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Alberta Electric System Operator 2026 ISO Tariff Update Application

Date: November 7, 2025

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1. Introduction

1 Pursuant to sections 30 and 119 of the *Electric Utilities Act*, S.A. 2003, c. E-5.1 (Act), the Alberta Electric System Operator (AESO) submits this application (Application) to the Alberta Utilities Commission (Commission) for approval of:

a) the proposed 2026 Independent System Operator (ISO) tariff rates and riders;

b) the proposed 2026 Generating Unit Owner's Contribution (GUOC) rates; and

c) the updated amounts included in Appendix B-1, *2026 Rate Calculations* and Appendix B-2, *2026 Rate Calculations* (collectively, "Appendix B").

2 This Application also seeks approval from the Commission, pursuant to subsection 82(6) of the Act, of the proposed ISO tariff Rider F, *Balancing Pool Consumer Allocation Rider* for 2026 (Rider F).

1.1 Overview

3 As detailed further below, the AESO requests the Commission's approval of the changes to the rates to be charged by the AESO in 2026 for system access service that are presented in this Application.

4 Included in this Application is a request for approval of an update to the rate calculation for the DOS 7 Minute rate type (DOS 7)[1] that will remain in effect for one market participant in 2026 as part of the transition plan approved by the Commission in Decision 28989-D01-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service*.[2]

5 If approved, this Application would only change the levels (that is, the dollar-based and percentage of pool price amounts) included in the rates and local investment amounts[3] of the ISO tariff, based on costs and billing determinants forecast by the AESO for the 2026 calendar year.

6 This Application is consistent with the tariff rates update methodology accepted by the Commission in Decision 2010-606[4] and the GUOC methodology approved by the Commission in Decision 22942-D02-2019.[5]

7 The AESO is not seeking approval of its 2026 forecast costs that make up the AESO's revenue requirement in this Application. The AESO's forecast costs are approved through other processes provided for in relevant legislation, described below. The AESO's 2026 forecast ancillary services costs, losses costs and administrative costs have not, as of the date of filing this Application, been approved by the AESO Board. The AESO will file a letter to advise the Commission of AESO Board approval once it has been received, which is expected in January 2026.

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[1] Exhibit 29606-X0004, *Appendix B-1 – 2025 Rate Calculations,* (November 8, 2024) tab B-11.

[2] In Decision 28989-D01-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service* (July 31, 2024), para 7, with reasons provided in Decision 28989-D02-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service* (October 23, 2024), para 32, the Commission approved a transition plan for three existing market participants in which the Rate DOS, *Demand Opportunity Service* terms, conditions and rates in effect as of the date of the Decision were to continue in effect during the approved transition period.

[3] As set out in subsection 4.7(2)(b) of the ISO tariff approved in Decision 25175-D02-2020, *Alberta Electric System Operator 2018 ISO Tariff Compliance Filing Pursuant to Decision 22942-D02-2019 and 2020 ISO Tariff Update* (November 30, 2020).

[4] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff* (December 22, 2010), paras. 536-545.

[5] Decision 22942-D02-2019, *Alberta Electric System Operator 2018 Independent System Operator Tariff* (September 22, 2019), para. 323.

1.2 Organization of Application

8 This Application is organized into the following sections:

1 **Introduction**

2 **2026 Forecast Revenue Requirement** - Summarizes the AESO's forecast revenue requirement for 2025, including costs that have either been approved by the Commission (for transmission facility owner (TFO) tariffs) or proposed for approval by the AESO Board (for ancillary services, transmission line losses, and the AESO's own administration).

3 **2026 Rates and Riders Update** - Discusses the calculation of rate levels based on the 2026 forecast revenue requirement, 2020 classification and functionalization values approved by the Commission in Decision 22942-D02-2019, and the 2026 forecast billing determinants. The updates to Rider F and Rider J, *Wind and Solar Forecasting Service Cost Recovery* are also discussed in this section.

4 **2026 ISO Maximum Investment Levels Update** - Discusses the calculation of 2026 maximum investment levels using the 2026 escalation factor.

5 **Generating Unit Owner's Contribution Rates** - Discusses the methodology, process, and determination of 2026 generating unit owner's contribution rates.

6 **Conclusion**

9 This Application also includes the following appendices:

A **AESO 2026 Business Plan and Budget Proposal** - Document prepared by AESO management in consultation with stakeholders, containing the AESO's proposed 2026 business initiatives and proposed 2026 budgets and forecasts for ancillary services costs, transmission line losses costs, and administrative costs.

