast revenues, the actual bad debt expense by extension is expected to be much lower than the forecast bad debt expense, all else being equal. If the deferral account had an incentive for DERS to receive some of the savings that resulted from the actuals being lower than forecast, and the actuals were lower but primarily from lower commodity costs that DERS has no control over, DERS would benefit from circumstances out of its control, and not from managing its bad debt.

120. The same situation would exist if the deferral account had a ceiling above which DERS had to bear a percentage of the difference between the actual total bad debt expense and the forecast ceiling amount. In that case, if actual commodity costs, revenues and the resulting bad debt were significantly higher than the forecast amounts, DERS would be penalized for circumstances out of its control.

121. The mechanisms proposed by DERS and the UCA each have incentives for DERS if the actuals are lower than the forecast, which the Commission considers unfair because DERS cannot fully manage what the actuals will be. In addition, as explained previously, the mechanism proposed by the UCA is based on a combined DRT/RRT total bad debt expense forecast of $13.98 million that the Commission rejected.

4.7 Late payment charge deferral account and disposition of bad debt expense and late payment charge deferral accounts

122. DERS applied to continue with deferral account treatment for late payment charge revenue in 2023, the same as what was included in the 2020-2022 NSA and subsequently approved in Decision 26207-D01-2021. It stated that the late payment charge deferral account will act as a conventional deferral account and will capture 100 per cent of the difference between the approved forecasts and actuals in 2023.[125]

[124] Exhibit 27631-X0001, application, PDF page 60, paragraph 132.
[125] Exhibit 27631-X0001, application, PDF page 62, paragraph 141.

123. DERS proposed that it would combine the balances in the bad debt deferral account and the late payment charge deferral account, and would charge interest at a rate determined in accordance with Rule 023: *Rules Respecting Payment of Interest*, provided that the combined balance is greater than $5 million. It indicated that in order to dispose of the combined balances and applicable interest, it would either file a separate application or include it as part of its next RRO non-energy application.[126]

124. The CCA and the UCA did not comment on DERS' proposed late payment charge deferral account. The Commission finds that a deferral account should be established, as supported by DERS' reasons for requesting the deferral account.[127] While DERS indicated that the late payment charge deferral account it was applying for was the same as what was included in the 2020-2022 NSA and subsequently approved in Decision 26207-D01-2021, the Commission finds that is not the case. The deferral account in the 2020-2022 NSA was based on the combined DRT/RRT late payment charge forecasts, whereas in the illustrative model DERS presented for 2023,[128] the deferral accounts are separately calculated for the DRT and the RRT. To prevent any cross-subsidies between DRT and RRT customers, the Commission directs that separate late payment charge deferral accounts be established, as shown in the illustrative model[129] – one for the DRT and one for the RRT, with each one accounted for separately. The balance in the DRT late payment charge deferral account will be settled with DRT customers and the balance in the RRT late payment charge deferral account will be settled with RRT customers.

125. The Commission approves DERS' proposal to combine the balances in the DRT bad debt expense deferral account and the DRT late payment charge deferral account; and to combine the balances in the RRT bad debt expense deferral account and the RRT late payment charge deferral account, and to file a request to dispose of the combined balances, because this promotes regulatory efficiency. To further promote regulatory efficiency, the Commission directs that DERS include the request to dispose of the deferral account balances as part of its next RRO non-energy application, as opposed to filing a separate application, unless the next RRO non-energy application (that would include 2024 as part of the test years) has already been filed by the time DERS is ready to apply to dispose of the deferral account balances. In that case, the Commission directs DERS to file a separate application to dispose of the deferral account balances.

126. The Commission does not approve DERS' proposal to apply interest at a rate determined in accordance with Rule 023, provided that the combined balance is greater than $5 million. Other than indicating that the $5 million threshold was included in the 2020-2022 NSA,[130] DERS provided no justification for selecting a balance of $5 million, which is much greater than the $1 million minimum balance set out in Rule 023. The Commission considers that the issue of whether interest should be applied to the deferral account balances would be best addressed as part of DERS' request to dispose of the deferral account balances, because then all interested parties would be aware of what the deferral account balances are and would be able to comment on whether Rule 023 should apply.

[126] Exhibit 27631-X0001, application, PDF page 64, paragraph 146.
[127] Exhibit 27631-X0001, application, PDF pages 62-64, paragraphs 140-144.
[128] In Exhibit 27631-X0021.01.
[129] In Exhibit 27631-X0021.01.
[130] Exhibit 27631-X0065, response to DERS-AUC-2022OCT19-014, PDF page 22.

4.8 ATCO System Change

127. ATCO Electric Ltd. and ATCO Gas (ATCO Utilities) is migrating onto a new customer information system. While the migration was to be completed at the end of 2022 or early 2023, the go-live date has been delayed. The reason for this delay is explained in Section 4.8.1.

128. DERS submitted that ATCO Utilities' new customer information system has an impact on its own system changes, manual billing-related exception handling, agent training and customer communications. The impacts on DERS' operations were assessed based on its experience with a previous system change carried out by ATCO Gas related to the realignment of its gas meter reading routes in 2018. DERS submitted it incurred $1.2 million in costs to manage the ATCO Gas Cycle change.

129. Under the change management category, DERS created a project called ATCO System Change to track costs in mitigating the effects of ATCO Utilities' new customer information system. For 2023, DERS estimated that $1.305 million is required to manage the changes associated with the ATCO System Change. Additionally, DERS stated these change management costs are the predominant reason for the increase from the 2022 forecast to the 2023 customer operations forecast.[131]

4.8.1 Updated request on ATCO System Change

130. In response to a Commission IR, DERS revised its estimate from $1.305 million to $1.6 million.[132] However, DERS noted that the costs could be lower or much higher than DERS' estimate depending on the success of ATCO Utilities' migration. Because of the uncertainty in costs, DERS proposed to create a deferral account for ATCO System Change costs, and to include any true-up amounts with its bad debt and late payment charge deferral true-up filing.[133]

131. On behalf of the UCA, InterGroup agrees that ATCO System Change costs are best included in a deferral account. However, it differs from DERS in that it recommended the revenue requirement forecast to be set at $1.2 million based on the actual costs incurred by DERS during the 2018 ATCO Gas Cycle Change.[134] Under this recommendation, InterGroup noted that DERS' 2023 overall customer operations expense should be set at $39.809 million, as compared to the DERS requested $40.209 million.[135]

132. There remains uncertainty with respect to how Proceeding 27657[136] will affect the ATCO System Change costs. Given the difficulty in accurately forecasting the impacts of the ATCO System change, the Commission is of the view that deferral account treatment is warranted.

133. In weighing DERS' forecast and InterGroup's recommendation to use actuals from the 2018 ATCO Gas Cycle Change Project, the Commission places more weight on the latter. The actuals from the ATCO Gas Cycle Change Project should inform the best estimate for the ATCO System Change Project forecast. Accordingly, the Commission approves $1.2 million for the revenue requirement forecast on the ATCO System Change project and DERS' proposal to

131 Exhibit 27631-X0001, application, paragraph 59.
132 Exhibit 27631-X0065, DERS-AUC-2022OCT19-016 (a) – (c), including Table DERS-AUC02022OCT19-016.
133 Exhibit 27631-X0065, IR response to DERS-AUC-2022OCT19-016 (a) – (c) and Exhibit 27631-X0074, attachment to IR response to DERS-AUC-2022OCT19-016 Updated deferral account model.
134 Exhibit 27631-X0098, InterGroup evidence, PDF page 8.
135 Exhibit 27631-X0098, InterGroup evidence, PDF page 7.
136 Proceeding 27657, DERS request for Enforcement of AUC Rule 004 on ATCO.

include any true-up amounts with DERS' bad debt and late payment charge deferral true-up filing.

