Decision **27672-D02-2022**

Alberta Utilities Commission

ATCO Electric Ltd.

2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates – Reasons for Approval

December 20, 2022

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1 Decision summary

1. In Decision 27672-D01-2022 (Decision D01),[1] the Alberta Utilities Commission directed ATCO Electric Ltd. to make certain adjustments to its 2023 revenue requirement, 2023 rates, options, riders and rate schedules and to provide updated schedules, including rate calculations. The Commission determined with reasons to follow that:

- Subject to the adjustments directed in paragraph 2 of Decision D01, ATCO Electric has complied with all applicable directions from Decision 26615-D01-2022[2] and Decision 26616-D01-2022.[3]

- The calculation of ATCO Electric's 2023 distribution rates including the calculation of the distribution-connected generation (DCG) credits, options and riders was approved on an interim basis, effective January 1, 2023, subject to ATCO Electric filing an updated set of schedules reflecting the findings in Decision D01.

- The 2023 system access service (SAS) rates were approved as filed effective January 1, 2023.

- The updated customer and retailer terms and conditions for electric distribution service were approved effective January 1, 2023.

- The stand-alone schedule of Supplementary Service Charges was approved effective January 1, 2023.

- ATCO Electric's 2023 Available Company Investment (maximum investment levels (MILs)) amounts will be set in Proceeding 27658.

- ATCO Electric's request for approval of its final 2021 rates, including the K-bar amounts, was granted.

2. In this decision (Decision D02), having reviewed ATCO Electric's filing made pursuant to Decision D01, the Commission provides its reasons for the determinations made in Decision D01. For the reasons that follow, the Commission has determined that:

[1] Decision 27672-D01-2022: ATCO Electric Ltd. 2023 Cost-of-Service Compliance Filing and 2023 Rates, Proceeding 27672, December 7, 2022.
[2] Decision 26615-D01-2022: ATCO Electric Ltd., FortisAlberta Inc., 2023 Cost-of-Service Review, Proceeding 26615, July 28, 2022.
[3] Decision 26616-D01-2022: ATCO Gas, Apex Utilities Inc., 2023 Cost-of-Service Review, Proceeding 26616, September 1, 2022.

- ATCO Electric has complied with Decision 26615-D01-2022 and Decision 26616-D01-2022, and therefore, the Commission approves the resulting 2023 forecast revenue requirement.

- ATCO Electric's 2023 distribution rates including the DCG credits, options and riders, set out in Appendix 4 to this decision, are approved on an interim basis, effective January 1, 2023. These rates will remain interim pending finalization of all outstanding placeholders (such as 2022 actual closing rate base). These 2023 rates will be finalized following approval of all outstanding placeholders, and any required true-up adjustments made in accordance with directions subsequently provided by the Commission.

3. In Decision 26849-D01-2021,[4] the Commission approved ATCO Electric's proposed plan for collection of the 2021 deferred amount (that is, the amount associated with a deferral of the 2021 distribution rates increase) using its interim Rider J starting January 1, 2022. As this plan was previously approved, the Commission approves in this decision the requested amount to be collected by way of Rider J, effective January 1, 2023.

4. ATCO Electric was also directed to include its 2021 annual transmission access charge deferral account (TACDA) true-up and Balancing Pool adjustment in this application. For the reasons that follow, the Commission approves the requested amounts to be collected by way of Rider G and Rider B, respectively, effective January 1, 2023.

2 Introduction and background

5. Since 2013, rates for the electric and natural gas distribution utilities under the Commission's jurisdiction have been set under performance-based regulation (PBR).[5] PBR plans applied to the four large electric distribution facility owners (DFOs): ATCO Electric, FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and the two large natural gas DFOs: ATCO Gas and Pipelines Ltd., and Apex Utilities Inc.

6. Under the PBR plans that ran from 2013 to 2017 (PBR1[6]) and 2018 to 2022 (PBR2[7]), each utility's rates (or revenue-per-customer in the case of gas DFOs) were adjusted annually by means of an indexing mechanism that tracked the rate of inflation (I factor), less an offset to reflect the productivity improvements each DFO was expected to achieve during the PBR plan period (X factor), plus other specific adjustments. These other adjustments included the ability to flow-through certain costs that should be recovered from, or refunded to, customers directly (Y factors), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor). As well, K and K-bar factor adjustments served to provide supplemental capital funding. As a result, with the exception of these specifically approved adjustments,

[4] Decision 26849-D01-2021: ATCO Electric Ltd., 2022 Annual Performance-Based Regulation Rate Adjustment, Proceeding 26849, December 16, 2021, paragraphs 68 and 71.
[5] Until 2015, ENMAX Power Corporation was regulated under a different form of PBR, a 2007-2013 formula-based ratemaking plan followed by cost-of-service rebasing in 2014.
[6] Decision 2012-237: Rate Regulation Initiative Distribution Performance-Based Regulation, Proceeding 566, September 12, 2012.
[7] Decision 20414-D01-2016 (Errata): 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, February 6, 2017.

during a PBR term, a utility's revenues were no longer linked to its costs. This decoupling of costs and revenues was intended to promote behaviours that increase productivity and decrease costs.

7. At the end of the PBR2 plan, each DFO's costs and revenues were realigned through a "rebasing" process[8] that involved a one-year cost-of-service (COS) review based on 2023 forecast costs. Under the COS regulatory framework, a regulator first determines the total amount of money required by a utility to provide its regulated services in a year. This is referred to as the revenue requirement, and it is made up of the total annual operation and maintenance (O&M) and administrative expenses of the company plus the utility's capital-related costs (depreciation, interest on debt, and return on equity (ROE)). Rates are then established by dividing the revenue requirement for each customer class by the billing units (such as the monthly charge, or dollars per kilowatt hour).

8. For ATCO Electric and Fortis, the 2023 rebasing was approved in Decision 26615-D01-2022 and ATCO Electric had certain directions applicable to it in Decision 26616-D01-2022. In addition to reviewing the 2023 forecast revenue requirement, Decision 26615-D01-2022 also included consideration of the efficiencies achieved by the DFOs and the sharing of those efficiency gains with customers, as well as an assessment of the prudence of actual costs incurred to-date by the DFOs during the PBR2 term.

9. In Decision 26615-D01-2022, the Commission also determined that the 2023 rates established as a result of the 2023 COS review will be used as "going-in rates" for the next PBR term, referred to as PBR3, which will commence on January 1, 2024.

10. In Decision 26615-D01-2022, the Commission directed several changes to the applied-for revenue requirement of both ATCO Electric and Fortis. In Decision 26616-D01-2022, the Commission directed certain further changes to ATCO Electric's applied-for revenue requirement pertaining to information technology (IT)/Customer Information System (CIS) costs. In the present application, ATCO Electric has filed information to support its compliance with those Commission directions.

11. In addition to responding to the Commission's directions, the utilities were also required to include, in their respective compliance filings, the calculation of 2023 rates based on the approved revenue requirement. Each utility was directed to include the following information that typically accompanies the calculation of rates in compliance filings:

- 2023 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.
- 2023 distribution tariff based on the approved revenue requirement and the associated bill impact analysis.
- Terms and conditions of service for 2023 for approval.

8 As explained in Decision 20414-D01-2016 (Errata), paragraph 26, depending on the context, the word "rebasing" can be used as a noun (the process of rebasing); an adjective (the rebasing process); or as a verb (the process involves rebasing costs and revenues).

- True-up of the prior approved deferral accounts such as the amounts included in the Y factor and 2021 TACDA true-up.

- Currently approved deferral accounts and rate riders, which shall continue to be applied in 2023. The differences between forecast and actual costs for amounts in these accounts will be trued up in future annual PBR rate adjustment filings.

- Any other items required to support the proposed 2023 distribution tariff.

12. The Commission has reviewed the entire record in coming to this decision; lack of reference to a matter addressed in evidence or argument does not mean that it was not considered.

3 Compliance with Decision 26615-D01-2022 and Decision 26616-D01-2022

13. In Decision 26615-D01-2022 and in Decision 26616-D01-2022 (pertaining to IT/CIS costs), the Commission ordered ATCO Electric to revise its applied-for 2023 revenue requirement to reflect the Commission's findings and directions in those decisions. The Commission's directions applicable to the present proceeding are set out in Appendix 2 to this decision.

14. ATCO Electric filed an updated forecast revenue requirement for 2023 of $443.3 million, reflective of the directions in Decision 26615-D01-2022 and Decision 26616-D01-2022, compared to the originally applied-for revenue requirement of $494.3 million in Proceeding 26615.[9] ATCO Electric also submitted Excel schedules to support its revised 2023 revenue requirement.

15. In this proceeding, the following aspects of ATCO Electric's compliance with Decision 26615-D01-2022 were identified: the Wildfires Mitigation Program (WMP) (Direction 25), escalation of certain 2023 O&M and capital costs forecast under the non-mechanistic approach, the calculation of income tax, and ATCO Electric's response to Direction 28 – Natural Resources Canada (NRCan) funding. There was also discussion arising from Direction 19 of Decision 26616-D01-2022, regarding the CIS Replacement Program. These issues are addressed in the sections below.

16. For all other directions, the Commission is satisfied that the 2023 revenue requirement filed by ATCO Electric complies with the directions set out in Decision 26615-D01-2022 and Decision 26616-D01-2022.

3.1 ATCO Electric filing subsequent to Decision 27672-D01-2022

17. After Decision D01 was issued, ATCO Electric revised its revenue requirement to $443.1 million[10] to reflect the directions in that decision. Specifically, the update corrected the

[9] Exhibit 27672-X0001, application, paragraph 8, Table 1.
[10] Exhibit 27672-X0064, Table 1; Exhibit 27672-X0066, Appendix B-1, Schedule 1.

carrying charges and removed the escalation of the non-mechanistic portion of the forecast for certain O&M costs and capital programs.[11]

18. The Commission has reviewed ATCO Electric's updated schedules filed in response to Decision D01 and finds that they satisfactorily addressed the directions in Decision 26615-D01-2022 and Decision 26616-D01-2022. Therefore, the Commission approves ATCO Electric's revised 2023 forecast revenue requirement of $443.1 million.

3.2 CIS Replacement Program

19. In Proceeding 26616, ATCO Electric stated that it is undertaking a replacement of its CIS, which is an in-house developed, custom-built application that currently supports customer care and billing functions, as well as meter management capabilities.[12]

20. In the current application, ATCO Electric updated the in-service date of its CIS Replacement Program, stating that several contributing factors have led to schedule delays. ATCO Electric stated that these delays were a result of several factors, including the requirement for rigorous testing across all levels, the amount of time to execute data conversion and reconciliation of legacy records, and the COVID-19 pandemic impacting resource availability. As a result, it estimated that the targeted go-live date for the Meter-to-Cash (M2C) project, which supports the tariff billing, would be changed from September 2022 to the end of Q2 2023. ATCO Electric explained that it was not seeking an increase to the forecast capital additions for the M2C project from the placeholder costs approved in Decision 26616-D01-2022.[13]

21. ATCO Electric requested approval to shift its forecast 2022 capital additions for the M2C project of $53.7 million from 2022 to 2023. The impact to its 2023 revenue requirement is a reduction of $13.7 million.[14]

22. The City of Calgary raised several issues with the shift of the in-service date of the CIS Replacement Program, including:

- The actual spend of $55.5 million, compared to the total forecast project cost of $70.1 million, is incongruent with ATCO Electric's indication that $53.7 million of CIS costs may need to be shifted to 2023. Calgary stated that if $55.5 million of those forecast project costs ($70.1 million) have already been booked as of September 2022, then only $14.6 million of costs remain to be incurred in 2023.[15]

- The shift in forecast costs may result in ATCO Electric seeking to avoid having to carry actual CIS project costs incurred to the end of 2022 into 2024 opening rate base.

- The shift of CIS costs should not prevent any subsequent testing by parties of the final CIS projects to be included in rate base to establish 2024 going-in rates.[16] The only reasonable explanation to account for the significant time delays in project

[11] Decision 27672-D01-2022, paragraph 2.
[12] Decision 26616-D01-2022, paragraph 253.
[13] Exhibit 27672-X0001, application, paragraphs 68-73.
[14] Exhibit 27672-X0001, application, paragraphs 74-75.
[15] Exhibit 27672-X0050, Calgary argument, paragraphs 13-14.
[16] Exhibit 27672-X0050, Calgary argument, paragraphs 8 and 16.

implementation is that the CIS system is "rife with defects, whether in design or otherwise." Any future proceeding to test the actual CIS costs should include assessment of the functionality and operability of the CIS.[17]

- If any CIS project costs were incurred under the IBM/Kyndryl contract, those costs should be reduced by the same amounts as ordered for IT managed services in Decision 26616-D01-2022.[18]

23. In response, ATCO Electric confirmed that total forecast spend is $68.3 million, not $70.1 million. Further, ATCO Electric explained that the CIS Replacement Program consists of two projects, one of which is complete and went live in September 2022, and thus was included as an addition to rate base in 2022 and the M2C project. ATCO Electric stated that the actual spend of $55.5 million as of September 2022 consists of $14.6 million for the already completed project and $40.9 million for the M2C project, which is included in construction work in progress until it goes live in 2023, at which time the capital addition (i.e., $53.7 million) would be included in rate base, which is in line with its submission that $53.7 million of costs would need to be shifted into 2023.[19]

24. ATCO Electric also noted that there are a number of factors that have contributed to the delayed testing and resolution of defects, none of which include the avoidance of having to carry actual CIS costs into 2024 opening rate base. ATCO Electric stated that Calgary has confused the opening 2024 rate base used for setting going-in rates for PBR3, submitting that the Commission determined that the forecast 2023 closing rate base will be used to fix going-in rates for PBR in 2024. As a result, forecast M2C project costs, not actual costs, would be included in going-in rates.[20]

25. ATCO Electric explained that for the project of this size, scope and complexity it is important to thoroughly test the system before it is launched. It is common and expected to find defects along the way and resolution of such defects leads to a higher quality system.[21]

26. ATCO Electric indicated that it has never suggested that the shift of the CIS Replacement Program costs to 2023 would avoid the prudence review contemplated in Decision 26615-D01-2022 that the Commission can examine "variances between the actual opening 2023 rate base and the 2022 placeholder amount in a future proceeding."[22]

27. ATCO Electric confirmed that any contemplated services under the MSA were forecast to be provided by Wipro and these costs were adjusted to reflect the Commission's prescribed rates resulting from the IT Common Matters Decision. ATCO Electric reduced its forecast by $1.8 million as directed in Decision 26616-D01-2022.[23] ATCO Electric further indicated that for actual costs charged to the projects for MSA services, the prescribed rates resulting from either

17 Exhibit 27684-X0060, Calgary reply argument, paragraphs 9 and 12.
18 Exhibit 27672-X0050, Calgary argument, paragraphs 9, 19-21.
19 Exhibit 27672-X0061, ATCO Electric reply argument, paragraphs 3-4.
20 Exhibit 27672-X0061, ATCO Electric reply argument, paragraphs 6 and 8.
21 Exhibit 27672-X0044, AE-CAL-2022OCT25-001(c).
22 Exhibit 27672-X0061, ATCO Electric reply argument, paragraph 7; Decision 26615-D01-2022, paragraph 233.
23 Exhibit 27672-X0001, application, paragraph 58.

Decision 20514-D02-2019,[24] respecting Wipro, or Decision 26616-D01-2022, respecting IBM/Kyndryl, have and will continue to be applied.[25]

28. The Commission considers that a delay in implementation does not necessarily suggest that the CIS Replacement Program is rife with defects. The Commission notes that the very nature of the testing stage of such replacement programs is designed to find and address defects. The Commission is not persuaded by Calgary's arguments that the delay in the in-service date for the program was strategically motivated to, for instance, avoid the prudence review of 2022 costs or to not reflect the full amount of capital additions for this program in the 2024 opening rate base. Rather, the Commission is persuaded that the delay is the result of testing and implementation issues that are not atypical for such a large, once-in-generation IT system replacement. However, the Commission acknowledges that delay may have unintended effects, as further discussed below.

29. The Commission agrees that shifting capital additions for the CIS Replacement Program to 2023 may have the effect of removing some of the costs of this program from a possible prudence review before setting the PBR3 going-in rates. This is because the Commission indicated in Decision 26616-D01-2022 that it may undertake a review of the prudence of 2022 actual capital additions and adjust the 2023 opening rate base accordingly; however, the 2023 closing rate base will be based on the approved 2023 forecast capital additions, with no true-up to actuals in setting the going-in rates.[26]

30. The Commission notes that it reviewed ATCO Electric's forecast for this program and approved it in Decision 26616-D01-2022. ATCO Electric confirmed that it is not seeking a change to its forecast costs as a result of the delayed implementation of the project and that the $13.7 million reduction to the 2023 forecast revenue requirement resulted primarily from the application of the mid-year convention.[27] The Commission is satisfied that ATCO Electric's actual spend for the CIS Replacement Program as of September 30, 2022, of approximately $55.5 million,[28] tracks reasonably closely to the information filed in Proceeding 26616 that underlined Commission approval. For these reasons, and consistent with its findings in Decision 26616-D01-2022, the Commission confirms that the going-in rates for PBR3 will be set based on approved 2023 forecast costs.

31. The Commission also acknowledges that, due to the application of the mid-year convention, the 2023 forecast rate base on which going-in rates for the PBR3 plan are based will reflect only half of the CIS Replacement Program capital additions shifted to 2023. This may or may not have an effect on the amount of incremental capital funding that ATCO Electric receives depending on the specifics of any approved capital funding mechanism. However, this issue would equally apply to any other large capital addition incurred in 2023. This, and other capital-related issues, will be considered in Proceeding 27388 to set the parameters of the PBR3 plans as part of the capital funding provision considerations.

