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Alberta Electric System Operator
2027 ISO Tariff Update Application

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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 2027 Independent System Operator (ISO) tariff rates and riders;

b) the proposed 2027 Generating Unit Owner's Contribution (GUOC) rates; and

c) the updated amounts included in Appendix B, *2027 Rate Calculations*.

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 2027 (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 2027 for system access service that are presented in this Application.

4 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[1] of the ISO tariff, based on costs and billing determinants forecast by the AESO for the 2027 calendar year.

5 This Application is consistent with the tariff rates update methodology accepted by the Commission in Decision 2010-606[2] and the GUOC methodology approved by the Commission in Decision 22942-D02-2019.[3]

6 The AESO is not seeking approval of its 2027 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 2027 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 2027.

1.2 Organization of Application

7 This Application is organized into the following sections:

1 Introduction

2 2027 Forecast Revenue Requirement - Summarizes the AESO's forecast revenue requirement for 2027, 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 2027 Rates and Riders Update - Discusses the calculation of rate levels based on the 2027 forecast revenue requirement, 2020 classification and functionalization values approved by the Commission in Decision 22942-D02-2019, and the 2027 forecast billing determinants. The

[1] 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).
[2] Decision 2010-606, *Alberta Electric System Operator 2010 ISO Tariff* (December 22, 2010), paras. 536-545.
[3] Decision 22942-D02-2019, *Alberta Electric System Operator 2018 Independent System Operator Tariff* (September 22, 2019), para. 323.

updates to Rider F and Rider J, *Wind and Solar Forecasting Service Cost Recovery* are also discussed in this section.

4 **2027 ISO Maximum Investment Levels Update** - Discusses the calculation of 2027 maximum investment levels using the 2027 escalation factor.

5 **Generating Unit Owner's Contribution Rates** - Discusses the methodology, process, and determination of 2027 generating unit owner's contribution rates.

6 **Conclusion**

8 This Application also includes the following appendices:

A **AESO 2027 Business Plan and Budget Proposal** - Document prepared by AESO management in consultation with stakeholders, containing the AESO's proposed 2027 business initiatives and proposed 2027 budgets and forecasts for ancillary services costs, transmission line losses costs, and administrative costs. This document is not expected to be complete until December; the AESO will provide it once it is available.

B **2027 Rate Calculations** - Microsoft Excel workbooks which calculate the updated dollar and percentage of pool price amounts for the 2027 rates, based on the same methodology used for the AESO's currently approved rates.

C **2027 Escalation Factor and Investment Levels** - Microsoft Excel workbook which calculates the composite inflation index and escalation factor used to update maximum investment levels.

D **2027 Rates, Riders of the ISO Tariff -** The proposed 2027 rates and riders that incorporate the 2027 updated amounts included as Appendix B to this Application.

E **2027 Rates, Riders of the ISO Tariff (blackline)** - The blackline version of the proposed 2027 rates and riders that incorporate the 2027 updated amounts included as Appendix B to this Application.

1.3 Relief Requested

9 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[4] and Commission Decision 22942-D02-2019.[5] The AESO requests that the Commission approve this Application as applied for, including:

(i) the updated amounts included in the 2027 Rate Calculations files, included as Appendix B to this Application;

(ii) the proposed 2027 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.

[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.

10 The AESO respectfully requests that this Application be approved effective January 1, 2027. The AESO further requests that the Commission issue its approval on or before December 18, 2026 to allow for the proposed tariff updates to be implemented by the AESO effective January 1, 2027 on a prospective basis. If the timing of this Application does not permit the granting of final approval on or before December 18, 2026, the AESO requests that the Commission approve this Application on an interim basis effective January 1, 2027, with ISO tariff rates and amounts, set out in subsections (i) and (ii) above, approved on an interim refundable basis.

11 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,[6] 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 2027 Forecast Revenue Requirement

12 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 2027 are detailed in Table B1 of Appendix B to this Application.

