Appendix A: AMP Alternatives Comparison

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1. Introduction

1 This document describes the alternatives for the implementation of the adjusted metering practice (AMP) that the AESO considered with stakeholders following issuance of AUC Decision 27047-D01-2022, including the associated objectives, costs and benefits of each alternative. Other considerations that were discussed with stakeholders with respect to the AMP implementation alternatives are also described below, including the AESO's rationale for selecting the Substation Lifecycle Trigger as its recommended alternative, timing of AMP implementation, and cost treatment.

2 This document is organized as follows:

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2. The AESO's Original Proposed Implementation Plan

3 In the previously proposed AMP implementation plan that was denied by the Alberta Utilities Commission (Commission or AUC) in AUC Decision 27047-D01-2022,[1] the AESO proposed the implementation of the AMP without "legacy treatment", meaning that the AMP would be required to be implemented immediately at all existing and new DFO substations[2] with no exceptions (Original Proposed Implementation Plan).[3]

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[1] Exhibit 27047-X0003.

[2] A transmission substation that provides system access service to an electric distribution system.

[3] Legacy treatment means that SAS at certain DFO substations would not be required to comply with the AMP. Put another way, legacy treatment means that SAS at certain DFO substations with reverse flows would not accurately reflect the flows to and from the transmission system.

4 The Original Proposed Implementation Plan would ensure accurate SAS contracting, measurement, and billing[4] at all DFO substations by requiring that all SAS provided to DFOs complies with the AMP. However, compliance would come at a cost since some existing DFO substations would require potentially expensive retrofits to install the feeder level metering required to measure reverse feeder flows (see Appendix B – Cost Benefit Analysis).

5 Under the Original Proposed Implementation Plan, the AESO also proposed that all new DFO substations would have meters installed at the feeder level in preparation for any potential reverse flows in the future.

3. Alternatives Considered Subsequent to AUC Decision 27047-D01-2022

6 In AUC Decision 27047-D01-2022, the Commission denied the Original Proposed Implementation Plan and directed the AESO to provide prescribed cost information if the AESO wished to proceed with another proposed implementation plan.

7 Consequently, in March and April of 2023, the AESO consulted with stakeholders on the continued need, benefit, cost information and approaches to implementing the AMP.[5] Throughout this consultation, the AESO received stakeholder feedback that spanned from support for the Original Proposed Implementation Plan to complete opposition to any form of AMP implementation. Written stakeholder feedback also demonstrated that stakeholders remained concerned with the capital costs associated with AMP implementation, particularly if an existing DFO substation would require significant retrofitting for feeder level metering. Other stakeholder concerns included the accuracy of the AESO's cost estimates and the impact analysis conducted by the AESO, how metering costs should be recovered, and the timing of AMP implementation with regard to the DCG credit phase-out and other ISO tariff initiatives.

8 Following that consultation and stakeholder feedback, the AESO initiated further consultation with stakeholders[6] to better understand their concerns with AMP implementation, specifically around the costs associated with metering, and to understand if alternatives to the Original Proposed Implementation Plan could address their concerns.

9 In consideration of the stakeholder comments around metering costs, the AESO explored potential alternatives in a manner that minimizes or eliminates costs by focusing on how the significant feeder-level metering work would be triggered. To do so, the AESO employed the following principles:[7]

1. Transmission facilities that are required as part of a connection project initiated in response to a request for new or amended system access service (SAS) should be completed before the AESO can provision the requested SAS.

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[4] If SAS contracting is based on feeder-level flows, then it follows that measurement and billing for that SAS must also be based on feeder-level flows. Separating contracting from measurement and billing would create an unworkable solution. See AESO Post-Disposition Request for Clarification (May 19, 2021) on proceeding 26215, along with Decision 26215-D02-2021.

[5] See Appendix F – Stakeholder Engagement Summary and Materials.

[6] Starting May 31, 2023. See Appendix F – Stakeholder Engagement Summary and Materials.

[7] An initial version of these principles was discussed with stakeholders during one-on-one meetings. See Appendix F – Stakeholder Engagement Summary and Materials, AMP – Minimize or Eliminate Meter Costs, at PDF 181,

2. Market participants should be made aware of the connection project costs associated with a new or amended SAS prior to making their connection decisions.
3. The costs associated with the construction or alteration of transmission facilities as part of a connection project are connection costs which may be classified as participant-related or system-related costs, pursuant to the ISO tariff.
4. The AESO will not retroactively charge market participants for connection costs after connection decisions have already been made.
5. Any exemptions from AMP compliance should be strictly limited, and administered in an unbiased, transparent and consistent manner. More specifically, the AESO considers that exemptions may be warranted where:
    a. AMP compliance would require the incurrence of costs that significantly outweigh the benefits achieved; and
    b. AMP compliance could be achieved in an alternate timeframe that is reasonable to consider in light of other relevant factors, including upcoming scheduled maintenance, and anticipated facility upgrades. That is, it does not permanently exempt the AESO or a DFO from having to comply with the applicable AMP provisions.