24 Decision 20514-D02-2019: The ATCO Utilities (ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd.), Information Technology Common Matters Proceeding, Proceeding 20514, June 5, 2019.
25 Exhibit 27672-X0061, ATCO Electric reply argument, paragraph 9.
26 Decision 26615-D01-2022, paragraphs 57 and 233.
27 Exhibit 27672-X0044, AE-CAL-2022OCT25-002(a).
28 Exhibit 27672-X0044, AE-CAL-2022OCT25-001(d).

32. The Commission does not accept Calgary's suggestion that only such costs that were not spent in 2022 should be shifted to 2023,[29] i.e., $55.5 million of the CIS costs spent in 2022 as capital additions should be recorded to actual 2022 rate base. As ATCO Electric explained, consistent with widely accepted accounting standards, the costs for the M2C project would be included in construction work in progress until it goes live in 2023, at which time these costs would be added to rate base.

33. For the reasons set out above, the Commission finds ATCO Electric's updated 2023 forecast revenue requirement, which reflects the shift of capital additions for the CIS Replacement Program to 2023, to be reasonable.

3.3 Comprehensive Wildfire Mitigation Program

34. In response to Direction 25 of Decision 26615-D01-2022, ATCO Electric filed its Comprehensive Wildfire Mitigation Program (CWMP) monitoring proposal. ATCO Electric states that its proposal is a cost-effective approach to monitor the progress of its CWMP and measure the effectiveness of related capital expenditures and includes the processes and procedures required to: (i) track and report all details relating to wildfire incidents; (ii) identify the measures to be implemented to resolve the incidents; and (iii) assess the effectiveness of those measures in mitigating the incidents.[30]

35. As part of its CWMP monitoring proposal, ATCO Electric has proposed that incident tracking and reporting processes be improved by standardizing data collection for wildfire incident tracking, which will result in simplified analysis and the ability to identify long-term and emerging trends.[31] In its proposal, ATCO Electric stated that a summary of wildfire incidents, including any external variables that influenced wildfire incidents, and an analysis of historical wildfire incidents will be presented to senior leadership annually.[32]

36. ATCO Electric proposed three measures that it said will allow it to monitor the effectiveness its capital investments: the number of outages related to vegetation contact with powerlines, the number of wildfire incidents related to vegetation contact with powerlines, and the number of wildfire incidents due to powerline assets/equipment. While external variables, such as higher-than-average wind or precipitation levels, can lead to significant variability in the number of wildfire incidents, ATCO Electric submitted that analyzing these measures from a long-term perspective will allow for the assessment of mitigation measures.[33]

37. In response to a Commission IR, ATCO Electric explained that its CWMP monitoring proposal is cost-effective as it relies on enhancements to existing processes and tools, which can be adopted with modest additional costs and is a more cost-effective approach than creating one or more entirely new systems. For example, the improved quality and standardization of the

[29] Exhibit 27672-X0050, Calgary argument, paragraph 14.
[30] Exhibit 27672-X0001, application, PDF page 54.
[31] Exhibit 27672-X0001, application, PDF pages 55-56. ATCO Electric also noted that outages from vegetation contact is an indicator of wildfire incidents as ignition depends on a number of environmental factors, such as wind and humidity. Exhibit 27672-X0001, application, PDF page 55.
[32] Exhibit 27672-X0001, application, PDF pages 56-57.
[33] Exhibit 27672,X0001, application, PDF page 58. In Exhibit 27652-X0047, AE-CCA-2022OCT25-001(c), ATCO Electric explained that a year-over-year comparison should be avoided as external variables can cause significant variance in wildfire incidents, and it is not common practice or practical to make annual adjustments to its CWMP to account for such externalities.

incident data collected at the initial reporting phase of the wildfire incident will allow for cost-effective analysis and trending. Further training of first-responder field employees in wildfire incident investigation is cost effective as it reduces the requirement for follow up site visits to determine wildfire incident causes, or ignition mechanisms. Also, since ATCO Electric is already required to report wildfire incidents in accordance with its Wildfire Agreement with the Government of Alberta (GOA), the CWMP monitoring proposal is not anticipated to result in a significant increase in cost. A further cost-effective component is the collaborative work undertaken with the GOA and the other Alberta electrical utilities as a member of the Power Line Wildfire Prevention Task Group to create an Alberta-specific Electrical Utility Wildfire Mitigation Best Practice. As part of this best practice, the wildfire incident investigation process and associated data collection will become standardized across the electric utilities that operate within the Forest Protection Area.[34]

38. Further, ATCO Electric explained that it provided a realistic and reasonable schedule for the proposed deliverables. To be cost-effective, ATCO Electric will implement the CWMP monitoring proposal using existing resources, including its registered professional foresters who have existing obligations and responsibilities in addition to implementation of the CWMP monitoring proposal. As such, it would be difficult to condense the milestones without increasing costs or negatively impacting quality.[35]

39. The Consumers' Coalition of Alberta (CCA) expressed concern that the CWMP monitoring proposal was not cost-effective as ATCO Electric did not identify the cost of each individual process within the proposal, nor did it attempt to identify and quantify the benefits to be obtained.[36] Additionally, the CCA raised concern with ATCO Electric's milestone dates for key deliverables and submitted that the schedule for implementing the proposal was "unacceptably slow" and suggested that ATCO Electric develop its CWMP monitoring proposal on an accelerated schedule.[37]

40. The Commission has reviewed the CWMP monitoring proposal as well as related information request (IR) responses, and has also considered the views put forward by the CCA in this proceeding. The Commission notes that its direction did not expressly impose a particular time frame within which ATCO Electric must develop a cost-effective monitoring proposal, nor did it require ATCO Electric to propose a quantifiable cost-benefit analysis to support its Wildfire Mitigation Program. While the submissions of the CCA are relevant and reasonable, the Commission finds that ATCO Electric's proposal meets the requirements stipulated in Direction 25 of Decision 26615-D01-2022, and that ATCO Electric has complied with this Commission direction. The Commission directs ATCO Electric to provide an update on the implementation of its CWMP monitoring proposal as part of an application to establish 2024 rates. As part of this update, ATCO Electric is to provide a status update on the key deliverable milestones proposed in Table 2 of its CWMP monitoring proposal.

34 Exhibit 27672-X0001, application, PDF page 52.
35 Exhibit 27672-X0039.01, AE-AUC-2022OCT25-002(a)-(b).
36 Exhibit 27672-X0056, CCA revised argument, paragraph 15.
37 Exhibit 27672-X0056, CCA revised argument, paragraph 4.

3.4 Non-mechanistic O&M and capital programs

41. In its application, ATCO Electric updated the non-mechanistic portion of the forecast[38] to adjust by the escalation factors approved in Section 5.2 of Decision 26615-D01-2022 for the following O&M and capital programs:

- O&M USA account 593.1: Vegetation Management
- O&M USA account 583: Overhead Line Expenses
- The non-mechanistic portion of the Wildfires Mitigation Capital Program
- Non-Mechanistic Transportation Equipment capital subprogram within the General Support Program
- New capital Grid Modernization Program

42. In response to a Commission IR, ATCO Electric explained that it had used the applied-for escalation factors in its derivation of these forecast costs to account for cost increases in doing the work. ATCO Electric also stated that this is consistent with the Commission's direction in Decision 26615-D01-2022 in footnote 2 where the Commission stated that the precise amount of disallowance for the Overhead Line Expenses O&M account (USA 583) program may be affected by the Commission's findings on escalation factors, i.e., ATCO Electric was to recalculate using approved escalators, and then apply the reduction directed by the Commission in that decision.[39]

43. In its argument, the Office of the Utilities Consumer Advocate (UCA) stated that in Decision 26615-D01-2022, the Commission indicated that it found the escalation factors useful for non-mechanistic costs only in terms of variance explanations and it did not expect any update to the escalation factors to have any impact of the non-mechanistic forecasts.[40]

44. In Decision 26615-D01-2022, the Commission accepted the hybrid approach in forecasting 2023 costs put forward by ATCO Electric in forecasting its 2023 capital additions and O&M costs.[41] ATCO Electric's hybrid approach consisted of a combination of mechanistic forecasts, based on the escalated actual 2018-2020 average costs, and non-mechanistic forecasts, that used a bottom-up forecasting methodology, to arrive at the overall O&M and capital forecast. For some capital programs, ATCO Electric used both methods (i.e., it forecast costs using the mechanistic approach for some projects within a capital grouping and used the non-mechanistic approach for other projects within that capital grouping).[42]

[38] As explained in Decision 26615-D01-2022, at paragraph 27, a non-mechanistic approach, or a "bottom-up" methodology, is a traditional way to forecast costs under COS regulation.
[39] Exhibit 27672-X0039.01, AE-AUC-2022OCT25-006, AE-AUC-2022OCT25-007 and AE-AUC-2022OCT25-008.
[40] Exhibit 27672-X0052. UCA argument, paragraph 11.
[41] Decision 26615-D01-2022, paragraphs 4 and 197.
[42] Decision 26615-D01-2022, paragraphs 196 and 312.

45. At paragraph 6 of Decision 26615-D01-2022, the Commission directed ATCO Electric to recalculate its respective 2023 forecasts under the mechanistic approach to reflect the escalation factors approved in that decision.

46. The Commission agrees with the UCA that ATCO Electric was directed to update only the mechanistic portion of the forecast, i.e., the three-year average for the above five O&M and capital programs by the approved escalation factors. Therefore, the Commission denies the adjustment for any portion of the forecast that is above the three-year average. As stated by the Commission in Decision D01 at paragraph 2, "The non-mechanistic portion of the forecast for the above five O&M and capital programs, i.e., the incremental amount above the three-year average, should not be adjusted by the escalation factors approved in Section 5.2 of Decision 26615-D01-2022."

3.5 Calculation of income tax

47. In an IR, the Commission asked ATCO Electric to elaborate on the income tax deferral refund of $14.232 million for 2023.[43] ATCO Electric explained that a majority of the refund was attributable to the 2021 rate relief deferral program approved in Decision 26170-D01-2020.[44] The Commission has reviewed the breakdown of the income tax refund attributable to the rate relief deferral program and the other factors that make up the deferral and is satisfied that the calculations were done correctly.

48. In its argument, the UCA expressed concern that the reduction in capital expenditure related to directions 26, 27 and 28 in Decision 26615-D01-2022 and the subsequent removal of capital cost allowance related to the programs resulted in the increased income tax which alters the 2023 revenue requirement in a way that will artificially increase going-in rates for the next PBR term.[45] The UCA further submitted that the Commission should provide direction that there could be an adjustment related to this issue in the PBR3 Proceeding 27388. However, the UCA did not dispute the income tax calculations made by ATCO Electric.[46]

49. In its reply argument, ATCO Electric noted that the UCA's concern is outside the scope of this proceeding, and on the basis of the UCA not disputing the income tax calculations, the Commission should approve its compliance with directions 26, 27 and 28.[47]

50. The Commission is not convinced that the change in capital cost allowance amounts resulting from the reduction in capital expenditures in response to the Commission directions warrants a direction for inclusion in Proceeding 27388. Further, any increase to the revenue requirement in 2023 attributable to changes in the capital cost allowance is a feature of the income tax calculations, which were not disputed by the UCA; therefore, the Commission approves the income tax calculations as filed.

3.6 Natural Resources Canada funding

51. In Decision 26615-D01-2022, the Commission considered a new Grid Modernization Program (GMP) proposed by ATCO Electric to ensure its distribution system can accommodate

[43] Exhibit 27672-X0034, AE-AUC-2022OCT25-001.
[44] Exhibit 27672-X0039.01, AE-AUC-2022OCT25-001.
[45] Exhibit 27672-X0052, UCA argument, paragraph 26.
[46] Exhibit 27672-X0052, UCA argument, paragraph 26.
[47] Exhibit 27672-X0061, ATCO Electric reply argument, paragraphs 18 and 19.

a fundamental shift in grid usage that will be brought about by a rise in Distributed Energy Resources, electric vehicles, and decarbonization efforts.[48] The GMP comprises three categories of projects: Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI) and Asset Modernization projects. ADMS will provide a foundation that enables other operational functions and advanced capabilities and uses information received from AMI and Supervisory, Control and Data Acquisition (SCADA) devices. AMI will collect grid data such as real-time outage and energy usage data. Asset modernization projects will provide data and remote visibility and control at key devices, the ability to identify the location of system issues and the ability to then remotely reconfigure the system to address these issues.[49]

52. ATCO Electric applied for grant funding in the 2022-2024 period through NRCan's Sustainable Resource Electrification Pathways (SREP) program. In the hearing for Proceeding 26615, ATCO Electric confirmed that it had secured funding of 50 per cent of its expenditures for the ADMS project and that applications for the remaining two projects (i.e., AMI and Asset Modernization projects) were in progress.[50]

53. In Decision 26615-D01-2022, the Commission found the GMP to be reasonable and approved the 2023 forecast capital additions subject to adjustments to reflect the approval of the NRCan grant for the ADMS project and any other subsequent grants received from NRCan for the Asset Modernization and AMI projects.[51]

54. In response to Direction 28, ATCO Electric confirmed that it had reflected the grant secured from NRCan in the amount equal to 50 per cent of the ADMS project capital addition. Specifically, out of the total 2023 forecast capital additions of $5.9 million for this project, $2.95 million was recorded as a contribution (i.e., an offset to rate base).[52]

55. The UCA asked ATCO Electric to assess the possibility that the funding for this project may not materialize if there is a change in policy or government. The UCA also asked ATCO Electric to explain all impacts if this project carries forward into 2024. In response, ATCO Electric explained that the contribution agreement executed between NRCan and ATCO Electric does not include changes in government policy, nor federally elected officials in the termination provisions. ATCO Electric indicated that the funding is available for a three-year period starting in 2022 and, accordingly, will still be available if the ADMS project carries forward into 2024. ATCO Electric stated further that there is a "low likelihood" that the funding will not materialize.[53]

56. The Commission has reviewed the updated schedules and is satisfied that ATCO Electric has recorded 50 per cent of its 2023 forecast costs in the amount of $2.95 million as a contribution to reflect the grant for the ADMS project. Given the above, the Commission is satisfied that ATCO Electric has complied with the direction at paragraph 373 of Decision

48 Decision 26615-D01-2022, paragraph 364.
49 Decision 26615-D01-2022, paragraphs 365-366.
50 Decision 26615-D01-2022, paragraph 367.
51 Decision 26615-D01-2022, paragraph 372.
52 Exhibit 27672-X0001, application, paragraph 47; Decision 26615-D01-2022, paragraph 365, Table 25; Exhibit 27672-X0066, Appendix B-1, Schedule 4.2.
53 Exhibit 27672-X0045, AE-UCA-2022OCT25-004(a)-(c).

26615-D01-2022. The 2023 forecast capital additions costs for the ADMS project are also approved.

57. As for the status of its NRCan grant applications for the AMI and Asset Modernization projects, ATCO Electric explained that NRCan has not yet resumed accepting and processing project applications for the SREP program. However, once the program resumes in the fall, ATCO Electric indicated that as an existing SREP applicant, it will submit an updated application for AMI and Asset Modernization projects. ATCO Electric noted that new applicants will only be invited to apply once existing applicants have had sufficient time to update and resubmit their applications.[54]

58. The Commission is satisfied with the explanation provided by ATCO Electric regarding the status of its NRCan grant applications for the AMI and Asset Modernization projects. The Commission acknowledges that the SREP program had not resumed at the time of the compliance filing. ATCO Electric is therefore directed to provide the updated status of its NRCan grant applications for the AMI and Asset Modernization projects, including any information it may have on whether it has secured or is likely to secure the grants, in an application dealing with 2024 rates. If one or more of the grant applications are approved, ATCO Electric is directed to remove the amount of any grant funding from its 2023 forecast costs for the relevant projects in the application dealing with 2024 rates. If the status of the grant application is not available at that time, the Commission will consider whether any adjustments are required to ATCO Electric's forecasts for these projects based on the information provided at the time of the application dealing with 2024 rates.

4 2023 rate adjustments

59. As noted above, the purpose of this proceeding is for the Commission to consider both ATCO Electric's compliance with Decision 26615-D01-2022 and Decision 26616-D01-2022, and to determine ATCO Electric's distribution rates for 2023, based on the revenue requirement resulting from the approvals in those decisions. As such, the Commission has reviewed the rate adjustment aspect of ATCO Electric's application in much the same way as it has done in past annual PBR rate adjustment filings.

60. ATCO Electric applied for updates to its K-bar factor and Y factor, including an efficiency carryover mechanism (ECM). ATCO Electric did not apply for any rate adjustments associated with Type 1 capital trackers or Z factor.

4.1 2021 actual costs

61. In Decision 26615-D01-2022, the Commission stated it was prepared to accept the non-audited 2021 actual costs as prudently incurred unless otherwise noted in that decision or in Decision 26616-D01-2022. The Commission also indicated that its finding would be subject to the review of each utility's explanations for any variances between the non-audited 2021 actual expenditures filed in that proceeding in April 2022 and the audited costs reported in the 2021

[54] Exhibit 27672-X0001, application, paragraphs 47-49.

Rule 005: *Annual Reporting Requirements of Financial and Operational Results* filings as part of this compliance filing.[55]

62. ATCO Electric recorded an O&M variance of approximately $15,000 between preliminary and final actuals, and a capital additions variance of approximately $6,000. ATCO Electric explained that the variances were due to a cost-coding correction and rounding.[56] The Commission finds ATCO Electric's explanations to be reasonable and confirms its finding in Decision 26615-D01-2022 that ATCO Electric's 2021 costs were prudently incurred.

4.2 Y factor deferral accounts

63. Under PBR, Y factors include costs that do not qualify for capital treatment or Z factor treatment that the Commission considers should be directly recovered from or refunded to customers. ATCO Electric applied for the inclusion of Y factor amounts in its 2023 rates as these cost items continue to be subject to the previously established deferral account treatment in the 2023 COS year.

