Alberta Electric System Operator

Application for Revised Adjusted Metering Practice Implementation Plan and Related Amendments to Independent System Operator Tariff and Rules

April 11, 2024

Alberta Utilities Commission
Decision 28441-D02-2024
Alberta Electric System Operator
Application for Revised Adjusted Metering Practice Implementation Plan and Related Amendments to Independent System Operator Tariff and Rules
Proceeding 28441

April 11, 2024

Published by the:
Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

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

Contents

1 Decision summary

1. For the reasons set out in this decision, the Alberta Utilities Commission:

- finds that the revised adjusted metering practice (AMP) implementation plan submitted by the Alberta Electric System Operator (AESO) provides a reasonable way to implement the AMP that meets the requirements of the *Electric Utilities Act*;
- approves the related amendments to the Independent System Operator (ISO) tariff and Section 503.17 of the ISO rules; and
- finds that the AESO has complied with the Commission direction issued at paragraph 23 of Decision 27047-D01-2022.[1]

2 Introduction and background

2. This decision is related to practices for metering (i.e., measuring) electric energy that enters and exits the transmission system,[2] [3] and to contracting and billing practices for transmission system access service (SAS), at transmission substations[4] that serve distribution facility load (referred[5] to as distribution facility owner (DFO) substations by the AESO).

3. The AESO explained that under the current net metering practice, a DFO substation is treated as a single point of delivery and supply, which aggregates and nets electric energy flowing out of and into the transmission system on each feeder against each other.[6] SAS at each DFO substation is then contracted and billed under a single agreement for demand transmission service (DTS), and a single agreement for supply transmission service (STS), based on the substation's overall net flow.

---

1 Decision 27047-D01-2022: Alberta Electric System Operator, Application for Approval of the Adjusted Metering Practice Implementation Plan and Associated Section 502.10 of the ISO Rules Proceeding 27047, Application 27047-A001, May 31, 2022, PDF page 9, paragraph 23.

2 Section 1(1)(ccc) of the *Electric Utilities Act*: "transmission system" means all transmission facilities in Alberta that are part of the interconnected electric system.

3 Consistent with the Commission's findings in Decision 22942-D02-2019: Alberta Electric System Operator, 2018 Independent System Operator Tariff, Proceeding 22942, Application 22942-A001, September 22, 2019, PDF page 162, paragraph 686, the point at which feeders exit a substation is the demarcation point between the transmission system and the electric distribution system.

4 Section 1(1)(ccc) of the *Electric Utilities Act*: a "transmission facility" includes substations, transformers and switchgear.

5 Exhibit 28441-X0002.01, application, PDF page 3, paragraph 1.

6 Proceeding 27047, Exhibit 27047-X0003, Appendix A - AMP Implementation Plan, PDF pages 3-4.

4. In Decision 22942-D02-2019,[7] the Commission found that the current net metering practice could cause significant erosion of billing determinants because of increased distribution connected generation (DCG) proliferation. Billing determinants are a function of the measured energy flows to and from the transmission system and are used to determine what a customer pays for transmission system access service.[8] The netting of reverse flows (electric energy flowing into the transmission system) caused by DCGs against existing DTS load causes billing determinant erosion,[9] as net metering reduces DTS billing determinants compared to the separate gross metering of DTS and STS. The Commission also found that continuation of the current net metering practices would increase the cross-subsidy of DCG by DTS load customers. Based on these concerns, the Commission approved the AESO's AMP in Decision 22942-D02-2019.

5. The AESO explained that under the AMP, each individual feeder at a DFO substation is recognized as a single point of delivery and supply, and electric energy flowing out of and into the transmission system is measured separately at each feeder.[10] For SAS contracting and billing purposes at DFO substations, DTS agreements would be based on the total sum of the electric energy flowing out of the transmission system, and STS agreements would be based on the total sum of the electric energy flowing into the transmission system, as measured at each individual feeder.

6. In Decision 25848-D01-2020,[11] the Commission directed the AESO to proceed with development of an AMP implementation plan. Subsequently, in Decision 26215-D02-2021,[12] the Commission instructed the AESO to file an application regarding the AMP implementation plan.

7. In compliance with Decision 26215-D02-2021, the AESO submitted[13] an AMP implementation plan for the Commission's approval in Proceeding 27047, proposing to implement the AMP immediately at all existing and new DFO substations with no exceptions. Under this plan, DFO substations with reverse flows were required to have feeder-level metering, and were required to amend their SAS agreements and measurement point definition records to be compliant with the AMP.[14] In some instances, DFO substations would have been required to undertake retrofits, including replacements of existing low-voltage switchgear ahead of normal lifecycle replacement, in order to install the feeder-level metering necessary to measure reverse flows.

---

7 Decision 22942-D02-2019: Alberta Electric System Operator, 2018 ISO Tariff Application, Proceeding 22942, September 22, 2019, PDF pages 153-154, paragraphs 638-645.

8 Decision 26911-D01-2022: Alberta Electric System Operator, Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application, Proceeding 26911, November 10, 2022, PDF page 10, paragraph 28.