B **2026 Rate Calculations** - Microsoft Excel workbooks which calculate the updated dollar and percentage of pool price amounts for the 2026 rates, based on the same methodology used for the AESO's currently approved rates.

C **2026 Escalation Factor and Investment Levels** - Microsoft Excel workbook which calculates the composite inflation index and escalation factor used to update maximum investment levels.

D **2026 Rates, Riders of the ISO Tariff -** The proposed 2026 rates and riders that incorporate the 2026 updated amounts included as Appendices B-1 to this Application.

E **2026 Rates, Riders of the ISO Tariff (blackline)** - The blackline version of the proposed 2026 rates and riders that incorporate the 2026 updated amounts included as Appendix B-1 to this Application.

1.3 Relief Requested

10 For the reasons outlined in this Application, the AESO submits that the proposed updates to the ISO tariff are just and reasonable. Further, the AESO submits that the proposed ISO tariff rate updates and amounts set out in subsections (i) and (ii) below comply with the updated methodology approved by the Commission for the

ISO tariff in Decision 2010-606[6] and Commission Decision 22942-D02-2019.[7] The AESO requests that the Commission approve this Application as applied for, including:

(i) the updated amounts included in the 2026 Rate Calculations files, included as Appendix B-1 and Appendix B-2 to this Application;

(ii) the proposed 2026 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J, and GUOC Rates; and

(iii) the proposed Rider F.

11 The AESO respectfully requests that this Application be approved effective January 1, 2026. The AESO further requests that the Commission issue its approval on or before December 19, 2025 to allow for the proposed tariff updates to be implemented by the AESO effective January 1, 2026 on a prospective basis. If the timing of this Application does not permit the granting of final approval on or before December 19, 2025, the AESO requests that the Commission approve this Application on an interim basis effective January 1, 2026, with ISO tariff rates and amounts, set out in subsections (i) and (ii) above, approved on an interim refundable basis.

12 For additional clarity, the AESO requests that the updated rates and riders proposed in this Application apply on a go-forward basis only, commencing on the effective date approved by the Commission. Consistent with the Commission's statements in Decision 2014-242,[8] the AESO submits that the currently approved deferral account rider and reconciliation mechanisms should continue to be used to address any variances between costs and revenues occurring prior to the approval of the applied-for rates. The AESO is not seeking any retroactive adjustments with respect to the rates proposed for approval in this Application.

2. AESO 2026 Forecast Revenue Requirement

13 The AESO's revenue requirement consists of costs related to wires, ancillary services, transmission line losses, and the AESO's own administration (which includes other industry costs and general and administrative costs). The AESO's forecast costs for 2026 are detailed in Table B1 of Appendix B to this Application.

14 The total revenue requirement forecast for 2026 of $2,636.9 million represents an increase of $66.7 million (or 2.5%) from the 2025 total revenue requirement forecast of $2,570.1 million included in the 2025 ISO Tariff Rates Update Application.[9] The increase primarily results from a forecast increase of $25.8 million (or 10.2%) in 2026 ancillary services costs, an increase of $23.5 million (or 1.2%) in 2026 wires costs, an increase of $9.5 million (or 8.8%) in 2026 general and administrative costs and an increase in losses costs of $7.17 million (or 5.5%).

2.1 AESO Board Approval of Costs

15 The AESO is not seeking approval of its 2026 forecast revenue requirement in this Application. The AESO's forecast costs are approved through other processes provided for in relevant legislation, described below. These costs, as provided in column A of Table B-1 of Appendix B, are addressed in the AESO *2026 Business Plan and Budget Proposal,* included as Appendix A to this Application.

16 With respect to the AESO's costs, including their approval processes:

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[6] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff* (December 22, 2010), paras. 536-545.

[7] Decision 22942-D02-2019, *Alberta Electric System Operator 2018 Independent System Operator Tariff* (September 22, 2019), para. 323.

[8] Decision 2014-242*, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update* (August 21, 2014), paras. 680 and 691.

[9] Proceeding 29606, *AESO 2025 ISO Tariff Update Application*, filed November 8, 2024.

a) Wires costs reflect the amounts paid by the AESO to TFOs in the TFO tariffs approved by the Commission under section 37 of the Act. The wires costs forecast included in the AESO *2026 Business Plan and Budget Proposal* reflects TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared.

b) Ancillary services costs reflect recovery of the prudent costs incurred by the AESO related to the provision of ancillary services acquired from market participants under subsection 30(4) of the Act.

c) Losses costs reflect recovery of the prudent costs of transmission line losses under subsection 30(4) of the Act.

d) Administrative costs reflect the transmission-related costs and expenses incurred by the AESO and described under subsection 1(1)(g) of the *Transmission Regulation*, Alta Reg 86/2007.