4.9 Hearing cost reserve

134. Under Rule 022*: Rules on Costs in Utility Rate Proceedings,* the Commission may award costs for parties' participation in regulatory proceedings. When regulatory costs are awarded by the Commission through its cost claim process, DERS pays the awarded costs and the amounts are recorded in the applicable DRT or RRT hearing cost reserve account.

135. As part of its DRT and RRT non-energy revenue requirements, DERS includes (i) a forecast for the opening balance in the hearing cost reserve accounts; (ii) a forecast for the regulatory costs it expects to pay out over the test period (allocated 50/50 between DRT and RRT, unless the regulatory costs can be fully attributed to either a DRT matter or an RRT matter); and (iii) the resulting amount it will recover through rates during the test period in order for the estimated balance in the hearing cost reserve accounts to be zero at the end of the test period. The resulting recovery of amounts through rates for each year are described on the revenue requirement schedules as "hearing reserve."

136. The hearing cost reserve accounts are trued-up in the subsequent DRT and RRT non-energy revenue requirements to account for the actual regulatory cost amounts that are approved by the Commission. DERS requested permission to continue the hearing cost reserve accounts for the DRT and the RRT for 2023. The forecast 2023 hearing reserve costs are $0.311 million for the DRT and $0.142 million for the RRT.

137. On behalf of the UCA, InterGroup presented evidence that DERS has a history of over-forecasting hearing costs. InterGroup stated that DERS' 2022 initial forecast of $0.410 million (which includes costs for the 2023 DRT and RRT application) was well over double the costs of the negotiated 2020-2022 proceeding, and that DERS' updated 2022 forecast of $0.338 million still represents a more than doubling of the estimated hearing cost from 2021 that covered three fiscal years.[137]

138. In terms of recoveries, InterGroup noted that the negotiated settlement in Proceeding 26207 provided for recoveries that were excessive for 2021 and 2022, which resulted in funding available in 2022 to offset the majority of the forecast costs for the current proceeding, leaving only a remaining forecast balance of $0.104 million at year end 2022.[138] Additionally, InterGroup noted that DERS had not provided support for its $0.349 million forecast spending in 2023 related to the 2024 to 2025 DRT and RRT application.

139. Before the UCA evidence from InterGroup was filed, DERS indicated that the costs for the 2024-2025 DRT and RRT application is based on the costs for the current application plus inflation.[139] DERS did not address InterGroup's recommendation to exclude 2024 and 2025 costs in rebuttal evidence but it did argue that hearing reserve costs are subject to deferral account treatment and that there is no reason that DERS should vary from past practice and put current hearing costs onto future customers.[140]

137 Exhibit 27631-X0098, InterGroup evidence, PDF page 14.
138 Exhibit 27631-X0098, InterGroup evidence, PDF page 15.
139 Exhibit 27631-X0065, DERS-AUC-2022OCT19-026.
140 Transcript, Volume 1, page 50, lines 15-18.

140. In addition to the view that DERS' 2022 forecast is speculative, the UCA and InterGroup view that the inclusion of forecast hearing costs in 2023 associated with the 2024 to 2025 DRT and RRT application goes against good regulatory practice. Subsequently, the UCA and InterGroup recommended approval of $0.104 million for the DRT and RRT hearing cost reserve account recoveries in 2023. Specifically, the Commission understands that the UCA is recommending to approve $93,600 for the DRT and $10,700 for the RRT.[141]

141. On March 10, 2023, DERS filed $0.258 million in cost claims for its 2023 non-energy application.[142] The Commission notes that this amount is less than the revised $0.338 million forecast that DERS provided earlier on the record of this proceeding. Based on the recent costs of $0.258 million, the Commission directs DERS to update the hearing cost reserve and hearing cost recovery amounts in the compliance filing.

142. In respect to hearing costs related to the 2024 to 2025 DRT and RRT application, InterGroup suggested that a more sensible allocation of these costs would be to have these costs recovered over the 2024-2025 period to which the costs relate, which is consistent with good regulatory practice.[143] Further, the UCA argued that declining to fund a speculative forecast of future hearing costs at this time provides much needed relief to customers currently struggling with energy affordability.[144]

143. The Commission agrees with the UCA and InterGroup on both points. Accordingly, the Commission directs DERS to exclude the forecast costs for the 2024-2025 DRT and RRT application, and for DERS to update the hearing costs in 2023 to reflect its recently filed cost claims in the compliance filing.

5 Other matters

5.1 Terms and conditions

144. DERS indicated that its current terms and conditions of service (T&Cs) (one set for DRT service and one set for RRT service) were approved in Decision 24237-D01-2019.[145] It stated that it has not made material changes to its T&Cs for several years and determined that certain editorial changes as well as clarifications regarding practices, policies, and customer responsibilities were warranted especially given the growing costs related to bad debt and unknown customers.[146] DERS requested approval of the revised T&Cs that were included as part of the application.[147] It also provided blacklined versions that highlighted the changes made to the current T&Cs.[148]

141 Exhibit 27631-X0002.01, worksheet Schedule 5.1.6, Excel cell J33 and Exhibit 27631-X0003.01, worksheet Schedule 5.2.6, Excel cell J32.

142 Proceeding 28082, Exhibit 28082-X0005, Summary of Total Costs Claimed Form U1, PDF page 7 and Exhibit 28082-X0001, CCA Cost Claim, PDF page 6. ($186,534.64+ $70,983 = $0.258 million)

143 Exhibit 27631-X0114, UCA-DERS-2020DEC20-003 (d).

144 Transcript, Volume 1, page 141, lines 20-23.

145 Decision 24237-D01-2019: Direct Energy Regulated Services, 2019 Default Rate Tariff and Regulated Rate Tariff, Proceeding 24237, December 5, 2019.

146 Exhibit 27631-X0001, application, PDF page 95, paragraph 236.

147 Exhibit 27631-X0030, DRT terms and conditions of service – clean. Exhibit 27631-X0032, RRT terms and conditions of service – clean.

148 Exhibit 27631-X0031, blackline version of DRT T&Cs. Exhibit 27631-X0033, blackline version of RRT T&Cs.

145. The UCA and the CCA did not comment on the proposed revisions to the T&Cs. The Commission reviewed the proposed revisions, and finds that they are in accordance with the objectives DERS had for making them.[149] The Commission approves the revisions to the T&Cs as filed. As part of its review, the Commission noted some minor grammatical and spelling corrections in the revised T&Cs, as listed below. The Commission directs DERS to make these corrections and file the corrected T&Cs as part of the compliance filing, in Microsoft Word format.

146. The corrections that need to be made and incorporated in the DRT T&Cs in Exhibit 27631-X0030 are as follows:

- Page 11 of 33, Section 4.3(c), second line: delete the reference to Section 4.5 and replace it with a reference to Section 4.4.
- Page 11 of 33, Section 4.3, second last line before Section 4.4: delete the word "disconeection" and replace it with "disconnection."
- Page 11 of 33, Section 4.4, first line: delete the word "priving" and replace it with "providing."
- Page 15 of 33, Section 6.1, first line: delete the word "Suject" and replace it with "Subject."
- Page 19 of 33, Section 8.5, second line: delete the phrase "Terms and the Customer of Record" and replace it with "Terms and Conditions and the Customer of Record."
- Page 21 of 33, Section 8.9, first line: delete the word "of" from the phrase "an amount more than of what is owed."
- Page 21 of 33, Section 8.9, fourth line: delete the word "credi6t" and replace it with "credit."
- Page 22 of 33, Section 8.11, second line: delete the word "Deault" and replace it with "Default."

