Alberta Electric System Operator 2018 ISO Tariff Update

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Prepared for: Alberta Utilities Commission

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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”) applies to the Alberta Utilities Commission (“Commission”) for approval of its 2018 update to the Independent System Operator (“ISO”) tariff. As outlined in further detail below, this annual tariff update application seeks approval of changes to the rates to be charged by the AESO for system access service and to the maximum investment levels provided under section 8 of the ISO tariff.

2 The updates proposed in this application change only the levels (that is, the dollar-based and percentage of pool price amounts) included in the rates and section 8 of the ISO tariff, based on costs and billing determinants forecast by the AESO for the 2018 calendar year. This application does not include any changes to the structure of the rates or to the provisions of the terms and conditions (other than maximum investment levels) currently approved in the 2017 ISO tariff.

1.1 Background

3 On December 22, 2010, the Commission issued Decision 2010-606,[1] in which the AESO’s proposed annual tariff update was summarized as follows:

> *In conjunction with its proposal for major updates, the AESO proposed to make annual tariff update filings involving the following three principal components:*
>
> - *an annual revenue requirement update using the approach to the wires cost forecast as described in section 2.2 of the Application, plus forecasts for ancillary services costs, losses costs and administration costs approved by the AESO Board for the forecast year;*
> - *revised rate levels for each AESO rate calculated from the forecast revenue requirement and forecast billing determinants using rate calculations and rate design approved in the most recent comprehensive tariff application; and*
> - *annual updates to investment amounts approved in the most recent comprehensive tariff reflecting an escalation factor based on the most recent Conference Board of Canada Alberta consumer price index (CPI).*[2]

4 The Commission approved the AESO’s proposal in Decision 2010-606, and the AESO has subsequently applied for tariff updates between its major tariff applications in accordance with this approach.

5 The AESO’s most recent approved major tariff application was filed on July 17, 2013, by which the AESO sought approval from the Commission for the 2014 ISO tariff[3] and approved on a final basis in Decision 3473-D01-2015.[4] The AESO’s most recent major tariff application was filed on September 14, 2017, by which the AESO sought approval from the Commission for the 2018 ISO tariff.[5] The AESO’s most recent tariff update application was filed on October 20, 2016, by which the AESO sought approval from the Commission for the 2017 ISO tariff.[6] The Commission approved the current form of the 2017 ISO tariff, effective January 1, 2017, by way of Decision 22093-D01-2016[7] on an interim refundable basis and by way of Decision 22093-D02-2017[8] on a final basis. The 2017 ISO tariff approved in that decision reflected costs and billing

[1] Decision 2010-606.
[2] *Ibid* at paragraph 537.
[3] Proceeding 2718, Exhibit 0002.
[4] Decision 3473-D01-2015.
[5] Proceeding 22942, Exhibit 0002.
[6] Proceeding 22093, X0008.
[7] Decision 22093-D01-2016.
[8] Decision 22093-D02-2017.

determinants for the 2017 calendar year. The AESO is now filing this annual tariff update application to reflect costs and billing determinants for the 2018 calendar year.

6 In accordance with the approach referred to above, this tariff update application consists of formulaic updates to: (i) the AESO's annual revenue requirement, based on the AESO's updated forecast costs for 2018; (ii) rate, rider, and maximum investment level amounts using the rate calculation methodology already approved by the Commission in Decision 3473-D01-2015;[9] and (iii) the investment amounts first approved in Decision 3473-D01-2015,[10] updated in Decision 21302-D01-2016,[11] and then updated in Decision 22093-D02-2017,[12] in accordance with the escalation factor described below. In the AESO's view, the updates proposed in this application will limit potential misallocations that might occur if the AESO continued to rely on Rider C, *Deferral Account Adjustment Rider*, to allocate revenue and cost imbalances to market participants.

7 The AESO has applied for updated 2018 bulk system, regional system and point of delivery cost functionalization and 2018 classification as part of its 2018 comprehensive ISO tariff application, filed on September 14, 2017 and currently being considered by the Commission in Proceeding 22942 ("Comprehensive Application").[13] A supplementary 2018 tariff update application may in the future be required, depending on the Commission's decision regarding the Comprehenseive Application..