17 The ancillary services costs, losses costs, and administrative costs described above are approved by the AESO Board (consisting of the "ISO members" appointed under section 8 of the Act) in accordance with the *Transmission Regulation*. Section 3 of the *Transmission Regulation* requires that the AESO consult with market participants with respect to proposed costs to be approved by the AESO Board. Subsection 48(1) of the *Transmission Regulation* provides that a reference to "prudent" or "appropriate" in the Act in relation to the costs of ancillary services and losses means the amounts of those costs that have been approved by the AESO Board. In addition, subsection 46(1) of the *Transmission Regulation* provides that the AESO's administrative costs, once approved by the AESO Board, must be considered as "prudent" by the Commission unless an interested person satisfies the Commission otherwise.

18 The budget development process (BDP) includes strategically focused consultations that take place throughout the annual budget development cycle. Senior executive stakeholders are invited to meet one-on-one with a subset of AESO Board and Executive members to share their perspectives on what they believe the AESO should be focusing on in the near term. For the current budget cycle, these initial consultation sessions occurred in June 2025, where stakeholders outlined key strategic areas for the AESO to consider when developing the 2026 budget, outlined in Appendix A, *Business Plan and Budget Proposal*. The AESO shared the proposed budget with stakeholders mid-October and addressed questions during the October 29, 2025 Stakeholder Session, to confirm that the AESO had determined appropriate areas of focus, priorities, and pace, based on the June 2025 meetings. Stakeholder insights and expertise were considered by the AESO in determining its corporate focus areas and associated priorities for 2026.[10]

19 As of the date of filing of this Application, the AESO's 2026 forecast ancillary services costs, losses costs and administrative costs have not been approved by the AESO Board. The AESO will file a letter to advise the Commission of AESO Board approval once it has been received. The AESO Board approval is expected in January 2026.

2.2 Wires Costs

20 As shown in column A of Table B-1 of Appendix B, the 2026 forecast costs for wires are $2,049.0 million and represent approximately 77.7% of the AESO's transmission revenue requirement.

[10] Additional information on the AESO's business priorities and budget for 2026 is available on the AESO Engage website at www.aesoengage.aeso.ca by following the path Home ▶ Projects ▶ 2026 Budget Development Process.

21 The AESO has determined the 2026 wires costs for TFOs using the following approach, which was described in section 2.2.1 of the AESO's 2014 ISO tariff application and 2013 ISO tariff update,[11] approved in Decision 2010-606, and updated in Decision 22093-D02-2017[12]:

a) If a TFO has received final Commission approval for its applicable tariff, the AESO includes the approved costs for that -TFO tariff.

b) If a TFO has applied for its tariff, the Commission has issued an initial decision on the application, and the TFO has submitted a refiling in compliance with the decision, the AESO includes the TFO tariff costs in the refiling.

c) If a TFO has applied for its tariff but the Commission has not yet issued an initial decision on the application or an initial decision has been issued but the TFO has not yet submitted its compliance refiling, the AESO includes the most recent of the following: (i) the TFO tariff costs last approved by the Commission on a final basis for the TFO plus 72% of any increase or decrease included in the TFO's tariff application above or below the prior approved costs, and (ii) the TFO tariff costs last applied-for by the TFO in a compliance refiling plus 72% of any increase or decrease included in the TFO's tariff application above or below the prior approved costs.

d) If a TFO has not yet applied for its tariff, the AESO includes the most recent of the following: (i) the TFO tariff costs last approved by the Commission on either a final or interim basis, and (ii) the TFO tariff costs last applied-for by the TFO in a compliance refiling.

22 As noted in the 2014 ISO tariff application, "the inclusion of 72% of an applied-for increase or decrease in (c) above was determined from the percentages of applied-for changes which had received final approval in recent transmission facility owner tariff applications, and is not meant to indicate any predetermination of the result of a transmission facility owner tariff proceeding, nor be interpreted as AESO support for any specific components of a transmission facility owner tariff application."[13]

23 The TFO tariff costs are included as Table B-2 of Appendix B to this Application.

2.3 Ancillary Services Costs

24 As shown in column A of Table B-1 of Appendix B, the forecast 2026 costs for ancillary services are $278.1 million and represent approximately 10.6%% of the AESO's transmission revenue requirement. Ancillary services, as defined in subsection 1(1)(b) of the Act, are services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency. The largest component of ancillary services costs is operating reserve, which represents the real power capability above system demand required to provide for regulation, forced outages and unplanned outages.