10 Principles 1-4 are collectively referred to in this document as the “Connection Project Principles” and principle 5 is referred to as the “Exemption Principle”.

11 Described below are the additional AMP implementation alternatives that the AESO considered in consultation with stakeholders and in reliance upon the principles described above.

(a) Alternative 1: SASR Trigger

12 To minimize AMP implementation costs, the AESO explored an alternative that would not require SAS at all DFO substations with reverse flows to become compliant as soon as the AMP becomes effective:

- At DFO substations with feeder level metering, SAS agreements and MPDRs will be updated to be compliant with the AMP.
- At DFO substations with transformer level metering, the substation will not be retrofitted to install feeder level metering because SAS is not required to be compliant with the AMP. Instead, SAS agreements and MPDRs will be updated to reflect the flows at the most granular level of metering available.

13 On a go-forward, new and amended SAS must comply with the AMP, even if compliance requires retrofitting the DFO substation for feeder level metering. That is, as part of the connection project that the AESO initiates in response to a request for new or amended SAS, the AESO would require the installation of meters at the feeder level to provide the new or amended SAS in a manner that complies with the AMP.

14 Additionally, the AESO considered including the same requirement from the Original Proposed Implementation Plan that all new DFO substations should have meters installed at the feeder level in preparation for any potential reverse flows in the future. However, the AESO decided that as long as the new DFO substation was capable of feeder level metering, then that would significantly reduce the cost incurred in the future if there are reverse flows and the meters must be installed. Whether the feeder level meters are also installed at the time of constructing the new DFO substation will depend on the TFOs requirements at the time of construction.

15 This alternative (Alternative 1: SASR Trigger) is consistent with the Connection Project Principles because of the relationship between the cost to connect and SAS. After the AMP is effective, DFOs are aware that reverse flows may trigger the need to install feeder-level meters to comply with the AMP, so the choice is left to the DFO to determine if they will pay the connection costs to receive the new or amended SAS.

16 Alternative 1 is also consistent with the Exemption Principle in that it is reasonable to exempt the existing SAS for DFO substations where there are reverse flows but no feeder-level metering in place to measure those flows. Exemptions from the AMP would also be limited to existing DFO substations which would incur significant costs to install feeder-level metering. Exemptions would be lost if a DFO submits a future SASR for a new or amended STS.

17 Based on the AESO's preliminary analysis, there will be 5 – 12 DFO substations that likely already have reverse feeder flows[8] but do not have feeder level metering. SAS at these DFO substations would not be required to comply with the AMP immediately once it is in effect. Based on the AESO's Connection Project List, there are 2 - 3 additional DFO substations that are likely to reverse in the near-term and could therefore require the installation of feeder level meters as part of those projects.

(b) Alternative 2: Substation Lifecycle Trigger (Recommended)

18 Another alternative (Alternative 2: Substation Lifecycle Trigger) further minimizes AMP implementation costs by reducing (1) the scope of the physical work required to comply with the AMP; and (2) the number of existing substations that would require physical work to comply with the AMP:

1. TFOs for the approximately 70 existing DFO substations with meters at the transformer level advised the AESO that a significant portion of the costs to install meters at the feeder level is due to the need to "retrofit" existing substation infrastructure to accommodate the equipment required for feeder level metering, specifically the switchgear lineups that connect the substation to the distribution feeders. However, the TFOs also advised that a significant portion of substation assets, including the switchgear lineups related to feeder level metering, are approaching their end of life and would undergo significant lifecycle alterations within the next 10-20 years.[9] When those lifecycle alterations include the replacement of a switchgear lineup, either independently or as part of a substation rebuild (a "Lifecycle Replacement"), the majority of the work required for a retrofit is being done *anyways*, and the incremental work required to prepare the substation for

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[8] To determine if a DFO substation was "likely" to reverse, the AESO looked at the total MW capacity of DCG installed downstream of that substation. All substations with 5 MW or more of DCG and half of the substations with 1 MW to 5 MW of DCG were assumed to reverse. Actual reversals will be dependent on the specific load and generation at each substation, and feeder, and may not align with assumptions.

[9] The City of Red Deer advised that the majority of their substations are at least 30 years old.

EPCOR Distribution and Transmission Inc. advised that they expect to replace a majority of their switchgear in the 2030 to early 2040s timeframe. See also EDTI 2023-2025 TFO Tariff Application, Exhibit 27675-X0006.02, PDF 109 "In the context of EDTI's aging transmission infrastructure, it is important to understand the profile and vintage of EDTI's assets in service. EDTI experienced a significant increase in asset additions in the mid-1970s to mid-1980s. Many of these assets are now nearing their operational performance design limits and/or the end of their useful lives and EDTI will have no choice but to replace much of this equipment within the next number of years at substantial cost under a significant capital infrastructure replacement program."