147. The correction that needs to be made and incorporated in the RRT T&Cs in Exhibit 27631-X0032 is as follows:

- Page 18 of 29, Section 8.5, second line: delete the phrase "Terms and the Customer of Record" and replace it with "Terms and Conditions and the Customer of Record."

5.2 Rate model

148. As part of its application, DERS included DRT and RRT revenue requirements models in the form of Excel files.[150] After IRs were issued, DERS updated these models as attachments to its IR responses under new exhibits.[151] While DERS eventually updated the revision number of the exhibits of the original DRT and RRT revenue requirements,[152] the record now comprises duplicate copies of the DRT and RRT revenue requirement models.

[149] DERS' objectives for making the changes to the T&Cs are in Exhibit 27631-X0001, DERS' application, PDF pages 95-96, paragraph 236.
[150] Exhibits 27631-X0002 and 27631-X0003.
[151] Exhibits 27631-X0066 and 27631-X0067.
[152] Exhibits 27631-X0002.01 and 27631-X0003.01.

149. In the future, the Commission prefers that DRT and RRT revenue requirement models be updated by revision without the filing of new attachments. This approach will lead to a cleaner record and promote better readability for all parties in future applications.

5.3 Performance-based regulation and cost-of-service mechanisms

150. The Commission acknowledges that the CCA and J. Thygesen raised concerns with ATCO Utilities creating downstream costs to DERS that are eventually borne by customers.

151. J. Thygesen stated that the ATCO System Change costs are unreasonable in the sense that any savings on the ATCO side are captured by the shareholder whereas the downstream costs to DERS are paid for by customers. J. Thygesen also submitted that costs DERS is incurring should be offset by the cost savings on the ATCO side.[153]

152. The CCA argued that customers who pay all the costs in the system are paying twice: (i) the first payment is to ATCO to pay for the services it was providing at the forecasted levels; and (ii) the second payment is to DERS for the changes triggered by ATCO.[154] To mitigate the impacts to customers from this change, the CCA suggested that the Commission could have directed in performance-based regulation rebasing proceedings that any savings from systems be netted off against downstream effects.[155]

153. The Commission notes that there is currently a proceeding regarding the enforcement of Rule 004 on ATCO Gas and ATCO Electric to address specific issues related to the ATCO System Change.[156] This decision focuses on DERS' revenue requirements based on a cost-of-service model. Therefore, this non-energy proceeding is not the appropriate forum for the issues to be addressed.

6 Order

154. It is hereby ordered that:

(1) Direct Energy Regulated Services submit a compliance filing to this decision to reflect the Commission's findings and directions, on or before July 7, 2023.

Dated on May 4, 2023.

Alberta Utilities Commission

(original signed by)

Renée Marx
Commission Member

[153] Exhibit 27631-X0099.01, Thygesen Evidence, paragraphs 70-73.
[154] Transcript, Volume 1, page 96, lines 23-25, page 97, lines 1-7.
[155] Transcript, Volume 1, page 97, lines 8 to 13.
[156] Proceeding 27657, DERS Request for Enforcement of AUC Rule 004 on ATCO.

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
Direct Energy Regulated Services (DERS)
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP InterGroup Consultants Ltd.

Alberta Utilities Commission Commission panel R. Marx, Commission Member Commission staff L. Berg (Commission counsel) E. Chu D. Mitchell K. O'Neill

Appendix 2 – 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. DERS' application included the following proposals: a new method to forecast merchant fees; a budget increase to customer information operations; five per cent for labour inflation; an increase to staff full-time equivalents (FTEs); a bad debt deferral account; an expansion of the change management category and the addition of a deferral account for the ATCO System Change Project; and revised terms and conditions of service. During the proceeding, interveners also raised concerns over credit charges and the hearing cost reserve account. The Commission's decisions on these issues can be summarized as follows:

   (a) The Commission approves DERS' new method to forecast merchant fees, which provides transparency between recurring and one-time payments forecast amounts.

   (b) The Commission disallows DERS' customer information forecast of $224,047, and approves the amount of $84,000 for customer information consistent with the amounts approved for 2021 and 2022.

   (c) The Commission denies DERS' proposed five per cent increase for labour inflation. Instead, the Commission approves three per cent to account for labour inflation.

   (d) The Commission denies DERS' proposed increase of 2.4 FTEs for its Digital and Marketing team.

   (e) The Commission denies DERS' bad debt expense forecast. Instead, the Commission directs DERS to recalculate its bad debt expense forecast according to the methodology set out in Section 4.6.1 below.

   (f) The Commission denies DERS' proposed bad debt deferral account. Instead, the Commission approves a symmetrical deferral account such that if aggregate bad debt exceeds the revised forecast, 100 per cent of the difference will be deferred to the account of customers; and if aggregate debt is less than the revised forecast, 100 per cent of the difference will be credited to customers.

   (g) The Commission approves the inclusion of the ATCO System Change Project into the change management category; a forecast of the project at $1.2 million; and a conventional deferral account for the project if the actual cost exceeds $1.2 million.

   (h) The Commission approves the revised terms and conditions of service filed in exhibits 27631-X0030 and 27631-X0032 subject to the minor amendments in Section 5.1 below. The Commission directs DERS to incorporate the amendments in Section 5.1 and refile the documents in the compliance filing.

   (i) The Commission approves the letter of credit charge at 225 basis points and the parental corporate guarantee charge at 40 basis points.

   (j) The Commission denies DERS' hearing reserve of $0.453 million for 2023. Instead, the Commission directs DERS to update the hearing cost reserve and hearing cost recovery amounts in the compliance filing by updating the hearing costs to match

DERS' cost claims in Proceeding 28082 in addition to excluding the costs for the 2024-2025 DRT and RRT application.

(k) For its 2023 non-energy DRT and RRT revenue requirements, DERS is required to submit a compliance filing to reflect the Commission's findings and directions, on or before July 7, 2023. .... paragraph 4

2. The Commission determines that DERS could update Excel cell AO29 in Exhibit 27631-X0079 such that DERS' allocation percentage is calculated by dividing DERS' annual site count by the combined annual site count. The Commission has performed this calculation, and finds the regulated and competitive split to be 60.1 per cent regulated. Accordingly, the Commission directs DERS to apply the approved regulated and competitive split to all impacted revenue requirements in the compliance filing. .... paragraph 39

3. After considering the CCA's proposal to obtain clarification from Desert Sky and Five Point whether competitive commercial and industrial customers were excluded from the fair market value benchmarks, the Commission finds there would be little value in applying potential changes that will only apply for one more year given that the existing CC&B agreements expire at the end of 2024. There will be more value if DERS address the customer mix in its next application when it applies for a fair market value on its CC&B system. Accordingly, the Commission declines the CCA's request to obtain clarifications and affidavits from DERS' benchmark consultants. The Commission directs DERS to address the customer mix input in the next non-energy application. .... paragraph 40

4. Accordingly, the Commission directs DERS to investigate the feasibility of passing on the associated merchant fees to customers electing to pay by credit card for the DRT in its next non-energy application.. paragraph 54