1.2 Organization

8 Similar to previous ISO tariff update applications, this application is organized into the following sections:

1 **Introduction** — Provides background on the application and specifies the relief requested.

2 **2018 Forecast Revenue Requirement** — Summarizes the AESO's forecast revenue requirement for 2018, including costs that have been approved either by the Commission (for transmission facility owner ("TFO") tariffs) or by the AESO Board (for ancillary services, transmission line losses, and the AESO's own administration).

3 **2018 Tariff Update** — Discusses the calculation of rate levels based on the 2018 forecast revenue requirement, 2018 wires costs functionalization and classification approved in Commission Decision 2013-421,[14] and 2018 forecast billing determinants.

4 **2018 Maximum Investment Levels Update** — Discusses the calculation of 2018 maximum investment levels using the 2018 escalation factor.

5 **Conclusion** — Reiterates the relief requested.

9 This application also includes the following appendices:

A **AESO Board Decision** — AESO Board decision issued on August 8, 2017, approving forecasted ancillary services costs, forecasted losses costs, and the AESO's business plan and budget for 2018.

B **AESO 2018 Business Plan and Budget Proposal** — Document prepared by AESO management in consultation with stakeholders, as submitted to the AESO Board on May 30, 2017, containing the

[9] See footnote 4.
[10] See footnote 4.
[11] See footnote 6.
[12] See footnote 7.
[13] Exhibit 22942-X002 at paras 18, 49-78
[14] Decision 2013-421, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update Negotiated Settlement – Cost Causation Study, issued November 27, 2013.

AESO's proposed 2018 business initiatives and proposed 2018 budgets and forecasts for ancillary services costs, transmission line losses costs, and administrative costs.

C **2018 Rate Calculations** — Microsoft Excel workbook which calculates the updated dollar and percentage of pool price amounts for the 2018 rates, based on the same methodology used for the AESO's currently approved rates.

D **2018 Escalation Factor and Investment Levels** — Microsoft Excel workbook which calculates the composite inflation index and escalation factor used to update maximum investment levels.

E **2018 Rates, Riders, and Section 8 of the ISO Tariff** — The proposed 2018 rates, riders, and section 8 that incorporate the 2018 updated amounts included as Appendices C and D to this application.

F **2018 Rates, Riders, and Section 8 of the ISO Tariff (blackline)** — The blackline version of the proposed 2018 rates, riders, and section 8 that incorporate the 2018 updated amounts included as Appendix C to this application.

1.3 Relief Requested

10 For the reasons outlined below, the AESO submits that the tariff updates proposed in this application are just and reasonable, and respectfully requests that the Commission approve this annual tariff update application, including (i) the updated amounts included as Appendix C to this application, and (ii) the proposed 2018 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC and Rate STS, Rider J and Section 8 included as Appendix E to this application, which incorporates the updated amounts.

11 The AESO respectfully requests that this application be approved effective January 1, 2018. If the timing of this application does not permit the granting of final approval prior to January 1, 2018, the AESO also requests that the Commission approve this application on an interim refundable basis effective as of that date. The AESO further requests that the Commission issue its approval (whether on an interim or final basis) on or before December 28, 2017 as this is the last approval date that will allow the AESO to implement the proposed tariff updates effective January 1, 2018 on a prospective basis and inform market participants in advance of rate changes. For additional clarity, the AESO requests that the updated rates, riders and investment levels proposed in this application apply on a go-forward basis only, commencing from the effective date approved by the Commission. Consistent with the Commission's statements in Decision 2014-242,[15] the AESO submits that 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.

[15] Decision 2014-242, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, issued August 21, 2014, at para 617.

2 AESO 2018 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 2018 are detailed in column A of Table 2-1. For comparison, Table 2-1 includes costs approved in the AESO Board Decision for 2018 (included as Appendix A to this application), updated forecast costs for 2017,[16] forecast costs for 2017,[17] and the recorded costs for 2016 and 2015, in columns B, C, D, and E, respectively.