13 The total revenue requirement forecast for 2027 of $2,831.3 million represents an increase of $194.4 million (or 6.9%) from the 2026 total revenue requirement forecast of $2,636.9 million included in the 2026 ISO Tariff Rates Update Application.[7] The increase primarily results from a forecast increase of $95.9 million (or 66.6%) in 2027 losses costs, an increase of $46.6 million (or 2.3%) in 2027 wires costs, an increase of $28.8 million (or 10.4%) in 2027 ancillary services costs and an increase of $19.3 million or (16.5%) in 2027 general and administrative costs.

2.1 AESO Board Approval of Costs

14 The AESO is not seeking approval of its 2027 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 *2027 Business Plan and Budget Proposal,* which will be included as Appendix A to this Application after the initial filing, once it is available in December 2026.

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

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 *2027 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.

[6] Decision 2014-242, *Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update* (August 21, 2014), paras. 680 and 691.
[7] Proceeding 30427, *AESO 2026 ISO Tariff Update Application*, filed November 11, 2025.

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.

16 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.

17 The budget development process (BDP) includes strategically focused consultations that take place throughout the annual budget development cycle. Senior executive stakeholders from industry 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 2026, where stakeholders outlined key strategic areas for the AESO to consider when developing the 2027 budget, outlined in Appendix A, *Business Plan and Budget Proposal,* to be provided in December 2026. The AESO will share the proposed budget with stakeholders on November 17, 2026 and will address questions during the December 2, 2026 Stakeholder Session, to confirm that the AESO has determined appropriate areas of focus, priorities, and pace, based on the June 2026 meetings. Stakeholder insights and expertise were considered by the AESO in determining its corporate focus areas and associated priorities for 2027.[8]

18 As of the date of filing of this Application, the AESO's 2027 forecast ancillary services costs, losses costs and administrative costs have not been approved by the AESO Board. The AESO Board approval is expected to be obtained on December 10, 2026, after which, the AESO will file a letter to advise the Commission of AESO Board approval in January 2027.

2.2 Wires Costs

19 As shown in column A of Table B-1 of Appendix B, the 2027 forecast costs for wires are $2,095.5 million and represent approximately 74.0% of the AESO's transmission revenue requirement.

20 The AESO has determined the 2027 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,[9] approved in Decision 2010-606, and updated in Decision 22093-D02-2017[10]:

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

[8] Additional information on the AESO's business priorities and budget for 2027 is available on the AESO Engage website at www.aesoengage.aeso.ca by following the path Home ▶ Projects ▶ 2027 Budget Development Process.
[9] Exhibit 0026.00.AESO-2718, paras. 53-57.
[10] Decision 22093-D02-2017, *Alberta Electric System Operator 2017 ISO Tariff Update* (April 4, 2017), para. 37.

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.

21 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."[11]

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

2.3 Ancillary Services Costs

23 As shown in column A of Table B-1 of Appendix B, the forecast 2027 costs for ancillary services are $306.9 million and represent approximately 10.8% 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.

24 Ancillary services costs are primarily a function of volume forecasts and market-based commodity pricing forecasts. The 2027 forecast costs for ancillary services were based on a forecast average pool price of $50.24/MWh.

2.4 Losses Costs

25 As shown in column A of Table B-1 of Appendix B, the 2027 forecast costs for transmission line losses are $240.0 million and represent approximately 8.5% of the AESO's transmission revenue requirement. Losses are 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.

26 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts. The 2027 forecast costs for losses were based on a forecast average pool price of $50.24/MWh.

2.5 Administrative Costs

27 As shown in column A of Table B-1 of Appendix B, the 2027 general and administrative and other industry costs are $188.8 million and represent approximately 6.7% of the AESO's transmission revenue requirement.

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

1(1)(g) "ISO's own administrative costs" means

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

(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.

29 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 *2027 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. 2027 Rates and Riders Update

30 The 2027 rate calculations are included as Appendix B to this Application, in Tables B-1 through B-16.

31 The rate calculations use the following inputs:

(a) the 2027 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;[12] and

(c) the 2027 forecast billing determinants prepared by the AESO.