9 Exhibit 28441-X0022, Appendix F- Stakeholder Engagement Summary and Materials, PDF page 35.

10 Proceeding 27047, Exhibit 27047-X0003, Appendix A - AMP Implementation Plan, PDF pages 3-4.

11 Decision 25848-D01-2020: Alberta Electric System Operator – Stage 2 Review and Variance of Decision 22942-D02-2019, Adjusted Metering Practice and Substation Fraction Methodology, Proceeding 25848, Application 25848-A001, December 23, 2020.

12 Decision 26215-D02-2021: Alberta Electric System Operator, Review and Variance of Decision 26215-D01-2021, Proceeding 26215, June 3, 2021.

13 Proceeding 27047, Exhibit 27047-X0002.01, Compliance Filing Pursuant to Decisions 25848-D01-2020 and 26215-D01-2021, and Application for Approval of Proposed Amended Section 502.10 of the ISO Rules.

14 Proceeding 27047, Exhibit 27047-X0002.01, Compliance Filing and Proposed Amended Section 502.10, and Exhibit 27047-X0003, Appendix A - AMP Implementation Plan.

8. In Decision 27047-D01-2022,[15] the Commission denied the proposed AMP implementation plan, finding that the AESO did not provide sufficient information for the Commission to determine whether approval of the application was in the public interest or supported the fair, efficient and openly competitive operation of the electricity market. Specifically, the Commission was not satisfied by the level of accuracy and completeness of the cost estimates provided by the AESO, and it was unclear to the Commission how much benefit can be achieved through the AMP implementation with the phase out of DCG credits. The Commission also provided direction to the AESO about the information that should be included if the AESO chose to file a subsequent application for approval of an AMP implementation plan.

9. On August 31, 2023, the AESO filed the current application with the Commission, requesting approval of the following:[16]

- a revised AMP implementation plan;
- amendments to sections 3.6(2), 3.6(3) and 5.2(2) of, and the addition of sections 3.6(4) and 3.6(5) to, the terms and conditions of the ISO tariff; and
- amendments to Section 503.17 of the ISO rules, *Revenue Metering System*.

10. The AESO also requested confirmation that it satisfactorily responded to the Commission direction issued at paragraph 23 of Decision 27047-D01-2022, regarding cost information that the AESO was directed to include in any subsequent application for approval of an AMP implementation plan.

11. The Commission issued notice of the application on September 5, 2023, advising interested parties to file a statement of intent to participate (SIP) by September 12, 2023. AltaLink Management Ltd., Capital Power Corporation, the City of Lethbridge, The City of Red Deer, the Consumers' Coalition of Alberta, the DCG Consortium,[17] ENMAX Power Corporation, FortisAlberta Inc., Lionstooth Energy, the Office of the Utilities Consumer Advocate, the University of Alberta, and Versorium Energy Ltd. each filed a SIP.

12. The Commission did not establish a formal issues list in this proceeding, but determined that the scope of this proceeding would be limited to the reasonableness and feasibility of the AESO's proposed AMP implementation plan.[18] In that regard, the Commission found that concerns related to the necessity of the AMP, including its ability to address billing determinant erosion and the consideration of alternative solutions to solve billing determinant erosion, are outside the scope of this proceeding.[19]

13. The Commission 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.

---

[15] Decision 27047-D01-2022, PDF pages 4 and 6-9, paragraphs 2, 14, 16-17 and 22.
[16] Exhibit 28441-X0002.01, application.
[17] BluEarth Renewables Inc., Elemental Energy Renewables Inc., RWE Canada Ltd.
[18] Exhibit 28441-X0053, AUC letter - Process schedule, PDF page 2, paragraphs 6-7.
[19] As an example, please refer to Exhibit 28441-X0096, DCG Consortium Evidence - Power Advisory - Christine Runge, PDF pages 16-18, paragraphs 58-65, where the DCG Consortium filed evidence suggesting that because the issue of billing determinant erosion will be addressed through a future ISO tariff rate design, implementation of the AMP will result in undesirable consequences without any long-term benefits.

3 Legislative and regulatory framework

14. The AESO has applied for Commission approval of amendments to the ISO rules under Section 20.2(1) of the *Electric Utilities Act* and the tariff (specifically the terms and conditions).

15. After considering a proposed ISO rule, in accordance with Section 20.21(1) of the *Electric Utilities Act*, the Commission may, by order, approve the ISO rule, direct the AESO to revise the ISO rule or refuse to approve the ISO rule.

16. In accordance with Section 20.21(2) of the *Electric Utilities Act*, the Commission may approve an ISO rule filed under Section 20.2 only if the Commission is satisfied:

> (a) that the ISO rule
>
> (i) is not technically deficient,
>
> (ii) supports the fair, efficient and openly competitive operation of the electricity market, and
>
> (iii) is in the public interest,
>
> and
>
> …
>
> (c) that the Independent System Operator, in developing the rule, complied with the Commission rules made under section 20.9.

17. Section 20.9 of the *Electric Utilities Act* requires the Commission to make rules requiring the AESO to consult with parties in the development of ISO rules and authorizes the Commission to develop rules governing the AESO's process in the development of those rules. Rule 017: *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission* is the Commission rule that was created in response to Section 20.9 of the *Electric Utilities Act*.

