Appendix B – Adjusted Metering Practice Cost Benefit Analysis

Date: August 31, 2023

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1. Purpose

1 In Decision 27047-D01-2022, the Commission directed the AESO, should it wish to file a further application to implement the adjusted metering practice (AMP), to include the following information:[1]

- AACE Class 3 (-20% to +30%) 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.
- AACE Class 5 (-50% to 100%) estimates for the total theoretical maximum cost of implementation across all phases.
- Quantification of the benefits of implementation of the AMP, including a cost-benefit analysis.

2 In this document, the AESO responds to the above direction across the three alternatives for AMP implementation that it has explored with stakeholders to date:

- The AESO's Original Proposed Implementation Plan
- Alternative 1: SASR Trigger
- Alternative 2: Substation Lifecycle Trigger (Recommended Alternative)

3 See the Appendix A – AMP Alternatives Comparison for a description of those alternatives.

2. Cost Estimates and Cost Review and Oversight Mechanisms

4 Implementing the AMP at a DFO substation[2] requires administrative actions by the AESO, DFOs, and meter data managers to update system access service agreements to reflect new contract capacities; and to update the measurement point definition records (MPDRs) and meter data systems that aggregate meter data into billing data. At DFO substations where changes to implement the AMP would be exclusively administrative in nature, work that is part of day-to-day operations will be done to update MPDRs, meter data systems, and SAS agreements. In these cases, there are no capital costs required to implement the AMP because the substation already has feeder-level meters.

5 At DFO substations without feeder level metering, in addition to administrative actions, implementing the AMP would first require physical actions to install the meters on the feeders in order to measure the flows to and from the transmission system. Once there are meters at the feeder level, then the SAS agreements and MPDRs can be amended. These physical actions would incur capital costs, which make up the AMP implementation costs for the purpose of this cost-benefit analysis.

6 The capital costs of AMP implementation will depend on the scope of work required to install meters on the feeders and the timing of the work, which depends on how the AMP is implemented:

- Under the Original Proposed Implementation Plan and Alternative 1, at any of the approximately 70 existing DFO substations where meters are at the transformer level, substantial *retrofitting* of

[1] Decision 27047-D01-2022, at para 23.

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

the substation will be required to change over to a feeder metering system in order to comply with the AMP when there are reverse flows.[3]

- Under Alternative 2, at the approximately 70 existing DFO substations where meters are at the transformer level, meters will not be installed at the feeder level until the appropriate infrastructure capable of feeder level metering is in place (i.e. the Metering Infrastructure). Metering Infrastructure will be installed at these DFO substations as part of a Lifecycle Replacement in the future.[4] Then, once the Metering Infrastructure is in place, the scope of work for AMP compliance is reduced to inserting (or "plugging in") the meter, configuring and testing.

7 The costs associated with each of those scopes of work is estimated in the next sections.

2.1 Cost for Retrofitting an Existing DFO Substation to Install Feeder Level Metering

8 At DFO substations with transformer level meters, retrofitting the substation to install feeder level metering will require a transmission facility project by the applicable TFO. Cost estimates for transmission facility projects are required to be completed in accordance with Section 504.5 of the ISO rules, *Service Proposals and Cost Estimating*. As indicated in the AESO Information Document #2015-002R associated with this rule, the AESO has adopted the Association for the Advancement of Cost Engineering (AACE) cost management practices as a foundation for estimating the costs of transmission facility projects. Table 1 in Information Document #2015-002R sets out the typical purpose and methodology used for each of the estimate classes.

9 The estimated cost for retrofitting an existing DFO substation with transformer level meters to install meters at the feeder level,[5] is $750,000 on average (-50% / +100% AACE Class 5). Since this is an *average* cost, there will be some DFO substations that could be retrofitted for significantly less, and some for significantly more.

10 To comply with the Commission's direction to obtain AACE Class 3 estimates,[6] the AESO discussed the cost, timing, and amount of work required to develop AACE Class 3 estimates with TFOs for the substations that would most likely require physical changes. They advised the AESO that, for each substation, they would require:

- Approximately 2-6 months of time to prepare an AACE Class 3 estimate; and

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[3] See Appendix A – AMP Alternatives Comparison for additional details regarding retrofitting a DFO substation.

[4] See Appendix A – AMP Alternatives Comparison for additional details regarding "Metering Infrastructure" and "Lifecycle Replacements".

[5] The AESO obtained the average estimate of $750,000 (-50% / +100%) per substation from the TFOs in the service areas where these retrofits could occur. See Exhibit 27047-X0002, Application, PDF 17; Exhibit 27047-X0078, AESO Responses to AUC IRs, PDF 9-10; Appendix F – Stakeholder Engagement Summary and Materials, Moving Forward With the AMP, PDF 53.

[6] AESO Information Document #2015-002R states that AACE Class 3 estimates are typically used for budget authorization or control (e.g., Service Proposal Estimates) when approximately 10-40% of the project deliverables are complete.

- Up to $75,000 to complete the work required to develop the AACE Class 3 estimates. This work would include site visits, site assessments, feasibility assessments, project planning, preliminary engineering, and the development of execution plans among other tasks.

11 Ultimately, the AESO has decided not to proceed with obtaining AACE Class 3 estimates because it would be premature to initiate these transmission facility projects and advance them sufficiently in order to develop AACE Class 3 estimates and forecast a completion date for the projects. It also does not seem prudent to incur the costs or to direct TFOs to do the work required for AACE Class 3 estimates if the AMP could be implemented in a manner that does not require immediately retrofitting existing DFO substations to comply with the AMP.

2.2 Cost of Installing Meters When Metering Infrastructure Is in Place

12 At DFO substations undergoing Lifecycle Replacements that include the replacement of a switchgear lineup, it is efficient to install the Metering Infrastructure because the additional work (and costs) to get that infrastructure in place is negligible. See Appendix A – AMP Alternatives Comparison for details of the scope of work.