5. Notwithstanding the approval of the LC and PCG charges for the 2023 test year, the Commission agrees with the UCA that there is merit in exploring whether DERS, as a stand-alone entity, would be able to secure a more favourable credit rate. Accordingly, the Commission directs DERS to provide the Commission, in its next non-energy application, the LC rate from NRG, the best rate that would be available to DERS as a stand-alone entity, and the PCG charge. .... paragraph 61

6. Taking the average of the rest of the data from the Average Weekly Earnings and ATB, the Commission calculates three per cent for labour increase. Accordingly, the Commission directs DERS to incorporate a three per cent labour inflation into its labour forecast in its compliance filing. .... paragraph 78

7. In a response to a Commission IR, DERS provided total remuneration details and components of labour costs including base salaries, benefits and short-term incentives. The Commission finds the details of the composition of total remuneration to be helpful in understanding year-to-year labour variances. For the compliance and future non-energy applications, the Commission directs DERS to file similar total remuneration details. .... paragraph 91

8. The Commission finds that the average of the corresponding actual bad debt expense as a percentage of revenue for the years 2017-2019 should be used to forecast the bad debt component for the DRT and the RRT for 2023. Using the percentages reported above, this results in an average of 0.93 per cent for the DRT and 1.91 per cent for the RRT, and

the Commission directs DERS to use these percentages in the compliance filing when forecasting the bad debt component of the total bad debt expenses for 2023. .... paragraph 107

9. With regard to collection agency costs, DERS used the average of the actual 2017, 2018 and 2019 collection agency costs as a percentage of the revenues for those years to arrive at the 0.17 per cent forecast percentage for the DRT and the 0.16 per cent forecast percentage for the RRT. It explained why it chose to use these three years and not use information for 2020 and 2021. The Commission considers that the explanation provided by DERS, which describes that collection actions were suspended or limited for periods in 2020 and 2021, justifies why the percentages for 2020 and 2021 should not be used. The Commission approves the 0.17 per cent of revenues forecast percentage for the DRT for 2023, for forecasting the collection agency costs component of the total bad debt expense forecast, and the Commission directs DERS to use this percentage in its compliance filing. The Commission also approves the 0.16 per cent of revenues forecast percentage for the RRT for 2023, for forecasting the collection agency costs component of the total bad debt expense forecast, and the Commission directs DERS to use this percentage in its compliance filing. .... paragraph 108

10. Having regard to the evidence in this proceeding, the Commission finds that for the 2023 year, the fairest deferral account mechanism for the total bad debt expense for the DRT and the RRT is the traditional deferral account mechanism. If the actual costs exceed the approved forecast, the difference is collected from customers; if the actual costs are less than the approved forecast, the difference is refunded to customers. This is commonly referred to as a symmetrical deferral account. The Commission directs that in order to prevent any cross-subsidies between DRT and RRT customers, separate total bad debt expense deferral accounts be established; one for the DRT and one for the RRT, and each one be accounted for separately. The balance in the DRT total bad debt expense deferral account will be settled with DRT customers and the balance in the RRT total bad debt expense deferral account will be settled with RRT customers. .... paragraph 117

11. The CCA and the UCA did not comment on DERS' proposed late payment charge deferral account. The Commission finds that a deferral account should be established, as supported by DERS' reasons for requesting the deferral account. While DERS indicated that the late payment charge deferral account it was applying for was the same as what was included in the 2020-2022 NSA and subsequently approved in Decision 26207-D01-2021, the Commission finds that is not the case. The deferral account in the 2020-2022 NSA was based on the combined DRT/RRT late payment charge forecasts, whereas in the illustrative model DERS presented for 2023, the deferral accounts are separately calculated for the DRT and the RRT. To prevent any cross-subsidies between DRT and RRT customers, the Commission directs that separate late payment charge deferral accounts be established, as shown in the illustrative model– one for the DRT and one for the RRT, with each one accounted for separately. The balance in the DRT late payment charge deferral account will be settled with DRT customers and the balance in the RRT late payment charge deferral account will be settled with RRT customers... paragraph 124

12. The Commission approves DERS' proposal to combine the balances in the DRT bad debt expense deferral account and the DRT late payment charge deferral account; and to combine the balances in the RRT bad debt expense deferral account and the RRT late payment charge deferral account, and to file a request to dispose of the combined balances, because this promotes regulatory efficiency. To further promote regulatory

efficiency, the Commission directs that DERS include the request to dispose of the deferral account balances as part of its next RRO non-energy application, as opposed to filing a separate application, unless the next RRO non-energy application (that would include 2024 as part of the test years) has already been filed by the time DERS is ready to apply to dispose of the deferral account balances. In that case, the Commission directs DERS to file a separate application to dispose of the deferral account balances. .... paragraph 125

13. On March 10, 2023, DERS filed $0.258 million in cost claims for its 2023 non-energy application. The Commission notes that this amount is less than the revised $0.338 million forecast that DERS provided earlier on the record of this proceeding. Based on the recent costs of $0.258 million, the Commission directs DERS to update the hearing cost reserve and hearing cost recovery amounts in the compliance filing..... paragraph 141

14. The Commission agrees with the UCA and InterGroup on both points. Accordingly, the Commission directs DERS to exclude the forecast costs for the 2024-2025 DRT and RRT application, and for DERS to update the hearing costs in 2023 to reflect its recently filed cost claims in the compliance filing.. paragraph 143

15. The UCA and the CCA did not comment on the proposed revisions to the T&Cs. The Commission reviewed the proposed revisions, and finds that they are in accordance with the objectives DERS had for making them. The Commission approves the revisions to the T&Cs as filed. As part of its review, the Commission noted some minor grammatical and spelling corrections in the revised T&Cs, as listed below. The Commission directs DERS to make these corrections and file the corrected T&Cs as part of the compliance filing, in Microsoft Word format. .... paragraph 145

Appendix 3 – Commission-initiated consultation on the regulated rate tariff

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Appendix 3 -
Commission-initiate

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Appendix 4 – RRT consultation final results

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Appendix 4 - RRT
consultation final re

(consists of 27 pages)

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November 22, 2013

To: Consultation parties and parties on the Alberta Utilities Commission's distribution list for electricity matters

Commission-initiated consultation on the regulated rate tariff

1. The undersigned has been directed by the Alberta Utilities Commission (the AUC or the Commission) to outline the Commission's views on the regulated rate tariff (RRT) consultation.

2. The Commission has reviewed the final results document dated November 21, 2013, (Final Results document) associated with the RRT consultation that involved the following parties (the parties).

- Direct Energy Regulated Services
- ENMAX Energy Corporation
- EPCOR Energy Alberta Inc.
- The Consumers' Coalition of Alberta
- The Office of the Utilities Consumer Advocate

3. The main outcome of the RRT consultation was the production of a final results document. The final results document includes standardized cost and risk component names and descriptions for inclusion, as applicable, in energy price setting plan applications and non-energy (administration charge) applications. The parties have endorsed the use of these standardized cost and risk component names and descriptions in regulatory processes associated with these applications. The Commission considers that if all parties uniformly adopt these application elements in the regulatory processes for regulated rate tariff applications, it should lead to a more efficient process for regulatory review.

4. According to the results of the consultation, the parties are of the view that a simpler approach for including a "reasonable return for the obligation on the owner to provide electricity services"[1] in the regulated rate tariffs should be determined. The parties also endorsed the idea that the reasonable return should be considered in one regulatory proceeding. The Commission has determined that it will initiate a generic proceeding to examine not only the reasonable return component, but all aspects of the energy price setting plans.