3.1 Specific Rate Changes

32 Where applicable, rates in the ISO tariff have been updated to reflect the 2027 forecast revenue requirement, the 2020 classification and functionalization of wires costs, and the 2027 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*.

[12] 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.

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

33 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.[13] 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 2027, 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.

34 On a cumulative forecast basis, the AESO is forecast to undercollect $131,193 through Rider J by the end of 2026. The wind and solar annual forecasting service cost for 2027 is forecast to be $293,448, representing an increase of $80,733 from the expected annual forecasting service cost of $212,715 in 2026. The AESO ran its calculations based on these forecasts and proposes to set the Rider J charge at $0.02/MWh.

35 The proposed 2027 Rider J charge will increase from $0.01/MWh to $0.02/MWh, 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 2027. 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 – 2023	Actual 2024	Actual 2025	Forecast 2026	Forecast 2027
1	Contracted wind and solar forecasting service* ($000)	$3,442.5	89.0	$186.2	$212.7	$293.4
2	Volumes (GWh)	63,486.4	13,886.9	15,910.3	17,614.5	21,032.3
3	Rider J Charge ($/MWh)	-	0.01	0.01	0.01	0.02
4	Revenue ($000)	3,360.9	117.2	143.0	178.1	420.6
5	Annual (undercollection) / overcollection ($000)	(81.6)	28.2	(43.2)	(34.6)	127.2
6	**Cumulative Balance (undercollection) / overcollection ($000)**	**$(81.6)**	**($53.4)**	**($96.6)**	**($131.2)**	**($4.0)**

* Assumes solar forecasting begins in 2022

3.3 Rider F, Balancing Pool Consumer Allocation

36 The AESO is seeking approval of the 2027 ISO tariff Rider F, providing for a $3.42 per megawatt hour (MWh) charge for all demand transmission service (Rate DTS) and demand opportunity service (Rate DOS) market

[13] 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, 2027 through December 31, 2027, inclusive.

37 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.

38 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.

39 On October 30, 2026, the Balancing Pool notified the AESO of a consumer charge for 2027 of $3.42/MWh for an estimated annualized amount of $231,224,048.82. A copy of the Balancing Pool's notice to the AESO is included as Appendix F to this Application.

40 The AESO has confirmed that the proposed $3.42/MWh consumer charge for Rider F for metered energy from January 1, 2027 to December 31, 2027 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]	[B]	[C]	[D = B ÷ C]
Period	**Annualized Amount Refund (Charge)**	**Metered Energy Forecast MWh**	**Annual Credit (Charge) $/MWh**
January - December 2027	($231,224,048.82)	67,609,371	($3.42)

41 The AESO proposes that all substantive aspects of Rider F, including applicability criteria and use of a $/MWh amount approach, continue unchanged for 2027 metered energy from the Rider F that is currently in effect.

42 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 2027 Forecast Billing Determinants

43 The rate calculations for the 2027 rates update are based on the AESO's forecast of billing determinants for 2027. The 2027 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 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. More information on the AESO's LTO, 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 2027 and 2026 rate calculations are provided in Table B-12 of Appendix B to this Application.

44 Table 3-4 below provides a comparison of the forecast billing determinants in this Application as well as the forecast used in 2026 ISO tariff update application to the 2024 and 2025 recorded billing determinants. Based on the economic modelling described above, the AESO expects above average load growth in 2027. This is shown in Table 3-2 below, where the 2027 billing determinant forecast shows an increase over the 2026 forecast for all determinants. DTS has grown more than forecast over the 2026 rates update and year to date load growth has increased. The DTS energy forecast takes into account load growth continuing as well as some large load projects connecting, which includes data centers that have met project certainty criteria.