13 Once the Metering Infrastructure is in place, then the incremental cost to implement the AMP is primarily the costs for the meters themselves. Based on conversations with the TFOs, the AESO understands that the cost of a single meter is between $2,000 - $11,000, depending on the make and model. The number of meters required at a substation will depend on the number of feeders on the same switchgear array, this is typically between 1 to 10 on a bus, with 8 meters being the typical number. The AESO will use an estimate of $60,000 per substation for the incremental cost of installing the meters when feeder Metering Infrastructure is already in place.[7]

14 The above estimate is not an AACE Class level estimate because it is not an estimate for a service proposal for a transmission facility project, it is an estimate for the “materials” cost for the meters.

2.3 Capital Cost Review and Oversight Mechanisms

15 As directed by the Commission, in lieu of providing AACE Class 3 level estimates and forecast completion dates for the scopes of work proposed in an AMP implementation plan, the AESO could include mechanisms for cost review and oversight.

16 The AESO proposes 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 will be either an AESO-directed transmission facility project (which could be a connection project that the AESO initiates in response to a system access service request (SASR) or a “system” project initiated by the AESO), or a TFO-initiated Lifecycle Replacement project.

17 For the Original Proposed Implementation Plan and Alternative 1, retrofitting an existing DFO substation with transformer level meters to install feeder level metering will be executed as a transmission alteration project and follow the same capital cost review and oversight mechanism as any other transmission facility project, namely:

[7] $7,500 per meter x 8 meters per bus.

- The AESO would direct the applicable TFO to initiate a transmission facility project, including a direction to develop a preliminary cost estimate at AACE Class 5 level of accuracy.
    - If this transmission alteration is in response to a DFO SASR, then the alterations will occur as part of a connection project and the DFO will be provided the AACE Class 5 estimate. The DFO may cancel the SASR, and connection project, if they do not wish to pay the connection costs.
    - If this transmission alteration is initiated by the AESO, then the alterations will occur as part of a “system” project.
- If possible, the TFO would include these projects in their TFO General Tariff Application (GTA) to provide the Commission with visibility of when the projects are forecasted to occur. Including a project in their GTA may not be possible if this is a transmission alteration as part of an AESO connection project.
- Since the replacement and installation of metering equipment would constitute an alteration to a transmission facility, the TFOs would file the applicable facilities application with the Commission to request approval of the alteration (e.g. a Facility Application or, if the alteration is sufficiently minor, a Letter of Enquiry). This application would require an AACE Class 3 cost estimate for the Commission’s economic assessment pursuant to AUC Rule 007.
- For all transmission facility projects, as the transmission alteration project progresses, the TFO will provide AACE cost estimates of increasing accuracy to the AESO in accordance with Section 504.5 of the ISO rules, *Service Proposals and Cost Estimating*.
    - If this is a connection project, then the costs will be recovered as part of the connection project, pursuant to the ISO tariff. The AESO will use the cost estimates to develop the construction contribution determinations and advise the DFO of any required contributions. The DFO may cancel the SASR, and connection project, if they do not wish to pay the connection costs.
    - If this is a system project, then the costs will be recovered through the ISO tariff from all Alberta ratepayers.

18 For the recommended Alternative 2, the installation of Metering Infrastructure will occur as part of a TFO-initiated Lifecycle Replacement project that is occurring regardless.

19 If the feeder level meters are also installed at that time as the Lifecycle Replacement project (for example, if there are already reverse flows at the DFO substation), then the cost review and oversight would be as follows:

- As part of their ongoing monitoring and planning for transmission assets, TFOs will identify required lifecycle work for assets within a DFO substation, this can include preventative maintenance, upgrades, or replacements of the asset.
- The TFO files a GTA for approval from the Commission that includes the proposed Lifecycle Replacement projects for the applicable test years. The TFO will include details regarding the applicable assets, timing, and scope of work for the lifecycle alterations.

20 If the feeder level meters are not installed at the same time of the TFO-initiated Lifecycle Replacement project, then they may be installed in the future when there are reverse flows and those meters are required for AMP-compliance. In these cases, the incremental cost of installing the meters would be

included as part of the connection project that the AESO initiates in response to the SASR for those future reverse flows, and would follow the cost review and oversight mechanisms for a transmission facility project, as described above.

3. Total Implementation Costs by Alternative

21 For each of the alternatives considered, the AESO used two inputs to estimate the total implementation cost: (1) the number of DFO substations where costs are incurred because of reverse flows; and (2) the per substation estimate based on the required scope of work to become AMP compliant.

22 For the Original Proposed Implementation Plan and Alternative 1: SASR Trigger, the scope of work is to retrofit existing DFO substations with transformer level meters to install meters at the feeder level. The AACE Class 5 estimate per DFO substation for this work is $750,000 (-50% / +100%).[8]

23 For the recommended Alternative 2: Substation Lifecycle Trigger, the scope of work is limited to installing the meters once the Metering Infrastructure is in place. The estimate per substation is $60,000.

24 The number of DFO substations that would incur costs depends on the chosen alternative.

3.1 Original Proposed Implementation Plan

25 The AESO does not expect all 70 existing DFO substations with transformer level meters to require a retrofit because not all will have reverse flows. As part of implementing without legacy treatment, some of these 70 DFO Substations will be retrofitted to install meters at the feeder level as part of Phase 2 because they already have reverse flows and some will be retrofitted in the future as part of Phase 3 if there are new reverse flows.[9]

- Based on the 2023 information available to the AESO, of the 70 DFO substations with transformer level meters, the AESO estimates that there are 5-12 that likely already have reverse flows at the feeder level.[10] These numbers would be known with certainty following the feeder flow assessment in Phase 1.
- To estimate the number of remaining DFO substations that may be retrofitted in Phase 3, the AESO examined the current Connection Project List[11] to determine which DFO substations without feeder metering have in-flight projects for the connection of new DCG, and the capacity of

[8] The estimated cost for retrofitting an existing DFO substation with transformer level meters to feeder level metering,[8] is $750,000 on average (-50% / +100% AACE Class 5). Since this is an *average* cost, there will be some DFO substations that could be retrofitted for significantly less, and others for significantly more.

[9] See Exhibit 27047-X0003, AMP Implementation Plan at PDF 5-10.

[10] To determine if a DFO substation was “likely” to reverse, the AESO looked at the total MW capacity of DCG installed downstream. 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 conditions at each substation and may not align with assumptions.

[11] As of July 1, 2023.