18. Furthermore, in accordance with Section 121(2) of the *Electric Utilities Act*, when considering whether to approve a tariff application (a tariff means a document that sets out rates and terms and conditions[20]) the Commission must ensure that:

> (a) the tariff is just and reasonable,
>
> (b) the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law, and
>
> …

4 How should the Commission assess the AESO's proposed ISO rule and tariff changes?

19. The AESO's proposed AMP implementation plan includes the following primary features:[21]

[20] *Electric Utilities Act*, Section 1(1)(aaa).
[21] Exhibit 28441-X0005, Appendix C - Revised Implementation Plan, PDF pages 4-5, paragraphs 9-10.

- The plan entails updating the existing SAS[22] agreements at DFO substations that have feeder-level metering in place. For new and existing DFO substations where feeder-level metering or the metering infrastructure is in place, the plan will require all system access service requests (SASRs) submitted after the AMP is effective to be compliant with the AMP.

- For DFO substations that do not have feeder-level metering or metering infrastructure in place but have reverse flows, compliance with the AMP will not be immediately required. Instead, transmission facility owners (TFOs) will be required to install the feeder-level metering and to update SAS agreements to comply with the AMP when the switchgear lineup for the substation will be replaced in the future.

- The cost allocations (between participant[23] and system[24]) for AMP implementation would be consistent with the cost-causation principle, and the way in which the costs of meters and metering infrastructure are allocated for all AESO-directed transmission facility projects or TFO-initiated lifecycle replacement projects.[25]

20. The proposed AMP implementation plan is codified by the following amendments to the ISO rules and the terms and conditions of the ISO tariff, which the AESO is also requesting approval of in this application:

- Amendments to sections 3.6(2) and 3.6(3) of the ISO tariff require Rate DTS contract capacities to reflect the total electric energy flowing from the transmission system to each of the feeders, and Rate STS contract capacities to reflect the total electric energy flowing from each of the feeders to the transmission system.[26]

- The addition of a new Section 3.6(4) to the ISO tariff, which makes an exception to the requirements in sections 3.6(2) and 3.6(3) of the ISO tariff by allowing contract capacities to be set on a net basis for industrial complexes that apply for new or modified SAS agreements, if an industrial system designation has been obtained under Section 4 of the *Hydro and Electric Energy Act*.[27] This addition was already approved by the Commission in Decision 26215-D02-2021, with an effective date to be specified by the Commission in its approval of an AMP implementation plan.

---

22 As defined in the AESO's Consolidated Authoritative Document Glossary: system access service means "the service obtained by a market participant through a connection to the transmission system, and includes access to exchange electric energy and ancillary services."

23 As defined in Section 4 of the ISO tariff, Classification and Allocation of Connection Project Costs: participant-related costs are the costs deemed necessary by the ISO to accommodate a connection project, when taking into account the ISO's transmission system planning obligations. Please refer to Section 4 of the ISO tariff for a comprehensive listing of associated costs.

24 As defined in Section 4 of the ISO tariff, Classification and Allocation of Connection Project Costs: system-related costs are the costs of the connection project that have not been classified as participant-related, and include incremental transmission facility costs in excess of the ISO's preferred connection alternative, to serve the market participant where, as determined by the ISO, economics or transmission system planning support the development of such transmission facilities. Please refer to Section 4 of the ISO tariff for more details.

25 Exhibit 28441-X0111, AESO rebuttal evidence, PDF page 18, paragraphs 84-85.

26 Exhibit 28441-X0005, Appendix C - Revised Implementation Plan, PDF page 4, paragraph 5.

27 Exhibit 28441-X0002.01, application, PDF page 14, paragraphs 45-46.

- An administrative amendment to Section 5.2(2) of the ISO tariff, to make reference to the new Section 3.6(4) of the ISO tariff.

- The addition of a new Section 3.6(5) to the ISO tariff, which exempts a DFO substation with reverse flows from complying with the AMP, if it does not have meters at the feeder level or switchgear that can accommodate the installation of meters at the feeder level.[28]

- Amendments to Section 503.17 of the ISO rules, *Revenue Metering System*, requiring TFOs at DFO substations to install and operate a revenue metering system that allows for financial settlement as required by the ISO tariff, including the ISO tariff amendments outlined above. The amendments will also require TFOs to install either a complete feeder-level metering system if a DFO substation has reverse flows, or to install infrastructure that is capable of supporting feeder-level metering for new and existing DFO substations that undergo the installation or replacement of switchgear lineups.[29]

21. The AESO requested that the proposed AMP implementation plan and the related amendments to the ISO tariff and the ISO rule be approved effective January 1, 2025.[30]

22. The Commission will assess the AESO's proposed ISO rule and tariff changes, applying the statutory requirements set out in Section 3 of this decision, in the context of the AMP implementation plan.

23. For reasons that follow, the Commission:

- finds that the AESO's proposed AMP implementation plan provides a reasonable way to implement the AMP in a manner that satisfies the requirements of the *Electric Utilities Act*;

- approves the related amendments to the ISO tariff and Section 503.17 of the ISO rules; and

- approves the AESO's requested effective date of January 1, 2025.

4.1 Do the rule amendments and the proposed AMP implementation plan meet the requirements set out in the Electric Utilities Act?