5. A separate letter will follow and include more details about the generic proceeding.

Sincerely yours,

Mike Hagan
Executive Director, Rates Division

[1] Section 6(1)(b)(i), *Regulated Rate Option Regulation*, AR 262/2005.

Final Results from the Regulated Rate Tariff Consultation

The parties below (the parties) endorse the results of this consultation as outlined in this document.

- Direct Energy Regulated Services (DERS)
- ENMAX Energy Corporation (ENMAX)
- EPCOR Energy Alberta Inc. (EPCOR)
- The Consumers' Coalition of Alberta (CCA)
- Office of the Utilities Consumer Advocate (UCA)

The parties believe that the results of this consultation, if implemented as outlined, will provide a more efficient process for regulatory review, oversight and implementation.

The parties understand that the Commission has not endorsed any matters outlined in this document.

Consultation results

- DERS, EPCOR and ENMAX will use the cost, risk compensation and return components (as applicable) as described in Appendix A in future energy price setting plan (EPSP) applications.
    - EPCOR agreed to supplement its current EPSP application (Proceeding ID No. 2845) by providing information that shows how the cost and risk compensation components outlined in Appendix A relate or map to the cost and risk compensation components outlined in its application.
- DERS, EPCOR and ENMAX will use the cost, risk compensation and return components, and deferral/reserve accounts (as applicable) as described in Appendix B in future non-energy applications.
- The quantum of each cost, risk compensation and return component, and the need for each deferral/reserve account must be tested by the Commission in a regulatory proceeding.
- The regulated rate option (RRO) providers and customer groups will have to provide their separate views to the Commission with respect to principles that the Commission should consider when ensuring that the risk compensation is just and reasonable.
- Bad debt expense will be collected through the non-energy charge (also referred to as the administration charge).
- Internal administration costs of the RRO providers incurred as a result of the operation of the EPSP will be included for recovery as part of the non-energy charge.
- That commercially sensitive information with respect to pricing parameters and details for acquiring forward market products should remain confidential to protect customer

information, to protect the integrity of the EPSPs and to maintain the integrity and fairness of any auction sessions and prices obtained.

- That as part of the regulatory process for future EPSP applications, the parties will share their views on (1) the aspects of the EPSPs that should be monitored and measured during the term of the EPSP, (2) the supporting rationale and (3) the party or parties that should perform the monitoring and measurement function.
    - The parties also agreed to identify (1) the specific information (for example, actual settled energy, hedge volume and associated price for each hedge transaction, etc.) required to perform this monitoring and measurement function and (2) when the information should be provided.
- Energy (versus non-energy) related costs as they pertain to the *Regulated Rate Option Regulation*, consists of the following items, as described in Appendix A.
    - base energy charge
    - shape risk product
    - Alberta Electric System Operator (AESO) collateral
    - counterparties collateral
    - NGX collateral
    - backstop collateral
    - other credit costs
    - NGX trading charges and transaction fees
    - AESO trading charges
    - retail adjustment to market (RAM) charges
    - uplift charges
- It is not necessary for the RRO providers to include incentives in their future EPSPs to enhance the liquidity in the Alberta forward financial electricity market for monthly flat (7x24) and extended peak (7x16) hedge products because the parties consider that the forward financial market is robust enough to facilitate risk management and price discovery.
- The RRO providers will be afforded the opportunity to decide whether to apply for any deferral accounts as part of their non-energy applications.

- That a simpler approach for including return (for the obligation on the owner to provide electricity services) in the regulated rate tariffs should be determined and that the return should be considered as one component, in one regulatory proceeding and recovered through one charge.

    - The determination of the return as part of a generic-type proceeding is appropriate since the return components have not been reviewed since 2006, and the parties consider that they would be able to provide more relevant evidence on this matter since there are now more competitive supply options available for comparison purposes.
    - That the Commission would need to approve a transition plan to allow the RRO providers to move from recovering the return through two charges to one charge.
    - That the income tax gross up may not be an issue depending on the methodology used to determine the return.

- With respect to the following costs, while the amount ($/MWh) embedded each month in the monthly energy charge can be different, the amount ($/MWh) for each individual cost item will be the same for each customer rate class within a service area:

    - AESO collateral
    - counterparties collateral
    - NGX collateral
    - backstop collateral
    - other credit costs
    - NGX trading charges and transaction fees
    - RAM charges[1]
    - uplift charges
    - external EPSP development and regulatory costs

- With respect to the "Other Risks" as described in Appendix A, the amount embedded in the monthly energy charge for the recovery of any of these approved risks will be applied through one amount ($/MWh). This amount will be the same for each customer rate class.

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1 EPCOR calculates a RAM $/MWh forecast amount for customers in the EPCOR Distribution & Transmission Inc. service territory and a separate RAM $/MWh forecast amount for customers in the FortisAlberta Inc. service territory.

On other matters:

- ENMAX agreed to determine how it could enhance its reporting on Schedule 4 of the AUC Rule 005[2] reporting requirements.
    - ENMAX committed to work with DERS to review how DERS reports its numbers under Schedule 4 and to report back to the Commission prior to May 1, 2014, the next due date for RRO provider AUC Rule 005 filings.
- The RRO providers agreed that in future EPSP applications they will clearly outline the information, such as senior officer attestations, they would propose to file with the Commission as part of their monthly energy charge applications in order to make the review and acknowledgement process as efficient as possible.
- A summary of the load forecasting methodology used by each RRO provider is provided in Appendix C.
    - EPCOR, DERS and ENMAX agreed that during the term of their next energy price setting plans, they would propose to actively assess refinements to their load forecasting methodologies and file any changes with the Commission for approval prior to implementation.

[2] AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

Appendix A
Energy Charge – Cost, Risk Compensation and Return Components

1. Commodity Risk: risks related to the procurement and settlement of energy acquired in advance of actual consumption[3]

Item	Description	Comments
Commodity risk compensation	When hedging is undertaken using flat or peak products, the RRO providers face financial losses or gains in relation to these procured forward market transactions and spot market purchases through the AESO power pool. There are two factors that create these losses and gains. The first factor is the difference between the price per unit of the hedges undertaken in the forward market and the price per unit settled in the Alberta power pool for each hour of a given month (**price differential**). The second factor is related to the difference in the amount of energy hedged by the RRO providers and actual amount of total energy allocated (metered load plus unaccounted for energy and distribution system losses) to the RRO customers (**energy differential**). The load forecast for each RRO provider is used as the basis for the hedging volume target but there will always be a variation between the forecast amount and hedged amount because the RRO providers use block hedging products that do not fit perfectly with the shape of the hourly load requirements. This risk is related to the costs components (net of forward market transactions and spot market purchases) discussed above but it also includes revenue risk associated with the variance between forecast and actual energy consumption. The revenue risk for a single customer class (the hedging products are not split between customer classes) is included in the commodity risk, while the revenue risk that arises from splitting an average hedge cost into separate average hedge costs for individual customer rate classes is covered separately under the customer class risk.	All parties agreed that without any commodity risk compensation, the RRO providers will incur losses in both the short and long term. If a RRO provider obtains some, or all, of the shape risk product (described separately below), the commodity risk faced by the RRO provider is reduced because the seller of the shape risk product has agreed to absorb part of the price differential and energy differential.