Table 3-4 – 2027and 2026 Forecast and 2025 and 2024 Recorded Billing Determinants

Rate DTS Billing Determinants	Units	2027 Forecast	2026 Forecast	2025 Recorded[14]	2024 Recorded
Coincident Metered Demand	MW-months	107,234.5	98,029.5	99,437.8	95,223.7
Billing Capacity (Total)	MW-months	171,012.0	163,449.5	162,268.7	163,016.9
Highest Metered Demand	MW-months	136,552.1	125,530.0	126,801.5	124,653.5
Metered Energy (All Hours)	GWh	66,489.6	61,118.4	62,042.2	60,446.4
Market Participants (Total)	customer-months	5,420.8	5,349.3	5,390.3	5,362.7

45 The AESO considers that the 2027 forecast provides the best estimate of billing determinants for the rate calculations in this Application given the available information.

3.5 Bill Impacts

46 As noted in sections 2 and 3.4 of this Application, the AESO's 2027 forecast revenue requirement has increased primarily due to an increase in losses costs, wires costs, ancillary services costs and general and administrative costs. The AESO's 2027 forecast of billing determinants has also increased. The connection charge under the AESO's 2027 updated Rate DTS will decrease by 3.3% mainly due to an increase in billing determinants that will more than offset the increase in costs. When all DTS charges are considered, the AESO's 2027 updated rates represent an overall decrease of 2.6% from the 2026 rates.

47 The percentage changes to the different components of Rate DTS are provided in Table B-13 of Appendix B to this Application. The Rate DTS decrease of 2.6% represents a revenue-weighted average decrease 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.

48 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 57.5% in 2027 relative to 2026 due to an increase in expected energy. The losses charge is provided as an estimate only; transmission losses are determined based on hourly energy, pool price and loss factors within a settlement period.

49 The overall result is an increase of 0.6% to the 2026 rates currently in place when considering changes to both DTS and STS.

[14] As per Exhibit 30987-X0001, *AESO 2025 Deferral Account Reconciliation - Application,* table 3-1, page 21.

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

51 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.

52 To allow individual market participants to estimate the impact of the 2027 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 2026 Rate DTS and the updated 2027 Rate DTS, to allow the impact of the rates update on an individual service to be estimated.

53 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 57.5% represents a revenue-weighted average increase over all components of the rate.

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

55 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[15] in Proceeding 790, although the AESO notes that the losses charge remains as approved on an interim basis in Commission Decision 2014-242.[16]

56 Under the Restructured Energy Market (REM), the market-clearing process will determine the marginal impact that an additional MW supplied at each location has on system losses and reflect the value of that impact in the Locational Marginal Price (LMP). Therefore, since system losses will be reflected in LMPs, transmission losses no longer need to be recovered through Rate STS and Rider E, *Losses Calibration Factor Rider* of the ISO tariff. The AESO intends to file an application with the Commission in 2027 in order for this and other REM-related ISO tariff changes to be in place for the commencement of the REM. Rider E also recovers the costs of small-scale micro-generation as required in the Micro-generation Regulation, so with the anticipated removal of Rider E, the forthcoming REM-related ISO tariff changes will detail recovery of the small-scale micro-generation costs through an ISO fee contemplated under section 7(6)(b)(ii) of the Micro-generation Regulation.

[15] 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.
[16] Decision 2014-242, *Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update* (August 21, 2014), para. 730.

4. Maximum Investment Levels Update

57 This Application includes updated investment amounts approved in Decision 22942-D02-2019[17] to revise the existing point of delivery cost curve to Option 2[18] and reflect an escalation factor based on a composite of specified recent inflation indices.

58 The AESO has accordingly updated the composite inflation index used for developing the point of delivery cost function to 2027, 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 2027 on the Escalation Factor sheet, and the 2027 investment levels on the 2027 Investment sheet.

59 The resulting escalation factor for updating the 2027 maximum investment levels in section 4 of the ISO tariff, *Classification and Allocation of Connection Projects Costs* (Section 4), is 1.2374 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.