24. The Commission finds that the ISO rule amendments and the proposed AMP implementation plan are:

(i) not technically deficient;

(ii) support the fair, efficient and openly competitive operation of the electricity market; and

[28] Exhibit 28441-X0005, Appendix C - Revised Implementation Plan, PDF page 4, paragraph 7
[29] Exhibit 28441-X0002.01, application, PDF page 14, paragraph 47.
[30] Exhibit 28441-X0002.01, application, PDF page 16, paragraph 58.

(iii) are in the public interest.

25. The Commission also finds that the AESO fulfilled its obligation to adequately consult with stakeholders in developing the ISO rule amendments and the AMP implementation plan.

4.1.1 Is the ISO rule not technically deficient?

26. The Commission is satisfied that the ISO rule is not technically deficient.

27. The proposed amendments to Section 503.17 of the ISO rules, which are needed to implement the AMP, are consistent with the statutory scheme and authorized by sections 20(1)(a), 20(1)(c) and 20(1)(l) of the *Electric Utilities Act*;[31] and are complete and reasonably self-contained.

28. Furthermore, consistent with the Commission's AMP-related findings in Decision 22942-D02-2019 and the intent of the AMP, the proposed ISO rule amendments will address billing determinant erosion caused by reverse flows from DCG proliferation.

29. The ISO rule amendments also accurately reflect the AESO's proposed AMP implementation plan. This notably includes the transitional exemption on immediate compliance with the AMP for DFO substations that have reverse flows without the appropriate feeder-level metering, until the meters are installed at the feeder level as part of future DFO substation lifecycle alterations.

30. AltaLink stated that the AMP would address netting across feeder-level meters, but will not capture the netting that occurs below the feeder-level meters when DCG supply and load are located on the same feeder.[32] Accordingly, AltaLink recommended that the Commission direct the AESO: (i) to more broadly investigate the extent of billing determinant erosion occurring on the distribution systems; and (ii) to propose solutions to such billing determinant erosion and, if no further action is proposed, to explain the rationale.[33]

31. The Commission finds this issue to be outside the scope of this proceeding, because the purpose of this proceeding is to assess the reasonableness and feasibility of the AESO's proposed AMP implementation plan and not to consider solutions to other forms of billing determinant erosion, which is a tariff rate design matter. Accordingly, the Commission will not adopt AltaLink's recommendations.

---

[31] Sections 20(1)(a), (c) and (l) of the *Electric Utilities Act* state: The Independent System Operator may make rules respecting:
"(a) the practices and procedures of the Independent System Operator; …
(c) the operation of the interconnected electric system; …
(l) any other matter the Independent System Operator considers necessary or advisable to carry out its duties, responsibilities, and functions under this Act and the regulations."

[32] Transcript, Volume 1, pages 37-38, lines 21-25 and 1-2.

[33] Transcript, Volume 1, pages 51-52, lines 17-20 and 5-8.

4.1.2 Do the ISO rule amendments and the proposed AMP implementation plan support the fair, efficient and openly competitive operation of the electricity market?

32. The Commission finds that the AESO's proposed AMP implementation plan and related amendments to the ISO rules support the fair, efficient and openly competitive operation of the electricity market, because they are correcting differential treatment (i.e., reducing billing determinant erosion specific to DCG proliferation) that currently exists between:[34] (i) DFO substations with and without reverse flows; and (ii) transmission connected generators (TCGs) and DCGs.

33. For a DFO substation that has reverse flows, the current net metering practice under-measures the total electric energy flowing into and out of the substation, because it nets (i.e., cancels out) these electric energy flows against each other. Accordingly, the associated billing determinants that are used to calculate Rate DTS at a DFO substation with reverse flows under-represent the load served by the transmission system at the DFO substation, resulting in lower Rate DTS charges when compared to DFO substations that do not have reverse flows.[35]

34. When considering whether the implementation plan supports the fair, efficient and openly competitive operation of the electricity market, the Commission is also concerned with the differential treatment of TCGs and DCGs. Because of the netting of flows discussed in the previous paragraph, DFO substations with DCGs (and consequently the DCGs themselves) also receive lower Rate STS charges when compared to TCGs. All else being equal, whether a generator is interconnected at a transmission or distribution voltage will not significantly affect the impact it will have on the bulk and regional transmission system. Instead, like a TCG, a DCG located in an area where load exceeds generation can be expected to generally off-load the transmission network and conversely, one located in an area where generation exceeds load can be expected to generally increase the loading on the transmission network. TCGs and DCGs also enjoy similar benefits from being connected to the electricity network, most notably from being able to sell their output in the power pool. Accordingly, the Commission finds that in order to support the fair, efficient and openly competitive operation of the electricity market, TCGs and DCGs should, to the degree possible, face similar treatment with respect to the transmission tariff (i.e., transmission losses charges[36] under Rate STS).

35. In addition to the issues discussed above, to determine whether the AESO's proposed AMP implementation plan and the related amendments to the ISO rule support the fair, efficient and openly competitive operation of the electricity market, the Commission must also assess the following pertinent issues that emerged during the course of this proceeding: (i) whether the proposed AMP implementation plan and the related ISO rule amendment are unjustly discriminatory; and (ii) whether the AESO's proposed cost allocation methodology to implement the AMP supports the fair, efficient and openly competitive operation of the electricity market.