Table 2-1 – 2018 Forecast, 2017 Updated Forecast, 2016 and 2015 Recorded Cost Components

Cost Component	2018 Forecast ($ 000 000) A	2017 Updated Forecast ($ 000 000) B	2017 Forecast ($ 000 000) C	2016 Recorded ($ 000 000) D	2015 Recorded ($ 000 000) E
Wires	1,720.3	1,734.0	1,729.4	1,711.4	1,566.6
Ancillary services	179.2	118.9	182.6	93.2	171.2
Losses	96.8	74.1	111.9	41.1	77.4
Administrative	100.8	98.7	99.9	100.4	98.5
Revenue Requirement	**2,097.1**	**2,025.6**	**2,123.9**	**1,946.0**	**1,913.7**

Note: Numbers may not add due to rounding

13 The 2018 updated forecast costs represent a decrease of $26.8 million (or 1.3%) over the 2017 forecast costs. The decrease primarily results from a forecast decrease of $9.1 million (or 0.5%) in wires costs.

2.1 AESO Board Approval of Costs

14 The AESO is not seeking approval in this application of its 2018 forecast revenue requirement. The AESO's forecast costs are approved through other processes provided for in relevant legislation. These costs, as provided in column A of Table 2-1, were addressed in the AESO 2017-2018 Business Plan and Budget Proposal dated May 30, 2017, included as Appendix B to this application and AESO Board Decision 2017-2018-BRP-001 dated August 8, 2017, included as Appendix A.

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

16 (a) Wires-related 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 2017-2018 Business Plan and Budget Proposal reflected TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared in early 2017, as discussed in more detail below.)

17 (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.

[16] 2017 Updated Forecast includes 2017 forecast costs and updated wires costs reflecting recent TFO filings, compliance filings and decisions for 2017.
[17] 2017 Forecast reflects amounts applied for in AESO's 2017 ISO Tariff Update application, approved in Decision 22093-D02-2017, issued April 4, 2017.

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

19 (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*.

20 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* addresses consultation and approval of those costs and 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.

21 The practice established by the AESO to carry out consultation on ancillary services, losses, and administrative costs is the Budget Review Process. The Budget Review Process is a transparent stakeholder process which provides a prudence review with input from stakeholders. At the conclusion of the Budget Review Process, AESO management proposes a business plan and budget to the AESO Board, including a request for approval of ancillary services costs, losses costs, and administrative costs.

22 As part of the AESO Budget Review Process for its 2017-2018 budget, AESO management consulted with stakeholders in a planning process that had been first established with stakeholders in 2009. In early-2017, the AESO reviewed the business initiatives established for 2018 and prepared a forecast budget required to deliver those business initiatives. Following consultation with stakeholders and incorporating appropriate amendments arising from it, AESO management submitted the *2017-2018 Business Plan and Budget Proposal* to the AESO Board on May 30, 2017. This document (included as Appendix B to this application) includes details on the consultation process and on the proposal for the AESO's business plan and budget as it relates to forecasted ancillary services costs, forecasted losses costs, and the AESO's business priorities and budget for 2018. The *2017-2018 Business Plan and Budget Proposal* was also provided to stakeholders and posted on the AESO website.

23 The AESO's 2018 forecast costs were approved by the AESO Board on August 8, 2017. A Board Decision Document was posted on the AESO website and is included as Appendix A to this application.

24 Additional information on the AESO's business priorities and budget for 2018 is available on the AESO website at www.aeso.ca by following the path About the AESO ▶ Business planning and financial reporting ▶ Business plan and budget ▶ 2017-2018.

2.2 Wires Costs

25 The 2018 forecast costs for wires are $1,720.3 million and represent approximately 82.0% of the AESO's transmission revenue requirement. Wires costs include primarily wires-related costs of TFOs as well as two small non-wires costs.