ENMAX Power Corporations 's 2023-2025 TCOS Application stated that their transmission system grew significantly during the 1970s, and many of those assets installed at that time are now at, or nearing, the end of their useful lives. Additionally, over the past five years, the number of major substation assets that are more than 40 years old has grown by almost 40%. See Exhibit 27581-X0016 at PDF 25.

feeder level metering (the "Metering Infrastructure", as further described in the table below) is therefore minimal.

TFOs advised that allowing them to manage the installation of the Metering Infrastructure at their DFO substations would be the most efficient and cost-effective approach because they will have more flexibility around scheduling the work in consideration of resource planning; they can consider joint planning of discrete projects at the same substation; they can develop a coordinated replacement program across multiple assets; and they can optimize construction across projects and DFO substations.

TFO stakeholders have agreed that in cases where a new DFO substation is built, or a Lifecycle Replacement occurs before there are reverse flows, allowing them the option to exclude the meters from the Metering Infrastructure is more cost-effective and operationally efficient since it will allow them to operate and maintain fewer meters until they are required. The table below provides details for what the scope of work for installing feeder level metering includes:

Figure 1:

	Description of Substation Work Required Specific to Feeder Level Metering
Retrofit Existing Substation for Feeder Level Metering	• Replace existing switchgear with new switchgear that includes revenue-class current transformers or install stand-alone revenue-class current transformers. • Install new racks for revenue meters and wiring terminations. • Install revenue meters and all associated wiring from measurement transformers and communications. • Expand the control building if required for new switchgear and/or additional rack space. • Expand the substation site if required for additional equipment or control building expansion.
Install Metering Infrastructure with Lifecyle Replacement	• Include revenue-class current transformers in the switchgear specifications. • Ensure necessary rack space for revenue meters and wiring terminations in design. • Run wiring from measurement transformers and communications to designated rack space and terminate.
Add Meters to Existing Metering Infrastructure	• Add revenue meters to the designated rack spaces and connect to existing wiring terminations. • Test measurement accuracy and communications.

2. Exempting any of the 70 DFO substations with transformer level metering from having to comply with the AMP if there are reverse flows would mean that no DFO substation would undergo a retrofit to install meters at the feeder level. To ensure that this does not permanently enshrine non-compliance with the AMP, the AESO will require that the Metering Infrastructure is installed when these DFO substations inevitably undergo Lifecycle Replacements in the future.[10]

[10] See Appendix E – ISO Rule Revisions.

Additionally, the AESO will require that the Metering Infrastructure is installed when new DFO substations are constructed. If the Metering Infrastructure is in place and there are reverse flows, then the AESO will require that the meters be installed in order to comply with the AMP.

19 As with Alternative 1, under this alternative the AESO would not require SAS at all DFO substations with reverse flows to become compliant as soon as the AMP becomes effective:

- At DFO substations with feeder level metering, SAS agreements and MPDRs will be updated to be compliant with the AMP.
- At DFO substations with transformer level metering, the substation will not be retrofitted to install feeder level metering because SAS is not required to be compliant with the AMP. Instead, SAS agreements and MPDRs will be updated to reflect the flows at the most granular level of metering available.[11]

20 However, under this alternative on a go-forward, new and amended SAS is not required comply with the AMP if the feeder level metering or Metering Infrastructure is not in place at the DFO substation. The trigger for installing the Metering Infrastructure at the 70 substations without feeder level metering would be a future Lifecycle Replacement that would be addressed by the TFO. New DFO substations will be required to include Metering Infrastructure and whether the feeder level meters are also installed at the time of constructing the new DFO substation will depend on the TFOs requirements at the time of construction.

21 Though this alternative would not always adhere to the Connection Project Principles (specifically, Principle 1), the AESO recommends this alternative to the Commission because of the significant capital cost savings that would result from deferring AMP compliance until Lifecycle Replacements take place. There are no immediate capital costs required to implement the AMP under Alternative 2.

22 As previously stated, there will be 5 – 12 DFO substations that likely already have reverse feeder flows but do not have feeder level metering. SAS at these DFO substations would be exempt from the AMP once it is in effect. From conversations with the DFOs and DCG stakeholders, the AESO does not expect that there will be new reverse flows at a significant number of the remaining DFO substations without feeder level metering (i.e. the AESO does not expect a large number of DFO substations where SAS is exempt from the AMP). Additionally, as these substations undergo Lifecycle Replacements over time, the Metering Infrastructure will be installed so that the SAS can be compliant with the AMP if reverse flows exist or arise in the future.

4. Evaluation of Alternatives

(a) AMP Implementation Objectives

23 Based on feedback from stakeholders, the AESO identified the following objectives to be achieved by AMP implementation. These objectives are:

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[11] See Appendix C – Revised Implementation Plan for additional details.