---

[34] Transcript, Volume 1, page 14, lines 24-25, and page 15, lines 1-8.

[35] From Exhibit 28441-X0002.01, application, PDF page 5, paragraphs 9-13, and Exhibit 28441-X0003, Appendix A - AMP Alternatives Comparison, PDF page 12, paragraphs 30-34.

[36] https://www.aeso.ca/grid/grid-related-initiatives/loss-factors/: During the transmission of electricity, some energy is "lost" from the transmission system, usually in the form of heat. This lost energy is known as transmission losses. The AESO recovers the cost of transmission losses from generating facilities and other services by establishing a percentage loss factor, for each generating facility or service that reflects its location and contribution to transmission losses.

4.1.2.1 Are the ISO rule amendments and the proposed AMP implementation plan unjustly discriminatory?

36. For reasons that follow, the Commission finds that the ISO rule amendments and the proposed AMP implementation plan are not unjustly discriminatory and support the fair, efficient and openly competitive operation of the electricity market.

37. The Commission acknowledges that some of the differential treatment outlined above will still remain under the AESO's proposed AMP implementation plan, because DFO substations with reverse flows would be temporarily exempt from complying with the AMP if they do not have meters at the feeder level, or metering infrastructure that can accommodate the installation of meters at the feeder level.[37] However, the Commission finds that this differential treatment is not unjustified, is transitional in nature and will only apply to a small number of DFO substations.

38. In the Commission's view, physical constraints (i.e., that some DFO substations have the required feeder-level metering infrastructure and others do not) provide valid justification for the differential treatment that would occur under the AESO's proposed AMP implementation plan.[38] This physical constraint puts a capital cost on the implementation of the AMP, which necessitates a cost-efficient implementation plan. In that regard, the Commission is persuaded that the AESO's preferred plan is the most cost-efficient option to implement the AMP that has been proposed on the record of this proceeding. This is because the proposed AMP implementation plan minimizes capital costs when compared to the originally proposed plan. Under the original plan, the capital costs of retrofitting a DFO substation to install feeder-level metering are significantly more than doing so as part of broader DFO substation lifecycle work under the AESO's currently proposed plan.[39]

39. Furthermore, the Commission previously found that billing determinant erosion specific to DCG proliferation, at even modest levels, must be remedied.[40] Absent the AMP, billing determinant erosion specific to DCGs is expected to be exacerbated by the recent increasing number of DCGs.[41] These concerns necessitate an AMP implementation plan that reduces billing determinant erosion specific to DCGs within a reasonable timeframe. In that regard, the Commission finds that the AESO's proposed AMP implementation plan, in addition to being the most cost-efficient plan that was proposed on the record of this proceeding, also implements the AMP in a timely manner while reducing the associated billing determinant erosion at an overwhelming majority of DFO substations.[42]

40. In the Commission's view, the benefits of implementing the AMP at a majority of DFO substations, in a timely and cost-efficient manner, also provide valid justification for exempting some DFO substations from immediate AMP compliance until lifecycle replacements occur. This is because only 5-12 DFO substations out of approximately 450 are currently expected to be exempt under the AMP.[43] The Commission expects that any resulting discrimination that will

---

37 Exhibit 28441-X0003, Appendix A - AMP Alternatives Comparison, PDF pages 12-13, paragraphs 30-36.
38 Transcript, Volume 1, page 124, lines 6-11.
39 Exhibit 28441-X0004, Appendix B - Cost Benefit Analysis.
40 Decision 22942-D02-2019, PDF page 154, paragraph 643.
41 Exhibit 28441-X0002.01, application, PDF pages 5-6, paragraphs 9-19.
42 Exhibit 28441-X0002.01, application, PDF page 11, paragraph 33.
43 Exhibit 28441-X0002.01, application, PDF page 11, paragraph 33.

exist under the AESO's proposed AMP implementation plan will be minimal, and is not persuaded that the potential adverse effects associated with this discrimination will significantly outweigh the benefits (i.e., a cost-efficient AMP implementation that reduces billing determinant erosion in a timely manner at a majority of DFO substations) that the AMP would achieve during the exemption period.

41. The DCG Consortium argued that by not implementing the AMP equally at all DFO substations, DCGs connected to AMP-compliant DFO substations would be subject to higher costs (transmission losses charges under Rate STS) compared to DCGs connected to AMP-exempt DFO substations.[44] Accordingly, the DCG Consortium recommended that the Commission delay implementation of the AMP until it can be made effective at all DFO substations with connected DCGs.[45]

42. The Commission finds that this recommendation does not support the fair, efficient and openly competitive operation of the electricity market, because it would allow billing determinant erosion specific to DCG proliferation to continue and accrue at all DFO substations for decades (another 40 to 50 years according to the AESO's estimates).[46] The Commission therefore finds that even if the AMP resulted in some DCGs not facing transmission losses charges because of delayed AMP implementation, that would be preferable to all DCGs not facing these charges. The Commission also finds that the allocation of loss factor[47] charges incurred by DFOs to DCGs is a DFO tariff matter. The implementation of AMP is not determinative of how that allocation will be accomplished and so the concerns raised by the DCG Consortium are properly addressed in future DFO tariff proceedings.