DCG already connected to those substations. The AESO estimates there are 2 to 3 additional DFO substations that are likely to reverse over the next two years.[12]

- The AESO does not have enough information to reliably estimate how many of the remaining DFO substations will begin to reverse after the next two years. However, after discussions with the applicable DFOs, the AESO does not expect new reversals at many of the remaining DFO substations, because of the large amount of load served at these substations in comparison to the amount of DCG that could locate in these areas.

26 Based on the above breakdown of the 70 DFO substations that are *likely to reverse*, the AESO estimates that the implementation cost for the AMP without legacy treatment is:

Phase 2	$3.8M to $9.0M for 5-12 substations
Phase 3	*Near-term:* $1.5M to $2.3M for 2-3 substations

27 The AESO also estimates the total *theoretical maximum* cost of implementation without legacy treatment (by assuming that all 70 DFO substations will be retrofitted) to be:[13]

Total Cost (Theoretical Max)	$52.5M for 70 substations

Cost Treatment

28 As described in the Original Proposed Implementation Plan:

- AMP compliance costs incurred as part of Phase 2 would be part of substation alteration projects that would be initiated and directly assigned by the AESO to the applicable TFO. The costs would be recovered as a transmission system cost from all Alberta ratepayers.[14]

- AMP compliance costs incurred as part of Phase 3 would be part of connection projects triggered by a request for new or amended SAS. The connection costs would be recovered through a combination of participant-related costs paid by the applicable DFO and system-related costs determined by the AESO.[15]

29 See the Capital Cost Review and Oversight Mechanisms subsection above for how these capital costs would be reviewed and approved.

3.2 Alternative 1: SASR Trigger

30 The AESO still does not expect all 70 DFO substations to require a retrofit because not all of these substations will have reverse flows. Also, since a SASR could trigger connection project costs for the

[12] Due to shorter connection timelines, the majority of SASRs submitted to the AESO that are related to the connection of new DCG have requested energization dates no further than two years out from the time of application. As such, the Connection Project List cannot be used to reliably predict DCG additions beyond that timeframe.

[13] See Appendix F – Stakeholder Engagement Summary and Materials, Moving Forward With the AMP, at PDF 55.

[14] Exhibit 27047-X0003, Appendix A – AMP Implementation Plan, PDF 8.

[15] Exhibit 27047-X0003, Appendix A – AMP Implementation Plan, PDF 10.

installation of meters at the feeder level, fewer DFO substations overall may be retrofitted. As part of a Connection Project, the participant-related cost of retrofitting the substation to install meters at the feeder level would require a contribution from the market participant (DFO),[16] and if these costs are to be flowed through to the DCG seeking a connection, then that may deter the DCG from connecting downstream of that substation.

31 Since existing DFO substations with reverse flows but transformer level meters will be exempted from immediate AMP compliance, no capital costs for AMP implementation would be incurred until a future SASR is submitted that requires the installation of feeder level metering. Based on a review of the AESO's Connection Project List, there is currently 1 SASR for the connection of a new DCG at a DFO substation that likely already reverses, in addition to the 2 to 3 DFO substations likely to have new reversals in the next two years. Assuming that these DCG still wish to connect despite the participant-related costs that will be flowed through to them, then it is likely that 3 to 4 DFO substations will require physical work in the near-term.

32 Based on the above breakdown of the 70 DFO substations that are *likely to reverse* – under Alternative 1: SASR Trigger, the AESO estimates the implementation cost as follows:

By January 1, 2025	$0
After January 1, 2025 (Future SASRs)	*Near-term:* $2.3 to $3.0M for 3 to 4 substations

33 The AESO also estimates the *total theoretical maximum* cost of AMP implementation under Alternative 1: SASR Trigger (by assuming that any SASR would trigger a reversal and therefore a retrofit, and that all DFO substations would eventually be retrofitted over an indefinite number of years), to be:

Total Cost (Theoretical Max)	*Near-term:* $3.8M for 5 substations *Long-term:* $48.8M for remaining 65 substations

34 AMP Implementation costs incurred under this Alternative 1 would follow the same cost treatment as detailed in the Original Proposed Implementation Plan.

3.3 Alternative 2: Substation Lifecycle Trigger (Recommended)

35 Under this alternative, the AESO still does not expect all 70 DFO substations to require feeder level metering because not all of these DFO substations will have reverse flows. However, for the purposes of determining the costs associated with this alternative, the AESO has assumed that the 7-15 DFO substations that either currently have reverse flows or are *likely to have reverse flows*[17] will also undergo a Lifecycle Replacement (and also undergo the incremental work to have meters installed at the feeder level) between years 2030-2040. On this basis, the AESO estimates that the cost of AMP implementation under the Substation Lifecycle Trigger alternative is:

[16] Exhibit 27074-X0003, AMP Implementation Plan, PDF 9-10.

[17] See Appendix A – AMP Alternatives Comparison for details on the estimated 5-12 DFO substations that currently reverse and estimated 2 to 3 DFO substations that may reverse in the near-term.

By January 1, 2025	$0
Future Lifecycle Replacement	Near-term: $0 2030-2040: $420k to $900k for 7-15 subs

36 Additionally, the AESO estimates the *total theoretical maximum* cost of AMP implementation under this Alternative 2: Substation Lifecycle Trigger (by assuming that all 70 DFO substations would have meters installed at the feeder level at some point in the future), to be:

Total Cost (Theoretical Max)	2030-2040: $420k to $900k for 7-15 subs 2040 onwards: $3.3M for remaining 58 subs

4. Quantifying Implementation Benefits by Alternative

37 The primary benefit of the AMP is that it allows for Rate DTS and Rate STS billing determinants that accurately reflect each market participant's flows to and from the transmission system.[18] To quantify the benefits of the AMP, the AESO performed an impact analysis to compare the impact to billing determinants, rates, and billing allocation with and without the AMP.

38 The impact analysis shows that the billing determinants for DTS and STS are higher under the AMP because the AMP resolves the artificial billing determinant erosion due to the current measurement practice. This is a benefit to all transmission market participants because the higher billing determinants directly translate to lower DTS rates for all users of the transmission system.