64. A summary of the proposed Y factor amounts is shown in Table 1 with each line item briefly explained below:

Table 1. Applied-for 2023 Y factor amounts[57]

Item	2023 ($000)
2023 deferral account placeholders	8,819
Deferral account true-ups as of July 31, 2022	(14,615)
Other proceeding true-ups	(4,431)
Efficiency carryover mechanism (Note 1)	6,813
Y factor adjustments	**(3,414)**
Carrying charges (Note 2)	(149)
Total Y factor adjustment net of carrying charges	**(3,563)**

Note 1: In Section 4.2.1 of this decision, the Commission directs ATCO Electric to revise the applied-for ECM amount at the time of the true-up.
Note 2: ATCO Electric reported carrying charges separately and did not include them as part of its Y factor adjustments. Since these relate to amounts shown in the table, they have been included.
Note 3: This table does not include the Y factor costs that are recovered by way of separate riders or rates (such as transmission access costs).

65. Deferral account placeholders are ATCO Electric's 2023 forecasts for the following costs: combined AUC and intervener costs, distribution to transmission contributions, Alberta Electric System Operator (AESO) load settlement costs. These placeholders will be trued up to actual incurred costs once they become available. Deferral account true-ups represent the true-up of combined AUC and intervener costs, AESO load settlement costs and deductions of deferrals for income taxes to actual costs as of July 31, 2022. Other proceeding true-ups include the 2021 K-bar true-up refund of $2.1 million (on a final basis) and 2022 K-bar true-up refund of $2.3 million (on an interim basis) to reflect the 2021 actual cost of debt.

55 Decision 26615-D01-2022, paragraph 231.
56 Exhibit 27672-X0001, application, Table 16 Variance between Final 2021 Actual and Preliminary 2021 Actual, PDF page 28, paragraph 77.
57 Exhibit 27672-X0001, application, Table 17, PDF page 29; Exhibit 27672-X0039.01, AE-AUC-2022OCT25-004 REVISED November 7, 2022; Exhibit 27672-X0049, AE-AUC-2022OCT25-004(c), Attachment 3.

66. The calculation of the ECM amounts is addressed in Section 4.2.1 of this decision.

67. With respect to the calculation of carrying charges, in response to a Commission IR, ATCO Electric indicated it inadvertently used the Bank of Canada monthly bank rate instead of the Bank of Canada policy interest rate as stipulated in the updated Rule 023: *Rules Respecting Payment of Interest* that came into effect on March 1, 2022. ATCO Electric revised its carrying charges calculations to comply with Rule 023 requirements, and proposed a revised carrying charge refund of $0.149 million. ATCO Electric provided details of the calculations in Appendix E.[58] [59]

68. With the exception of ECM amounts (addressed is Section 4.2.1), the Commission approves the inclusion of the applied-for Y factor amounts in 2023 rates as these amounts are treated under long-standing, approved deferral accounts for ATCO Electric. The Commission has also reviewed ATCO Electric's carrying costs provided in an IR response and finds that they are properly calculated and consistent with the applicable provisions of Rule 023. The Commission reviewed the calculations of forecast and true-up components of the 2023 Y factor and finds them to be accurate and consistent with previously approved methodologies.

4.2.1 ECM

69. A utility's incentive to find efficiencies weakens as the end of the PBR term approaches because there is less time remaining for the utility to benefit from any efficiency gains. The Commission approved the inclusion of the efficiency carryover mechanism, or ECM, to address this weakening of incentives by permitting the utilities to carry a portion of earnings in excess of the approved ROE from the prior PBR term to the following years. The ECM was approved for both the PBR1 and PBR2 plans.

70. Specifically, the ECM ROE add-on is calculated as 50 per cent of the difference between the average allowed and average actual ROEs over the course of a PBR term, with an upper limit of 0.5 per cent. This ROE add-on applies for two years after the end of a PBR plan and is collected by way of a Y factor.[60]

71. In Decision 20414-D01-2016 (Errata), the Commission pointed out that it is necessary to determine the rate base or rate bases to which the approved ROE add-on percentage will be applied in order to calculate the associated ECM dollar amount to be included in customer rates. In that decision, the Commission approved an ECM calculation based on the mid-year rate base during the final year of the PBR1 term. Consistent with the overall approach to the PBR2 rebasing, the Commission directed the final approved 2017 notional mid-year rate base as the value to which the approved ROE add-on percentage would be applied, with an escalation of the calculated ECM dollar amount by the approved I-X value for each of 2018 and 2019 to arrive at the ECM dollar amounts for each of those years. Finally, in that decision, the Commission stated that the same ECM calculation would also apply to determine the ECM dollar amounts for the PBR2 term.[61]

58 Exhibit 27672-X0039.01, AE-AUC-2022OCT25-004 REVISED November 7, 2022; Exhibit 27672-X0049, AE-AUC-2022OCT25-004(c), Attachment 3.
59 Exhibit 27672-X0068, Appendix E – Carrying charges.
60 Decision 20414-D01-2016 (Errata), paragraph 79.
61 Decision 20414-D01-2016 (Errata), Appendix 5, PDF page 100.

72. ATCO Electric showed that, based on its returns over the PBR2 term, it qualifies for the maximum allowed ECM ROE add-on of 0.5 per cent. ATCO Electric calculated the interim 2023 ECM dollar amount of $6.8 million (shown in Table 1 above) by applying the add-on of 0.5 per cent to the 2023 forecast rate base.

73. In support of this approach, ATCO Electric noted that as the 2017 notional mid-year rate base formed the basis of going-in rates for the PBR2 plan, ATCO Electric applied the ECM calculation to its 2023 forecast mid-year rate base that will form the basis of its going-in rates for the PBR3 plan. ATCO Electric asserted that this is consistent with the PBR1 and PBR2 terms and eliminates the need to escalate 2022 values into 2023 dollars.

74. In an IR, the Commission asked ATCO Electric to comment on the use of the 2022 mid-year rate base in the ECM calculation, as was done by Apex and EPCOR. ATCO Electric stated that using the 2022 mid-year rate base aligns with paragraph 83 of Decision 20414-D01-2016 (Errata) where the Commission indicated that the ECM should be calculated using the mid-year rate base during the final year of the PBR term. However, ATCO Electric also pointed out that doing so would depart from the use of the mid-year rate base used to form going-in rates as selected by the Commission in paragraph 84 of Decision 20414-D01-2016 (Errata). In addition, ATCO Electric observed that there is no I-X index for the 2023 COS year (to translate the ECM dollars into 2023 amounts), which it said is a further departure from the methodology approved in Decision 20414-D01-2016 (Errata).[62]

75. The interveners did not comment on this issue.

76. The Commission finds that the 2023 ECM dollar amount will be calculated based on the 2022 actual approved mid-year rate base. In Decision 20414-D01-2016 (Errata), the Commission based the ECM calculation on the mid-year rate base during the final year of the PBR term. In support of this approach, the Commission stated that because the ECM ROE add-on percentage is calculated based on a utility's earnings in the PBR term, it should not be applied to the actual rate base amounts outside of that term.[63] The Commission continues to find this approach to be reasonable and further notes that to the extent a utility's 2023 rate base is different from its 2022 rate base, basing the ECM calculation on the 2023 mid-year rate base may result in windfall gains or losses to the utility.

77. In Decision 20414-D01-2016 (Errata), the Commission explained that the choice of the 2017 notional mid-year rate base (rather than an actual 2017 rate base) was reflective of the overall rebasing approach for the PBR2 plan.[64] In the Commission's view, such choice was not meant to be inconsistent with the separate determination to base the ECM calculation on the mid-year rate base of the final year of the PBR term.

78. ATCO Electric pointed out that if an ECM dollar amount is calculated based on 2022 mid-year rate base, a true-up to reflect the 2022 actual rate base is required to fully align with the utility's actual experience in the PBR2 term. The Commission agrees given the determinations in Decision 26616-D01-2022 that the 2022 actual closing rate base will form the basis of the

62 Exhibit 27672-X0039.01, AE-AUC-2022OCT25-009 (a-b).
63 Decision 20414-D01-2016 (Errata), paragraph 83.
64 Decision 20414-D01-2016 (Errata), paragraph 84.

mid-year rate base used to establish going-in rates for the PBR3 term.[65] Also, a true-up may be required to reflect the actual 2022 ROE as it may affect the ECM ROE add-on percentage.

79. ATCO Electric also pointed out that an ECM dollar amount calculated using the 2022 mid-year rate base should be escalated for 2023 and 2024, consistent with the methodology approved in Decision 20414-D01-2016 (Errata). As noted earlier, ATCO Electric noted that there is no I-X index for an intervening 2023 COS year. As such, ATCO Electric proposed to use the approved 2023 COS inflation escalator to escalate the ECM amount to 2023. Similarly, it submitted that the approved inflation for 2024, which is yet to be determined, should be used to escalate the ECM amount to 2024 dollars. ATCO Electric argued that an X factor should not be applied to the inflation of the ECM amount as it was not incorporated in the COS rebasing method for PBR3.

80. The Commission finds that it is reasonable to escalate the ECM dollar amount calculated using the 2022 mid-year rate base using the 2023 COS inflation escalator of 2.68 per cent approved in Decision 26615-D01-2022. Doing so is consistent with the Commission's approvals in that decision and the overall COS approach to rebasing. However, as the PBR3 plan starts on January 1, 2024, the Commission finds that the ECM dollar amount should be escalated for 2024 by the index approved in the PBR3 plan. This is consistent with the methodology in Decision 20414-D01-2016 (Errata).

81. Given the relatively small difference between using mid-year 2022 and mid-year 2023 as the basis for calculating the 2023 ECM dollar amount,[66] and the interim nature of this amount (as explained above), there is no need to update the 2023 rates at this time. The Commission directs ATCO Electric to true up its 2023 ECM dollar amount, reflecting the findings and methodology approved in this decision, upon the approval of the 2022 actual rate base.

4.3 Forecast billing determinants

82. Forecast billing determinants are used to allocate a DFO's revenue requirement to rate classes and to calculate the resulting rate adjustments.

83. In its application, ATCO Electric filed detailed 2023 billing determinant forecasts.[67] ATCO Electric submitted that its forecast 2023 billing determinants were based on the same methodology approved in prior PBR annual rate adjustment applications and reflect the forecasting methodology approved in its last Phase 2 decision, Decision 25645-D01-2020.[68] [69]

84. In Decision 26849-D01-2021, the Commission directed ATCO Electric to continue to provide information on any variances from forecast to actual billing determinants by rate class and to identify variances larger than ± five per cent on an annual basis.[70] In the application, ATCO Electric reconciled forecast and actual billing determinants from 2021 and noted variances of larger than ± five per cent for the small general service rate D21P, irrigation, REA

65 Exhibit 27672-X0039.01, AE-AUC-2022OCT25-009(c).
66 In Exhibit 27672-X0043, AE-AUC-2022OCT25-009(d) Attachment 1, ATCO Electric showed that using the 2022 mid-year rate base would result in a 2023 ECM dollar amount of $6.6 million.
67 Exhibit 27672-X0071, Appendix H, schedules S.1 and S.2.
68 Decision 25645-D01-2020: ATCO Electric Ltd., 2019 Distribution Tariff Phase II Compliance Filing, Proceeding 25645, July 23, 2020.
69 Exhibit 27672-X0001, application, paragraph 135.
70 Decision 26849-D01-2021, paragraph 36.

irrigation, both large general service rate classes, oilfield, street light rate classes and sentinel light rate classes in 2021.[71]

85. In an IR response, ATCO Electric provided a variance calculation and explanation for the small general service Rate D22 rate class, which it said was inadvertently missed in the application.[72] The Commission has reviewed the variance calculation and is satisfied with the provided explanation.

86. No party objected to ATCO Electric's billing determinant forecast or its variance explanations.

87. The Commission considers ATCO Electric's explanation for the billing determinant variances from forecasts to be reasonable. ATCO Electric explained that seasonal trends affected consumption, differences between actual and forecast demand differences and higher AESO costs, which are flow-through costs. Finally, ATCO Electric noted that its relatively small rate classes create disproportionately high variances. Such variances do not generally call into question the predictive value of the methodology used to generate the forecasts. The Commission directs ATCO Electric to continue to provide information on any variances from forecast to actual billing determinants by rate class and to identify the cause of variances larger than ± five per cent on an annual basis.

88. The Commission finds that the methodology and the resulting 2023 forecast billing determinants are reasonable. Accordingly, the billing determinant forecast is approved, as filed.

5 2021 TACDA true-up

89. All electric distribution utilities accessing the electric transmission system in the province are charged by the AESO for transmission services provided in relation to customers in their service areas. The purpose of the annual TACDA true-up is to ensure that revenues collected through a distribution utility's transmission access charges in a year recover the AESO tariff charges paid by the utility in that year.

90. In PBR plans, as a dollar-for-dollar flow-through of the AESO tariff charges, TACDA amounts were eligible for Y factor treatment. The same treatment is extended to the 2023 COS year. The utility does not assume any volume or price risk, but also does not earn any return, nor risk losses, in flowing through these costs to customers.

91. The annual TACDA true-up schedules are based on the harmonized framework approved by the Commission for all four distribution utilities in Decision 3334-D01-2015.[73]

71 Exhibit 27672-X0071, Appendix H, Schedule S.4.
72 Exhibit 27672-X0039.01, AE-AUC-2022OCT25-010, PDF pages 39 and 40.
73 Decision 3334-D01-2015: Commission-Initiated Review, Electric Transmission Access Charge Deferral Accounts – Annual Applications, Proceeding 3334, Application 1610728-1, July 21, 2015.

5.1 Total net true-up amount

92. ATCO Electric applied for a net 2021 TACDA collection of $3.344 million from customers. The components of the total applied-for true-up amount are listed in Table 2 and are further described in this section:

Table 2. Components of the applied-for 2021 TACDA true-up Rider G

Component	True-up amount collection/(refund) ($ million)	Methodology to attribute the true-up amount to rate classes
2019 TAC deferral account true-up	0.16	Determined as the difference between the amount approved for collection or refund by rate class and the amount actually collected or refunded for each rate class.
2021 SAS deferral true-up	5.99	AESO costs are allocated to rate classes using ATCO Electric's Phase 2 cost-of-service methodology underlying its SAS rates, with the exception of Rate T31 for transmission direct-connect customers. Since Rate T31 customers are billed on a flow-through basis, no amounts have been allocated to this customer class.
2021 AESO deferral account reconciliation (DAR) true-up	(2.02)	Allocated to the rate classes (excluding Rate T31) in proportion to the actual 2021 energy consumed by rate class.
2021 Balancing Pool true-up	(1.17)	Allocated to rate classes (Rate T31) in proportion to the actual 2021 energy consumption by rate class.
Carrying costs	0.38	Allocated to the rate classes in proportion to their deferral balances (for which carrying costs have been assessed) allocated to them in the preceding components of this true-up calculation.
Total collect/(refund)	**3.34**	**Calculated as the sum of all items**

Source: Exhibit 27672-X0024, Appendix O, paragraph 10.

93. The deferral account rider true-up ensures that the amounts actually collected or refunded through a previously approved rider equal the amounts approved by the Commission. In 2021, ATCO Electric was approved to collect $6.48 million through TACDA true-up Rider G.[74] The actual collection was $6.32 million, necessitating a further collection of $0.16 million.

94. The SAS deferral true-up ensures the actual transmission access revenues received from SAS rates and related quarterly riders equals the actual transmission costs incurred. ATCO Electric's total 2021 transmission access revenues for distribution-connected customers, including revenues received through its quarterly TACDA true-up riders, amounted to $337.12 million which, compared to total costs of $343.11 million, results in a required collection of $5.99 million.

95. The AESO DAR deals with any variances between the actual costs the AESO incurs and the revenues it receives to ensure that "… on an annual basis, no profit or loss results from its operation."[75] Any such variances are refunded to, or recovered from, market participants by way of the AESO DAR, typically undertaken on an annual basis. The distribution utilities flow through these collections or refunds to customers in their service areas. The Commission

[74] Exhibit 27672-X0024, Appendix O, paragraph 14.
[75] Under Section 14(3) of the *Electric Utilities Act*.

approved the AESO's 2021 DAR in Decision 27547-D01-2022.[76] The reconciliation resulted in a $2.02 million refund to ATCO Electric's customers.

96. ATCO Electric's Balancing Pool true-up ensures that its Balancing Pool refund to, or collection from, its customers matches its settlement with the AESO.[77] In 2021, the AESO collected $27.72 million from ATCO Electric. Due to differences between forecast and actual billing determinants, ATCO Electric collected $28.891 million from its customers in 2021, necessitating a net refund of $1.17 million.

97. ATCO Electric calculated carrying costs on outstanding amounts related to the true-up balances in accordance with Rule 023.[78] The rate used was the Bank of Canada's target for overnight interest rates plus 1.75 per cent.[79] The total carrying costs amounted to a $0.381 million collection from customers.

98. ATCO Electric's application and schedules are consistent with the harmonized framework approved by the Commission in Decision 3334-D01-2015. The Commission finds the amounts comprising the 2021 annual TACDA true-up to be reasonable. The Commission also finds the assignment of the individual components of the 2021 TACDA true-up to rate classes to be consistent with previously approved methodologies and reasonable in the circumstances. Accordingly, the Commission approves a net collection of $0.381 million set out in Table 2 of this decision.

5.2 Rider G rate and effective period

99. ATCO Electric proposed to apply the 2021 annual TACDA true-up by way of a Rider G. To smooth rates over time and promote rate stability, ATCO Electric proposed Rider G to be in effect over a 12-month period from January 1, 2023, to December 31, 2023.

100. ATCO Electric calculated Rider G by summing the 2021 TACDA true-up components and related carrying costs by rate class and divided these amounts by the 2023 forecast billing determinants. The resulting true-up amounts and the proposed Rider G rate are set out in the table below:

76 Decision 27547-D01-2022: Alberta Electric System Operator, 2021 Deferral Account Reconciliation, Proceeding 27547, August 18, 2022.