4.1.2.2 Does the AESO's proposed cost allocation methodology to implement the AMP support the fair, efficient and openly competitive operation of the electricity market?

43. Given that the AESO is proposing to allocate the cost of the AMP by using existing principles and mechanisms that are frequently used for other capital transmission facility projects in Alberta, the Commission finds that using them to allocate the costs of the AMP to market participants (such as DFOs) or as a system cost is also reasonable in these circumstances and, accordingly, supports the fair, efficient and openly competitive operation of the electricity market.

44. The DCG Consortium stated that the costs of the AMP are not caused by DCG but rather by the AMP itself, and therefore the costs should always be considered system costs.[48] The Commission does not agree with this assessment. In cases where a substation undergoes a lifecycle replacement but has no reverse flows, AMP would only require that the new switchgear come with the capability to install feeder-level metering, but the actual installation of the meters

[44] Exhibit 28441-X0096, DCG Consortium Evidence - Power Advisory - Christine Runge, PDF page 11, paragraph 38, and Transcript, Volume 1, page 83, lines 10-16.
[45] Transcript, Volume 1, page 80, lines 3-5.
[46] Transcript, Volume 1, page 19, lines 3-16, and Exhibit 28441-X0076, AESO-DCG-2023OCT04-001 to 004, IR response AESO-DCG-2023OCT04-001(d), PDF page 5.
[47] https://www.aeso.ca/grid/grid-related-initiatives/loss-factors/: Loss factors are used to determine the transmission losses charges that apply to system access service under rates of the ISO tariff, including Rate STS.
[48] Exhibit 28441-X0096, DCG Evidence of Power Advisory- Christine Runge, PDF page 22, paragraphs 80-84.

can be deferred until such a time as a DCG connects to a feeder at a DFO substation and causes reverse flows.[49] Furthermore, the AMP only requires feeder-level metering at DFO substations with reverse flows.[50] Given that DCGs produce the reverse flows that cause billing determinant erosion, and given that future reverse flows will be caused by the individual connection of DCGs, which will in turn drive the need for feeder-level metering in the future, the AESO's proposed cost allocation reflects cost-causation principles.

45. Lionstooth argued that the flow-through of AMP costs to DCGs could deter generation from connecting to certain substations, and that it would be preferrable if generation were incented to connect closer to load.[51] The Commission finds that the question of how or if DFOs pass costs along to DCGs is a distribution tariff matter, and outside the scope of this proceeding.

4.1.3 Are the ISO rule amendments and the proposed AMP implementation plan in the public interest?

46. The Commission finds that the AESO's proposed AMP implementation plan and the related amendments to the ISO rules are in the public interest because, as the Commission found in the previous section of this decision: (i) the AESO's plan is the most cost-efficient option that has been proposed on the record of this proceeding to implement the AMP; (ii) the AESO's plan reduces the associated billing determinant erosion at an overwhelming majority of DFO substations; and (iii) the AESO's plan implements the AMP in a timely manner. The AESO's proposed AMP implementation plan has also garnered the most stakeholder support to date.[52]

47. The Commission also finds it in the public interest to approve the AESO's requested effective date of January 1, 2025, for its proposed AMP implementation plan and the related ISO rule amendments. This is because: (i) each year that the AMP is delayed results in continued billing determinant erosion; and (ii) delaying the AMP creates a risk of potentially missing substations upgrades in 2025, adding years onto the time that the AMP could be fully implemented.[53]

48. The DCG Consortium argued that the estimates and analyses used by the AESO to support the proposed AMP implementation plan had poor assumptions that overestimated the benefits, and underestimated the costs, of implementing the AMP.[54] The Commission is not persuaded by the DCG Consortium's arguments. First, the Commission agrees with the AESO that it would either be too prohibitive to obtain more accurate information at this stage, or the information is not available.[55] Second, to the extent that the benefits of the AMP are less than estimated by the AESO, the Commission previously found that billing determinant erosion specific to DCG proliferation, at even modest levels, must be remedied.[56] Last, to the extent that

[49] Exhibit 28441-X0003, Appendix A- AMP Alternatives Comparison, PDF page 6-7, Figure 1.
[50] Exhibit 28441-X0002.01, application, PDF pages 7-8, paragraphs 20-23.
[51] Transcript, Volume 1, page 105, lines 14-22.
[52] Exhibit 28441-X0002.01, application, PDF pages 3 and 9, paragraphs 4 and 28, and Exhibit 28441-X0022, Appendix F - Stakeholder Engagement Summary and Materials.
[53] Transcript, Volume 1, page 13, lines 11-20.
[54] Exhibit 28441-X0096, DCG Consortium Evidence - Power Advisory - Christine Runge, PDF pages 5-8, paragraphs 13-15 and 20-26, and Transcript, Volume 1, page 76, lines 9-13.
[55] Exhibit 28441-X0111, AESO rebuttal evidence, PDF pages 10-11, paragraph 40; Exhibit 28441-X0022, Appendix F – Stakeholder Engagement Summary and Materials, PDF page 41; and Exhibit 28441-X0004, Appendix B - Cost Benefit Analysis.
[56] Decision 22942-D02-2019, PDF page 154, paragraph 643.

the costs of the AESO's proposed AMP implementation plan are greater than estimated, the Commission is nonetheless persuaded that the AESO's proposed plan is the most cost-efficient option to implement the AMP that has been proposed on the record of this proceeding.