26 The AESO has determined the 2018 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,[18] approved in Decision 2010-606, referred to in Decision 2014-242[19] and updated in Decision 22093-D02-2017:[20]

> *(a) If a transmission facility owner has received final Commission approval for its applicable tariff, the AESO includes the approved cost for that transmission facility owner tariff.*
>
> *(b) If a transmission facility owner has applied for its tariff, the Commission has issued an initial decision on the application, and the transmission facility owner has submitted a refiling in compliance with the decision, the AESO includes the transmission facility owner tariff costs included in the refiling.*
>
> *(c) If a transmission facility owner 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 transmission facility owner has not yet submitted its compliance refiling, the AESO includes the most recent of the following: (i) the transmission facility owner tariff costs last approved by the Commission on a final basis for the transmission facility owner plus 72% of any increase or decrease included in the transmission facility owner's tariff application above or below the prior approved costs, and (ii) the transmission facility owner tariff costs last applied-for by the transmission facility owner in a compliance refiling plus 72% of any increase or decrease included in the transmission facility owner's tariff application above or below the prior approved costs.*
>
> *(d) If a transmission facility owner has not yet applied for its tariff, the AESO includes the most recent of the following: (i) the transmission facility owner tariff costs last approved by the Commission on either a final or interim basis, and (ii) the transmission facility owner tariff costs last applied-for by the transmission facility owner in a compliance refiling.*

27 As discussed in greater detail below, the Commission has issued decisions[21,22] approving certain 2018 TFO tariffs, and applications have been filed for several 2018 TFO tariffs. Therefore, in accordance with the foregoing approach, the AESO has forecast the 2018 wires costs in Table 2-1 to reflect these approvals and applications.

28 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."[23]

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[18] Exhibit 0026.00.AESO-2718, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, dated July 19, 2013, at paras 53-57.
[19] Decision 2014-242, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, issued August 21, 2014, at para 43.
[20] Decision 22093-D02-2017 at para 37.
[21] Decision 20802-D01-2015, The City of Red Deer Compliance Filing to Decision 3599-D01-2015, issued October 23, 2015.
[22] 20818-D01-2015 FortisAlberta Inc. 2016 Annual Performance-Based Regulation Rate Adjustment Filing, issued December 17, 2015
[23] Exhibit 0026.00.AESO-2718, at para 58.

29 The TFO tariff costs included in this application are included as Table C-2 of Appendix C to this application. These costs are also included in column A of Table 2-2 below.

Table 2-2 – AESO 2018 Forecast Revenue Requirement ($ 000 000)

Line No.	Description	2018 Forecast A	2017 Updated Forecast B	2017 Forecast C	2016 Recorded D	2015 Recorded E
	WIRES					
	TFO Wires-Related Costs					
1	AltaLink	892.1	866.2	868.6	822.3	732.4
2	ATCO Electric	625.4	664.8	664.8	691.3	644.2
3	Isolated Generation	(3.1)	(1.7)	(3.0)	(1.3)	(2.4)
4	Subtotal ATCO Costs	622.3	663.1	661.8	689.9	641.7
5	ENMAX Power Corporation	80.1	79.7	73.9	74.8	74.1
6	EPCOR Distribution & Transmission	99.3	98.6	98.6	99.8	93.9
7	City of Lethbridge	7.1	7.1	7.1	6.3	6.3
8	TransAlta Utilities Corporation	4.9	4.9	4.9	4.5	4.9
9	City of Red Deer	4.3	4.3	4.3	3.9	3.5
10	FortisAlberta (Farm Transmission)	4.7	4.7	4.7	4.8	4.7
11	Subtotal TFO Wires-Related Costs	1,714.9	1,728.6	1,723.9	1,706.3	1,561.5
	Non-Wires Costs					
12	Invitation to Bid on Credits (IBOC)	1.9	1.9	1.5	1.8	1.4
13	Location Based Credit Standing Offer (LBC SO)	3.5	3.5	4.0	3.2	3.7
14	Subtotal IBOC/LBC SO Costs	5.4	5.4	5.5	5.0	5.1
15	TOTAL WIRES COSTS	1,720.3	1,734.0	1,729.4	1,711.4	1,566.6
	ANCILLARY SERVICES					
	Operating Reserves					
	Active					
16	Regulating	37.6	21.3	27.2	29.4	33.0
17	Spinning	55.7	33.8	57.7	16.1	42.0
18	Supplemental	32.2	13.7	40.7	7.2	30.2
19	Subtotal Active Reserves	125.5	68.8	125.7	52.6	105.2
	Standby					
20	Regulating	4.6	5.2	6.9	8.1	5.0
21	Spinning	12.9	11.2	12.4	4.8	19.8
22	Supplemental	4.9	3.4	3.5	1.2	8.3
23	Subtotal Standby Reserves	22.4	19.8	22.7	14.1	33.1
24	Trading Fees and Other Related Charges	(1.2)	(0.5)	(1.3)	(0.2)	(1.0)
25	Subtotal Operating Reserves	146.6	88.2	147.1	66.5	137.3
	Other Ancillary Services					
26	Black Start	4.3	2.1	2.1	2.1	2.1
27	Transmission Must Run (TMR)	5.3	4.8	4.0	0.7	9.6
28	Load Shed Service for Imports (LSSi)	17.3	18.1	20.0	18.2	17.4
29	Reliability Services from BC	2.9	2.9	2.9	2.9	2.1
30	Transmission Constraint Rebalancing (TCR)	0.1	0.1	4.0	0.0	-
31	Poplar Hill	2.8	2.8	2.5	2.8	2.6
32	Interruptible Load Remedial Action Scheme (ILRAS)	-	-	-	-	-
33	Generator Load Remedial Action Scheme	-	-	-	-	-
34	Subtotal Other Ancillary Services	32.6	30.7	35.5	26.7	33.8