25 Ancillary services costs are primarily a function of volume forecasts and market-based commodity pricing forecasts. The 2026 forecast costs for ancillary services were based on a forecast average pool price of $51.26/MWh.

2.4 Losses Costs

26 As shown in column A of Table B-1 of Appendix B, the 2026 forecast costs for transmission line losses are $144.1 million and represent approximately 5.5% of the AESO's transmission revenue requirement. Losses are

[11] Exhibit 0026.00.AESO-2718, paras. 53-57.

[12] Decision 22093-D02-2017, *Alberta Electric System Operator 2017 ISO Tariff Update* (April 4, 2017), para. 37.

[13] Exhibit 0026.00.AESO-2718, para. 58.

the energy lost on the transmission system when power is transmitted from suppliers to loads. Losses are the residual of the metered generation plus scheduled imports less metered loads and less scheduled exports.

27 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts. The 2026 forecast costs for losses were based on a forecast average pool price of $51.26/MWh.

2.5 Administrative Costs

28 As shown in column A of Table B-1 of Appendix B, the 2026 general and administrative and other industry costs are $165.7 million and represent approximately 6.3% of the AESO's transmission revenue requirement.

29 Administrative costs are defined in paragraph 1(1)(g) of the *Transmission Regulation* as follows:

> 1(1)(g) "ISO's own administrative costs" means
>
> (i) the transmission-related costs and expenses of the ISO respecting the administration, operation and management of the ISO,
>
> (ii) the transmission-related costs and expenses of the ISO respecting reliability standards and reliability management systems, and
>
> (iii) the transmission-related costs and expenses required to be paid, or otherwise appropriately paid, by the ISO, except for the following:
> (A) costs for the provision of ancillary services;
> (B) costs of transmission line losses;
> (C) amounts payable under TFO transmission tariffs.

30 The AESO Board approves the AESO's administrative costs in their entirety. However, only the transmission-related portions of those costs (as defined in subsection 1(1)(g) of the *Transmission Regulation*) are recovered through the ISO tariff. Further, the AESO *2026 Business Plan and Budget Proposal* allocates administrative costs among the four functions of the AESO; namely, transmission, energy market, renewables (the Renewable Electricity Program) administration and load settlement.

3. 2026 Rates and Riders Update

31 The 2026 rate calculations are included as Appendix B to this Application, in Tables B-1 through B-16.

32 The rate calculations use the following inputs:

(a) the 2026 forecast revenue requirement discussed in section 2 of this Application;

(b) the functionalization and classification of wires costs and the point of delivery cost function approved for 2020 in Decision 22942-D02-2019;[14] and

(c) the 2026 forecast billing determinants prepared by the AESO.

[14] Exhibit 22942-X0025, Appendix D, *Transmission System Cost Causation Study 2018 Update*, filed September 14, 2017, page 5, Table D-5. At the time of writing this application, the 2020 classification and functionalization values were the most recently approved values available. See also: Decision 26911-D01-2022, *Alberta Electric System Operator Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application,* para 156, which orders the AESO's current rate design continue until further order or decision of the Commission.

3.1 Specific Rate Changes

33 Where applicable, rates in the ISO tariff have been updated to reflect the 2026 forecast revenue requirement, the 2020 classification and functionalization of wires costs, and the 2026 forecast billing determinants. Specifically, levels of dollar-based and percentage of pool price amounts have been updated in the following rates:

- Rate DTS, *Demand Transmission Service*;
- Rate FTS, *Fort Nelson Demand Transmission Service*;
- Rate PSC, *Primary Service Credit;*
- Rate DOS, *Demand Opportunity Service*;
- Rate XOS, *Export Opportunity Service*; and
- Rate XOM, *Export Opportunity Merchant Service*.

34 As described in section 1 above, two appendices have been included within this Application as Appendix B, *2025 Rate Calculations* (B-1 and B-2). The levels for each of the above rates have been calculated in accordance with Appendix B-1 to this Application and are reflected in the rate sheets included as Appendix D to this Application.