Affordability and Economic Efficiency

This objective considers the costs incurred for the physical work required to implement the AMP. This objective would be achieved through a combination of minimizing the costs incurred by ratepayers and ensuring those costs are incurred efficiently, which includes consideration of whether the benefits of the AMP outweigh the cost of implementation. Additionally, because increases in economic efficiency will improve affordability by enabling the lowest cost provision of delivered electricity over the long run, this objective also considers whether the price signals from the allocation of costs will enhance economic efficiency.

Accurate SAS

This objective is achieved by ensuring that contracting, measurement, and billing for SAS accurately reflects flows to and from the system. SAS rates and charges that are based on accurate contract capacities and measurement of transmission system usage ensure that market participant billing appropriately reflects their use of the transmission system and that market participants face incentives based on accurate signals. Being able to accurately quantify market participants use of the transmission system is foundational to a rate design that supports efficient charges and encourages efficient use of the transmission system. Put another way, billing determinants that do not accurately reflect the use of the transmission system distort the rate design signals to market participants since the amount of transmission they use may not accurately reflected in what they pay.

Fairness

This objective considers whether AMP implementation leads to undue discrimination and addresses inter-customer subsidies. This objective would be achieved by ensuring that ideally, all (or practically, as many possible) DFO substations are subject to the same measurement practice for ISO tariff billing. In the context of the ISO tariff, fairness is typically considered from the perspective of transmission market participants only. However, since the AESO has a public interest mandate, this assessment is also considered from the perspective of other types of market participant groups.

(b) Affordability and Economic Efficiency Assessment

24 To assess how well each alternative met this objective, the AESO assessed the quantified costs and benefits of each of Alternatives 1 and 2 against the Original Proposed Implementation Plan, and how the alternatives impact economic efficiency. See Appendix B – Cost Benefit Analysis for details of the analysis.

Cost-Benefit

Figure 2:

	Cost of AMP Implementation		
	Original Proposed Implementation Plan	**Alternative 1: SASR Trigger**	**Alternative 2: Substation Lifecycle Trigger**
Based on Likely Reversals	$5.2 to $11.3M	$2.3M to $3M	$420k to $900k
Theoretical Max Cost	$52.5M	$52.5M	$4.2M

The above costs are based on 5 - 12 DFO substations that likely reverse currently, and 2 – 3 additional DFO substations in the near-term. Through discussions with the DFOs for DFO substations that would require physical work to implement the AMP, the cost of implementing the AMP based on likely reversals is much more probable than the theoretical max based on the likelihood of reverse flows at these DFO substations.

Figure 3:

	Impact to 2021 Billing Determinants		
	Original Proposed Implementation Plan	**Alternative 1: SASR Trigger**	**Alternative 2: Substation Lifecycle Trigger**
DTS – Coincident Metered Demand	2.9% increase	2.8% increase	2.8% increase
DTS – Metered Energy	2.4% increase	2.2% increase	2.2% increase
DTS – Billing Capacity	0.2% increase	0.2% increase	0.2% increase
STS – Metered Energy	2.4% increase	2.2% increase	2.2% increase

Figure 4:

	Impact to 2021 DTS Rates		
	Original Proposed Implementation Plan	**Alternative 1: SASR Trigger**	**Alternative 2: Substation Lifecycle Trigger**
Bulk – Coincident Metered Demand	2.8% decrease	2.7% decrease	2.7% decrease
Bulk – Metered Energy	2.5% decrease	2.5% decrease	2.5% decrease
Regional – Billing Capacity	0.2% decrease	0.2% decrease	0.2% decrease
Regional – Metered Energy	2.2% decrease	2.2% decrease	2.2% decrease

Figure 5:

	Impact to SAS Billing Allocation for All Market Participants		
	Original Proposed Implementation Plan	**Alternative 1: SASR Trigger**	**Alternative 2: Substation Lifecycle Trigger**
Amount of $ Reallocated (DTS)	$16.3M	$17.1M	$17.1M
Amount of $ Reallocated (STS)	$4.85M	$4.56M	$4.56M

Though the above numbers for the benefit and impact to 2021 billing determinants, rates, and billing allocation are based on a conservative scenario (i.e. the numbers represent a ceiling for 2021 benefit and impact), it is not unlikely that future reversals will approach that magnitude because (as the AESO previously described[12]) the artificial billing determinant erosion under the current practice has been steadily increasing and will continue to increase as more DCG connect downstream of the transmission system.