77 Under Section 82 of the *Electric Utilities Act*, each year the Balancing Pool is required to forecast its revenues and expenses to determine any excess or shortfall of funds. Based on this forecast, the Balancing Pool determines an annualized amount that will be refunded to, or collected from, electricity consumers over the year "… so that no profit or loss results, after accounting for the annualized amount under section 82(7) as a revenue or expense of the Balancing Pool." This amount, known as the consumer allocation, applies to all market participants who receive SAS from the AESO and is recovered through Rider F of the AESO tariff. The consumer allocation is based on the amount of electric energy consumed annually. In 2021, the Balancing Pool charged a consumer allocation of $2.20 per megawatt hour (MWh), which was unchanged in 2022.

78 Rule 023 applies as the lag in the implementation of the refund exceeds 12 months and the revenue amount is sufficient per Section 3(2)(c) to warrant the awarding of carrying costs.

79 Exhibit 27672-X0024, Appendix O, paragraph 23.

Table 3. True-up amounts and proposed Rider G rate by rate class

Rate class	Total true-up ($)	Rider G rate ($/kWh)
Residential	(1,361,310)	(0.00123)
Small General Service	(1,290,679)	(0.00150)
Irrigation Pumping Service	25,112	0.00761
Large General Service	5,749,331	0.00088
Transmission Connected	-	-
Oil Field	(343,643)	(0.00116)
REA Farm Service	122,898	0.00170
Farm Service	470,842	0.00110
Street Lights	(22,380)	(0.00142)
Private Lights	(6,216)	(0.00283)
Total	**3,343,956**	

Source: Exhibit 27672-X0025, Appendix O – Attachment 1, Schedule 1.0.

101. As shown in Table 3, while the net true-up amount results in a collection, Rider G across individual rate classes will result in either a collection or refund from customer classes. This is due to the relative size of the components of the true-up amounts apportioned to each rate class. In Section 6.2, the Commission assesses the total bill impact of ATCO Electric's 2023 rates, including Rider G.

5.3 Inclusion of TACDA true-up in the annual PBR rate adjustment filings

102. In previous decisions, the Commission found that including TACDA true-up applications as part of the annual PBR rate adjustment filings is effective in enhancing regulatory efficiency and reducing administrative burden.

103. In 2023, there will not be an annual PBR rate adjustment filing as the parameters of the PBR3 plans are currently considered in Proceeding 27388. As such, the Commission directs ATCO Electric to file its 2022 TACDA true-up application as part of a proceeding to establish the January 1, 2024, rates (such as a compliance filing to Proceeding 27388).

104. Subject to the outcome of Proceeding 27388 to establish the parameters of the PBR3 plan (including the issue of when annual rate changes will occur), the Commission directs ATCO Electric to continue including the annual TACDA true-up in its future annual PBR rate adjustment filings, starting with the 2025 annual PBR rate adjustment filing.

6 2023 rates

105. In this section the Commission must assess how system access service (SAS) rates and the distribution rates will be recovered by ATCO Electric's distribution tariff – through its distribution rates, SAS rates and rate riders – and assess the resulting bill impacts.

6.1 System access service rates

106. In its application, ATCO Electric requested approval of its 2023 SAS rates, to be effective January 1, 2023.[80] ATCO Electric's proposed 2023 SAS rates reflect its latest forecast of AESO volumes and prices, as of the date of the application. The volume forecast was prepared

[80] Exhibit 27672-X0001, application, paragraph 111.

using its previously approved method; the price forecast relied on the AESO's 2022 Independent System Operator tariff structure and rates as approved in Decision 26980-D01-2021.[81]

107. As a result, the SAS payments forecast for distribution-connected customers decreased from $377.028 million included in 2022 PBR rates, to $367.051 million for 2023. This decrease in forecast SAS payments reflects a decrease of 2.65 per cent in the transmission SAS rates.[82]

108. To determine its 2023 SAS rates, ATCO Electric applied a scaling approach to its 2022 transmission rates approved in Decision 26849-D01-2020, and noted that this approach was approved in Decision 23895-D01-2018.[83] [84] ATCO Electric provided the calculations and assumptions that were used to arrive at the 2023 SAS rates in the application.

109. Additionally, ATCO Electric updated its 2023 Balancing Pool adjustment rider to align with the AESO's Rider F rate of $2.20/MWh approved in Decision 27694-D01-2022.[85] This value is unchanged from 2022.

110. No intervener objected to ATCO Electric's calculation of its 2023 SAS rates.

111. The Commission has reviewed ATCO Electric's calculations of its proposed 2023 SAS rates and the underlying assumptions, and finds them to be reasonable and consistent with its past SAS rate proposals. Therefore, the Commission approves the proposed 2023 SAS rates as filed.

6.2 Distribution rates

112. In Section 3.1, the Commission approved ATCO Electric's interim 2023 forecast revenue requirement, reflective of the adjustments directed in the D01 decision. In Section 4 of this decision, the Commission approved individual components of ATCO Electric's 2023 rates including its billing determinant forecast for 2023. As well, the Commission approved other components of ATCO Electric's distribution rates: the 2021 TACDA true-up in Section 5 and SAS rates in Section 6.1.

113. In Decision 26849-D01-2021,[86] the Commission approved ATCO Electric's proposed plan for collecting the 2021 deferred amount (that is, the amount associated with a deferral of the 2021 distribution rates increase) using its interim Rider J starting January 1, 2022, with the remaining balance of $21.8 million to be recovered in 2023. As this plan was previously approved, the Commission approves the collection of the remaining updated Rider J amount of $23.1 million,[87] effective January 1, 2023.

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81 Decision 26980-D01-2021: Alberta Electric System Operator, 2022 Independent System Operator Tariff Update and Rider J Amendment Application, Proceeding 26980, December 17, 2021.
82 Exhibit 27672-X0001, application, paragraph 112.
83 Exhibit 27672-X0001, application, paragraph 113.
84 Decision 23895-D01-2018: ATCO Electric Ltd., 2019 Annual Performance-Based Regulation Rate Adjustment Filing, Proceeding 23895, December 18, 2018.
85 Decision 27694-D01-2022: Alberta Electric System Operator, 2023 Balancing Pool Consumer Allocation – Rider F Application, Proceeding 27694, October 27, 2022.
86 Decision 26849-D01-2021, paragraphs 68 and 71.
87 Exhibit 27672-X0001, application, paragraph 110: The total 2023 estimated recovery is $23.1 million reflects updated actual collected Rider J amounts, up to and including July 2022 along with applying updated carrying costs.

114. The Commission has reviewed ATCO Electric's schedules and the calculations that underpin its 2023 rates and is satisfied they are accurately calculated and reasonable.

115. ATCO Electric provided bill impact schedules reflecting the 2023 rates, including all components of its distribution tariff that ATCO Electric proposed to go into effect on January 1, 2023. These are summarized in Table 4.

Table 4. Bill impacts of ATCO Electric's 2023 rates

Rate class description	Typical bill change – October 2022 to January 2023			
	Distribution and SAS charges (Note 1)		Total charges (bundled) (Note 2)	
	($)	(%)	($)	(%)
D11 – Residential	(8.64)	-6.7	3.46	1.3
D21 – Commercial	(33.90)	-5.8	(26.67)	-1.3
D25 – Irrigation	(54.65)	-5.6	(12.48)	-0.8
D26 – REA Irrigation	(26.22)	-4.2	41.09	3.7
D31 – Industrial	(66.69)	-5.2	50.05	1.1
D41 – Oilfield	(43.25)	-6.0	(38.64)	-1.6
D51 – REA Pooled	(3.32)	-4.6	4.10	1.3
D56 – Farm	(7.04)	-5.8	(8.14)	-2.1
D61 – Street Lights (No Investment)	(1.68)	-7.6	1.66	4.5
D61 – Street Lights (Investment)	(2.85)	-7.7	2.50	4.8
D63 – Private Lights	(1.09)	-7.4	0.74	2.5
T31 – T Connect	6,886	3.8	6,748	0.8

Source: Exhibit 27672-X0070, Appendix G, Rate comparisons.
Note 1: Distribution and SAS charges, excluding riders, retail, energy and local access fee charges.
Note 2: All charges, comprising of transmission and distribution base rates including Rider J, Rider G, Rider B, retail, energy and local access fee charges.

116. The Commission accepts as reasonable the general principles and methodologies used by ATCO Electric to calculate its 2023 rates and its proposed Rider J, which are consistent with previously approved practices and methodologies. The Commission also acknowledges the bill impacts that result, as shown in Table 4. In addition, the total bill impacts on all rate classes are significantly less than 10 per cent and do not result in rate shock.

117. Prior to the issuance of this decision, in Disposition 27839-D01-2022[88] the Commission approved the Q1 2023 SAS Deferral Rider S for ATCO Electric, resulting in further changes to customer bills. However, these changes do not affect the Commission's conclusions in this decision regarding the bill impact of the 2023 rates.

118. For the reasons set out above, the Commission approves ATCO Electric's 2023 distribution rates, as filed in Exhibit 27672-X0069, effective January 1, 2023, on an interim basis. These rates will remain interim until all remaining placeholders (such as those reflecting the 2022 actual approved closing rate base and recalculated ECM amounts) have been determined by the Commission. These 2023 distribution rates will be finalized following such approvals and any required true-up adjustments will be made in accordance with directions subsequently provided by the Commission.

[88] Disposition 27839-D01-2022: ATCO Electric Ltd., Quarterly AESO DTS Deferral Account Rider – Q1 2023, Proceeding 27839, December 12, 2022.

7 Other matters

7.1 Terms and conditions

119. ATCO Electric proposed some changes to its terms and conditions. In its Retailer Terms and Conditions it updated Schedule B (Disconnect Customer Site) to clarify its current practice that disconnects may be scheduled between 8 a.m. and 5 p.m. It also revised its Customer Terms and Conditions, mainly Article 2.1 (Definitions), Article 10.6 (Changes to Metering Equipment) to reflect the implementation and installation of AMI meters as ATCO Electric's standard meter going forward. Changes to Article 10.6 also allow for a customer to opt out of receiving an AMI meter. ATCO Electric also requested minor edits to Schedule A (Standard Supply Specifications) and Schedule B (Conditions of underground Services) to clarify the current practice for the conductors developers must supply for underground developments.

120. No party objected to ATCO Electric's proposed changes to its terms and conditions.

121. The Commission has reviewed the changes to the Retailer Terms and Conditions and the Customer Terms and Conditions and finds them to be reasonable, and therefore, each is approved, as filed.

7.2 Schedule of Supplementary Service Charges

122. ATCO Electric proposed some changes to its Schedule of Supplementary Service Charges. First, ATCO Electric calculated the Supplementary Service Charges for 2023 by adjusting the previously approved 2022 Supplementary Service Charges by the approved 2023 inflation escalator from Decision 26615-D01-2022 of 2.68 per cent.

123. Second, related to the adjustments to its Customer Terms and Conditions to address the implementation of AMI meters discussed above, ATCO Electric made changes to section "(f) Supplementary Meter Reads" of the Supplementary Service Charges to provide greater clarity. Standard meter read fees will apply to customers who either have an AMI meter, or a working automated meter reading (AMR) meter. This reflects the fact that, for a period of time, there will be two types of meters (AMI and AMR) in ATCO Electric's service territory both of which are capable of being read remotely. Therefore, the $9.00 per meter read fee will apply for supplementary meter reads of either type. ATCO Electric also proposed a Non-Standard Meter (non-AMI meter) or manual meter read fee of $137.00.[89] This fee will be charged where a customer has either (i) opted out of an AMI meter, or (ii) where a manual meter read is requested by a customer or retailer outside of the usual billing cycle. In either case, an ATCO Electric employee is required to drive to the meter location to obtain the meter read.[90] As noted above, ATCO Electric calculated the $137 fee by escalating the manual meter read fee approved for 2022 by the inflation escalator of 2.68 per cent.

124. The Non-Standard meter installation fee of $388.00 will apply to customers who request to have a "Non-standard meter" installed instead of a "Standard meter," which requires ATCO Electric to perform additional work. In response to a Commission IR,[91] ATCO Electric provided a breakdown of the labour, vehicle and materials costs to justify the $388.00 fee.

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89 Exhibit 27672-X0019, Appendix M-4, page 2.
90 Exhibit 27672-X0001, application, paragraph 130.
91 Exhibit 27672-X0039.01, AE-AUC-2022OCT25-005.

125. No party objected to ATCO Electric's proposed changes to its Schedule of Supplementary Service charges.

126. The Commission has reviewed ATCO Electric's proposed changes to its Schedule of Supplementary Service Charges. The Commission approves ATCO Electric's request to use the approved 2023 inflation escalator of 2.68 per cent to calculate its 2023 Supplementary Service Charges as this is generally consistent with the methodology during PBR that allowed for an annual adjustment using I-X to the Supplementary Service Charges as well as the overall approach to rebasing. The Commission has also reviewed the changes requested related to the implementation of AMI meters and the associated fees and finds them to be reasonable. As a result, the Commission approves ATCO Electric's Schedule of Supplementary Service Charges as filed.

7.3 Schedule of Available Company Investment

127. ATCO Electric proposed that its 2023 Available Company Investment (MIL) amounts be determined by adjusting the previously approved 2022 MILs by the approved 2023 escalation factor of 2.68 per cent from Decision 26615-D01-2022. The Commission is making no determinations regarding 2023 MILs in this decision. Determinations regarding the setting of 2023 MILs were made in Decision 27658-D01-2022.[92]

7.4 Finalization of 2021 interim rates

128. ATCO Electric requested that the Commission finalize its 2021 interim PBR rates. No party objected to the finalization of these rates. The Commission finds that all outstanding 2021 placeholders (such as K-bar and Y factor adjustments) have been trued up, and there are no outstanding matters related to the calculation of 2021 rates. The Commission approves ATCO Electric's request to finalize 2021 rates.

[92] Decision 27658-D01-2022: Residential Standards of Service and Maximum Investment Levels – Phase 1, Proceeding 27658, December 15, 2022, paragraph 48.

8 Order

129. It is hereby ordered that:

(1) ATCO Electric Ltd.'s 2023 distribution rates including the calculation of the distribution-connected generation credits, options and riders are approved on an interim basis, effective January 1, 2023. These rates will remain interim pending finalization of all outstanding placeholders.

(2) ATCO Electric Ltd.'s 2023 system access service rates are approved as filed effective January 1, 2023.

(3) ATCO Electric Ltd.'s updated customer and retailer terms and conditions for electric distribution service are approved effective January 1, 2023.

(4) ATCO Electric Ltd.'s stand-alone schedule of Supplementary Service Charges is approved effective January 1, 2023.

(5) ATCO Electric Ltd.'s 2021 rates, including the K-bar amounts, are approved as final.

Dated on December 20, 2022.

Alberta Utilities Commission

(original signed by)

Kristi Sebalj
Vice-Chair

(original signed by)

Cairns Price
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Russ Bell & Associates Inc.

Alberta Utilities Commission Commission panel K. Sebalj, Vice-Chair C. Price, Commission Member Commission staff P. Khan (Commission counsel) E. Deryabina A. Spurrell B. Edwards M. Logan

Appendix 2 – Directions applicable to the present proceeding from Decision 26615-D01-2022 and Decision 26616-D01-2022

(return to text)

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 decisions 26615-D01-2022 and 26616-D01-2022, the wording in the main body of those decisions shall prevail.

Directions from Decision 26615-D01-2022

1. The Commission directs the following adjustments to the applied-for escalation factors:
    - ATCO Electric is to use its actual labour cost increases for the period 2019-2020 in calculating its inflation escalator.
    - Fortis is to remove the materials price escalator from its inflation escalator for capital costs.
    - Both ATCO Electric and Fortis are to reduce their proposed customer growth escalator by 15 per cent.. paragraph 5
2. The Commission directs each of ATCO Electric and Fortis to recalculate their respective 2023 forecasts under the mechanistic approach to reflect the escalation factors approved in this decision. Further, the Commission directs Fortis to remove the customer growth escalator from the calculation of its unit prices for all of its capital additions where the forecast was obtained by multiplying the unit prices (calculated using the escalated 2018-2020 average) by the number of units (estimated from the bottom up)............ paragraph 6
3. Having determined that using the 2018-2020 average of historical costs is acceptable, the Commission also reviewed Fortis's and ATCO Electric's use of escalators. As explained in Section 3, under a mechanistic approach, the 2023 costs are forecast by escalating the average of actual 2018-2020 costs by chosen escalation factors. The same escalated 2018-2020 average costs were also used by each of ATCO Electric and Fortis to quantify their achieved efficiencies for costs forecast under a non-mechanistic approach and to justify the general reasonableness of those forecasts. Parties in this proceeding pointed out that for this reason the indexes used for escalating the 2018-2020 average play an important role in quantifying the achieved efficiencies and passing them on to customers. As further set out in Section 5.2 of this decision, the Commission agrees and directs some changes to the proposed escalators. Overall, for costs forecast using a mechanistic approach, the Commission is satisfied that the use of the 2018-2020 average, escalated by indexes approved in Section 5.2, results in a 2023 forecast that is reasonably reflective of the efficiencies achieved during the PBR2 term. .... paragraph 86

5. Both ATCO Electric and Fortis relied on the same weightings between CPI and labour costs currently established for the I factor. Both used reliable data for their historical and forecast CPI. The Commission also accepts, for the purposes of this decision, the calculation of CPI and labour escalators on a calendar-year basis (rather than a July-to-June basis as is currently done for the I factor calculation). Doing so aligns more closely with the utilities' costs and revenues, which are measured on a calendar-year basis. Given the Commission's approval to use the most up-to-date data, the Commission directs

ATCO Electric and Fortis to use the 2021-2023 CPI values as shown in tables 9 and 10 above in their respective compliance filings. .... paragraph 103