39 The impact analysis also shows that, from a billing perspective, Rate DTS (and Rate STS) costs would have been reallocated across market participants, with some market participants paying more, and others paying less. This reallocation of costs does not result in a net financial benefit for every individual market participant (because some will pay more). However, from the broader perspective of the ISO tariff and all transmission market participants, the reallocation of costs can be considered a benefit since market participants are paying more accurately for the SAS they take.

4.1 High-Level Methodology for Quantifying Benefits – Rate DTS

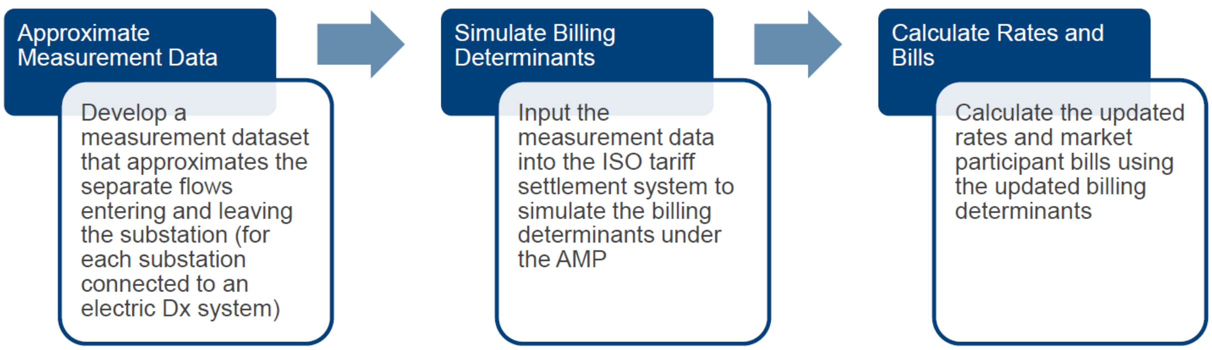
40 To estimate the billing determinants, rates and billing for a historical year (2021) under the AMP, the AESO simultaneously re-calculated all market participants' bills using an ISO tariff settlement system test environment. The result of this indicative analysis provides an estimate of how billing determinants, rates, and billing allocation are impacted by the AMP. Implementing the AMP will not result in the same impact every year because of the dynamic nature of load and generation flows at DFO substations, and because the measurement data is only approximate.

[18] See Appendix F – Stakeholder Engagement Summary and Materials, PDF 127.

41 The AESO selected 2021 as the comparison year because a full year[19] was required both to align with the annual revenue requirement and the billing determinants that are calculated on an annual basis, as well as to provide a full picture of the seasonal changes in generation and load.

42 The high-level methodology for the DTS impact analysis is described in the diagram below, and more details on each component are provided in the Attachment below.

Figure 1:



43 The DTS impact analysis was completed for two AMP scenarios:

- **AMP Everywhere**: SAS for all existing DFO substations would reflect the flows to and from the transmission system without netting, regardless of the type of metering installed at the substation. The results from this scenario quantifies the benefits under the Original Proposed Implementation Plan.

- **AMP with Limited Exemptions**: Only SAS for existing DFO substations that currently have feeder level meters installed would reflect the flows to and from the transmission system; SAS for substations with transformer level meters would continue to reflect net flows at the substation level. The results from this scenario quantifies the benefits under both Alternative 1: SASR Trigger and Alternative 2: Substation Lifecycle Trigger.

44 The results for the two scenarios are set out below. As noted in the detailed Attachment below, the results of the DTS impact analysis are based on a conservative scenario for flows due to data limitations and assumptions. Therefore, the results of the DTS impact analysis show the “ceiling” or upper end for billing, rate, and billing allocation impact due to the AMP.[20]

[19] 2021 was the most recent complete year when the analysis was started in the fall of 2022.

[20] Numbers in charts and tables may not add due to rounding.

4.2 Results of DTS Impact Analysis – Original Proposed Implementation Plan

Figure 2:

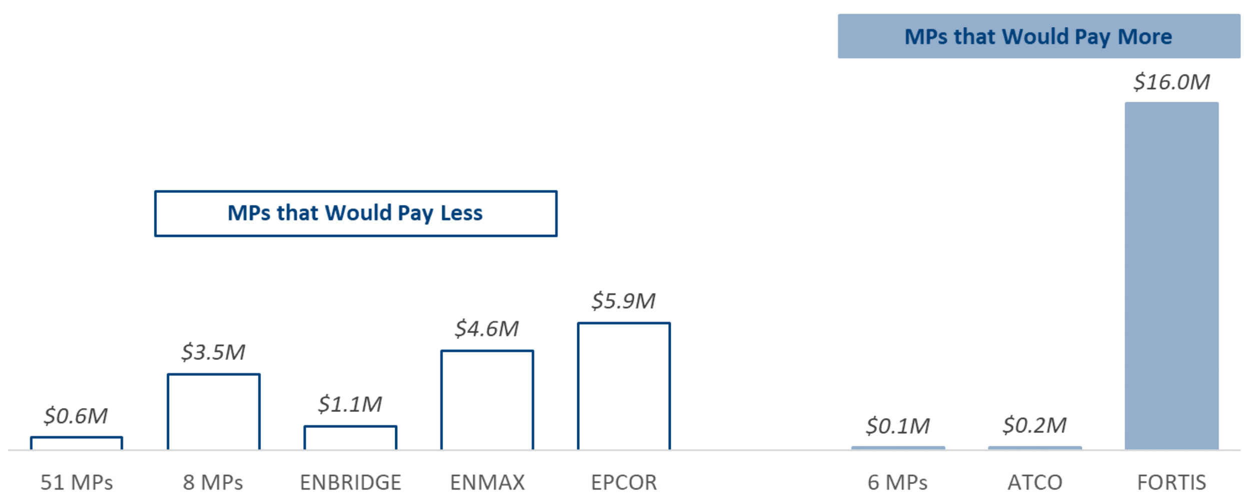
Billing Determinant	2021 Actual Billing Determinants	Change Due to the AMP	% Change Due to the AMP
Coincident Metered Demand*	93,115 MW	+ 2,700 MW	+ 2.9%
Metered Energy	59,014 GWh	+ 1,400 GWh	+ 2.4%
Billing Capacity	154,679 MW	+ 249 MW	+ 0.2%