3 For the purposes of this appendix, "consumption" is the amount of energy (MWh) expected to be consumed (forecast) or actually consumed (actual) by the end-use customers of the RRO provider and is equivalent to the term "customer metered load" or "sales". Total load is the amount of energy (MWh) allocated to a RRO provider by the load settlement agent and it includes an amount for consumption, distribution system losses and unaccounted for energy.

Item	Description	Comments
	The outcome from this "risk" may lead to a financial loss or gain for the RRO provider.	

2. Energy related costs

Item	Description	Comments
Base energy charge	This component of the overall energy charge could be developed in two ways depending on the approach implemented by the RRO provider. 1. If forward market hedging is undertaken by the RRO provider, this component would represent the weighted average unit cost ($/MWh) of all forward market hedge products acquired by the RRO provider. 2. In the second approach, hedging products are not used and instead, the base energy charge is determined by using the flat 7x24 NGX RRO 120 day index. In both cases, the unit charges noted above would be grossed up to allow for unaccounted for energy (UFE) and distribution system losses (DSL).	The RRO providers use forward financial contracts, also referred to as contracts for differences or financial swaps, for their hedging strategies. At settlement, one party pays the other party the difference between the agreed price and the hourly pool price for the contract period. The RRO providers use auction processes or targeted daily block purchases to acquire their hedges. If the RRO provider uses the second approach, or acquires only flat 7x24 hedges to replicate the flat NGX 120 day index, the RRO provider is also expected to contract for some of the shape risk product.
Shape risk product	**A preliminary description of this product is provided below. It is expected that this matter will be fully explored in a regulatory proceeding.** Shape risk addresses the hourly volume variances relative to amounts hedged that take place during the	These products are used when the RRO provider wants to transfer a portion of its commodity risk to other counterparties.

Item	Description	Comments
	course of a month and the actual load consumption plus UFE & DSL in each hour of the month. Shape risk has two components: (1) the hourly variance between the average actual load and the individual hours priced at the AESO hourly price, and (2) the aggregate variance of the difference between the forecast volume for the month and the actual consumption in the month. The shape risk product can include either or both of these components. If the first component is acquired by the RRO provider, the RRO provider would continue to bear the risk of the second component. The RRO provider would reflect the risk of this second component under the commodity risk compensation item discussed above. If the RRO provider acquires a shape risk product for the first component of shape risk, the RRO provider pays a fixed price per MWh to a counterparty based on a certain percentage of the RRO provider's actual load (including UFE and DSL) that is settled each month by the AESO in the Alberta power pool. The counterparty for this shape risk product agrees to accept a component of the shape risk at an established price and is responsible for the difference between the actual hourly load (including UFE and DSL) and the average hourly load (including UFE and DSL). Actual shape risk cost may be greater or lesser than the price that the counterparty agreed to.	DERS and ENMAX plan to acquire this product through an NGX auction process for their combined requirements. The competitive business unit of Direct Energy Marketing Limited and ENMAX Energy Corporation may offer to supply this product in the auction. DERS and ENMAX will use a back stop supply (at a price determined in advance of the auction) for this product in the event that insufficient volume is acquired at the auction to meet 100 per cent of the requirements.

Item	Description	Comments
Credit		
AESO collateral	Carrying costs incurred for posting financial security with the AESO • The carrying cost associated with providing sufficient credit support to secure the financial obligations of the RRO provider to the AESO. • The form of the security is usually in the form of one of the following: letter of credit, cash deposit or guarantee. • The AESO will grant unsecured credit limits to rated and non-rated entities depending on the credit rating or proxy credit rating. • The amount of financial security required is the amount by which the RRO provider's financial obligations owing to the AESO for two settlement periods exceeds the amount of any unsecured credit limit granted.	For its 2014+ EPSP, EPCOR includes this in its guarantee fee amount.
Counterparties collateral	Carrying costs incurred for posting financial security with any counterparties.	If required.
NGX collateral	Carrying costs incurred for posting financial security with the NGX. • The carrying cost associated with providing sufficient credit support to secure the financial obligations of the RRO provider to the Natural Gas Exchange. • The form of the security is usually in the form of one of the following: irrevocable letter of credit or cash deposit.	Natural Gas Exchange Inc. is a recognized exchange and clearing agency in the province of Alberta. For its 2014+ EPSP, EPCOR includes this in its credit costs amount.
Backstop collateral	Carrying costs incurred for posting financial security with any backstop suppliers. [Backstop stop suppliers could be used if the RRO provider does not acquire enough hedging products for a delivery month through an auction or through daily block procurement, and the remaining required volumes could be supplied to the RRO provider through a third- party back stop supplier.]	For its 2014+ EPSP, EPCOR includes this in its guarantee fee amount. Not expected to be applicable to DERS or ENMAX.
Other credit costs	These additional costs include: • placement costs for having a sufficient credit facility in place to meet the total financial security requirements of the AESO, counterparties, the NGX, and backstop suppliers	For its 2014+ EPSP, EPCOR includes this in its credit costs amount.

Item	Description	Comments
	• standby (undrawn) credit costs associated with differences between the estimated credit facility and the estimated posted (drawn) financial security requirements	
System fees		
NGX trading charges and transaction fees	This includes fees charged for purchases of specific swap products ($/MWh) on NGX and any costs charged by NGX for conducting auctions for hedge products and shape risk products.	
AESO trading charges	• These charges recover certain AESO costs, the portion of the AUC administration fee allocated to the wholesale electric market activities and costs required by the Market Surveillance Administrator. • The charge per megawatt hour of energy traded in the Alberta power pool is applied to the greater of the metered volume or the net settlement instructions for each asset for each hour to determine the overall expense owed by the RRO provider each month.	
Retail adjustment to market (RAM) charges	These charges are related to a post final adjustment mechanism (PFAM) made to all retailers in the settlement of load at a settlement ID (as defined in AUC Rule 021: *Settlement System Code Rules*), for the collection/payment required to offset the RSA (retailer specific adjustment) that is identified on the AESO pool statement for each retailer. The PFAM was introduced into the Alberta market through the Settlement Code, in May 2002. PFAM provides a process through which retailers can seek correction (without necessitating a re-settlement for the entire market) of errors that they discover in final settlement. Valid PFAM claims result in retail adjustment to market charges to market participants including electricity retailers and RRO providers.	
Uplift charges	Uplift charges are a result of the AESO resolving the issue of the mismatch of dispatch prices and the settlement price. The AESO makes payments to generators on the margin. These payments compensate generators that are dispatched intra-hour (i.e., for less than a full hour) when the hourly pool price is lower than that generator’s offer price.	

Item	Description	Comments
	Generators are compensated for the difference between their offer price and the hourly pool price for the portion of the hour for which their unit is dispatched. The cost of these uplift charges is flowed through to load customers in the power pool that include the RRO providers.	

3. External EPSP development and regulatory costs

Item	Description	Comments
External EPSP development and regulatory costs	External costs associated with the development of the EPSP including any amendments, and costs related to the AUC regulatory process dealing with the EPSP applications. It also includes any ongoing costs associated with any back stop provisions required if insufficient hedging products are acquired for a given delivery month. Costs in this component include legal and consulting fees and disbursements associated with the development of the EPSP , the preparation and filing of the EPSP for approval with the AUC, and all aspects of the AUC's regulatory approval process for the EPSP, including intervener hearing costs. In addition, it includes any EPSP development and regulatory costs incurred under the 2011-2014 EPSP (and 2011-2014 amended EPSP) that were not fully recovered under these plans.)	