As shown above, the change in annual DTS & STS billing determinants, and DTS rates across both Alternatives 1 and 2 is either very similar or the same. In both alternatives, the increase in billing

[12] Appendix F – Stakeholder Engagement Summary and Materials, AMP Background and Need for AMP, at PDF 26-27.

determinants leads to lower rates for all market participants. The cost of implementation decreases if the existing DFO substations that already reverse are not required to comply with the AMP[13] and more so under Alternative 2 where new reverse flows would not trigger the installation of feeder level metering and AMP compliance. Alternative 2 best achieves the Affordability and Economic Efficiency objective because it is the lowest-cost implementation that still achieves a majority of the benefit. Even if the impact to billing determinants, rates, and billing allocation does not reach the magnitude shown in the tables above, AMP implementation under either Alternative 1 or Alternative 2 is desirable because the administrative work required for AMP implementation requires no capital costs upon the AMP being effective and can be completed with minimal effort.

Economic Efficiency

26 Alternatives 1 achieves economic efficiency by ensuring that on a go-forward basis, costs to comply with the AMP are only incurred if a transmission market participant agrees to the cost in order to take new or amended SAS. Market participants have control over the costs that will be required to be incurred for AMP compliance and are provided a signal to make efficient decisions about the cost of new or amended SAS.

27 However, under Alternative 2, the appropriate signal to transmission market participants and their end-use customers is absent since the physical work required to comply with the AMP will be deferred and coupled with Lifecycle Replacements at the DFO substation in the future. Nevertheless, deferring the work and taking advantage of economies of scope by undertaking the work as part of the Lifecycle Replacements results in the best overall long term efficiency and highest affordability. Alternative 2 achieves the majority of the benefits of the AMP at the lowest overall cost.

(c) Accurate SAS Assessment

28 This objective is best achieved by the Original Proposed Implementation Plan, where there are no exemption to the AMP and contracting, measurement, and billing at ***all*** DFO substations accurately reflects the flows to and from the system.

29 However, the AESO's 2021 analysis shows that 93% of the consumed energy that leads to artificial billing determinant erosion is at the existing DFO substations that only require administrative work to comply with the AMP.[14] As such, implementing the AMP at those DFO substations – under either Alternative 1 or Alternative 2 - will already resolve the lion's share of the current artificial billing determinant erosion. Additionally, since both Alternative 1 and Alternative 2 ensure that exemption from AMP compliance is time-limited, the relevant DFO Substations will eventually undergo Lifecycle Replacements and have feeder-level meter installed, enabling the accurate measurement of energy flows and therefore compliance with the AMP at that point in time.

(d) Fairness Assessment

Across DFO Market Participants

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[13] The 2021 impact analysis for Alternative 1: SASR Trigger and Alternative 2: Substation Lifecycle Trigger results in the same impact to billing determinants, rates, and billing allocation because the analysis is based on not requiring DFO substations with transformer level metering and *existing* reverse flows to comply with the AMP (i.e. the analysis does not account for any additional exemptions provided in the future under Alternative 2: Substation Lifecycle Trigger).

[14] Consumed energy refers to the amount of DCG energy consumed by distribution load at the substation. See Appendix F – Stakeholder Engagement Summary and Materials, Background & Ongoing Need, at PDF 26.

30 This objective is best achieved by the Original Proposed Implementation Plan where all DFO substations would be subject to the same feeder-based measurement practice and therefore billed for SAS the same way. If all DFO substations are contracted, measured, and billed accurately based on their flows to and from the transmission system then there is no misallocation of transmission costs at DFO substations (i.e. everyone is paying their fair share).

31 This fairness objective is not fully achieved under Alternatives 1 and 2 because the AMP-compliant DFO substations will be billed based on feeder-level flows and the exempted DFO substations will continue to be billed on metering that does not accurately reflect the flows to and from the transmission system. Exempting some facilities from complying with the AMP represents differential treatment.

32 However, the AESO considers that the differential treatment in Alternatives 1 and 2 is not unreasonable because it is aligned with the Exemption Principle. Limited exemptions are reasonable because:

- Immediate compliance with the AMP at these DFO substations with no feeder level metering infrastructure would require significant costs to retrofit the substation, and it would be more cost-effective in the long run if compliance is deferred until the DFO undergoes Lifecycle Replacements in the future;
- Deferring compliance does not significantly diminish the overall impact/benefit of implementing the AMP since the vast majority (93%) of the artificial billing determinant erosion will be resolved by mere administrative actions;[15]
- Deferring compliance means that non-compliance with the AMP is not permanently enshrined.

33 Differential treatment for Rate DTS billing at a number of DFO substations means that Rate DTS billing will be lower at those substations than what it should be because billing determinants will still underrepresent the flows from the transmission system by about 7%.[16] This would directly cause a subsidy effect because there will be higher Rate DTS billing at some substations (both DFO substations and non-DFO substations) due to the continued misallocation.

34 Though Alternatives 1 and 2 do not fully resolve the misallocation that is occurring due to the artificial billing determinant erosion, it significantly reduces the subsidy effect of the misallocation since approximately $17M will be reallocated across all transmission market participants. Alternatives 1 and 2 also mitigate the differential treatment provided to DFO substations that are not immediately AMP compliant, by ensuring that SAS is based on the flows through the most granular level of metering available at the substation.