Figure 3:

Charge Component	Based on Actual Billing Determinants	Based on AMP Billing Determinants	Change Due to the AMP	% Change Due to the AMP
Bulk System				
Coincident Metered Demand*	$10,906 /MW	$10,601 /MW	- $306 /MW	- 2.8%
Metered Energy	$1.21 /MWh	$1.18 /MWh	- $0.03 /MWh	- 2.5%
Regional System				
Billing Capacity	$2,997 /MW	$2,992 /MW	- $4.83 /MW	- 0.2%
Metered Energy	$0.92 /MWh	$0.89 /MWh	- $0.02 /MWh	- 2.2%

**The coincident system peak for the months of September, November, and December also changed (15 minutes, 30 minutes, and 1 day, respectively).*

Figure 4:



The indicative analysis is not meant to provide an exact estimate of how much more or less a particular market participant would pay after the AMP is implemented, since their actual bills would be a function of the actual rates that are in place and their actual billing determinants at that time.[21]

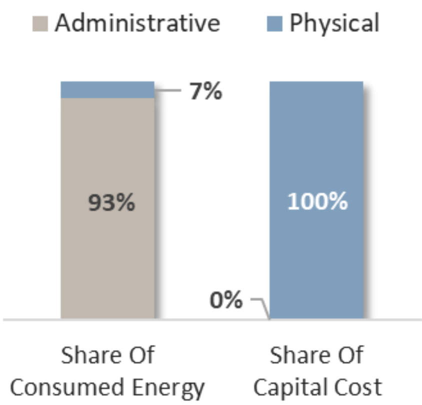
[21] The ~$0.5M difference in the sum of bills for market participants that would have paid less to the sum of bills for market participants that would have paid more is due to the over-collection of POD and Ancillary Services components with AMP since these rates were not updated and billing determinants increased.

45 The indicative analysis shows that under the AMP, the annual amounts that each market participant would pay for DTS would change. Approximately $16.3M would have been reallocated between market participants during 2021, as follows:

- Some market participants would have paid less because the AMP led to lower rates for all. Market Participants with higher billing determinants (generally, higher consumption) would see a larger reduction in their bills.
- Some DFOs that had large amounts of DCG flows would have paid more. Some non-DFO market participants also paid more due to the coincident system peak interval changing.

46 The AESO also delineated the 2021 consumed energy[22] and billing determinant impact for all DFO substations by administrative or physical changes to comply with the AMP. This showed that:

Figure 5:



Type of Change Required at Substation	DTS Billing Determinant	Increase in 2021 BDs Post-AMP
Administrative	CMD (MW) Billing Capacity (MW) Metered Energy (GWh)	+ 2,516 MW + 233 MW + 1,312 GWh
Physical	CMD (MW) Billing Capacity (MW) Metered Energy (GWh)	+ 207 MW + 16 MW + 101 GWh

- The majority (93%) of the consumed energy, which is the proxy for billing determinant erosion, was at DFO substations that only require administrative actions (i.e. no capital costs incurred to implement the AMP).
- The majority of the DFO substations (90 Category B substations based on this conservative scenario) would require only administrative changes.

4.3 Results of DTS Impact Analysis – Alternatives 1 and 2

Figure 6:

Billing Determinant	2021 Actual Billing Determinants	Change Due to the AMP	% Change Due to the AMP
Coincident Metered Demand*	93,115 MW	+ 2,563 MW	+ 2.8%
Metered Energy	59,014 GWh	+ 1,312 GWh	+ 2.2%
Billing Capacity	154,679 MW	+ 233 MW	+ 0.2%

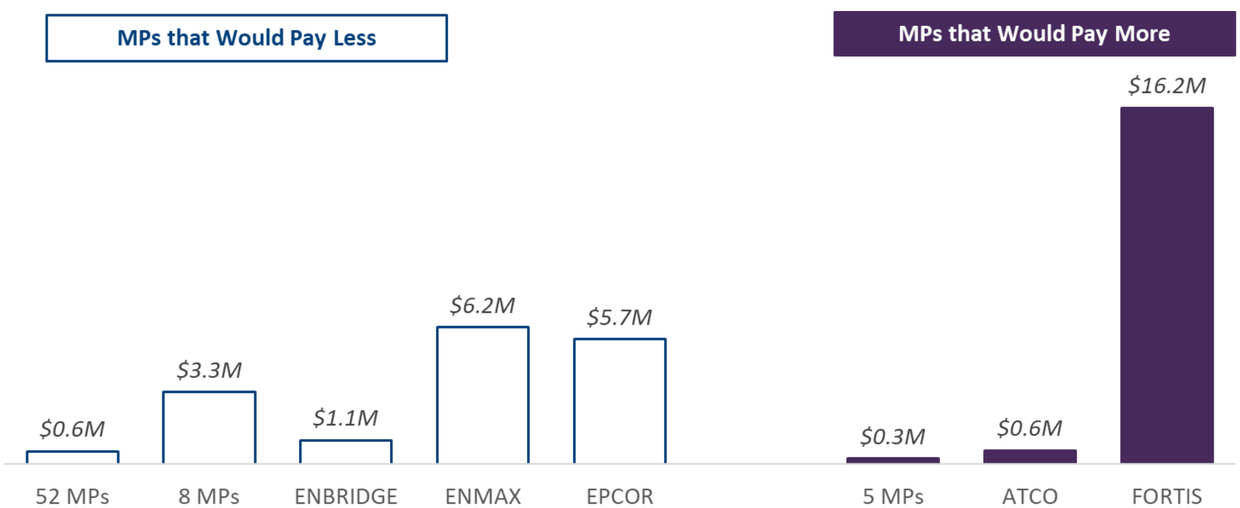
[22] "Consumed energy" represents the amount of DCG energy consumed by distribution load at the DFO substation. See Appendix F – Stakeholder Engagement Summary and Materials, Background & Ongoing Need, at PDF 26.