35 The AESO is also seeking Commission approval of an update to the rate calculation for the DOS 7 Minute rate type (DOS 7)[15] that will remain in effect for one market participant in 2026 as part of the transition plan approved by the Commission in Decision 28989-D01-2024.[16] Appendix B-2, tab B-11, sets out the proposed updates to the rate calculation for DOS 7 for 2026. The 2026 rate has been updated in accordance with the methodology for rates updates in Decision 2010-606.[17]

36 In accordance with the transition plan approved in Decision 28989-D02-2024, the market participant that, at the time of the decision, was on the DOS Term rate type and the two market participants that were, at that time, on DOS 7 were provided with the opportunity to renew their existing qualification periods for an additional one-year term.[18] All three market participants elected to renew their qualification periods and, accordingly, continued to receive their respective DOS 7 or DOS Term rate type after the updates to Rate DOS, *Demand Opportunity Service* took effect on February 1, 2025.[19]

37 As described in the AESO's Updates to Rate DOS Application, the qualification periods for each of the three market participants will expire on different dates.[20] The qualification periods for two market participants will end in November 2025 and the qualification period for the third market participant, receiving DOS 7, will end in February 2026. Accordingly, a calculated rate for DOS 7 must remain in effect until the end of that market participant's qualification period, after which service under DOS 7 will no longer exist and no market participants will receive, or be eligible for, service under DOS 7.

38 Should the Commission approve the proposed updates to the 2026 DOS 7 rate calculation, the AESO will inform the impacted market participant directly of the updated calculated rate.

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[15] Exhibit 29606-X0004, *Appendix B-1 – 2025 Rate Calculations,* filed November 8, 2024, tab B-11.

[16] Decision 28989-D01-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service* (July 31, 2024), para 7, with reasons provided in Decision 28989-D02-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service* (October 23, 2024), para 32.

[17] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff, (*December 22, 2010), paras 546-551.

[18] Decision 28989-D01-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service* (July 31, 2024), with reasons provided in Decision 28989-D02-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service* (October 23, 2024), para 32.

[19]Amendments to Rate DOS terms and conditions and rate sheet, approved in Decision 28989-D01-2024, *Alberta Electric System Operator Updates to Rate Demand Opportunity Service* (July 31, 2024), para 7, took effect on February 1, 2025.

[20] Exhibit 28989_X0002, *Alberta Electric System Operator Updates to Rate DOS Application*, filed April 23, 2024, paras. 87-93

3.2 Rider J, Wind and Solar Forecasting Service Cost Recovery Rider

39 As the AESO explained in its 2014 ISO tariff application, charges under Rider J recover both costs associated with the AESO's contracted wind forecasting service as well as variances from forecasts of costs and energy initially used to determine the values of the rider.[21] In Commission Decision 26980-D01-2021, the Commission approved amendments to Rider J to include the additional recovery of forecasting service costs for solar-powered generating units. In 2026, Rider J is expected to recover all costs of the contracted wind and solar forecasting service that have been incurred since it was initially implemented in 2011.

40 On a cumulative forecast basis, the AESO is forecast to under collect $31,068 through Rider J by the end of 2025. The wind and solar annual forecasting service cost for 2026 is forecast to be $209,580, representing an increase of $13,080 from the expected annual forecasting service cost of $196,500 in 2025. The AESO ran its calculations based on these forecasts and proposes to set the Rider J charge at $0.01/MWh.

41 The proposed 2026 Rider J charge will remain at $0.01/MWh, as it is in the current ISO tariff, for the recovery of the forecasting service costs. Table 3-2 below illustrates the changes from year to year to achieve as close to a zero balance as possible at the end of 2026. Table 3-2 only includes forecast solar costs, volumes and revenues starting in 2022.

Table 3-2 – Wind and Solar Forecasting Service Cumulative Balance

Line No.	Description	Actual 2010 – 2022	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026
1	Contracted wind and solar forecasting service* ($000)	$3,306.7	74.4	$89.0	$196.5	$209.6
2	Volumes (GWh)	52,196.1	11,867.5	17,303.3	20,196.0	20,091.0
3	Rider J Charge ($/MWh)	-	-	0.01	0.01	0.01
4	Revenue ($000)	3,360.9	-	117.2	157.4	200.9
5	Annual (undercollection) / overcollection ($000)	54.2	(74.4)	28.2	(39.1)	(8.7)
6	**Cumulative Balance (undercollection) / overcollection ($000)**	**$54.2**	**($20.2)**	**$8.0**	**($31.1)**	**($39.7)**

* Assumes solar forecasting begins in 2022

3.3 Rider F, Balancing Pool Consumer Allocation

42 The AESO is seeking approval of the 2026 ISO tariff Rider F, providing for a $1.26 per megawatt hour (MWh) charge for all demand transmission service (Rate DTS) and demand opportunity service (Rate DOS) market

[21] Exhibit 0026.00.AESO-2718, ISO Tariff Application (Revised), filed July 19, 2013, paras. 124-126.

participants (excepting the City of Medicine Hat and BC Hydro at Fort Nelson) for metered energy from January 1, 2026 through December 31, 2026, inclusive.