[15] As noted above, 93% of the 2021 consumed energy is currently at DFO substations where feeder level metering is in place and compliance to the AMP would only require administrative actions.

[16] Since 93% of the 2021 consumed energy is at the existing DFO substations that only require administrative work to comply with the AMP.

35 The magnitude of the differential treatment is also relatively small. As shown in the chart below, based on current flows, the AESO expects that only 5-12 of the 450 DFO substations[17] (0.01% to 0.02%) would be exempt from the AMP once it is effective. The AESO does not expect the number of DFO substations that would be exempt from immediate AMP compliance to grow substantially in the near future (potentially 3 additional DFO substations in the next two years).

36 Both Alternatives 1 and 2 have a similar impact on non-DFO market participants with industrial facilities in that all market participants (both DFO and non-DFO) would only be subject to the new ISO tariff contract capacity requirements per the proposed ISO tariff revisions[18] if triggered by a SASR that they submit.

Across Generation Market Participants

37 The Commission has found that in order to support a level playing field between DCG and TCG, DCG customers "…should be flowed-through Rate STS charges if the electricity generated by the DCG enters the transmission system at the distribution utility's point of delivery (i.e. substation)".[19] Under the current measurement practice, there are a number of DFO substations that do not have a Rate STS in place for the reverse flows at the feeder-level so they are not billed Rate STS for their flows onto the transmission system. At substations where Rate STS is in place, contracting, measurement and billing is based on net flows at the substation level, which underrepresents the flows entering the transmission system.[20] Since a Rate STS bill may be a charge *or a credit* due to the location specific loss factor, the issue is not necessarily that DFOs are underpaying for Rate STS (transmission losses) under the current measurement practice. Rather, the issue is not having a loss factor and Rate STS for the electricity that enters the transmission system, which directly impacts the allocation of losses for the entire transmission system.

38 To level the playing field between TCG and DCG with respect to Rate STS billing, implementing the AMP at all DFO substations would ensure the most fairness between TCG and DCG since Rate STS at DFO substations will more accurately reflect the DCG flows that enter the transmission system.

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[17] Exhibit 27047-X0002, Application, PDF 11.

[18] See Appendix D – ISO Tariff Revisions.

[19] Decision 26090-D01-2021, at para 61.

[20] See Exhibit 26090-X0084, AESO Evidence on DCG Credit Module for Fortis's 2022 Phase II Distribution Evidence, footnote 17 at PDF 10, and Exhibit 22942-X0529, Fortis Response to Undertakings 1 to 6, PDF 113, where Fortis notes that if the adjusted metering practice had been in place in 2018, the total Option M credits paid to BluEarth regarding its two Bull Creek Generating Units #1 and #2 would have been reduced by approximately 38% as a result of those units "not being able to displace the DTS load on the adjacent distribution feeders". As stated by Fortis, this impact would have also included an "estimated 88% increase to the STS metered energy for which the AESO charges transmission loss charges/credits at the POD per its STS tariff".

39 Under Alternatives 1 and 2, DCG located at DFO substations that are exempt from the AMP would not be flowed through Rate STS charges that are reflective of their flows onto the transmission system. Though Alternatives 1 and 2 do not level the playing field with respect to Rate STS billing for TCG and **all** DCG, they both still ensure that the majority of DFO substations will have more accurate Rate STS that can be flowed-through to a majority of the downstream DCG. Excluding micro-generation, currently there are only 9 DCG located at DFO substations without feeder level metering and 130 DCG at DFO substations with feeder level metering. Based on the AESO's Connection Project List, there could be up to 5 more DCG that connect to DFO substations without feeder level metering and up to 51 more DCG that connect to DFO substations with feeder level metering.

Across DCG

40 In addition to the different Rate STS treatment for DCGs at AMP-compliant and exempt DFO substations, DCG stakeholders have also raised concerns about differential treatment as it relates to DCG credits and flowed-through connection costs.

41 DCG stakeholders raised the concern that, for the remainder of the DCG credit phase-out period (until January 1, 2026), they would receive different DCG credit amounts based on whether they are connected to an AMP-compliant DFO substation or a non-compliant one. A DFO substation that is AMP-compliant will have higher SAS billing determinants and Rate DTS bill than under the current measurement practice, which leads to lower DCG credits (in comparison to the DCG credit amount under the current measurement practice).[21]

42 Though this concern about the unfairness on the impact to DCG credit is best addressed by the Original Proposed Implementation Plan, the magnitude of the differential treatment under Alternatives 1 and 2 is small compared to the total number of DCG receiving DCG credits:

- The AESO estimates that DCG credits are provided to 4 DCG located at the DFO substations without feeder level metering and 130 DCG located at DFO substations with feeder level metering.[22] The differential treatment of DCG is further mitigated by the fact that DCG credits are not available to all existing DCG, as well as the eventual phase-out of the credits[23] for all DCG.[24]
- Based on the amount of DCG credits provided by DFO service area,[25] the total annual amount of DCG credits provided at DFO substations without feeder level metering has generally been less

[21] A simplification of the DCG credit calculation is that DCG Credit = Hypothetical Rate DTS bill without DCG operating – Actual Rate DTS bill from the AESO. See Appendix F – Stakeholder Engagement Summary and Materials, DCG Credits and the AMP at PDF 32.