49. Fortis argued that implementation of the AMP on January 1, 2025, reduces DCG credits for those DCGs who take service at DFO substations compliant with AMP, compared to those DCGs who take service from DFO substations that are exempt from compliance on that date.[57] Fortis proposed that implementation be delayed to January 1, 2026 (by one year), which is when the phase-out of DCG credits ends. It also stated that implementation before January 1, 2026, would be too administratively burdensome. The Commission is not persuaded by these arguments. Fortis did not submit an estimate of the actual administrative costs of implementing the AMP to support its claim that implementation prior to the phase-out of DCG credits would be too administratively burdensome.[58] Further, there is already differential treatment with respect to DCG credits, because not all DFOs offer DCG credits.[59] The phase-out of DCG credits (reduced by 20 per cent per year over five years ending December 31, 2025) means that any credits offered in 2025 will already have been reduced by 80 per cent. Given the benefits of implementing the AMP in a timely manner, the Commission does not find it reasonable to delay the implementation of the AMP to avoid further reductions to the already-reduced DCG credits offered by some DFOs, especially given that this impact will only occur for a single year.

4.1.4 Did the AESO fulfill its obligation to adequately consult with stakeholders?

50. Sections 4 and 5 of Rule 017 require the AESO to post notice of proposed rules, receive comments from stakeholders on the proposal and provide written responses to stakeholder comments. All of this must be posted on the AESO's website.

51. Having reviewed the details of the consultation conducted by the AESO provided in the application,[60] the Commission is satisfied that the ISO, in developing the rule amendments, complied with the Commission rules (and specifically the informational and consultation requirements established by Rule 017) made under Section 20.9 of the *Electric Utilities Act*.

4.2 Do the ISO tariff amendments and the proposed AMP implementation plan meet the requirements set out in the Electric Utilities Act?

52. The Commission finds that the ISO tariff amendments and the proposed AMP implementation plan are:

(i) just and reasonable; and

(ii) not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law.

[57] Transcript, Volume 1, pages 96-97.
[58] Transcript, Volume 1, page 13, lines 21-25, and page 14, lines 1-6.
[59] Transcript, Volume 1, page 125, lines 5-9.
[60] Exhibit 28441-X0022, Appendix F - Stakeholder Engagement Summary and Materials.

4.2.1 Are the ISO tariff amendments and the proposed AMP implementation plan just and reasonable?

53. The Commission finds that the AESO's proposed AMP implementation plan and the related ISO tariff amendments are just and reasonable for the reasons identified in sections 4.1.2 and 4.1.3 of this decision. Namely, these reasons are: (i) that the AESO's plan is the most cost-efficient option that has been proposed on the record of this proceeding to implement the AMP; and (ii) the AESO's plan implements the AMP within a reasonable timeframe while reducing the associated billing determinant erosion at an overwhelming majority of DFO substations.

54. The Commission also finds it reasonable to approve the AESO's requested effective date of January 1, 2025, given the concerns around continued billing determinant erosion and prolonged implementation if the AMP is delayed. The reasons for this finding are set out in Section 4.1.3 of this decision.

4.2.2 Are the ISO tariff amendments and the proposed AMP implementation plan unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the Electric Utilities Act or any other enactment or any law?

55. The Commission finds that the AESO's proposed AMP implementation plan and the related ISO tariff amendments are not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the *Electric Utilities Act* or any other enactment or any law, for the reasons identified in Section 4.1.2 of this decision. Namely, these reasons are: (i) the proposed AMP implementation plan is correcting differential treatment (i.e., reducing billing determinant erosion specific to DCG proliferation) that currently exists; (ii) physical constraints, and the benefits of implementing the AMP at a majority of DFO substations in a timely and cost-efficient manner, provide valid justification for the residual transitional differential treatment that would occur under the AESO's proposed AMP implementation plan; and (iii) the potential adverse effects associated with this transitional differential treatment is not likely to significantly outweigh the benefits that the AMP would achieve during the exemption period.

4.3 Which issues are outside the scope of this proceeding?

56. The registered parties brought up several issues which the Commission finds are outside the scope of this proceeding. Those issues are outlined below.

57. The DCG Consortium filed evidence on the following issues:[61]

(i) the revised AMP implementation plan does not consider how changes in load consumption will influence transmission system energy flows and Rate STS calculations;

(ii) the AMP can lead to unfair and unequal application of Rate STS to DCGs depending on whether they are directly connected or behind-the-meter; and

(iii) the impact of distribution system arrangements and day-to-day operational decisions on Rate STS calculations must be assessed under the AMP.

[61] Exhibit 28441-X0097, DCG Consortium evidence - Power Advisory - Travis Lusney.