Figure 7:

Charge Component	Based on Actual Billing Determinants	Based on AMP Billing Determinants	Change Due to the AMP	% Change Due to the AMP
Bulk System				
Coincident Metered Demand*	$10,906 /MW	$10,614 /MW	- $292 /MW	- 2.7%
Metered Energy	$1.21 /MWh	$1.18 /MWh	- $0.03 /MWh	- 2.5%
Regional System				
Billing Capacity	$2,997 /MW	$2,993 /MW	- $4.51 /MW	- 0.2%
Metered Energy	$0.92 /MWh	$0.90 /MWh	- $0.02 /MWh	- 2.2%

**The coincident system peak for the months of September, November, and December also changed (15 minutes, 30 minutes, and 1 day, respectively).*

Figure 8:



The indicative analysis is not meant to provide an exact estimate of how much more or less a particular market participant would pay after the AMP is implemented, since their actual bills would be a function of the actual rates that are in place and their actual billing determinants at that time.[23]

- The indicative analysis shows that under the AMP, the annual amounts that each market participant would pay for DTS would change. Approximately $17.1M would have been reallocated between market participants during 2021, as follows:
    - Some market participants would have paid less because the AMP led to lower rates for all. Market participants with higher billing determinants (generally, higher consumption) would see a larger reduction in their bills.

[23] The ~$0.2M difference in the sum of bills for market participants that would have paid less to the sum of bills for market participants that would have paid more is due to the over-collection of POD and Ancillary Services components with AMP since these rates were not updated and billing determinants increased.

- Some DFOs that had large amounts of DCG flows would have paid more. Some non-DFO market participants also paid more due to the coincident system peak interval changing.

4.4 High-Level Methodology for Quantifying Benefits Rate STS

47 Quantifying the STS billing impacts of implementing the AMP cannot be performed to the same level of detail as the DTS impact analysis because the bill for Rate STS is made up of a single charge that also depends on a POS specific loss factor:

- **MWh Per Hour X Hourly Pool Price X POS-Specific Loss Factor**

48 To perform an accurate comparison of STS charges between the 2021 billing with and without the AMP, the AESO's loss factor process would need to be rerun for 2021. A loss factor for each new POS that was required for the AMP would need to be generated, and recalculations would need to be performed for every existing POS loss factor. This would be a complicated and time-consuming exercise and would be unlikely to improve on the indicative findings from this analysis due to the dynamic nature of loss factors.

49 The AESO's analysis will give a reasonable approximation of the impact of the AMP by using the 2021 average loss factor of 2.87%. The consumed energy from the DTS impact analysis represents the additional MWh under the AMP that would be subject to Rate STS charges, and this value can be multiplied by the hourly pool prices and 2.87% to calculate the additional overall STS charges.

50 Additional details are provided in the Attachment below.

4.5 Results of STS Impact Analysis – Original Proposed Implementation Plan

51 The impact to STS billing for all market participants is a 2.4% increase to the metered energy billing determinant resulting in $4.85M in reallocated STS charges.

4.6 Results of STS Impact Analysis – Alternatives 1 and 2

52 The impact to STS billing for all market participants is a 2.4% increase to the metered energy billing determinant resulting in $4.56M in reallocated STS charges.

5. Attachment

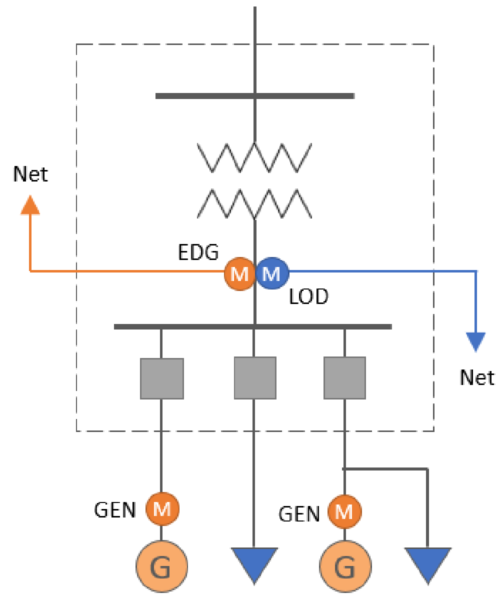
5.1 Detailed Methodology for Quantifying Impact to Rate DTS

5.1.1 Methodology Details: Approximate Measurement Data

Develop a measurement dataset that approximates the separate flows entering and leaving the substation (for each substation connection to an electric distribution system).

<u>Available Data</u>

53 The AESO has a limited set of measurement data available that it receives for financial settlement purposes, including ISO tariff billing. This data is provided directly by the Meter Data Managers (MDMs) in the Daily System Measurement (DSM) format for all system level measurement points[24]. This data is described in the diagram above.



- Existing DFO substations may have a mixture of feeders dedicated to load, dedicated to generation, and shared between load and generation
- The AESO receives Daily System Measurement data for all System Level measurement points, which includes:
  - EDG type data, for net flows into the substation from the distribution system
  - LOD type data, for net flows out of the substation into the distribution system
  - GEN type data, for flows from interval-metered DCG or micro-generation onto the distribution system
- Data received is for MWh in 15-minute intervals

54 The EDG and LOD data that the AESO receives is netted at the substation level, and the AESO does not receive individual feeder metering data (if that data exists at all) or the data for the individual site loads on a feeder. While the AESO does have the mapping of DCG to the upstream substation, there is no visibility of which specific feeder a DCG is connected to. As a consequence, the AESO has no ability to determine what volume of load is served by a DCG on each feeder, and therefore also has no ability to determine individual flows between a feeder and substation.

55 The AESO spoke with DFOs to understand:

- The existence of mappings between DCG and the feeders they connect to.

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[24] See AUC Rule 021 Settlement System Code Rules for more information on system level measurement data and the DSM transaction type.

- If feeder-level loads were available, and/or if mapping and data was available for individual loads connected to feeders.
- The possibility of getting feeder level metering data at substations from the MDMs.

56 The conclusion was that most detailed data was either unavailable, incomplete, or would entail an unreasonable undertaking to provide and process. Detailed data would need to be provisioned, analyzed, aggregated, and converted to the DSM format and time interval that the AESO tariff settlement system requires, either by the DFO, MDM or the AESO. Each new data point represents over 35,000 intervals of data for a year, and systems would likely need to be developed to perform the necessary conversions and aggregations.