[22] Currently, there are 9 DCG connected to the DFO substations without feeder level metering. Of the 9, 3 are located in the EPCOR Distribution and Transmission Inc. service area where DCG credits are not available, and 2 DCG located in ENMAX Power Corporation's service area presumably do not receive any DCG credits as they are under the 1 MW eligibility threshold per ENMAX Power Corporation's Distribution Tariff for D600 Large Distributed Generation customers.

For the 130 DCG connected to the DFO substations with feeder level metering, the ATCO Electric Ltd. D32 Price Schedule and FortisAlberta Inc. Option M Schedule did not appear to have a minimum eligibility threshold.

[23] Decision 26090-D01-2021, at para 88.

[24] DCG Credits are not available in the EPCOR Distribution and Transmission Inc. service area. Decision 26090-D01-2021, at para 57.

[25] See Exhibits 24116-X0522, X0511, X0502 for historical DCG credit amounts and DFO TACDA application schedules for more recent DCG credit amounts.

than $1M annually,[26] and typically make up less than 3% of total DCG credits across all the DFO service areas where they are available. The magnitude of the differential treatment of DCG credits is further minimized when the annual DCG credit phase-out multiplier is applied.

43 DCG stakeholders have also raised concerns about differential treatment as it relates to connection costs, and therefore the cost treatment of feeder level metering costs. Under the Original Proposed Implementation Plan and Alternative 1, a new DCG could be flowed-through different connection costs based on whether it is connecting to a DFO substation that requires administrative or physical work to comply with the AMP.[27] However, under Alternative 2, the retrofit of a DFO substation to install feeder level metering is no longer triggered by a SASR. The installation of the Metering Infrastructure and associated costs would not occur until the DFO substation undergoes Lifecycle Replacements, which would be planned for by the TFO and not as part of a connection project initiated in response to new reverse flows.

5. Recommended Alternative

44 Based on the evaluation of the objectives, considering the stakeholder feedback and concerns about the cost of implementation, the denial of the Original Proposed Implementation Plan, and consideration of the cost-benefit analysis directed by the Commission, the AESO recommends that the AMP should be implemented following proposed Alternative 2: Substation Lifecycle Trigger. Though this alternative does not fully achieve the SAS Accuracy objective, that is outweighed by the significant gains in Affordability and Economic Efficiency. Alternative 2 also slightly outweighs Alternative 1 in terms of Fairness.

6. Other Alternatives

(a) Status Quo / No AMP / Delay AMP

45 One alternative that some stakeholders proposed was to simply not implement the AMP due to concerns that the cost of implementation is too high, that the effort could be used for other ISO tariff initiatives, or that the AMP may not be required if a future Rate DTS bulk and regional rate design does not require measured billing determinants. Similarly, other stakeholders proposed that the AMP should be delayed until the future Rate DTS bulk and regional rate design is in place or until the DCG credit phase-out is complete.

46 The AESO disagrees with the positions to delay or not implement the AMP at all, as there is a continued benefit from the AMP to resolve the artificial billing determinant erosion, to lower Rate DTS rates for all market participants, and to resolve the ongoing annual Rate DTS and Rate STS misallocations. Not implementing the AMP is effectively allowing all DFO substations to be enshrined from having SAS contracting, measurement and billing that accurately reflects the flows to and from the transmission system.

[26] Exhibit 24116-X0502, EPC Responses to AUC Preliminary IRs, PDF 43.

[27] DFOs for the substations that would require physical work to install meters advised that they would flow through the associated connection costs to the DCG. At DFO substations that only require administrative work to comply with the AMP, there are no connection costs to flow through to the DCG.

47 These stakeholder concerns are also addressed by the AESO's recommended AMP implementation approach since it is a low-cost alternative that would incur very minimal capital cost to implement the AMP.[28]

48 The AESO's recommended effective date of January 1, 2025 coincides with the final year of the DCG credit phase-out where the phase-out multiplier is reduced to 20%.[29] Delaying the AMP until after the DCG credit phase-out is unnecessarily costly since it would gratuitously allow the continued misallocation of Rate DTS and Rate STS costs. If the Commission finds that there is reason to protect the DCG credits from the impact of the AMP then, as previously submitted by the AESO,[30] there are other ways to do so that do not require delaying the AMP implementation. That is also out of scope for this application and should be dealt with as a DFO tariff matter.