60 The AESO has applied the resulting 1.2374 escalation factor to the 2018 Rate DTS maximum investment levels to determine the 2027 Rate DTS maximum investment levels, as summarized in the 2027 Investment sheet included in Appendix C to this Application. The 2026 escalation factor of 1.2129 used in the 2026 ISO Tariff Update Application[19] was lower than the 2027 escalation factor of 1.2374, resulting in an increase to the 2027 investment levels.

5. Generating Unit Owner's Contribution Rates

61 There are no changes to the proposed 2027 GUOC rates from the approved 2026 GUOC rates. The AESO determined the proposed 2027 GUOC rates following the process approved by the Commission in Decision 27777-D01-2022[20]. The AESO also posted the proposed 2027 GUOC rates on the AESO website on July 17, 2026 to give market participants advance notice of the proposed rates.

62 The GUOC rates are determined using qualitative assessment based on engineering studies, in accordance with the methodology approved in Decision 22942-D02-2019.[21] The balance of load and generation for all planning regions are expected to remain largely the same in 2027, with no material changes. The proposed 2027 GUOC rates, differentiated by region, have been developed following the criteria and engineering study results described below.

63 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:

[17] Decision 22942-D02-2019, *Alberta Electric System Operator 2018 Independent System Operator Tariff* (September 22, 2019) para 201.
[18] Exhibit 22942-X0018.03, *Appendix V – Options for POD Cost Function Workbook*, Tab 'Option 2 Investment Proposed', Cells C11 to G11.
[19] Exhibit 29606-X0006, *Appendix C - 2025 Escalation Factor and Investment Levels*, Tab 'Escalation Factor', Cell E17.
[20] Decision 27777-D01-2022, *Alberta Electric System Operator 2023 Independent System Operator Tariff Update* (December 21, 2022), paras. 27-28.
[21] Decision 22942-D02-2019, *Alberta Electric System Operator 2018 ISO Tariff* (September 22, 2019), para. 323.

- $0/MW: generation development in the region can help defer load driven transmission development:
    a) Northwest planning region: Northwest is a load driven region with more load driven needs than generation driven needs. It will benefit from additional generation locating there. The region is already at minimum GUOC rate.

- $10,000/MW: the region has significant existing or near-term generation integration capability[22]:
    a) Edmonton planning region: Edmonton region has high generation integration capability; this is especially true because of the recent Coal to Gas retirements over the last few years. There has been minimal change over the previous year thus, the GUOC has been maintained.

- $20,000/MW: the region has limited existing or near-term generation integration capability and limited development interest:
    a) Northeast planning region: Northeast is a region with multiple needs. It is driven by generation in Fort McMurray and has transfer out constraints. However, the Fort Saskatchewan area is a load driven area with more load driven needs than generation driven needs. Geographically, a large majority of the region is behind the transfer-out constraint, thus the GUOC has been maintained.

    b) Calgary planning region: Available capability as well as the generation meeting inclusion and future interest does not differ significantly from last year thus the GUOC rate has been maintained.

- $30,000/MW: the region has limited existing or near-term generation integration capability and significant development interest
    a) None.
- $40,000/MW: the region does not have existing or near-term generation integration capability.
    a) South planning region: South is a generation driven region with a low generation integration capability. There have been project cancellations over the previous years. However, the region continues to be congested and is a poor location to connect. The region is already at maximum GUOC rate.

    b) Central planning 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 energization of CETO. The region is already at maximum GUOC rate.

64 The proposed 2027 GUOC rates, which the AESO is requesting to be made effective January 1, 2027, are set out in subsection 7.3(1) of the ISO tariff, as follows:

Table 5-1 – 2027 Generating Unit Owner's Contribution Rates

[22] 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.

Planning Region	2027 Rate ($/MW)	Current Rate ($/MW)
Northwest	$10,000	$10,000
Northeast	$30,000	$30,000
Edmonton	$20,000	$20,000
Central	$50,000	$50,000
Calgary	$30,000	$30,000
South	$50,000	$50,000

6. Conclusion

65 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 16th day of November, 2026.

Alberta Electric System Operator

Per: "*Annie Nguyen*"

Annie Nguyen

Manager, Tariff