6. Regarding labour costs, ATCO Electric used the Alberta AWE index as a substitute for its labour costs escalator for 2019 and 2020, and used its own actual or projected labour cost increases for 2021-2023. The Commission finds Fortis's approach of using its own actual or forecast labour cost growth for the entire 2019-2023 period to be more methodologically sound than ATCO Electric's approach because it uses the same data for both historical and forecast costs. The Commission considers the use of the utilities' actual and forecast labour costs is reasonable because the objective of this proceeding is to realign the utility's costs with prices. Further, in Section 5.3 of this decision, the Commission reviews the 2021-2023 proposed labour cost escalators developed by the utilities and finds them to be reasonable. As such, the Commission directs ATCO Electric to recalculate the 2019-2020 inflation index based its own labour cost data using the same methodology used for developing its 2021-2023 labour cost indexes as shown in Table 9 above. .... paragraph 104

8. As a result, the Commission finds that there is a need to introduce an offset to the customer growth escalation factors used by both utilities to account for its observations that (i) there is not an observed one-to-one relationship between customer growth and utility costs; and (ii) there exist economies of scale that are not accounted for in the application of the customer growth escalator. Having reviewed the record and exercised its judgment, the Commission directs each of the utilities to reduce their proposed customer growth escalation factors by 15 per cent. .... paragraph 124

10. ATCO Electric and Fortis updated their respective 2021 capital costs with non-audited 2021 actual amounts on April 1, 2022. As set out in Section 8.1, the Commission examined the utilities' 2021 non-audited actual capital additions in this proceeding and, except as noted otherwise in this decision, finds these amounts to have been prudently incurred, subject to reviewing the explanations for variances between the non-audited 2021 actuals provided in April 2022 and audited actuals provided in Rule 005 filings. Therefore, the Commission directs ATCO Electric and Fortis to incorporate the 2021 actual rate base into their compliance filings. .... paragraph 148

11. Accordingly, ATCO Electric's EERE program and Fortis's Low-Income DSM Initiative and Customer Education and Awareness of Smart Services and Technology Initiative are denied. The Commission directs ATCO Electric and Fortis to remove their respective expenditures associated with these programs and initiatives from their 2023 forecasts in their compliance filings. .... paragraph 171

14. For these reasons, the Commission finds that ATCO Electric's O&M and A&G forecasts derived using the mechanistic approach, and adjusted by using the escalation factors approved in Section 5.2, are reasonable. The Commission directs ATCO Electric to recalculate its 2023 O&M costs forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision. .... paragraph 200

15. It is not reasonable that customers should now be required to pay to restore service levels which ATCO Electric indicates were unsustainably eroded during the PBR term and for which customers derived no financial benefit until this rebasing, particularly where ATCO Electric continues to comply with legally imposed service standards. The Commission does accept however, that some level of incremental spending is required in

this program to reverse the erosion of internal metrics observed by ATCO Electric. For these reasons, the Commission denies 50 per cent of the proposed $2.6 million increase over ATCO Electric's escalated 2018-2020 average amount of $15.8 million, for a total approved amount of $17.1 million for this program. The Commission directs ATCO Electric to reflect this approved forecast for this program in its compliance filing. .... paragraph 210

17. With respect to ATCO Electric's submission that the $30.6 million forecast for 2023 has the potential to cause rate shock, in Decision 26521-D01-2021 the Commission allowed the DFOs to propose deferral treatment for some or all of the AESO customer contribution amounts that contribute significantly to rate shock. If such concerns arise in 2023, ATCO Electric is directed to consider this measure in its compliance filing to this decision. .... paragraph 225

24. For these reasons, the Commission finds that ATCO Electric's capital additions forecasts derived using the mechanistic approach, as adjusted by the escalation factors approved in Section 5.2, are reasonable. The Commission directs ATCO Electric to recalculate its 2023 capital additions forecast under the mechanistic approach to reflect the escalation factors approved in Section 5.2 of this decision. .... paragraph 316

25. The CCA and the UCA submitted that ATCO Electric's WMP was not supported by ATCO Electric system specific data and quantifiable measures to determine the cost-effectiveness of the mitigation measures adopted. The Commission agrees that ATCO Electric's evidence in this proceeding neither demonstrates that it evaluates the performance of its WMP, nor that it collects data when a wildfire does occur. Therefore, the Commission directs ATCO Electric to provide, in the compliance filing, a cost-effective proposal to monitor the progress of its WMP and measure the effectiveness of the related capital expenditures. The proposal should include processes and procedures required to (i) track and report all details relating to wildfire incidents; (ii) identify the measures to be implemented to resolve the incidents; and (iii) assess the effectiveness of those measures in mitigating the incidents. .... paragraph 337

26. For these reasons, the Commission denies ATCO Electric's 2023 forecast capital additions for the Line Rebuilds, Replacements and Life Extensions Program that are above the escalated 2018-2020 average. Therefore, the Commission approves capital additions of $39.065 million, subject to adjustments resulting from using the escalation factors approved in Section 5.2, and directs ATCO Electric to remove the additional forecast costs above this amount from this program in its compliance filing. .... paragraph 350

27. Based on the foregoing, the Commission approves 2023 forecast capital additions of $11.122 million for the Transportation Equipment Program, and directs ATCO Electric to remove $4.527 million in capital additions for this program in its compliance filing. .... paragraph 363

28. To reflect the grant funding that ATCO Electric has secured for the ADMS project, the Commission directs ATCO Electric to remove 50 per cent of its 2023 forecast costs in the amount of $2.95 million for this project in its compliance filing. The Commission also directs ATCO Electric to provide the status of its NRCan grant applications for the AMI and Asset Modernization projects including any early information it may have on whether it is likely to secure the grants. If one or more of the grant applications are

approved, ATCO Electric is directed to remove the amount of any grant funding amounts from its 2023 forecast costs for the relevant projects in the compliance filing. If the status of the grant application is not available at the time of the compliance filing, the Commission will consider whether any adjustments are required to ATCO Electric's forecasts for these projects based on the information provided at the time of the compliance filing. .... paragraph 373

29. The Commission is not persuaded that it is reasonable to adjust ATCO Electric's depreciation rates even though the Commission approved other elements of ATCO Electric's GMP. The Commission finds that great care must be exercised where a utility seeks to adjust its depreciation rates, which would have the effect of eliminating its stranded asset risk, where the proposed remaining expected service life of the assets in question is wholly within the utility's control. ATCO Electric's proposal to accelerate its depreciation rates in relation to this program is therefore denied. The Commission directs ATCO Electric to remove the $1.4 million in increased depreciation expense from its applied-for 2023 revenue requirement and recalculate its depreciation expense using the currently approved depreciation rates. .... paragraph 382

30. Throughout this decision, the Commission has issued various directions to Fortis and ATCO Electric. The Commission directs each utility to file a compliance application to finalize its 2023 forecast revenue requirement to reflect the approvals, denials and adjustments in this decision by September 26, 2022. .... paragraph 383

31. To assist the Commission in reviewing the compliance of Fortis and ATCO Electric with the directions in this decision, the Commission directs both utilities to support their revised 2023 revenue requirement, inclusive of 2023 forecasts, with accompanying Excel schedules. Specifically, each of the 2023 forecast amounts contained in the rebasing templates should either have a working formula showing how the number was determined (e.g., a formula that shows the calculation of the escalated 2018-2020 average), or reference to an associated working paper where such calculation was performed. The calculations should clearly illustrate how the utility's compliance with a Commission direction (e.g., denial of a capital project or the application of approved escalators) was achieved. .... paragraph 386

Directions from Decision 26616-D01-2022

19. Finally, ATCO Electric explained that, as the managed service provider at the time of the CIS Replacement project, Wipro was required to perform work on the CIS project. In preparing the CIS Replacement project business case, ATCO Electric forecast Wipro services costs of $6.7 million using the Wipro rates set out in the Wipro Master Services Agreement (Wipro MSA). As such, ATCO Electric identified that a $1.8 million reduction to the cost of the Wipro services involved in the CIS Replacement project was required to comply with the pricing directed in Decision 20514-D02-2019 (the IT Common Matters decision). ATCO Electric confirmed that actual costs charged to the project for these services performed by Wipro used the prescribed IT Common Matters rates. ATCO Electric proposed to make the necessary adjustment to the approved 2023 revenue requirement at the time of the compliance filing. The Commission agrees and directs ATCO Electric to remove $1.8 million in capital additions for this project in its compliance filing. .... paragraph 281

22. In addition, the ATCO Distribution Utilities provided no persuasive evidence that the IT rates with IBM/Kyndryl are just and reasonable. Based on the factors identified above, the Commission directs each of the ATCO Distribution utilities to reduce their 2023 IT managed services forecast costs by 15 per cent. In coming to this disallowance, the Commission reiterates that, unlike the Commission's concerns in the IT Common Matters decision about the shortcomings in the competitive procurement process employed by ATCO prior to selecting Wipro as its external managed IT services provider, here there was no competitive procurement process of any kind leading to the selection of IBM/Kyndryl. A 15 per cent reduction is appropriate in the circumstances of this case, given the paucity of relevant or compelling evidence to support the reasonableness of the IBM/Kyndryl rates. .... paragraph 389

24. Throughout this decision, the Commission has issued various directions to ATCO Gas, ATCO Electric and Apex. The Commission directs each of ATCO Gas and Apex to file a compliance application to finalize their respective 2023 forecast revenue requirements to reflect the approvals, denials, and adjustments in this decision by October 3, 2022. ATCO Electric must reflect the adjustments from this decision in its September 26, 2022, compliance filing, directed by the Commission in Decision 26615-D01-2022. .... paragraph 405

Appendix 3 – Summary of Commission directions

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

1. The Commission has reviewed the CWMP monitoring proposal as well as related information request (IR) responses, and has also considered the views put forward by the CCA in this proceeding. The Commission notes that its direction did not expressly impose a particular time frame within which ATCO Electric must develop a cost-effective monitoring proposal, nor did it require ATCO Electric to propose a quantifiable cost-benefit analysis to support its Wildfire Mitigation Program. While the submissions of the CCA are relevant and reasonable, the Commission finds that ATCO Electric's proposal meets the requirements stipulated in Direction 25 of Decision 26615-D01-2022, and that ATCO Electric has complied with this Commission direction. The Commission directs ATCO Electric to provide an update on the implementation of its CWMP monitoring proposal as part of an application to establish 2024 rates. As part of this update, ATCO Electric is to provide a status update on the key deliverable milestones proposed in Table 2 of its CWMP monitoring proposal. ....paragraph 40

2. The Commission is satisfied with the explanation provided by ATCO Electric regarding the status of its NRCan grant applications for the AMI and Asset Modernization projects. The Commission acknowledges that the SREP program had not resumed at the time of the compliance filing. ATCO Electric is therefore directed to provide the updated status of its NRCan grant applications for the AMI and Asset Modernization projects, including any information it may have on whether it has secured or is likely to secure the grants, in an application dealing with 2024 rates. If one or more of the grant applications are approved, ATCO Electric is directed to remove the amount of any grant funding from its 2023 forecast costs for the relevant projects in the application dealing with 2024 rates. If the status of the grant application is not available at that time, the Commission will consider whether any adjustments are required to ATCO Electric's forecasts for these projects based on the information provided at the time of the application dealing with 2024 rates. ....paragraph 58

3. Given the relatively small difference between using mid-year 2022 and mid-year 2023 as the basis for calculating the 2023 ECM dollar amount, and the interim nature of this amount (as explained above), there is no need to update the 2023 rates at this time. The Commission directs ATCO Electric to true up its 2023 ECM dollar amount, reflecting the findings and methodology approved in this decision, upon the approval of the 2022 actual rate base. ....paragraph 81

4. The Commission considers ATCO Electric's explanation for the billing determinant variances from forecasts to be reasonable. ATCO Electric explained that seasonal trends affected consumption, differences between actual and forecast demand differences and higher AESO costs, which are flow-through costs. Finally, ATCO Electric noted that its relatively small rate classes create disproportionately high variances. Such variances do not generally call into question the predictive value of the methodology used to generate the forecasts. The Commission directs ATCO Electric to continue to provide information

on any variances from forecast to actual billing determinants by rate class and to identify the cause of variances larger than ± five per cent on an annual basis...............paragraph 87

5. In 2023, there will not be an annual PBR rate adjustment filing as the parameters of the PBR3 plans are currently considered in Proceeding 27388. As such, the Commission directs ATCO Electric to file its 2022 TACDA true-up application as part of a proceeding to establish the January 1, 2024, rates (such as a compliance filing to Proceeding 27388). ....paragraph 103

6 Subject to the outcome of Proceeding 27388 to establish the parameters of the PBR3 plan (including the issue of when annual rate changes will occur), the Commission directs ATCO Electric to continue including the annual TACDA true-up in its future annual PBR rate adjustment filings, starting with the 2025 annual PBR rate adjustment filing. ....paragraph 104

Appendix 4 – 2023 Price schedules

(return to text)

Appendix 4 - 2023
Price schedules

(consists of 50 pages)

Appendix F

ATCO Electric Distribution

PRICE SCHEDULE INDEX

PRICE OPTIONS

Idle Service	Option F
Service for Non-Standard Transformation and Metering Configurations	Option H
REA Distribution Price Credit	Option P

PRICING ADJUSTMENTS (RIDERS)

Municipal Assessment	Rider A
Balancing Pool Adjustment	Rider B
Temporary Adjustment	Rider G
Interim Adjustment	Rider J
System Access Service (SAS) Adjustment	Rider S

Availability

For System Access Service and Electric Distribution Service for all Points of Service throughout the territory served by the Company. Price Schedule D11 is available for use by a single and separate household through a single-phase service at secondary voltage through a single meter. Price Schedule D11 is not applicable for commercial or industrial use.

Price

The charge for service in any one billing period is the sum of the Customer Charge and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Energy Charge
Transmission	-	4.81 ¢/kW.h
Distribution	123.12 ¢/day	7.87 ¢/kW.h
Service	23.52 ¢/day	-
TOTAL PRICE	$1.4664 /day	12.68 ¢/kW.h

Application

1. **Price Option -** the following price option may apply:
   Idle Service (Option F)

2. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

For System Access Service and Electric Distribution Service where an advanced metering infrastructure (AMI) meter has been installed. Price Schedule D13 is available by request only and at the discretion of the company for use by a single and separate household through a single-phase service at secondary voltage through a single meter. Price Schedule D13 is not applicable for commercial or industrial use.

Price

The charge for service in any one billing period is the sum of the Customer Charge and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Energy Charge	
		On Peak	**Off Peak**
Transmission	-	8.58 ¢/kW.h	3.43 ¢/kW.h
Distribution	123.12 ¢/day	14.03 ¢/kW.h	5.61 ¢/kW.h
Service	23.52 ¢/day	-	-
TOTAL PRICE	$1.4664 /day	22.61 ¢/kW.h	9.04 ¢/kW.h

On Peak rates will be applied between the hours of 4 p.m. to 9 p.m. Off Peak rates will be applied before 4 p.m. and after 9 p.m.

Application

1. **Price Option** - the following price option may apply:
   Idle Service (Option F)

2. **Price Adjustments -** the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

For System Access Service and Electric Distribution Service for all Points of Service throughout the territory served by the Company, with single or three-phase electric service at secondary voltage. Not applicable for any service in excess of 500 kW.

Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	**Demand Charge**	**Energy Charge**	
			For the first 200 kW.h per kW of billing demand	For energy in excess of 200 kW.h per kW of billing demand
Transmission	-	30.93 ¢/kW/day	0.57 ¢/kW.h	0.57 ¢/kW.h
Distribution	33.18 ¢/day	26.69 ¢/kW/day	3.71 ¢/kW.h	-
Service	28.43 ¢/day	-	-	-
TOTAL PRICE	61.61 ¢/day	57.62 ¢/kW/day	4.28 ¢/kW.h	0.57 ¢/kW.h

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) 85% of the difference between the highest metered demand in the twelve-month period including and ending with the billing period and 150 kW, if this is greater than zero;

(c) the estimated demand;

(d) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(e) 5 kilowatts.

Application

1. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

2. **Price Options** - the following price options may apply:
   Idle Service (Option F)
   Service for Non-Standard Transformation and Metering Configurations (Option H)
   REA Distribution Price Credit (Option P)

3. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

- For System Access Service and Electric Distribution Service for all Points of Service throughout the territory served by the Company, for customer owned and installed fixtures.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the fixtures.
- Not applicable for any service in excess of 1 kW.
- Available to Small Technology services with predictable energy consumption as determined by the Company

Price

Charges for service in any one billing period shall be the Customer Charge and Demand Charge, determined for each individual Point of Service.

	Customer Charge	Demand Charge
Transmission	-	75.69 ¢/kW/day
Distribution	91.45 ¢/day	30.33 ¢/kW/day
Service	16.72 ¢/day	-
TOTAL PRICE	$1.0817 /day	$1.0602 /day

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

Application

1. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

2. **Price Options** - the following price option may apply:
   Idle Service (Option F)

3. **Price Adjustments** - the following additional charges (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Limited Availability

- Available throughout the Company's territory, to eligible Points of Service as determined in the Company's sole discretion, for loads no greater than 500 kW.
- Available only when the Company determines that there is sufficient capacity. Service on this rate is interruptible for system security reasons.
- The Point of Service must be equipped with dedicated, revenue-approved time of use metering.

Price

The charge for service in any one billing period is the sum of the Customer Charge and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Energy Charge
Transmission	-	37.11 ¢/kW.h
Distribution	229.16 ¢/day	17.07 ¢/kW.h
Service	15.90 ¢/day	0.40 ¢/kW.h
TOTAL PRICE	$2.4506 /day	54.58 ¢/kW.h

Application

1. **Price Options** - the following price option may apply:
   Idle Service (Option F)

2. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment at the Customer's expense.

3. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Appendix F
ATCO Electric Distribution
Price Schedule D24
Standard Small General Service
Isolated Industrial Areas

Availability

For Electric Distribution Service, single or three-phase, for all Points of Service throughout the territory served by the Company distribution connected from an isolated industrial area. Not applicable for any service in excess of 500 kW.

Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	**Demand Charge**	**Energy Charge**	
			For the first 200 kW.h per kW of billing demand	For energy in excess of 200 kW.h per kW of billing demand
Distribution	33.18 ¢/day	26.69 ¢/kW/day	3.71 ¢/kW.h	-
Service	28.43 ¢/day	-	-	-
TOTAL PRICE	61.61 ¢/day	26.69 ¢/kW/day	3.71 ¢/kW.h	-

The billing demand for the Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) 85% of the difference between the highest metered demand in the twelve-month period including and ending with the billing period and 150 kW, if this is greater than zero;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 5 kilowatts.

Application

1. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

2. **Price Options** - the following price options may apply:
   Idle Service (Option F)
   Service for Non-Standard Transformation and Metering Configurations (Option H)
   REA Distribution Price Credit (Option P)

3. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

Availability

For System Access Service and Electric Distribution Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads. Not applicable for any service in excess of 150 kW.

Price

Charges for service in any one billing period during one Season shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	33.97 ¢/kW/day	0.56 ¢/kW.h
Distribution	40.41 ¢/day	39.58 ¢/kW/day	-
Service	45.88 ¢/day	-	-
TOTAL PRICE	86.29 ¢/day	73.55 ¢/kW/day	0.56 ¢/kW.h

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Application

1. **Idle Service -** in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer agrees to pay the minimum charge for the upcoming season.

2. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

3. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

For System Access Service and Electric Distribution Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads of Rural Electrification Association Customers and individual co-operative and colony farms with their own distribution systems. Not applicable for any service in excess of 150 kW.

Price

Charges for service in any one billing period during one Season shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

Customers in the REA O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	33.97 ¢/kW/day	0.56 ¢/kW.h
Distribution	12.73 ¢/day	12.63 ¢/kW/day	-
Service	45.88 ¢/day	-	-
TOTAL PRICE	58.61 ¢/day	46.60 ¢/kW/day	0.56 ¢/kW.h

Customers outside of the REA O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	33.97 ¢/kW/day	0.56 ¢/kW.h
Distribution	-	-	-
Service	45.88 ¢/day	-	-
TOTAL PRICE	45.88 ¢/day	33.97 ¢/kW/day	0.56 ¢/kW.h

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

REA Specific Charges:

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

The minimum charge for the season shall be 7 times the Service Charge and 7 times the Demand Charge.

Application

1. **Idle Service** - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer agrees to pay the minimum charge for the upcoming season.

2. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

3. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

- For System Access Service and Electric Distribution Service, single or three-phase distribution connected, for all Points of Service throughout the territory served by the Company. This rate is not applicable for any new Small Oilfield and Pumping Power service with yearly average operating demands of less than 75 kW, effective January 1, 2008.
- For distribution connected loads greater than 500 kW, the Point of Service must be equipped with interval data metering.

Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, Energy Charge and Charge for Deficient Power Factor, determined for each individual Point of Service:

	Customer Charge	**Demand Charge**		**Energy Charge**
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
Transmission	-	38.14 ¢/kW/day	46.24 ¢/kW/day	0.56 ¢/kW.h
Distribution	194.32 ¢/day	29.99 ¢/kW/day	21.02 ¢/kW/day	-
Service	156.61 ¢/day	-	0.54 ¢/kW/day	-
TOTAL PRICE	$3.5093 /day	68.13 ¢/kW/day	67.80 ¢/kW/day	0.56 ¢/kW.h

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedules D32 and D33);

(b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 50 kilowatts.

The billing demand for the Transmission charges shall be the higher of:

(a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedules D32 and D33);

(b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 12 month period including and ending with the billing period;

(c) the estimated demand;

(d) the Transmission Contract Demand (TCD);

(e) if any of the above are equal to or greater than 1000 kW in the past 24 months, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 24 month period including and ending with the current billing period;

(f) 50 kilowatts.

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D31 **Base Demand** as specified under the corresponding agreement.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 27.48 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. **Price Options** - the following price options may apply:
   Idle Service (Option F)
   Service for Non-Standard Transformation and Metering Configurations (Option H)
   REA Distribution Price Credit (Option P)

2. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Appendix F
ATCO Electric Distribution
Price Schedule T31
Large General Service / Industrial
Transmission Connected

Availability

- For System Access Service, for all Points of Service throughout the territory served by the Company that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.
- The Point of Service must be equipped with interval data metering.

Price

Charges for service in any one billing period shall be the sum of the Demand Charge, Energy Charge and charge for Deficient Power Factor, determined for each individual Point of Service.

	Demand Charge		**Energy Charge**
	For the first 500 kW of billing demand	For all billing demand over 500 kW	
Transmission	Current AESO DTS Rate Schedule less under frequency load shedding credit	Current AESO DTS Rate Schedule less under frequency load shedding credit	Charges per current AESO DTS Rate Schedule
Distribution	0.72 ¢/kW/day	-	-
Service	7.18 ¢/kW/day	-	-
TOTAL PRICE	7.90 ¢/kW/day **+ Current AESO DTS Rate Schedule less under frequency load shedding credit**	**Current AESO DTS Rate Schedule less under frequency load shedding credit**	

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period (including any contract opportunity demand delivered and billed under Price Schedule T33);

(b) 85% of the highest metered demand (including any contract opportunity demand delivered and billed under Price Schedule T33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) 50 kilowatts.

The billing demand for the Transmission charge shall be the higher of:

(a) The billing demand charged to ATCO Electric by AESO at a Point of Delivery, that is attributable to the customer at that Point of Delivery;

(b) the highest metered demand during the billing period;

(c) the ratchet level as set out by the AESO at a Point of Delivery, <u>where (a) through (c) exclude any contracted Opportunity Demand delivered and billed under Price Schedule T33;</u>

(d) the estimated demand;

(e) the Transmission Contract Demand (TCD) for Customers served from diversified PODs, or 90% of the TCD for Customers served from dedicated PODs;

(f) 50 kilowatts.

The 'highest metered demand' is defined for the purposes of this price schedule, according to the current approved AESO DTS Rate Schedule.

If energy is also taken under Transmission Opportunity Rate (Price Schedule T33), during the billing period, the billing demand will be the Price Schedule T31 **Base Demand** as specified under the corresponding agreement.

Charge for Deficient Power Factor – Power Factor Charges according to the current approved AESO DTS Rate Schedule will apply.

Application

1. **Price Options** - the following price option may apply:
   Service for Non-Standard Transformation and Metering Configurations (Option H)

2. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

- For Points of Service served by the Company with on-site generating equipment connected to the distribution system, which may be used to supply load at the same site.
- To provide standby power to the on-site load in the event of a forced outage or derate of on-site generating equipment, to provide power for generator startup, and to provide supplemental power if the on-site demand requirements exceed the generator capacity.
- To provide credits to Generators for reduced DTS charges from AESO.
- To charge Generators if the Point of Delivery attracts STS charges from AESO.
- For interconnection of the generator to the distribution system.
- The Point of Service must be equipped with 4-quadrant interval data metering, for both supply and demand, the cost of which will be in addition to the charges under this rate.

Price

Charges for service in any one billing period shall be the sum of the Customer Charges, Demand Charges, Energy Charges, Other Charges, Charge for Deficient Power Factor (determined for each individual Point of Service), and Fixed Charges defined below.

	Customer Charge	**Demand Charge**		**Energy Charge**
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
Transmission	-	38.14 ¢/kW/day	46.24 ¢/kW/day	0.56 ¢/kW.h
Distribution	194.32 ¢/day	29.99 ¢/kW/day	21.02 ¢/kW/day	-
Service	156.61 ¢/day	-	0.54 ¢/kW/day	-
TOTAL PRICE	$3.5093 /day	68.13 ¢/kW/day	67.80 ¢/kW/day	0.56 ¢/kW.h

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedule D33);

(b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD).

The billing demand for the Transmission charges shall be the higher of:

(a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedule D33);

(b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Transmission Contract Demand (TCD);

(e) if any of the above are equal to or greater than 1000 kW in the past 24 months, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D33) in the 24-month period including and ending with the current billing period;

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D32 **Base Demand** as specified under the corresponding agreement.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 27.48 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest billing kW demand in the same billing period, where billing demand is as defined in this price schedule.

If the Company incurs an increase to the Point-of-Delivery (POD) billing demand with AESO as a result of a standby event of the customer (i.e. the new demand at the POD is coincident with an outage of the generator), then an additional charge may apply, equal to the Transmission Demand Charge for Price Schedule T31, multiplied by the incremental POD demand incurred. This charge will apply for the current billing period, and for the next 11 billing periods.

Capital Recovery Charges:

The cost of the Incremental Interconnection Facilities will be determined as set out in Section 9.7 of the Customer Terms and Conditions for Electric Distribution Service. The total amount will be collected from the customer in accordance with Section 9.9 of the Customer Terms and Conditions for Electric Distribution Service. A contract will be arranged between the customer and the Company, specifying the contract term and the monthly amount, which will be calculated using the Company's Rate of Return, Income Tax and Depreciation in effect at the commencement of the contract term.

The Generating customer will be required to pay all replacement costs for incremental facilities as per Section 9.7 of the Customer Terms and Conditions for Electric Distribution Service.

Incremental Operations and Maintenance Charges:

The minimum monthly incremental Operations and Maintenance charge will be:

(0.00598% X Incremental Interconnection Cost) per day

The Generating customer will be required to pay for switching or isolation as per Section 9.10 of the Terms and Conditions.

Incremental Administration and General Charges:

The minimum monthly incremental Administration and General charge will be:

(0.00394% X Incremental Interconnection Cost) per day

Generator Credits for reduction in Billing Determinants at the Point of Delivery:

Credit = DTS * (A – B) * Multiplier **Where:**

A = Monthly Gross Billing Determinants at the POD to which the generator is connected (which will be determined by adding the interval output data metered at the generator to the net interval data metered at the POD).

B = Monthly Net Billing determinants at the POD to which the generator is connected.

DTS = The charges as per AESO's effective DTS tariff.

Multiplier is determined by the Effective Date:

Effective Date	Multiplier
Jan 1, 2022	0.8
Jan 1, 2023	0.6
Jan 1, 2024	0.4
Jan 1, 2025	0.2
Jan 1, 2026	0

The Company will calculate the generator credits on a calendar quarterly basis after all power production information has been provided to the Company in accordance with Section 9 of the Customer Terms and Conditions for Electric Distribution Service.

Generator Charges for a Point of Delivery:

Charge = STS * A **Where:**

A = Monthly **Net** Supply Billing determinants at the POS to which the generator is connected.

STS = The charges as per AESO's effective STS tariff.

Application

1. **Price Options** - the following price options may apply:
   Idle Service (Option F)
   Service for Non-Standard Transformation and Metering Configurations (Option H)
2. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Appendix F
ATCO Electric Distribution
Price Schedule D33
Transmission Opportunity Rate
Distribution Connected

Availability

- Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company for loads greater than 1,000 kW.
- Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.
- The Point of Service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.
- Telemetering is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing period shall be the sum of the following charges determined for each individual Point of Service. The AESO DOS charges will be applied according to the terms of the DOS option selected by the Customer:

	Customer Charges	Demand Charges	Demand Charges	Energy Charges	Energy Charges
		For all kW of Opportunity Contract Demand	For the peak kW above the Opportunity Contract Demand	For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand	For all kW.h metered above the Opportunity Contract Demand
Transmission	Transaction Charge per AESO DOS Rate Schedule	38.14 ¢/kW/day	46.24 ¢/kW/day	Per AESO DOS Rate Schedule	0.56 ¢/kW.h
Distribution	194.32 ¢/day	29.99 ¢/kW/day	21.02 ¢/kW/day	-	-
Service	156.61 ¢/day	-	0.54 ¢/kW/day	-	-
TOTAL PRICE	$3.5093 /day **+ AESO DOS Rate**	68.13 ¢/kW/day	67.80 ¢/kW/day	**Per AESO DOS Rate Schedule**	0.56 ¢/kW.h

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

Application

1. **Base Demand -** A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule D31 prior to receiving service under this rate (which will be submitted as part of the attached form).

   (a) For existing Customers, the Price Schedule D31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.

   (b) New Customers qualifying for this rate may select the Large General Service/Industrial D31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.

   (c) Once established, the Price Schedule D31 Base Demand remains fixed for the purposes of billing all future service on this rate.

2. **Applicable Charges** – This rate schedule applies in conjunction with rate D31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. D31 and D33, and D32 should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second and third block demand charges. The Service Customer Charge does not apply again as it has already been applied to the base load on Price Schedule D31.

3. **Options -** A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.

4. **Notice Period** - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.

5. **Load Curtailment** - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule D31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.

6. **Non-Compliance Charges** – In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.

7. **Price Options** – the following price options may apply:
   Service for Non-Standard Transformation and Metering Configurations (Option H)

8. **Price Adjustments -** the following price adjustments may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Appendix F
ATCO Electric Distribution
Price Schedule D33
Transmission Opportunity Rate
Distribution Connected

This form will be completed and signed by ATCO Electric after a telephone request from a Customer for Transmission Opportunity Service. The form will be faxed to the Customer upon which the Customer will confirm the information with a signature and fax the completed form back to ATCO Electric Control Centre – (780) 632-5959.

Customer Name: ____________________

Date of Request: __________
Time of Request: __________

1. OPPORTUNITY CONTRACT PERIOD:

Start Date:		**Start Time:**	
End Date:		**End Time:**	
		Number of Hours in Contract Period:	**Hours**

2. TRANSMISSION OPPORTUNITY SERVICE OPTION:

AESO "DEMAND OPPORTUNITY SERVICE":

DOS 7 Minutes:	
DOS 1 Hour:	
DOS Term:	

3. OPPORTUNITY CONTRACT DEMAND: __________ **kW**

4. BASE DEMAND:

Large General Service/Industrial Price Schedule D31 Base Demand:		kW
Sum of Demands on all Opportunity Service Contracts:		kW
Total Base Demand:		kW

Confirmation: 1) ______________________ for ATCO Electric
2) ______________________ for ______________

Appendix F
ATCO Electric Distribution
Price Schedule T33
Transmission Opportunity Rate
Transmission Connected

Availability

- For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.
- Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company from the Alberta Interconnected System for loads greater than 1,000 kW.
- Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.
- The point of service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.
- Telemetering is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing period shall be the sum of the following charges determined for each individual Point of Service. The current approved AESO DOS charges will be those according to the terms of the DOS option selected by the Customer:

	Transaction Charge	Demand Charges	Demand Charges	Energy Charges	Energy Charges
		For all kW of Opportunity Contract Demand	For the peak kW above the Opportunity Contract Demand	For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand	For all kW.h metered above the Opportunity Contract Demand
Transmission	Per AESO DOS Rate Schedule	-	Per Price Schedule T31	Per AESO DOS Rate Schedule	Per Price Schedule T31
Distribution	-	Per Price Schedule T31	Per Price Schedule T31	-	-
Service	-	Per Price Schedule T31	Per Price Schedule T31	-	-
TOTAL PRICE	**Per AESO DOS Rate Schedule**	**Per Price Schedule T31**	**Per Price Schedule T31**	**Per AESO DOS Rate Schedule**	**Per Price Schedule T31**

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

Application

1. **Base Demand -** A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule T31 prior to receiving service under this rate.

   (a) For existing Customers, the Price Schedule T31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.

   (b) New Customers qualifying for this rate may select the Large General Service/Industrial T31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.

   (c) Once established, the Price Schedule T31 Base Demand remains fixed for the purposes of billing all future service on this rate.

2. **Applicable Charges** - This rate schedule applies in conjunction with rate T31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. T31 and T33, and T31 again should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second block demand charges.

3. **Options** - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.

4. **Notice Period** - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.

5. **Load Curtailment** - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule T31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.

6. **Non-Compliance Charges** – In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.

7. **Price Options** – the following price option may apply:
   Service for Non-Standard Transformation and Metering Configurations Option H(d).

8. **Price Adjustments** - the following price adjustments may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Appendix F
ATCO Electric Distribution
Price Schedule T33
Transmission Opportunity Rate
Transmission Connected

This form will be completed and signed by ATCO Electric after a telephone request from a Customer for Transmission Opportunity Service. The form will be faxed to the Customer upon which the Customer will confirm the information with a signature and fax the completed form back to ATCO Electric Control Centre – (780) 632-5959.

Customer Name: ______

Date of Request: ______
Time of Request: ______

1. OPPORTUNITY CONTRACT PERIOD

Start Date:		**Start Time:**	
End Date:		**End Time:**	
		Number of Hours in Contract Period:	**Hours**

2. TRANSMISSION OPPORTUNITY SERVICE OPTION:

AESO "DEMAND OPPORTUNITY SERVICE":

DOS 7 Minutes:	
DOS 1 Hour:	
DOS Term:	

3. OPPORTUNITY CONTRACT DEMAND: ______ **kW**

4. BASE DEMAND:

Large General Service/Industrial Price Schedule T31 Base Demand:		kW
Sum of Demands on all Opportunity Service Contracts:		kW
Total Base Demand:		kW

Confirmation: 1) ______________________ for ATCO Electric
2) ______________________ for ______________

The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

ATCO

Appendix F
ATCO Electric Distribution
Price Schedule D34
Large General Service/Industrial
Isolated Industrial Areas

Availability

For Electric Distribution Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area. This rate is not applicable for any new Small Oilfield and Pumping Power service with yearly average operating demands of less than 75 kW, effective January 1, 2008.

Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, and Charge for Deficient Power Factor, determined for each individual Point of Service.

	Customer Charge	Demand Charge		Energy Charge
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
Distribution	194.32 ¢/day	29.99 ¢/kW/day	21.02 ¢/kW/day	-
Service	156.61 ¢/day	-	0.54 ¢/kW/day	-
TOTAL PRICE	$3.5093 /day	29.99 ¢/kW/day	21.56 ¢/kW/day	**-**

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period;

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 50 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 27.48 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. **Price Options** - the following price options may apply:
   Idle Service (Option F)
   Service for Non-Standard Transformation and Metering Configurations (Option H)
   REA Distribution Price Credit (Option P)

2. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

Availability

For System Access Service and Electric Distribution Service, single or three-phase, for all Points of Service throughout the territory served by the Company. This rate is available only to new Points of Service for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters with yearly average operating demand less than 75 kilowatts, effective January 1, 2008.