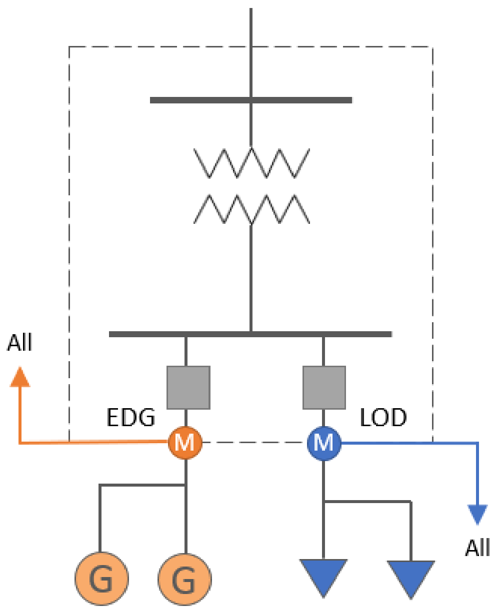
57 The collection of additional feeder-level data was therefore not considered feasible, and the DSM data that was already available to the AESO would be used for the analysis dataset.

Flow Assumptions

58 Given the available data, the AESO would have to make assumptions regarding how much load is served by DCG at the feeder level. To develop these assumptions, the AESO spoke with DFOs to understand the typical interactions between load and DCG at the feeder level. From these discussions it became evident that it was not possible to generalize how much load is offset by DCGs on the same feeder because:

- The number, type, and size of loads and DCG connected to each feeder was specific to the feeder and did not follow any typical pattern.
- The amount of load supplied by DCG is a function of load profiles and DCG production profiles; this would be unique to each feeder, and unique to the time of year. Line losses and unaccounted for energy also impact this relationship.
- Loads and DCG connected to a feeder change over the course of a year, and events such as maintenance, feeder switching, and outages affect the relationship between load and DCG.

59 For the above reasons, it was determined that any default percentage of DCG production assumed to supply load on the same feeder would be arbitrary, and would not provide a valid result for the analysis. The AESO therefore adopted a conservative scenario where DCG and loads would be modelled on separate, dedicated feeders. This flow scenario is described in the diagram below.



- For analysis, the AESO will assume all DCG is on a dedicated feeder, and all load is on a dedicated feeder
- Under this assumption, all DCG production will flow into the transmission system under the EDG data type, and all distribution load will be supplied from the transmission system under the LOD data type
- This will result in the ceiling for both implementation costs and billing impact under the AMP

60 This conservative flow scenario results in the maximum increase in billing determinants under the AMP, and the analysis will show the ceiling for the impact of the AMP. In reality, most DCG will supply some amount of load on the same feeder, and the impact and cost of implementing the AMP will be less than the analysis shows.

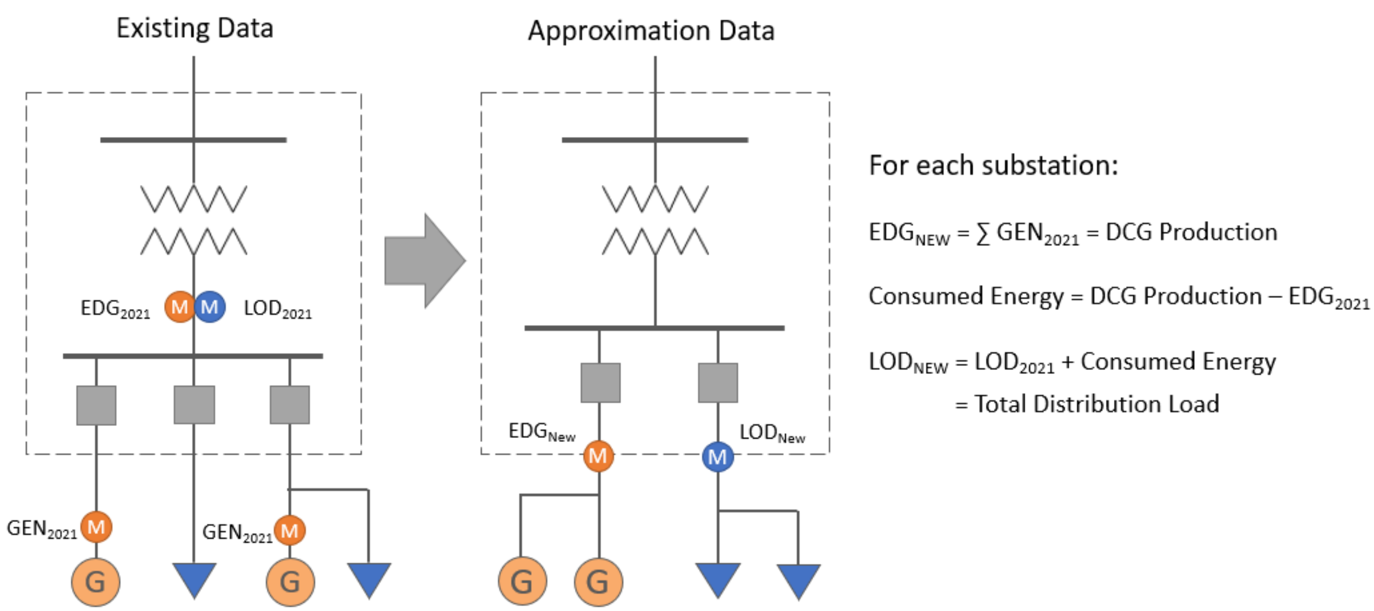
<u>Substation Data Approximation</u>

61 To develop a measurement dataset that reflects the separate flows entering and leaving a substation, and to align with the flow assumptions above, the AESO needed to calculate new EDG (POS) and LOD (POD) data for each substation with downstream DCG (including interval-metered micro-generation). The actual DSM data that was received from MDMs and used for ISO tariff billing for 2021 formed the base dataset for the approximations. All calculations performed for the approximation were done at the 15-minute interval level for all of 2021.