35	TOTAL ANCILLARY SERVICES	179.2	118.9	182.6	93.2	171.2
	LOSSES					
36	Pool Payment	96.8	74.1	111.9	41.1	77.4
37	TOTAL LOSSES COSTS	96.8	74.1	111.9	41.1	77.4

Table 2-2 – AESO 2018 Forecast Revenue Requirement ($ 000 000) (continued)

Line No.	Description	2018 Forecast A	2017 Forecast Budget B	2017 Updated Forecast C	2016 Recorded D	2015 Recorded E
	OTHER INDUSTRY COSTS					
38	Regulatory Process Costs	0.5	0.8	1.4	0.4	0.4
39	Western Electricity Coordination Council (WECC)	2.2	2.2	2.2	2.4	1.9
40	Share of Commission Costs	12.8	12.6	12.0	12.1	12.5
41	TOTAL OTHER INDUSTRY COSTS	15.5	15.6	15.6	14.9	14.8
	GENERAL AND ADMINISTRATIVE COSTS					
	Administrative Costs					
42	Staff and Benefits	49.0	47.7	47.7	49.4	47.7
43	Contract Services and Consultants	4.4	5.9	5.3	4.9	4.9
44	Administration	3.2	3.0	3.5	3.2	3.0
45	Facilities	5.4	5.2	5.6	5.1	5.5
46	Computer and Telecom Services and Maintenance	8.6	8.3	6.6	7.3	6.4
47	Subtotal Administrative Costs	70.6	70.1	68.9	69.9	67.5
	General Costs					
48	Market System Replacement	-	-	-	-	-
49	Interest	0.7	0.3	(0.2)	0.1	(0.1)
50	Amortization and Depreciation	14.1	12.7	15.7	15.5	16.3
51	Subtotal General Costs	14.8	13.0	15.5	15.6	16.2
52	TOTAL G&A COSTS	85.4	83.1	84.4	85.5	83.7
53	TOTAL G&A AND OTHER INDUSTRY COSTS	100.8	98.7	99.9	100.4	98.5
54	TOTAL REVENUE REQUIREMENT	2,097.1	2,025.6	2,123.9	1,946.0	1,913.7

Notes: Totals may not add due to rounding

30 The wires costs included in this application and set out in Table 2-2 above are based on the following Commission decisions and TFO tariff applications.

Line 1 AltaLink Management Ltd.

31 AltaLink received final approval of 2018 TFO tariff costs of $892.1 million. The AESO has accordingly included $892.1 million as the forecast TFO tariff costs for AltaLink for 2018.

Lines 2-4 ATCO Electric Ltd.