43 The Balancing Pool is a corporation established under subsection 75 of the Act. Pursuant to subsection 82(1) of the Act, the Balancing Pool is required to prepare a budget for each fiscal year setting out its estimated revenues and expenses to carry out its powers, duties, responsibilities, and functions under the Act. Based on this forecasted budget, the Balancing Pool notifies the AESO under subsection 82(4) of the Act of an annualized amount to be credited (or charged) to market participants for each fiscal year. Under subsections 82(5), 30(1) and 30(2)(b) of the Act, the AESO must include this annualized amount in the ISO tariff, and has done so through Rider F.

44 Rider F is applicable to all Rate DTS and Rate DOS market participants excepting the City of Medicine Hat and BC Hydro at Fort Nelson in accordance with Order U2006-307, wherein the predecessor to the Commission held the City of Medicine Hat and BC Hydro at Fort Nelson were ineligible for Rider F.

45 On October 8, 2025, the Balancing Pool notified the AESO of a consumer charge for 2026 of $1.26/MWh for an estimated annualized amount of $77,009,128.56. A copy of the Balancing Pool's notice to the AESO is included as Appendix F to this Application.

46 The AESO has confirmed that the proposed $1.26/MWh consumer charge for Rider F for metered energy from January 1, 2026 to December 31, 2026 is expected in order to charge the annualized amount to all market participants receiving service under Rate DTS and Rate DOS (excepting the City of Medicine Hat and BC Hydro at Fort Nelson) on a forecast basis.

Table 3-3 – Rider F Calculation

[A] **Period**	[B] **Annualized Amount Refund (Charge)**	[C] **Metered Energy Forecast MWh**	[D = B ÷ C] **Annual Credit (Charge) $/MWh**
January - December 2026	($77,009,128.56)	61,118,356	($1.26)

47 The AESO proposes that all substantive aspects of Rider F, including applicability criteria and use of a $/MWh amount approach, continue unchanged for 2026 metered energy from the Rider F that is currently in effect.

48 The proposed Rider F is included as Appendix D-7 to this Application. The format and language of the proposed Rider F is the same as the currently approved Rider F.

3.4 2026 Forecast Billing Determinants

49 The rate calculations for the 2026 rates update are based on the AESO's forecast of billing determinants for 2026. The 2026 billing determinants are estimated using a combination of historical analysis and a DTS energy forecast that is described below. The updated DTS energy forecast, developed using a methodology similar to that applied to create the AESO's 2024 Long-Term Outlook (LTO) with the most up to date actual load data and economic outlook, was used to estimate the billing determinants. The DTS energy forecast is generated from historic trends and economic growth (gross domestic product, population and employment) information and oilsands production forecasts. The AESO 2024 LTO, including its data file, is available on the AESO website at www.aeso.ca by following the path Grid ▶ Grid Planning ▶ Forecasting. A comparison of the billing determinants used in the 2026 and 2025 rate calculations are provided in Table B-12 of Appendix B to this Application.

50 Table 3-4 below provides a comparison of the forecast billing determinants in this Application as well as the forecast used in 2025 ISO tariff update application to the 2023 and 2024 recorded billing determinants. Based on the economic modelling described above, the AESO expects load growth in 2026. This is shown in Table 3-2 below, where the 2026 billing determinant forecast shows an increase over the 2025 forecast for all determinants, which is also in line with year-to-date recorded values for 2025.

Table 3-4 – 2026 and 2025 Forecast and 2024 and 2023 Recorded Billing Determinants

Rate DTS Billing Determinants	Units	2026 Forecast	2025 Forecast	2024 Recorded[22]	2023 Recorded
Coincident Metered Demand	MW-months	**98,029.5**	94,548.4	95,223.7	92,382.9
Billing Capacity (Total)	MW-months	**163,449.5**	163,368.8	163,016.9	162,127.9
Highest Metered Demand	MW-months	**125,530.0**	124,302.6	124,653.5	120,804.4
Metered Energy (All Hours)	GWh	**61,118.4**	60,430.8	60,446.4	60,112.9
Market Participants (Total)	customer-months	**5,349.3**	5,404.3	5,362.7	5,364.8

51 The AESO considers that the 2026 forecast provides the best estimate of billing determinants for the rate calculations in this Application given the available information.

3.5 Bill Impacts

52 As noted in sections 2 and 3.4 of this Application, the AESO's 2026 forecast revenue requirement has increased primarily due to an increase in ancillary services costs and an increase in the AESO's 2026 forecast of billing determinants. The connection charge under the AESO's 2026 updated Rate DTS will decrease by 0.3% mainly due to an increase in billing determinants that will more than offset the increase in wires costs. When all DTS charges are considered, the AESO's 2026 updated rates represent an overall increase of 1.1% from the 2025 rates, with DTS operating reserve charge making up the majority of the increase.