49 With respect to comments about an impending Rate DTS redesign and uncertainty of that outcome, the AESO notes that the AMP is not limited to Rate DTS. The AMP also impacts the accuracy of Rate STS at DFO substations since the current Rate STS is based on metered energy and a location specific loss factor established pursuant to Section 501.10 of the ISO rules, Transmission Loss Factors. Under the current measurement practice, not only would the metered energy billing determinants for Rate STS not accurately reflect the flow onto the transmission system, the AESO also cannot determine a location specific loss factor at a DFO substation if a Rate STS contract is not in place.

50 The AESO is applying to implement the AMP under the current Rate DTS and Rate STS design so that it can address the continued artificial billing determinant erosion and annual cost misallocations, the AMP is required now regardless of future changes to rate design and does not preclude future rate design changes. On the contrary, the AMP ensures that the billing determinants used by any future rate design will accurately reflect the use of the transmission system. This ensures that the rate designs will operate as intended and that market participants will face incentives based on accurate signals.

(b) Site Level Meters

51 During stakeholder consultation, some stakeholders questioned why meters at the feeder level are required to measure the flows to and from the transmission system, and if the AESO could use the existing site level meters (including load meters and DCG meters) to bill for transmission SAS and/or if the AESO could use an administrative solution to determine Rate DTS bills similar to the DCG credit calculation.[31]

52 As the AESO stated in its responses to the Q&A Session and Question Board Summary:

> In alignment with the Electric Utilities Act definitions of "transmission facility" and "transmission system", the AESO considers that the point at which feeders exit a substation to be the demarcation

[28] The AESO, DFOs, and meter data managers are the parties that will undertake the administrative work to implement the AMP, which can be completed in under 6 months.

[29] Decision 26090-D01-2021, at para 88.

[30] Exhibit 26090-X0122, AESO Rebuttal Evidence Submission on DCG Credit Module for Fortis's 2022 Phase II Distribution Tariff, at PDF 7. See also Exhibit 26090-X0084, AESO evidence on DCG Credit Module for Fortis's 2022 Phase II Distribution Tariff, at PDF 9 and 15.

[31] Appendix F – Stakeholder Engagement Summary and Materials, PDF 108-109.

point between the transmission system and the electric distribution system.[32] The substation bus, switches, breakers, and transformers that feeders connect to are also considered transmission facilities per the legislated definition of "transmission facility".

Under the AMP, measurement data must reflect the total energy flows of all feeders in each direction without netting. At substations with feeder metering, these flows are already metered and a change in the measurement practice aggregation is all that is required. However, at substations with transformer metering, new meters will need to be installed at the feeder connection points to have the basic energy flow data required for the AMP (where flows in both directions exist).

The installation of meters at the feeder connection in a substation is the only option for ensuring that SAS at a DFO substation complies with the AMP. The individual energy flows into and out of a substation on each feeder are required to produce the necessary measurement data and cannot be accurately extrapolated using other metered data available to settlement, due to issues with non-interval meters, distribution line losses, unaccounted for energy, different meter data managers (MDM), and the need to use deductive totalization against the transformer meter (a practice prohibited by Measurement Canada).

53 This means that it is not possible to calculate the flow on a feeder at the point of connection to the transmission substation by using the site level meters on the distribution system for a number of reasons, any one of which on its own preclude the use of site level meters.

54 Similarly, some stakeholders asked if the AESO could determine the billing determinants for Rate DTS in a manner similar to the DCG credit calculation. For the DCG credit calculations, DFOs manually calculate a hypothetical transmission charge based on estimating the DTS billing determinants had the DCG not been in operation by adding DCG energy flows back to the POD load.[33] While it may be possible to calculate this hypothetical flow of energy using existing meter data, the result is not relevant to the ISO tariff because it does not accurately represent the flows to and from the transmission system. Adding back **all** of the DCG energy flows to calculate a hypothetical transmission charge ignores the realty that some of the DCG energy flows will be used to serve load on the same feeder and therefore will not flow onto the transmission system.

55 Therefore, using a calculation similar to the DCG credit calculation would result in a change to the billing determinants required by the ISO tariff and what the ISO tariff bills for since transmission charges would apply to all flows on the AIES, and not just system access service on the transmission system.

56 The ISO tariff exists to recover transmission costs from market participants that obtain system access service through a connection to the transmission system, and the current ISO tariff specifically requires billing based on the flows at points of connection to the transmission system. Electric distribution service charges for flows that occur on the electric distribution system to customers connected to the distribution system (i.e. flows from DCG to load on the same feeder) fall under the purview of a DFO's distribution tariff. It is up to the DFO to determine how the DFO's transmission costs should be recovered from their distribution customers through their distribution tariff.

[32] See AUC Decision 22942-D02-2019, *2018 Independent System Operator Tariff* (September 22, 2019), paras. 670-686.

[33] FortisAlberta Inc. Distributed Generation Option M schedule, Option M Calculations section.