62 The new EDG data can be calculated simply by summing all of the GEN data from the DCG downstream of a substation. This represents all DCG energy flowing into the transmission system, per the flow assumptions. Note that the EDG data is not used in calculating the ISO tariff bill for rate DTS, but is used for calculating the ISO tariff bill for rate STS.

63 To calculate the new LOD data, the amount of DCG production being consumed by the distribution system needs to be determined. This “Consumed Energy” can be calculated by summing all of the GEN data from the DCG downstream of a substation, and then subtracting the existing EDG data (which represents DCG production in excess of load). The new LOD data can then be calculated by adding the Consumed Energy back to the existing LOD data. This represents all distribution loads being supplied by the transmission system, per the flow assumptions.

64 The calculations for the new EDG and LOD data for a substation are described in the diagram below:



65 The following table contains a detailed walkthrough of the steps taken, and the associated data volumes, to develop the approximate measurement data for each billing scenario:

Process Step		**AMP Everywhere**	**AMP w/ Limited Exemptions**
1	Create a duplicate data environment of the DSM files used for the original 2021 ISO tariff billing	537 billed DTS agreements 18.8M data records	
2	Map all EDG (POS) and GEN (DCG) measurement points to their associated substation and LOD (POD) measurement point	304 GEN points 44 EDG points 148 substations / LOD points	179 GEN points 43 EDG points 99 substations / LOD points
3	For each data interval, sum all GEN at each substation to get the substation “DCG Production”	304 GEN points 10.7M records	179 GEN points 6.3M records
4	For each data interval, subtract the EDG at each substation from the associated DCG Production to get the substation “Consumed Energy”	44 EDG points 1.5M records	43 EDG points 1.5M records

5	For each interval, add the Consumed Energy at each substation to the associated LOD to get the “Total Distribution Load” for each substation	148 substations 5.2M records	99 substations 3.5M records
6	Convert the Total Distribution Load into new LOD records in the DSM format and replace the corresponding LOD records in the data environment created in Step 1	148 LOD points 5.2M records	99 LOD points 3.5M records

5.1.2 *Methodology Details: Simulate Billing Determinants*

Input the measurement data into the ISO tariff settlement system to simulate the billing determinants under the AMP.

66 A replica of the ISO tariff settlement system was created and pointed to the approximate measurement data set, and billing runs were performed to simulate the billing for all 537 DTS agreements under the two AMP scenarios. The ISO tariff settlement system produced the billing determinants for each market participant as though the AMP scenarios had been in place for 2021 (2021 AMP BDs). The billing determinants that the analysis focused on were:

- Coincident Metered Demand;
- Billing Capacity; and
- Metered Energy

5.1.3 *Methodology Details: Calculate Rates and Bills*

Calculate the updated rates and market participant bills using the updated billing determinants.

<u>Posted Rates vs Perfect Rates</u>

67 For a given year, the ISO tariff rates are calculated and approved by the Commission, as part of an ISO tariff update process before the year begins. These prospective rates are calculated based on an estimated revenue requirement, and forecasted billing determinants. Once the rates are approved by the Commission, they are posted on the AESO website as part of the ISO tariff. These are referred to as “posted rates.”

68 In order to isolate the impact of the AMP on billing determinants, rates, and billing allocation, the AESO calculated “perfect” rates[25] for both the current measurement practice and AMP cases by removing the impact due to forecasting error and changes to revenue requirement. To do this, the AESO assumed that:

- There were no changes to the 2021 revenue requirement after it was forecasted; and
- The forecast billing determinants used to set rates match the billing determinants from the settlement system.

[25] Only the rates for the bulk and regional rate components were updated because the bulk, regional, and POD components recover the majority of the revenue requirement. POD rates were not updated because those rates are based on the investment cost function.

69 Under the perfect rates, the same revenue requirement is collected by the ISO tariff billing for both the 2021 with AMP and without AMP scenarios, and the impact of the AMP on the rates and individual market participant bills can be determined. The perfect rate calculations are explained in the diagram below.

Posted 2021 Rates = 2021 Estimated Revenue Requirements / Forecast 2021 Billing Determinants

Perfect 2021 Rates = 2021 Estimated Revenue Requirements / Actual 2021 Billing Determinants

Perfect AMP Rates = 2021 Estimated Revenue Requirements / Calculated 2021 AMP Billing Determinants

<u>ISO Tariff Bill Calculation</u>

70 After acquiring the 2021 billing determinants under the AMP and calculating the perfect rates for both with AMP and without AMP, the AESO recalculated each monthly DTS bill for both with and without AMP. To calculate the monthly bill for each market participant point of delivery, the following formula was used:

Monthly Bill = Market Participant's Billing Determinants$_{\text{Month}}$ x Rate

where the Rate is a function of the revenue requirement to be recovered through that particular billing determinant, and the total billing determinants (i.e., across all market participants) that it will be recovered through.

71 The difference between all DTS bills with and without the AMP is the amount of annual misallocation that is occurring due to the current measurement practice.

5.2 Detailed Methodology for Quantifying Impact to Rate STS

72 The following table details the steps taken and the associated data volumes used to determine the amount of new STS charges for each billing scenario:

Process Step		AMP w/o Legacy	AMP w/ Legacy
1	Sum the Consumed Energy for all substations in Step 4 of the DTS Impact Analysis process into total hourly values	148 substations 5.2M records	99 substations 3.5M records
2	Multiply the hourly Consumed Energy by the hourly pool price and the average system loss factor for 2021	8760 hours and records	8760 hours and records
3	Sum the hourly charges into a single value for 2021, representing the additional STS charges under the AMP	8760 records	8760 records

73 As actual system losses are not impacted by the AMP (the physical flows that cause losses are not changing), the amount the AESO needs to collect to cover losses remains the same. Therefore, an increase in STS billing to DFOs under the AMP represents a misallocation of charges in the Rate STS bills for other market participants.

74 However, while the overall impact of the new POS should be close to the average loss factor, the loss factor for the Rate STS charge is specific to the location of the substation and nature of the supply (and can vary from -12% to 12%). It is not possible to tell which POS would see an increase or decrease in their loss factor, or what the magnitude of the change would be at an individual POS for a market participant. For the same reason, it is not possible to accurately break down the increased STS charges across the DFOs, as each DFO may vary significantly from the average.