32 ATCO Electric filed for approval of 2018 TFO tariff costs of $606.6 million. ATCO Electric filed for approval in a second compliance filing of 2017 TFO tariff costs of $673.8 million. As well, ATCO Electric filed for approval of a 2013-2014 deferral account reconciliation shortfall of $0.2 million allocated to 2017. The AESO has accordingly included $625.4 million as the forecast TFO tariff costs for ATCO Electric for 2018.

33 ATCO Electric's TFO tariff costs are offset by payments to the AESO in respect of pool price for electric energy provided to isolated communities in accordance with the *Isolated Generating Units and Customer Choice Regulation*. The isolated generation cost offset is estimated at $3.1 million for 2018, based on 2016 recorded volumes for isolated communities and the 2018 forecast pool price.

34 The 2018 net forecast TFO tariff costs for ATCO Electric are $622.3 million.

Line 5 ENMAX Power Corporation

35 ENMAX has not yet applied to the Commission for approval of 2018 TFO tariff costs. ENMAX received approval of 2015 TFO tariff costs of $73.9 million in Decision 20819-D01-2015 on November 27, 2015. As well, ENMAX filed for approval of a 2015 deferral account reconciliation shortfall of $1.9 million and has not received a decision as of the filing of this application. ENMAX has filed for approval of 2017 TFO tariff costs of $81.9 million. The AESO has included 72% of the applied for increase of $6.6 million (from the approved 2015 TFO wires costs and 72% of the applied for increase in the 2015 deferral account reconciliation). The AESO has accordingly included $80.1 million as the forecast TFO tariff costs for ENMAX for 2018.

Line 6 EPCOR Distribution & Transmission Inc.

36 EPCOR has not yet applied to the Commission for approval of 2018 TFO tariff costs. EPCOR received final approval of 2017 TFO tariff costs of $99.3 million in Decision 22163—D01—2016. The AESO has accordingly included $99.3 million as the forecast TFO tariff costs for EPCOR for 2018. EPCOR has applied to the Commission to continue abovementioned 2017 TFO tariff costs on an interim basis.

Line 7 City of Lethbridge

37 The City of Lethbridge has not yet applied to the Commission for approval of 2018 TFO tariff costs. The City of Lethbridge received final approval of 2017 TFO tariff costs of $7.1 million in Decision 22136-D01-2016. The AESO has accordingly included $7.1 million as the forecast TFO tariff costs for City of Lethbridge for 2018. The City of Lethbridge has applied to the Commission to continue abovementioned 2017 TFO tariff costs on an interim basis.

Line 8 TransAlta Corporation

38 TransAlta has not yet applied to the Commission for approval of 2018 TFO tariff costs. TransAlta applied for approval of 2017 TFO tariff costs of $4.9 million. TransAlta received approval for interim 2017 TFO tariff costs of $4.9 million in Decision 22241-D01-2016. The AESO has accordingly included $4.9 million as the forecast TFO tariff costs for TransAlta for 2018.

Line 9 City of Red Deer

39 The City of Red Deer has not yet applied to the Commission for approval of 2018 TFO tariff costs. The City of Red Deer received final approval of 2017 TFO tariff costs of $4.3 million in Decision 22145-D01-2016. The AESO has accordingly included $4.3 million as the forecast TFO tariff costs for City of Red Deer for 2018. The City of Red Deer has applied to and received approval from the Commission to continue abovementioned 2017 TFO tariff costs on an interim basis.

Line 10 FortisAlberta Inc. (Farm Transmission)

40 Section 32 of the Act requires the AESO to pay owners of electric distribution systems for "farm transmission costs" as defined in the Act. FortisAlberta has not yet applied to the Commission for approval of 2018 farm transmission costs. FortisAlberta received final approval for 2017 farm transmission costs of $4.7 million in Decision 21980-D01-2016. The AESO has accordingly included $4.7 million as the forecast TFO tariff costs for FortisAlberta for 2018.

Lines 12-14 Non-Wires Costs

41 The AESO includes as wires costs two cost components that are not related to TFOs: Invitation to Bid on Credit ("IBOC") costs and Location Based Credit Standing Offer ("LBC SO") costs. These two programs were initiated to provide non-wires solutions for transmission issues in Alberta and their costs are included as wires costs for rate-setting purposes. The $5.4 million cost for the two programs was forecast by the AESO in conjunction with ancillary services costs and has been approved by the AESO Board, as evidenced by the AESO Board Decision included as Appendix A to this application.