53 The increases to the different components of Rate DTS are provided in Table B-13 of Appendix B to this Application. The Rate DTS increase of 1.1% represents a revenue-weighted average increase over all components of Rate DTS. While the AESO includes an estimate of the operating reserve charge, operating reserve costs are settled monthly based on the actual costs incurred and therefore the estimate of operating reserve costs do not impact the calculation for the proposed Rate DTS within this Application.

54 The estimate of Rate STS is expressed as a percentage of the cost of losses and overall revenue from STS, and is forecast to increase by 11.6% in 2026 relative to 2025 due to the forecasted pool price decreasing in the denominator.

55 The overall result is an increase of 1.7% to the 2025 rates currently in place when considering changes to both DTS and STS.

56 Deferral accounts provide certainty that the AESO's costs will be exactly recovered by revenue, either through base rates or through the deferral account rider and reconciliations. Adjustments to costs paid by the AESO will therefore flow to and impact market participants through deferral accounts if rates are not adjusted. The changes

[22] As per Exhibit 30213-X0002, *AESO 2024 Deferral Account Reconciliation - Application,* table 3-1, page 20.

in rates summarized above improve timeliness and accompanying accuracy of the recovery of costs from market participants.

57 Individual bill impacts experienced by market participants will vary, depending on the specific characteristics of a market participant's service including peak demand coincidence, billing capacity, load factor, and hourly pool price and transmission constraint rebalancing charge at the time of usage.

58 To allow individual market participants to estimate the impact of the 2026 rates on their own Rate DTS bills, the AESO has included a bill impact estimator as Table B-16 in the rate calculations included as Appendix B to this Application. The bill impact estimator calculates bills for a given set of billing inputs under both the current 2025 Rate DTS and the updated 2026 Rate DTS, to allow the impact of the rates update on an individual service to be estimated.

59 The changes to the different components of Rate STS are provided in Table B-13 of Appendix B to this Application. The Rate STS increase of 11.6% represents a revenue-weighted average increase over all components of the rate.

60 Individual bill impacts experienced by market participants will vary, depending on the specific characteristics of a market participant's system access service.

61 In particular, the AESO notes that the loss factors provided in Table B-13 of Appendix B to this Application are representative average loss factors only. The actual losses charge applicable to an individual market participant will be based on a location-specific loss factor determined in accordance with section 501.10 of the ISO rules, *Transmission Loss Factors* (Section 501.10), as specified in the ISO tariff Rate STS, *Supply Transmission Service*. Section 501.10 was approved by the Commission in Decision 790-D05-2016[23] in Proceeding 790, although the AESO notes that the losses charge remains as approved on an interim basis in Commission Decision 2014-242.[24]

4. Maximum Investment Levels Update

62 This Application includes updated investment amounts approved in Decision 22942-D02-2019[25] to revise the existing point of delivery cost curve to Option 2[26] and reflect an escalation factor based on a composite of specified recent inflation indices.

63 The AESO has accordingly updated the composite inflation index used for developing the point of delivery cost function to 2026, using additional Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta consumer price index. Appendix C included in this Application provides the composite inflation index values for 2018 to 2026 on the Escalation Factor sheet, and the 2026 investment levels on the 2026 Investment sheet.

64 The resulting escalation factor for updating the 2026 maximum investment levels in section 4 of the ISO tariff, *Classification and Allocation of Connection Projects Costs* (Section 4), is 1.2129 which represents an increase to the 2018 maximum investment levels. The increase reflects increases in the latest underlying indices used for the composite index. The detailed calculation of the composite inflation index is included in Appendix C of this Application.

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[23] Decision 790-D05-2016, *Milner Power Inc. and ATCO Power Ltd. Complaints Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology Phase 2 Module B, Compliance Filing* (November 30, 2016), para. 1.

[24] Decision 2014-242, *Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update* (August 21, 2014), para. 730.

[25] Decision 22942-D02-2019, *Alberta Electric System Operator 2018 Independent System Operator Tariff* (September 22, 2019) para 201.

[26] Exhibit 22942-0018.03, *Appendix V – Options for POD Cost Function Workbook*, Tab 'Option 2 Investment Proposed', Cells C11 to G11.

65 The AESO has applied the resulting 1.2129 escalation factor to the 2018 Rate DTS maximum investment levels to determine the 2026 Rate DTS maximum investment levels, as summarized in the 2026 Investment sheet included in Appendix C to this Application. The 2025 escalation factor of 1.1949 used in the 2025 ISO Tariff Update Application[27] was lower than the 2026 escalation factor of 1.2129, resulting in an increase to the 2026 investment levels.