Price

Charges for service in any one billing period shall be the sum of the Customer Charges, Demand Charges, Energy Charges and charge for Deficient Power Factor, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	35.83 ¢/kW/day	0.57 ¢/kW.h
Distribution	144.00 ¢/day	59.53 ¢/kW/day	-
Service	45.60 ¢/day	-	-
TOTAL PRICE	$1.8960 /day	95.36 ¢/kW/day	0.57 ¢/kW.h

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(e) 4 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

Estimated Demands - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand, plus a flat rate of $1.47 per kW in lieu of the charge for energy.

The **Metered demand** will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 59.98 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. **Demand Metered -** where services are demand metered, the meter will normally be read and reset at least once every two months.

2. **Price Options - the following price option may apply:**
   Idle Service (Option F)

3. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

For Electric Distribution Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area. This rate is available only to new Points of Service for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters with yearly average operating demand less than 75 kilowatts, effective January 1, 2008.

Price

Charges for service in any one billing period shall be the sum of the Customer Charges, Demand Charges, and charge for Deficient Power Factor, determined for each individual Point of Service:

	Customer Charge	**Demand Charge**
Distribution	144.00 ¢/day	59.53 ¢/kW/day
Service	45.60 ¢/day	-
TOTAL PRICE	$1.8960 /day	59.53 ¢/kW/day

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period;

(b) 85% of the highest metered demand during the 12 month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 4 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

Estimated Demands - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand.

The **Metered demand** will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 59.98 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Appendix F
ATCO Electric Distribution
Price Schedule D44
Small Oilfield and Pumping Power
Isolated Industrial Areas

Application

1. **Demand Metered -** where services are demand metered, the meter will normally be read and reset at least once every two months.

2. **Price Options -** the following price options may apply:
   Idle Service (Option F)

3. **Price Adjustments -** the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

Availability

For System Access Service and Electric Distribution Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to a Rural Electrification Association's distribution system.

Price

- Charges for service in any one billing period are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.
- Please refer to individual REA Tariffs to determine applicable REA charges.

REA Farms in O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	17.11 ¢/kV.A/day	0.57 ¢/kW.h
Distribution	2.80 ¢/day	5.85 ¢/kV.A/day	-
Service	32.58 ¢/day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	C_1 ¢ / service/ day	22.96 ¢/kV.A/day	0.57 ¢/kW.h

REA Farms Outside of O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	17.11 ¢/kV.A/day	0.57 ¢/kW.h
Distribution	See REA Tariff	See REA Tariff	-
Service	See REA Tariff	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	**C_1 ¢ / service /day**	**D_1 ¢/kV.A/day**	0.57 ¢/kW.h

kV.A capacity for billing purposes will be determined as follows:

(a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	30	35	50	80	100	200
Billing Capacity in kV.A	3	5	7.5	10	15	25

(b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;

ii. the estimated demand;

iii. 25 kV.A.

REA Specific Charges

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

Application

1. **Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.

2. **Price Option** - the following price option may apply:
Idle Service (Option F)

3. **Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
SAS Adjustment (Rider S)

Availability

- Applicable to any Rural Electrification Association, for whom the Company is not acting as the wire services provider, as set out in the EUA.
- For all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Rural Electrification Association's distribution system.

Price

Charges for service in any one billing period are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	17.11 ¢/kV.A/day	0.57 ¢/kW.h
Distribution	-	-	-
Service	22.55 ¢/day	-	-
TOTAL PRICE	22.55 ¢/day	17.11 ¢/kV.A/day	0.57 ¢/kW.h

kV.A capacity for billing purposes will be determined as follows:

(a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	30	35	50	80	100	200
Billing Capacity in kV.A	3	5	7.5	10	15	25

(b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;
ii. the estimated demand;
iii. 25 kV.A.

Application

1. **Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.

2. **Price Option** - the following price option may apply:
   Idle Service (Option F)

3. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

For System Access Service and Electric Distribution Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Company's distribution system.

Price

Charges for service in any one billing period are the sum of the Customer, Demand, and Energy Charges as indicated below, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	18.25 ¢/kV.A/day	0.57 ¢/kW.h
Distribution	57.33 ¢/day	16.02 ¢/kV.A/day	0.44 ¢/kW.h
Service	22.50 ¢/day	-	-
TOTAL PRICE	79.83 ¢/day	34.27 ¢/kV.A/day	1.01 ¢/kW.h

kV.A capacity for billing purposes will be determined as follows:

(a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	30	35	50	80	100	200
Billing Capacity in kV.A	3	5	7.5	10	15	25

(b) For non-breakered farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;
ii. the estimated demand;
iii. the contract demand;
iv. 25 kV.A.

Application

1. **Demand Metering -** when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions for Distribution Service Connections.

2. **Price Options -** the following price option may apply:
Idle Service (Option F)

3. **Price Adjustments -** the following price adjustments (riders) may apply:
Municipal Assessment (Rider A)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
SAS Adjustment (Rider S)

The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

Availability

- For System Access Service and Electric Distribution Service for all Points of Service throughout the territory served by the Company, for street lighting.
- Not available for private lighting.

Price

Charges for service in any one billing period are the sum of the Customer Charge and Demand Charge, determined for each individual Point of Service.

Decorative Lighting (61A)

- For decorative lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.
- Includes maintenance only.
- Specific contracts may require customers to purchase and maintain inventory of decorative lamps if the customer’s lighting fixtures are not the same as the standard used by the company.

	Decorative Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.037 ¢/W/day
Distribution	46.03 ¢/fixture/day	0.066 ¢/W/day
Service	6.97 ¢/fixture/day	-
TOTAL PRICE	53.00 ¢/fixture/day	0.103 ¢/W/day

Investment Option (61B)

- For lighting fixtures installed, owned, and maintained by the Company.
- A *Maintenance Multiplier* may be applied to the fixture charge for customers that request levels of maintenance above the normal service level, or for customers that request lighting fixtures which incur higher than average lighting costs.

	All Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.037 ¢/W/day
Distribution	91.08 ¢/fixture/day	0.066 ¢/W/day
Service	6.97 ¢/fixture/day	-
TOTAL PRICE	98.05 ¢/fixture/day [x Multiplier, if other than 1.00]	0.103 ¢/W/day

Distribution Investment Option (61C) (Closed)

- For customer owned and installed fixtures.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the fixtures.
- The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	All Fixtures	
	Customer Charge	**Demand Charge**
Transmission	-	0.037 ¢/W/day
Distribution	68.56 ¢/fixture/day	0.066 ¢/W/day
Service	6.97 ¢/fixture/day	-
TOTAL PRICE	75.53 ¢/fixture/day	0.103 ¢/W/day

No Investment Option (61E)

- Available for new installations only.
- For lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.
- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

	All Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.037 ¢/W/day
Distribution	46.03 ¢/fixture/day	0.066 ¢/W/day
Service	6.97 ¢/fixture/day	-
TOTAL PRICE	53.00 ¢/fixture/day	0.103 ¢/W/day

Application

1. **Price Option** - the following price option may apply:
   Idle Service (Option F)

2. **Price Adjustments** – the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Availability

For System Access Service and Electric Distribution Service for all Points of Service throughout the territory served by the Company, for sentinel lighting.

Price

Charges for service in any one billing period are the sum of the Customer Charge and Demand Charge determined for each individual Point of Service.

Investment Option (63A)

For standard sentinel lighting fixtures installed, owned, and maintained by the Company

	Customer Charge	Demand Charge
Transmission	-	0.037 ¢/W/day
Distribution	19.49 ¢/fixture/day	0.032 ¢/W/day
Service	16.00 ¢/fixture/day	-
TOTAL PRICE	35.49 ¢/fixture/day	0.069 ¢/W/day

Summer Village Option (63B)

- For standard sentinel lighting fixtures installed, owned and maintained by the Company
- For seasonal use only (six-month minimum period) by Municipal Corporations in summer villages.
- This portion of the rate is closed.

	Customer Charge	Demand Charge
Transmission	-	0.037 ¢/W/day
Distribution	31.42 ¢/fixture/day	0.032 ¢/W/day
Service	16.00 ¢/fixture/day	-
TOTAL PRICE	47.42 ¢/fixture/day	0.069 ¢/W/day

No Investment Option (63C)

- Available for new installations only.
- For standard lighting fixtures installed, owned, and maintained by the Company.
- The customer is responsible for the full cost of installation.
- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

	Customer Charge	Demand Charge
Transmission	-	0.037 ¢/W/day
Distribution	10.34 ¢/fixture/day	0.009 ¢/W/day
Service	16.00 ¢/fixture/day	-
TOTAL PRICE	26.34 ¢/fixture/day	0.046 ¢/W/day

Metering Option (63D) (Closed)

- For standard lighting fixtures installed, owned, and maintained by the Company.
- For service through the meter at the Point of Service.
- This portion of the rate is closed.

	Customer Charge	Demand Charge
Transmission	-	0.037 ¢/W/day
Distribution	20.68 ¢/fixture/day	0.032 ¢/W/day
Service	16.00 ¢/fixture/day	-
TOTAL PRICE	36.68 ¢/fixture/day	0.069 ¢/W/day

The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

Distribution Investment Option (63E) (Closed)

- For customer owned and installed lighting.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.
- The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	Customer Charge	Demand Charge
Transmission	-	0.037 ¢/W/day
Distribution	20.68 ¢/fixture/day	0.032 ¢/W/day
Service	16.00 ¢/fixture/day	-
TOTAL PRICE	36.68 ¢/fixture/day	0.069 ¢/W/day

Application

1. **Price Adjustments** - the following price adjustments (riders) may apply:
   Municipal Assessment (Rider A)
   Balancing Pool Adjustment (Rider B)
   Temporary Adjustment (Rider G)
   Interim Adjustment (Rider J)
   SAS Adjustment (Rider S)

Appendix F

ATCO Electric Distribution
Option F Idle Service

Availability

The Idle Service charge will apply to all Price Schedules listed below for Points of Service served by the Company throughout the territory when the Point of Service is temporarily disconnected with the intention of restoring service at a future date.

Price Adjustment

The Idle Service charges shall be:

Price Schedule	Applicability	Idle Service Charge
D11 D13	Service outside cities, towns, villages, summer villages, hamlets, First Nations reserves and Metis settlements	The price schedule monthly Distribution Customer Charge.
D21 D22 D23	Service outside cities, towns, villages, summer villages, hamlets, First Nations reserves and Metis settlements	The sum of the Distribution Customer Charge and the Distribution and Transmission Demand Charges as defined in the applicable rate schedules.
D34 D44	All Points of Service	The sum of the Distribution Customer Charge and the Distribution Demand Charge as defined in the applicable rate schedules.
D25 D26	All Points of Service between April 1st and October 31st	The sum of the Distribution Customer Charge and the Distribution and Transmission Demand Charges as defined in the applicable rate schedules.
D31 D32 D41	All Points of Service	The sum of the Distribution Customer Charge and the Distribution and Transmission Demand Charges as defined in the applicable rate schedules.
D33	All Points of Service	Charges based on base demand level established under Price Schedule D31.
T31	All Points of Service	Un-recoverable charges may apply per the Terms and Conditions Clause 14.1.1 (b)
T33	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D51 D52	All Points of Service	The sum of the Distribution Customer charge and the Distribution and Transmission Demand Charges applicable to a 3 kVA service.
D56	Breakered Service	The sum of the Distribution Customer charge and the Distribution and Transmission Demand Charges applicable to a 3 kVA service or the contracted demand, whichever is greater.
D56	Non-Breakered Service	The sum of the Distribution Customer charge and the Distribution and Transmission Demand Charges applicable to a 25kVA service or the contracted demand, whichever is greater.
D61	All Points of Service	The sum of the Distribution Customer Charge and the Distribution and Transmission Demand Charges.
D63	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).

The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

Application

1. If the Customer's Point of Service is reconnected within 12 months of disconnection, the minimum monthly charge for each month of disconnection will be applied to the Point of Service.
2. For further information on idle services, refer to Terms and Conditions 14.1 – Disconnection and Idle Service.

The Retailer will be responsible for any costs that the Company incurs from AESO as a result of a point of service going idle. If the point of service is not enrolled with a Retailer, the costs incurred from AESO will be charged directly to the Customer.

Availability

- For Points of Service throughout the territory served by the Company under Price Schedule D21, D24, D31, D32, D33, D34, T31 and T33 where metering and / or delivery voltage are non-standard.
- Standard service for distribution connected customers is delivered and metered at the utilization voltage. When delivery or metering is necessary at other voltages, for the convenience of either the customer or the Company, bills for service will be adjusted as outlined below in (a)
- Standard service for transmission connected customers is delivered to the customer and metered at the substation voltage. When delivery is required at lower voltages, bills for service will be adjusted as outlined below in (d).

Price Adjustment

(a) **(Closed)** If the point of delivery and metering is on the primary side (25 kV) of a transformer (including cases where one-point service is required by the customer for more than a single utilization voltage or point of use), and the customer owns or rents the necessary transformer(s), a **discount of -5.43 ¢/kW/day** of billing demand will be applied. This adjustment does not apply to customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.

(d) **(Closed)** Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent necessary transformer(s), are exempt from the Distribution Charge on the application rate, a **surcharge of 5.43 ¢/kW/day** billing demand will apply.

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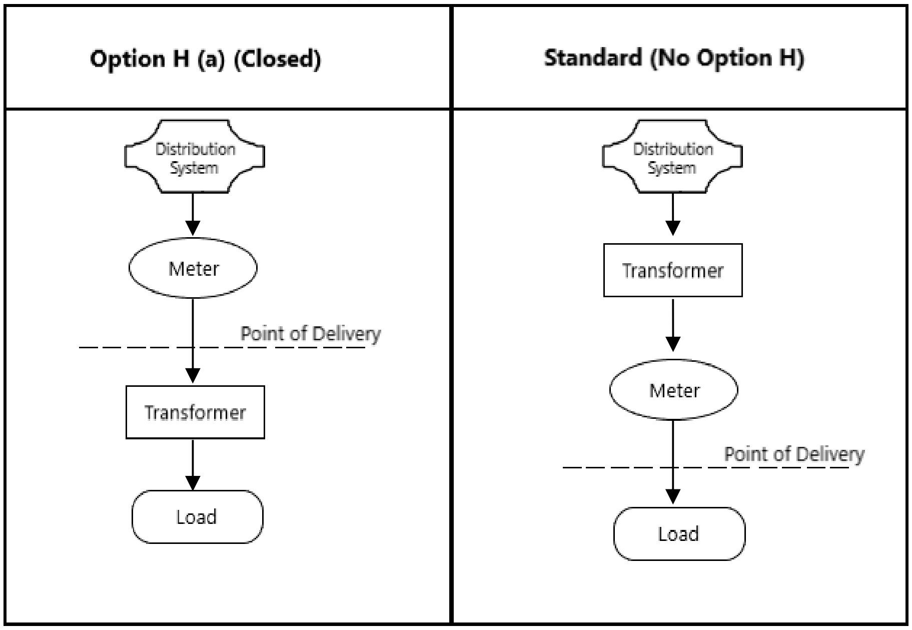
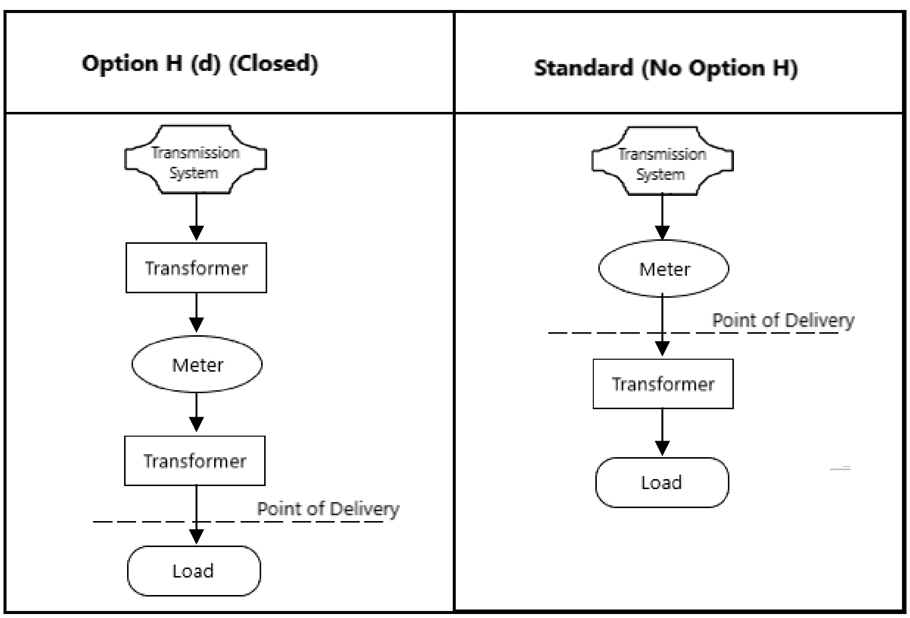
Appendix F
ATCO Electric Distribution
Option H
Service for Non-Standard Transformation
and Metering Configurations Complete Individual

Schematic of Metering and Transformation Configurations for Option H Definitions (Distribution Connected Customers)



Schematic of Metering and Transformation Configuration for Option H Definitions (Transmission Connected Customers)



The Company's *Terms and Conditions for Electric Distribution Service* apply to all retailers and customers provided with System and/or Distribution Access Service by the Company. The *Terms and Conditions* are available on the website www.atco.com.

Appendix F

ATCO Electric Distribution
Option P REA Distribution Price Credit

Availability

For all Pooled O&M REA Farm Points of Service throughout the territory served by the Company, served under Price Schedule D21 or Price Schedule D31.

Price Adjustment

Standard Small General Service Price Schedule D21
For REA farm Points of Service electing to take service under Small General Service Price Schedule D21, a credit adjustment of **42%** will be applied to the base bill.