4. Other Risks

Item	Description	Comments
Counterparty credit risk	The risk that the supplier from whom an energy hedge product or shape risk product was purchased defaults or goes bankrupt and can no longer supply a contracted hedge or shape risk product. The outcome from this risk depends on when the default occurs and what action the RRO provider can take. The outcome from this “risk” may lead to a financial loss or gain for the RRO provider.	This risk can be mitigated by using a central clearing facility such as NGX Clearing.
Recurring cost forecasting risk	Forecasting risk on both costs and usage for all credit costs. Forecasting risk on usage for external EPSP development and regulatory costs, NGX trading charges and transaction fees, retail adjustments to market charges, and uplift charges. This risk is related to the costs components noted above (risk that the forecast amounts will be different than the actual amounts) but it also includes revenue risk associated with the variance between forecast and actual energy consumption. The outcome from this “risk” may lead to a financial loss or gain for the RRO provider.	
Billing error risk	Under Section 17 of the *Regulated Rate Option Regulation*, an owner is not entitled to collect from a regulated rate customer any amount undercharged as a result of an incorrect meter reading, incorrect rate calculation, clerical error or other error of any kind that is made more than 12 months before the date of the bill. As a result, the RRO provider is at risk for any billing and/or energy calculation error that results in an undercharge that is not discovered within 12 months. The outcome from this “risk” would lead to a financial loss for the RRO provider.	

Item	Description	Comments
Customer class risk	Customer class risk arises from splitting a single procurement portfolio that represents the average cost of hedging base and peak products for the aggregated RRO portfolio into a set of average hedging costs for the individual customer rate classes. This is a risk associated with revenues and results from the variation between forecast and actual energy consumption. The revenue risk for a single customer class (the hedging products are not split between customer classes) is included in the commodity risk compensation. The outcome from this “risk” may lead to a financial loss or gain for the RRO provider.	Not applicable to ENMAX because does not split its hedging products between customer rate classes.
Other administrative risks	These are other risks that are known, but are not quantifiable. These risks include back stop counterparty credit risk and the risk that the RRO provider will incur new or increased prudent costs (for example, if the NGX, AESO or back stop supplier change their credit requirements) for a period of time before an amendment to the plan can be put in place to recover these new or revised costs. The outcome from this “risk” would lead to a financial loss or gain for the RRO provider.	

5. Return

- A return component will continue to be recovered through the energy charge (as applicable) until the Commission determines otherwise.

Appendix B
Non-energy Charge – Cost, Risk Compensation & Return Components and Deferral/Reserve Accounts

1. Non-energy - costs

The following cost categories will be used by the RRO providers but the display of the specific cost categories will vary from provider to provider due to different corporate structures, risk tolerances and legacy issues.

A RRO Provider may display some of the specific cost categories at an aggregate level rather than at the more detailed level. For example, while both ENMAX and EPCOR display customer service operations costs at the more detailed level set out below, DERS aggregates this cost category because it outsources these services. A component mapping table for DERS is provided at the end of this appendix.

A. Customer service operations

1. Billing services: is responsible for carrying out the billing, enrolment and customer escalation management functions and includes costs related to printing, processing and mailing bills, performing account reconciliations, resolving billing and payment exceptions, applying payments to customer accounts, and processing refunds.
2. Contact centre: is responsible for handling customer inquiries and includes costs related to responding to customer inquiries that take the form of telephone calls, emails, traditional mail and facsimiles, or that come through the RRO provider's website.
3. Collections: is responsible for collections activities in relation to aged receivables and includes costs related to completing credit checks for customer, determining and collecting security deposit requirements, and dealing with bankrupt customers. This also includes any costs incurred for the use of external collection agencies.
4. Technical training and communications: is responsible for the design and delivery of learning programs focused on skills required by employees to perform their jobs and the design and delivery of employee communications respecting procedural changes, industry changes and regulatory or legislative changes, developing and testing work requests and projects and the design and delivery of communications to customers regarding changes and issues that affect the service customers receive.
5. Information services: is responsible for information systems and applications maintenance and support, information systems planning and capital project oversight, and 24-hour, seven-day per week standby support for the systems and applications required to provide service to customer and to produce bills and includes costs related to staff costs, hardware, software licence fees, external contractor costs and desktop, network and server support.
6. Management: includes costs associated with the senior management and the various administrative functions required to support the customer service delivery functions, including management, administrative support, accounting, external legal, insurance, space rent and utilities and general allocation to capital.

B. RRO operations

1. RRO operations management support: is responsible for managing the RRO energy portfolios, overseeing and managing relations and agreements with affiliates and third parties, execution of the EPSP including load forecasting, energy procurement (hedging), hedge calculations and price setting, and operational project management for major initiatives.
2. RRO accounting: provides day-to-day accounting, maintenance of internal controls and financial reporting in support of RRO operations, including monthly, quarterly and annual financial reporting, the coordination of internal and external audits, ensuring compliance with internal controls and accounting policies, preparation of financial information for regulatory purposes, financial settlement and reporting (for both hedge contracts and AESO physical energy), and budgeting and forecasting.
3. RRO regulatory: is responsible for the regulatory affairs activities necessary to enable the RRO provider to provide utility service, including application development and prosecution, proceeding participation, relationship management with government, regulatory and industry agencies and other industry participants, research of regulatory issues.

C. Non-operating costs

1. Credit costs: costs to provide financial security to distribution system owners (DSOs) under the *Electric Utilities Act* and the DSO's terms and conditions of service and other supporting agreements requiring credit support.
2. Unbillable energy and DSO Costs: costs that arise when an existing customer has terminated RRO service at a site by closing their account and leaving no customer of record, or when a site is dropped back to the RRO with no customer information which creates periods of time where the RRO provider is unable to bill a customer for the energy and DSO charges incurred by the RRO provider.
3. Depreciation expense/rental expense
4. Cost of capital: consists of financing costs for debt incurred.
5. Cost of working capital: consists of working capital requirements and costs comprised of the lead and lag between revenues and expenditures and the Goods and Services tax.
6. Merchant fees: consists of merchant fees for providing customers the ability to pay by credit card.
7. Customer education costs: consists of costs to education customers regarding the structure of the deregulated Alberta electricity market.
8. Energy efficiency education costs: consists of program and communications costs to enable customers to effectively manage both the level and volatility in their consumption.
9. Cost to acquire/retain customers: consists of the costs a RRO provider must incur to acquire and/or retain customers on the RRO so that the RRO provider can continue to maintain a large enough customer base over which to spread the RRO providers fixed costs so that RRO customers are not negatively impacted by large increases in RRO rates. While none of the RRO providers have sought recovery of this item to date, all

consider this to a reasonable cost for inclusion as to manage the declining customer base being experienced. The providers deem this prudent to remaining RRO customers to manage costs especially as it pertains to fixed costs.

D. Corporate service costs

- Costs of activities managed centrally within the RRO provider's parent group due to their governance nature and for the purpose of realizing economies of scale by continuing to deliver these services under a shared service model. This includes costs for corporate service charges and corporate asset usage fees.

E. Bad debt expense

- Consists of the balances of accounts written off as uncollectible.

F. Revenue offsets

- Costs comprised of incidental revenues collected from customers, such as late payment charges, collection fees, dishonoured payment charges, retail connection fees and customer notification fees that are treated as offsets to allocated RRO costs.