58. These issues are outside the scope of this proceeding. The first and third issues identified are related to Rate STS calculation methodologies that are ISO tariff rate design issues. The second issue is related to the unfair or inequitable treatment with the flow through of Rate STS from DFOs to DCGs, which is a DFO tariff issue. All of the issues identified are also not caused by the proposed AMP implementation plan and are instead directed at the AMP itself, which was already tested and approved in Decision 22942-D02-2019.[62]

59. The DCG Consortium also filed evidence suggesting that it was not reasonable to measure energy at the feeder level for bulk and regional rates, and that Rate STS billing must continue to be calculated at the substation (not feeder) level.[63] The Commission finds that this issue is outside the scope of this proceeding because it represents a change to the definition of the AMP itself, rather than an alternative implementation methodology. The proposal for the AMP brought forward in Proceeding 22942[64] stated that the AMP would apply to both Rate DTS and Rate STS. The Commission approved the AMP's applicability to both Rate STS and Rate DTS in Decision 22942-D02-2019, and reiterated that approval in Decision 25848-D01-2020[65] and Decision 26215- D01-2021.[66]

5 Has the AESO complied with the Commission direction issued at paragraph 23 of Decision 27047-D01-2022?

60. In paragraph 23 of Decision 27047-D01-2022, the Commission directed the AESO to include the following information in any future AMP implementation plan application:

(a) AACE Class 3 (-20 per cent to +30 per cent) estimates and forecast completion date for all scopes of work proposed in the implementation plan. Alternatively, the AESO could include in its implementation plan mechanisms for cost review and oversight of future phases of AMP implementation.

(b) AACE Class 5 (-50 per cent to 100 per cent) estimates for the total theoretical maximum cost of implementation across all phases.

(c) Quantification of the benefits of implementation of the AMP, including a cost-benefit analysis.

61. The Commission finds that the AESO has complied with the Commission direction issued at paragraph 23 of Decision 27047-D01-2022.

62. In response to part (a), the AESO proposed that the capital costs incurred to implement the AMP should follow the existing capital cost review and oversight mechanism at the time the cost is incurred. This would be either an AESO-directed transmission facility project, which could be a connection project that the AESO initiates in response to a SASR or a system project

[62] Decision 22942-D02-2019, PDF pages 153-154, paragraphs 638-645, and PDF pages 196-197, paragraphs 844-845.
[63] Exhibit 28441-X0096, DCG Consortium evidence - Power Advisory - Christine Runge, PDF pages 18-19, paragraphs 66-72.
[64] Proceeding 22942, AESO 2018 ISO Tariff Application.
[65] Decision 25848-D01-2020, PDF page 13, paragraph 41.
[66] Decision 26215-D01-2021, PDF pages 8-12.

initiated by the AESO, or a TFO-initiated lifecycle replacement project.[67] The Commission finds that the AESO's decision to follow the existing capital cost review and oversight mechanism is reasonable, because the costs to produce the AACE Class 3 estimates for each substation and the time to advance the estimates would be prohibitive, based on the AESO's discussion with TFOs.[68] The Commission also finds it reasonable to use the existing capital cost review and oversight mechanism in this circumstance, given that it is frequently used for other capital transmission facility projects in Alberta.[69]

63. In response to parts (b) and (c), the AESO provided the total theoretical maximum cost of implementing the AMP for each implementation plan alternative, and a quantification and analysis of the costs and benefits of AMP implementation, in Appendix B of its application.[70]

6 Order

64. It is hereby ordered that:

(1) The Alberta Electric System Operator will proceed with the implementation of the adjusted metering practice in accordance with the revised implementation plan as filed, with an effective date of January 1, 2025.

(2) The Alberta Electric System Operator's Independent System Operator tariff and rule amendments are approved as filed, with an effective date of January 1, 2025.

Dated on April 11, 2024.

Alberta Utilities Commission

(original signed by)

Douglas A Larder, KC
Vice-Chair

(original signed by)

Vincent Kostesky
Acting Commission Member

[67] Exhibit 28441-X0004, Appendix B - Cost Benefit Analysis, PDF page 5, paragraph 16.
[68] Exhibit 28441-X0002.01, application, PDF page 13, paragraphs 39-42.
[69] Exhibit 28441-X0004, Appendix B - Cost Benefit Analysis, PDF pages 5-7, paragraphs 15-20.
[70] Exhibit 28441-X0004, Appendix B - Cost Benefit Analysis.

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Alberta Electric System Operator (AESO) McCarthy Tétrault
BluEarth Renewables Inc. Blake, Cassels & Graydon LLP
Capital Power Corporation
The City of Red Deer and the City of Lethbridge Chymko Consulting Ltd.
Consumers' Coalition of Alberta
DCG Consortium Blake, Cassels & Graydon LLP
Elemental Energy Renewables Inc. Blake, Cassels & Graydon LLP
ENMAX Power Corporation
FortisAlberta Inc. (Fortis)
Lionstooth Energy
Office of the Utilities Consumer Advocate
RWE Canada Ltd. Blake, Cassels & Graydon LLP
University of Alberta Chymko Consulting Ltd.
Versorium Energy Ltd.

Alberta Utilities Commission

Commission panel
- D.A. Larder, KC, Vice-Chair
- V. Kostesky, Acting Commission Member

Commission staff
- J. Graham (Commission counsel)
- A. Starkov
- C. Strasser
- N. Morter
- C. Fuchshuber
- O. Anozie