Large General Service / Industrial Price Schedule D31
For REA farm Points of Service electing to take service under Large General Service / Industrial Price Schedule D31, a credit adjustment of **28%** will be applied to the base bill.

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RIDER A:

MUNICIPAL TAX AND FRANCHISE FEE ASSESSMENT

(1) Overview

Rider A is applicable to Customers residing in municipalities which receive: (i) a property tax under the Municipal Government Act, or (ii) receive payment for specific costs which are not generally incurred by the Company.

The following may be exempt from the surcharge:

(a) Farm customers (Price Schedules D51, D52 and D56)
(b) Irrigation customers (Price Schedule D25 and D26)
(c) Customers within First Nation Reservations not listed

This Rider comprises two components which are summed: (i) a tax component and (ii) a fee component.

The **tax component** of Rider A is the estimated percentage of base revenue required to provide for the tax payable or specific cost incurred each year. To the extent that this percentage may be more or less than that required to pay the tax or specific cost, this component of the Rider will be adjusted on an annual basis or as needed to manage shortfalls or surpluses.

The **franchise fee component** of this Rider is a flat percentage payable to the franchised municipality. This percentage is set in accordance with the franchise agreement between the Municipal Authority and the Company.

The **total percentage** is the addition of the tax component and fee component and is shown by Municipal Authority in Table 1.

(2) Calculation

Rider A is calculated for each Taxation Authority as follows:

$$\textit{Rider } A_n = \frac{\textit{Shortfall/Surplus}_{n-1} + \textit{Forecast Property Tax}_n}{\textit{Forecast Base Revenue}_n} + \textit{Franchise Fee}_n$$

Where:
n = Current Year

Appendix F

ATCO Electric Distribution
Rider A Municipal Assessment

ATCO Electric

TABLE 1: TOTAL RIDER A

Municipal Authority (Price Area)	[1] Municipal Tax from Table 2 (%)	[2] Franchise Fee (%)	[3] Franchise Fee Effective Date (yy/mm/dd)	[4] = [1] +[2] Rider A Total (%)	Municipal Authority (Price Area)	[1] Municipal Tax from Table 2 (%)	[2] Franchise Fee (%)	[3] Franchise Fee Effective Date (yy/mm/dd)	[4] = [1] +[2] Rider A Total (%)
ACADIA (M034)	4.35	0.00		4.35	MANNING (T556)	1.51	6.00	12/01/01	7.51
ALLIANCE (V017)	1.65	6.00	05/01/01	7.65	MANNVILLE (V559)	2.38	9.00	20/01/01	11.38
ALLISON BAY (B219)	-0.20	0.00		-0.20	MARWAYNE (V562)	1.52	6.00	15/06/01	7.52
ANDREW (V024)	1.38	7.00	20/01/01	8.38	MCLENNAN (T574)	2.18	3.75	22/01/01	5.93
BEAVERLODGE (T051)	1.42	7.00	20/01/01	8.42	MINBURN (V589)	2.90	1.00	18/01/01	3.90
BERWYN (V063)	3.44	6.00	19/01/01	9.44	MORRIN (V598)	1.72	3.50	12/01/01	5.22
BIG VALLEY (V069)	1.01	2.00	16/01/01	3.01	MUNDARE (T604)	1.29	6.00	20/04/01	7.29
BIGSTONE (B110)	1.36	0.00		1.36	MUNSON (V607)	3.37	1.00	10/07/01	4.37
BONNYVILLE BEACH S.V. (S096)	0.68	0.00		0.68	MYRNAM (V610)	2.93	6.00	21/02/01	8.93
BONNYVILLE, TOWN OF (T093)	1.04	6.80	03/01/01	7.84	NAMPA (V619)	1.22	2.00	16/01/01	3.22
BOTHA (V099)	1.62	0.00	20/01/01	1.62	NORTHERN LIGHT (M022)	1.15	0.00		1.15
BUSHE RIVER I.R. 207 (B726)	0.44	0.00		0.44	NORTHERN SUNRISE COUNTY (M131)	0.66	0.00		0.66
CAMROSE (C022)	2.16	0.00		2.16	OPPORTUNITY (M017)	1.04	0.00		1.04
CARBON (V129)	1.32	8.00	22/01/01	9.32	OYEN (T648)	1.05	8.00	22/01/01	9.05
CASTOR (T147)	1.54	7.00	20/01/01	8.54	PADDLE PRAIRIE (N221)	2.19	0.00		2.19
CEREAL (V153)	-0.41	0.00	21/08/01	-0.41	PAINTEARTH (C018)	1.17	0.00		1.17
CLEAR HILLS (M021)	1.65	0.00		1.65	PARADISE VALLEY (V654)	1.27	10.00	22/01/01	11.27
COLD LAKE (T189)	1.15	4.25	03/01/01	5.40	PEACE (M135)	0.81	0.00		0.81
CONSORT (V195)	2.17	7.00	21/01/01	9.17	PEACE RIVER (T657)	1.82	11.50	22/02/01	13.32
CORONATION (T198)	1.11	3.75	04/01/01	4.86	PEAVINE (N172)	0.23	0.00		0.23
DELBURNE (V231)	1.64	1.50	08/01/01	3.14	PELICAN NARROWS S.V. (S659)	0.32	0.00		0.32
DELIA (V234)	2.42	5.00	11/01/01	7.42	RAINBOW LAKE (T690)	1.89	13.00	15/01/01	14.89
DERWENT (V237)	3.24	4.00	19/06/01	7.24	RED DEER (C023)	1.92	0.00		1.92
DEWBERRY (V246)	1.94	8.00	17/01/01	9.94	ROCHON SANDS S.V. (S708)	1.14	0.00		1.14
DOGHEAD I.R. (B218)	-0.29	0.00		-0.29	ROSALIND (V717)	2.01	0.50	13/04/09	2.51
DONALDA (V252)	2.21	11.00	22/01/01	13.21	RYCROFT (V729)	1.85	7.00	20/04/01	8.85
DONNELLY (V255)	1.48	2.25	10/01/01	3.73	SADDLE HILLS (M020)	0.49	0.00		0.49
DRIFTPILE RIVER FIRST NATION I.R. 150 (B220)	0.00	0.00		0.00	SADDLE LAKE I.R. (B638)	1.12	0.00		1.12
DRUMHELLER (K025)	1.27	9.00		10.27	SEXSMITH (T754)	1.55	5.50	12/01/01	7.05
EAST PRAIRIE (N174)	2.13	0.00		2.13	SLAVE LAKE (T766)	1.13	10.40	20/03/01	11.53
ELIZABETH (N187)	15.82	0.00		15.82	SMOKY LAKE (T769)	1.88	7.00	19/04/01	8.88
ELK POINT (T291)	1.89	5.00	20/01/01	6.89	SMOKY RIVER (M130)	1.82	0.00		1.82
ELNORA (V294)	1.37	1.50	20/01/01	2.87	SPECIAL AREAS (A001)	0.46	0.00		0.46
EMPRESS (V297)	2.45	2.00	07/01/01	4.45	SPIRIT RIVER (M133)	0.86	0.00		0.86
FAIRVIEW (M136)	2.64	0.00		2.64	SPIRIT RIVER, TOWN OF (T778)	1.63	5.50	12/02/01	7.13
FAIRVIEW (T309)	1.36	7.50	13/01/01	8.86	ST. PAUL, COUNTY OF (C019)	0.82	0.00		0.82
FALHER (T315)	1.46	7.00	20/01/01	8.46	ST. PAUL, TOWN OF (T790)	1.48	7.00	03/01/01	8.48
FISHING LAKE (N188)	6.86	0.00		6.86	STARLAND (M047)	1.10	0.00		1.10
FLAGSTAFF (C029)	1.43	0.00		1.43	STETTLER, COUNTY OF (C006)	1.64	0.00		1.64
FORESTBURG (V324)	2.04	11.00	21/01/01	13.04	STETTLER, TOWN OF (T805)	0.88	11.10	18/01/01	11.98
FORT MCMURRAY (K032)	0.58	10.00	14/01/01	10.58	STURGEON LAKE I.R. 154 (B770)	0.85	0.00		0.85
FOX CREEK (T342)	1.26	6.50	20/01/01	7.76	SUCKER CREEK FIRST NATION 150A (B792)	0.89	0.00		0.89
FT. MACKAY SETTLEMENT #467 (B982)	0.90	0.00		0.90	SWAN HILLS TOWN (T830)	2.90	10.00	21/01/01	12.90
FT. McMURRAY BAND (B352)	0.57	0.00		0.57	THREE HILLS (T845)	1.07	8.00	22/01/01	9.07
GADSBY (V351)	-0.84	0.00	21/08/01	-0.84	TROCHU (T857)	1.66	5.00	16/01/01	6.66
GALAHAD (V354)	1.81	9.00	22/01/01	10.81	TWO HILLS COUNTY (C021)	5.11	0.00		5.11
GIFT LAKE METIS SETT (N173)	3.92	0.00		3.92	TWO HILLS, TOWN OF (T863)	2.34	8.50	21/01/01	10.84
GIROUXVILLE (V366)	1.86	6.00	21/01/01	7.86	UPPER HAY LAKE I.R. 212 (B728)	0.27	0.00		0.27
GLENDON (V372)	2.04	1.50	03/01/01	3.54	VALLEYVIEW (T866)	1.17	5.25	06/01/01	6.42
GRANDE CACHE (T393)	1.08	0.00	21/01/01	1.08	VEGREVILLE (T875)	1.75	10.00	20/01/01	11.75
GRANDE PRAIRIE, COUNTY OF (C001)	0.58	0.00		0.58	VERMILION (T878)	1.13	8.00	21/01/01	9.13
GRANDE PRAIRIE, CITY OF (K035)	1.60	10.00	19/02/01	11.60	VETERAN (V881)	2.72	6.00	17/01/01	8.72
GRIMSHAW (T405)	1.08	6.00	10/07/01	7.08	VILNA (V887)	3.54	20.00	12/01/01	23.54
HALKIRK (V414)	1.47	5.00	21/01/01	6.47	WASKATENAU (V908)	2.30	1.00	19/01/01	3.30
HANNA (T417)	1.35	7.50	18/01/01	8.85	WEMBLEY (T911)	1.69	6.00	11/03/01	7.69
HAY LAKE I.R. 209 (B727)	1.39	0.00		1.39	WHEATLAND (C016)	0.52	0.00		0.52
HEISLER (V429)	4.74	8.00	21/01/01	12.74	WHITE SANDS S.V. (S922)	0.79	0.00		0.79
HIGH LEVEL (T435)	0.54	12.10	20/01/01	12.64	WHITEFISH I.R. 155 (B924)	1.10	0.00		1.10
HIGH PRAIRIE (T438)	1.24	9.00	22/01/01	10.24	WILLINGDON (V926)	1.93	2.00	08/01/01	3.93
HINES CREEK (V447)	2.67	2.75	19/01/01	5.42	WOOD BUFFALO (M018)	0.09	0.00		0.09
HORSESHOE BAY S.V. (S458)	0.52	0.00		0.52	WOOD BUFFALO PARK (L024)	0.61	0.00		0.61
HYTHE (V468)	1.55	10.00	20/01/01	11.55	YOUNGSTOWN (V932)	1.35	1.25	12/01/01	2.60
INNISFREE (V474)	4.22	5.00	17/01/01	9.22	BIG LAKE & KINUSO (M125, V505)	1.17	0.00		1.17
JASPER (R004)	0.69	8.00	22/01/01	8.69	BIRCH HILLS & WANHAM (M019, V896)	1.86	0.00		1.86
KITSCOTY (V508)	1.76	6.00	13/01/01	7.76	BONNYVILLE & ANNEXED AREA (M087, M088)	0.40	0.00		0.40
LAKELAND (C089)	0.33	0.00		0.33	JASPER (PARK & OUTSIDE TOWN) (L012, R003)	0.12	6.00	13/08/01	6.12
LAMONT (C030)	1.69	0.00		1.69	KNEEHILL & TORRINGTON (M048, V854)	1.02	0.00		1.02
LESSER SLAVE RIVER (M124)	0.35	0.00		0.35	LLOYDMINSTER (AB45, SK45)	0.93	11.00	15/01/01	11.93
LINDEN (V535)	2.06	6.00	15/01/01	8.06	MINBURN & LAVOY (C027, V523)	0.65	0.00		0.65
LOON RIVER CREE (B473)	1.89	0.00		1.89	SMOKY LAKE & WARSPITE (C013, V905)	1.08	0.00		1.08
M.D. of GREENVIEW (M016)	0.23	0.00		0.23	THORHILD & RADWAY (V687, C007)	5.56	0.00		5.56
MACKENZIE (M023)	1.05	0.00		1.05	VERMILLION RIVER (AB & SK) (C024, SK24)	1.33	0.00		1.33

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Availability

- This Rider B is designed to flow through a Balancing Pool Refund from the Alberta Electric System Operator (AESO).
- Applicable to all customers with the exception of customers served on Price Schedule D24, Price Schedule D34, and Price Schedule D44, at points of service, throughout the territory served by the Company for energy consumption **effective from January 1, 2023 to December 31, 2023.**
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	**Charge (¢/kW.h)** **"+" = Charge** **"-" = Refund**
D11 Residential	0.232
D13 Time of Use Residential Service	0.232
D21 Small General Service	0.232
D22 Small Technology	0.232
D23 Electric Vehicle Fast Charging Services	0.232
D25 Irrigation Pumping Service	0.231
D26 REA Irrigation Pumping Service	0.231
D31 Large General Service/Industrial – Distribution Connected	0.232
T31 Large General Service/Industrial – Transmission Connected	0.220
D32 Generator Interconnection and Standby Power	0.232
D33 Transmission Opportunity Rate – Distribution Connected	0.232
T33 Transmission Opportunity Rate – Transmission Connected	0.220
D41 Small Oilfield and Pumping Power	0.235
D51 REA Farm Service	0.234
D52 REA Farm Service – Excluding Wires Service Provider	0.234
D56 Farm Service	0.234
D61 Street Lighting Service	0.232
D63 Private Lighting Service	0.233

Note: Rider B does not apply to Rider A, Rider G, Rider J, and Rider S

Appendix F

ATCO Electric Distribution
Rider G Temporary Adjustment

Availability

- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective from **January 1, 2023 to December 31, 2023.**
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	**Charge (¢/kW.h)** **"+" = Charge** **"-" = Refund**
D11 Residential	-0.123
D13 Time of Use Residential Service	-0.123
D21 Small General Service	-0.150
D22 Small Technology	-0.150
D23 Electric Vehicle Fast Charging Services	-0.150
D25 Irrigation Pumping Service	0.761
D26 REA Irrigation Pumping Service	0.761
D31 Large General Service/Industrial – Distribution Connected	0.088
T31 Large General Service/Industrial – Transmission Connected	0.000
D32 Generator Interconnection and Standby Power	0.088
D33 Transmission Opportunity Rate – Distribution Connected	0.088
T33 Transmission Opportunity Rate – Transmission Connected	0.000
D41 Small Oilfield and Pumping Power	- 0.116
D51 REA Farm Service	0.170
D52 REA Farm Service – Excluding Wires Service Provider	0.170
D56 Farm Service	0.110
D61 Street Lighting Service	-0.142
D63 Private Lighting Service	-0.283

Note: Rider G does not apply to Rider A, Rider J, and Rider S.

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Appendix F

ATCO Electric Distribution
Rider J Interim Adjustment

Availability

- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective from **January 1, 2023 to December 31, 2023.**
- Rider J applies as a percentage (%) of total base Distribution and Service Component charges by rate class.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	**Charge (%)** **"+" = Charge** **"-" = Refund**
D11 Residential	12.08
D13 Time of Use Residential Service	12.08
D21 Small General Service	0.41
D22 Small Technology	0.41
D23 Electric Vehicle Fast Charging Services	0.41
D25 Irrigation Pumping Service	2.38
D26 REA Irrigation Pumping Service	2.38
D31 Large General Service/Industrial – Distribution Connected	0.02
T31 Large General Service/Industrial – Transmission Connected	2.96
D32 Generator Interconnection and Standby Power	0.02
D33 Transmission Opportunity Rate – Distribution Connected	0.02
T33 Transmission Opportunity Rate – Transmission Connected	2.96
D41 Small Oilfield and Pumping Power	-0.71
D51 REA Farm Service	0.05
D52 REA Farm Service – Excluding Wires Service Provider	0.05
D56 Farm Service	-0.24
D61 Street Lighting Service	14.81
D63 Private Lighting Service	11.10

Note: Rider J does not apply to Rider A, Rider G, and Rider S.

Availability

- Rider S is designed to dispense of the estimated System Access Service (SAS) deferral balance on the prospective basis for the proceeding quarter as well as including previous quarter true-ups of actual revenues and costs related to Riders.
- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective **January 1, 2023**.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below.

Applicable Distribution Tariff Price Schedule	**Charge (¢/kW.h)** **"+" = Charge** **"-" = Refund**
D11 Residential	1.255
D13 Time of Use Residential Service	1.255
D21 Small General Service	1.327
D22 Small Technology	1.327
D23 Electric Vehicle Fast Charging Services	1.327
D25 Irrigation Pumping Service	0.000
D26 REA Irrigation Pumping Service	0.000
D31 Large General Service/Industrial – Distribution Connected	1.369
T31 Large General Service/Industrial – Transmission Connected	0.000
D32 Generator Interconnection and Standby Power	1.369
D33 Transmission Opportunity Rate – Distribution Connected	1.369
T33 Transmission Opportunity Rate – Transmission Connected	0.000
D41 Small Oilfield and Pumping Power	1.238
D51 REA Farm Service	1.104
D52 REA Farm Service – Excluding Wires Service Provider	1.104
D56 Farm Service	1.086
D61 Street Lighting Service	1.129
D63 Private Lighting Service	1.130

Note: Rider S does not apply to Rider A, Rider G, and Rider J.