2. Non-energy – risk compensation

- The following non-energy risks may lead to a financial loss or gain for the RRO providers.
- The RRO providers are expected to propose to recover one or more of these risks through one risk compensation component.
- Some of these risks may not be applicable to a RRO provider if the AUC approves the potential deferral or reserve accounts outlined in Section 3 below.

1. RRO site count/attrition forecasting risk: the risk of variances between forecasted and actual costs and the associated cost recoveries.
2. Cost forecasting risk: the risk of variances between forecasted and actual customer service, RRO operating, corporate services and non-operating costs.
3. Bad debt forecasting risk: the risk of variances between forecasted and actual bad debt expense. This is further impacted by commodity price risk and transportation risk changes over the course of the test period. This also impacts risks associated with penalty revenue and working capital recoveries.
4. Risk of diseconomies of scale: the risk of losing large numbers of non-RRO sites resulting in a reduction of the customer base for which the RRO provider is able to spread recovery of its fixed costs. [For example, billing services for water customers]
5. Change in law risk: the risk that a law and regulation will change, which may impact a RRO provider's costs or ability to recover costs.
6. Risk of unforeseen natural events (e.g. floods, fires): the risk that an unforeseen natural event like a large flood or fire will impact a RRO provider's costs or ability to recover costs.
7. General business risks: the risk of variances due to changes in corporate activities, macro-economic influences and financial markets.

3. Non-energy – potential deferral and reserve accounts

1. Bad debt deferral account: deferral account to capture the variances between forecast and actual bad debt expenses related to all aspects of a customer's bill.
2. Site count deferral account: deferral account to capture the non-energy revenue impact associated with variances between forecast and actual site counts.
3. Hearing cost reserve account: reserve account to recover the variances between forecast and actual hearing costs, including external legal fees, for non-energy regulatory costs.
4. Short-term incentive deferral account: deferral account to capture any approved short-term incentive amounts included for recovery in revenue requirement but not actually paid out.

4. Return

- A return component will continue to be recovered through the non-energy charge (as applicable) until the Commission determines otherwise.

Component mapping table for DERS

Standardized components	DERS current line items
1. Non-energy costs	
A. Customer service operations	Customer care costs
B. RRO operations	Labour by department
	(DRT includes procurement labour)
C. Non-operating costs	Merchant fees
	Working capital
	Deemed tax
	Other administration costs
	Customer education and energy awareness
	Credit charges
D. Corporate service costs	Corporate costs
E. Bad debt expense	Bad debt (including collection agency fees)
F. Revenue offsets	Revenue offsets (including unbillable)
	Penalty revenue
2. Non-energy risk compensation	
3. Potential deferral and reserve accounts	Hearing costs
4. Return	Included in the EPSP

Appendix C
RRO Provider Load Forecasting Methodologies

EPCOR

1. The first output from load forecasting includes an hourly usage forecast by rate class.
- These forecasts are determined by applying **a site count forecast** to the **average weekly consumption per site forecast**.

Site count forecast

- The **site count forecast** is created by applying a forecast change in daily site counts that is determined based on the last six months of actual data, to forecast site counts for the ensuing six month period.
- The forecast daily site count change is unique for each rate class so it is calculated on a rate class basis.

Average weekly consumption per site forecast

- The **forecast average weekly consumption per site** is determined by first dividing the weather normalized actual daily load for rate classes that have net system load shape (NSLS) profiles, and the actual daily load for rate classes that do not have NSLS profiles by actual daily site counts.
- The resulting actual daily load per site is then aggregated weekly to yield actual weekly consumption per site for each rate class.
- The forecast weekly consumption per site is then calculated using the last 3 years of actual weekly consumption per site data.
- To determine the final forecast of average weekly consumption per site by rate class (AWCRC), a three-week centered moving average is applied to the forecast to smooth the week-to-week spikes or drops in consumption.

Hourly usage forecast by rate class

- The product of the **site count forecast** and **forecast average weekly consumption per site** for each rate class results in EPCOR’s average weekly consumption forecast.
- The resulting weekly consumption forecast will be shaped using weekly profiles based on historical settlement profile data to arrive at an hourly usage forecast.

2. The hourly usage forecasts by rate class are then grossed up for unaccounted for energy and distribution system losses.

3. The aggregated total load is used as the basis to determine the target hedging requirements.

ENMAX

ENMAX RRO load forecast methodology

ENMAX RRO load forecast is prepared using a Neural Network with regression models. The forecast model is adjusted with ARMA errors to fine tune the model to take into account historical fluctuations, trends, seasonality, cycles and predictions errors. The forecast model uses: settlement load data, daily sunlight hours, and calendar and weather trends. Estimation periods vary (three to six years) depending on which provides the best model statistics for the sample and forecast periods.

A preliminary hourly load forecast is prepared 15 days prior to the start of each price setting period. The hourly forecast contains hourly load shape by rate class grossed up for UFE & LL, historical settlement data, historical UFE & LL, estimated site count and net attrition growth. Sum of the average flat and peak forecasted load is used to determine the daily flat and peak target volume for procurement.

When the next month's settlement data is received, a final hourly load forecast is prepared for the prompt month. Using the same process the target volume is recalculated and any adjustment to the daily target volume is made.

ENMAX RRO site forecasting methodology

ENMAX utilizes a Commission approved exponential smoothing model in MetrixND forecasting software. Several years of historical monthly data are used to produce the forecast. Both residential and commercial sites are forecasted. The site forecast is not used in ENMAX's load forecasting model.

DERS

RRO load forecasting methodology

DERS will continue to utilize the Northstar system in order to complete its monthly and quarterly forecast. Forecasts will be developed at the rate class level.

1. Total RRO Load = $\sum LF_{RC}$ x $(1+DLL_{RC})$

Where

"LF_{RC}" is the Total Forecast for the Month for each rate class

"DLL_{RC}" is the distribution line loss factor and the forecast unaccounted for energy for the rate class

2. $LF_{RC} = (\sum (DSC_{RC} \times P_{RC} \times UF_{RC})) \times SF_{RC}$

Where:

"DSC_{RC}" is the current active site count by rate class

"P_{RC}" is the profile based on historical 2 years (2009-2011) of Net System Load Shape data from ATCO Electric and has weather normalized based on 20 year average

"UF_{RC}" is the hourly usage factor by rate class derived from the historical 2 year WSD settlement data. This data is weighted on the basis of 75% weighting for the most recent 12 months and a 25% weighted for the prior 12 months. Utilizes the latest settlement data (interim and final settlement data only)

"SF_{RC}" is site count factor applied to adjust the Total Forecast Load for a net growth and attrition factor

3. SF_{RC} = average monthly net growth and attrition based on previous 2 year actual site count net growth/attrition calculated at the rate class level.

4. The Distribution Line Loss Factor and the forecast Unaccounted for Energy for the Rate Class will be determined as follows:

$$\mathbf{DLL_{RC} = UFE_{RC} + LLF_{RC}}$$

where:

"UFE_{RC}" is the forecast Unaccounted for Energy for the Rate Class. **"LLF_{RC}"** means the Line Loss Factor for the Rate Class

a. The forecast Unaccounted for Energy (UFE_{RC}**)** for the Rate Class will be determined by calculating the average monthly Unaccounted for Energy over the most recent six calendar months for which Final Settlement is available for the Rate Class, as charged to the Company by the ISO.

b. The Line Loss Factor **(**LLF_{RC}**)** means the distribution line losses by Rate Class that are most recently approved by the AUC for ATCO Electric's distribution service area for each rate class and are expressed as a percentage of customers' usage for each Rate Class.