5. Generating Unit Owner's Contribution Rates

66 The proposed 2026 GUOC rates reflect a change from the approved 2025 GUOC rates for the Central planning region. There are no other changes proposed to the GUOC rates for 2026 relative to the 2025 GUOC rates. The AESO determined the proposed 2026 GUOC rates following the process approved by the Commission in Decision 27777-D01-2022[28]. The AESO also posted the proposed 2026 GUOC rates on the AESO website on May 27, 2025 to give market participants advance notice of the proposed rates.

67 The GUOC rates are determined using qualitative assessment based on engineering studies, in accordance with the methodology approved in Decision 22942-D02-2019.[29] The balance of load and generation for all planning regions are expected to remain largely the same in 2025, with no material changes. The proposed 2026 GUOC rates, differentiated by region, have been developed following the criteria and engineering study results described below.

68 In each region, the GUOC charge consists of the sum of two components:

1. $10,000/MW, payable by all Generation Facility Owners (GFOs) regardless of location in the province
2. A charge (of not more than $40,000/MW) payable by all GFOs, which varies by region based on the following criteria:

- $0/MW: generation development in the region can help defer load driven transmission development:
    a) Northwest planning region: All prior AESO Long Term Plans (LTPs) and more recent engineering studies have indicated that new generation in the Northwest planning region is desirable.

- $10,000/MW: the region has significant existing or near-term generation integration capability[30]:
    a) Edmonton planning region: With coal generation facilities retired or re-powered to gas operation, the AESO anticipates the Edmonton planning region has significant generation integration capability. This is also demonstrated in the 2022 Long Term Plan (LTP).

- $20,000/MW: the region has limited existing or near-term generation integration capability and limited development interest:
    a) Northeast planning region: The anticipated co-generation development at Suncor Energy Inc. will reduce the available generation integration capability.

[27] Exhibit 29606-0006, *Appendix C - 2025 Escalation Factor and Investment Levels*, Tab 'Escalation Factor', Cell E17.

[28] Decision 27777-D01-2022, *Alberta Electric System Operator 2023 Independent System Operator Tariff Update* (December 21, 2022), paras. 27-28.

[29] Decision 22942-D02-2019, *Alberta Electric System Operator 2018 ISO Tariff* (September 22, 2019), para. 323.

[30] Generation integration capability is strongly related to the total generation and load in the region. Typically, generation integration capability is higher in regions where load is higher. Therefore, there is an implicit relationship between generation integration capability and proximity to load. As a result, setting GUOC rates based on existing and near-term generation integration will incent generation to locate in areas of the transmission system where load exceeds generation.

b) Calgary planning region: Being one of the load centres in Alberta, Calgary planning region can benefit from generation developments in strategic locations. However, some of the key 240 kV lines transferring power into the region, such as the line going north from Shepard, are heavily loaded with limited available generation integration capability.

- $40,000/MW: the region has limited existing or near-term generation integration capability and significant development interest

  a) Central planning region: The change to the Central planning region GUOC rates reflects the current substantial interest in the Central East region. Although the Central East Transfer Out (CETO) project aims to reduce congestion, the strong interest for generation projects in the Central region is expected to continue following the construction of CETO.

- $40,000/MW: the region does not have existing or near-term generation integration capability.

  a) South planning region: Congestion on the transmission system has occurred in the South planning region. In addition, congestion is anticipated in more planning areas within the South planning region driven by strong interests in renewables developments. As a result, there is limited or no generation integration capability in some planning areas and the AESO is developing transmission plans to mitigate congestion in the region.

69 The proposed 2026 GUOC rates, which the AESO is requesting to be made effective January 1, 2026, are set out in subsection 7.3(1) of the ISO tariff, as follows:

Table 5-1 – 2026 Generating Unit Owner's Contribution Rates

Planning Region	2026 Rate ($/MW)	Current Rate ($/MW)
Northwest	$10,000	$10,000
Northeast	$30,000	$30,000
Edmonton	$20,000	$20,000
Central	$50,000	$40,000
Calgary	$30,000	$30,000
South	$50,000	$50,000

6. Conclusion

70 For the foregoing reasons, AESO requests that the Commission grant the approval of this Application, as applied for, and the relief requested in section 1.3 of this Application.

All of which is respectfully submitted this 7th day of November, 2025.

Alberta Electric System Operator

Per: "*Annie Nguyen*"

Annie Nguyen

Manager, Tariff