2.3 Ancillary Services Costs

42 The forecast 2018 costs for ancillary services are $179.2 million and represent approximately 9% 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 reserves, which represent the real power capability above system demand required to provide for regulation, forced outages and unplanned outages.[24]

43 Ancillary services costs are primarily a function of volume forecasts and market-based commodity pricing forecasts. The 2018 forecast costs for ancillary services were based on a forecast average pool price of $42.58/MWh.

2.4 Losses Costs

44 The 2018 forecast costs for transmission line losses are $96.8 million and represent approximately 5% of the AESO's transmission revenue requirement as provided in Table 2-1. 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.

45 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts. The 2018 forecast costs for losses were based on a forecast average pool price of $42.58/MWh.

2.5 Administrative Costs

46 The 2018 forecast cost for administration is $100.8 million and represents approximately 5% of the AESO's transmission revenue requirement.

47 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;*

[24] AESO Consolidated Authoritative Document Glossary

48 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 Board Decision provided as Appendix A to this application[25] allocates administrative costs among the three functions of the AESO; namely, transmission, energy market, and load settlement. The transmission-related portions of the AESO's administrative costs are included in the AESO's transmission revenue requirement detailed in Table 2-1 above.

[25] Appendix A, AESO Board Decision, page 8 of 14.

3 2018 Tariff Update

49 In accordance with the approach referred to in section 1.1 above, this application uses the rate calculation methodology approved by the Commission in Decision 3473-D01-2015[26] in connection with the AESO's 2014 ISO tariff application. Specifically, the AESO has used the 2014 rate calculations included as Appendix B of the AESO 2014 ISO tariff compliance filing[27] as the template for the 2018 rate calculations, updated to reflect the transmission constraint rebalancing charge approved in Decision 20623-D01-2015[28]. The 2018 rate calculations are included as Appendix C to this application, in Tables C-1 through C-16.

50 The rate calculations use the following inputs:

(a) the 2018 forecast revenue requirement discussed in section 2 of this application;

(b) the functionalization of wires costs approved for 2016 in Decision 2013-421;[29] and

(c) the 2018 forecast billing determinants prepared by the AESO.

3.1 Specific Rate Changes

51 Where applicable, rates in the ISO tariff have been updated to reflect the 2018 forecast revenue requirement, 2018 wires costs functionalization, and 2018 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 DOS, *Demand Opportunity Service*;
- Rate XOS, *Export Opportunity Service*; and
- Rate XOM, *Export Opportunity Merchant Service*.

52 The levels for each of the above rates have been calculated in accordance with Appendix C to this application. The updated rate sheets themselves are provided in the proposed 2018 ISO tariff included as Appendix E to this application.

53 Additional incidental changes to Rate PSC, *Primary Service Credit*; Rate STS, *Supply Transmission Service*, and Rider J, *Wind Forecasting Service Cost Recovery Rider*, are discussed below.

3.1.1 Rate PSC, Primary Service Credit

54 Consistent with the calculation of the 2014 primary service credit, the 2018 primary service credit is calculated as:

- 79% of the substation fraction ($/month) tier of the Rate DTS point of delivery charge;
- 79% of the first three capacity (7.5 MW, 9.5 MW, and 23 MW) tiers of the Rate DTS point of delivery charge; and
- 100% of the fourth capacity (remaining capacity above 40 MW) tier of the Rate DTS point of delivery charge.

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[26] See footnote 1.
[27] Proceeding 3473, Exhibit 0004.00.AESO-3473, Alberta Electric System Operator 2014 ISO Tariff Compliance Filing Pursuant to Decision 2014-242, revised as discussed in Exhibit 0044.01.AESO-3473, response to information request UCA-AESO-002.
[28] See footnote 2.
[29] Proceeding 2718, Exhibit 0265.02.AESO-2718, Alberta Transmission System Cost Causation Study Update dated January 17, 2014, at page 7, Figure 6.

55 As the Rate DTS point of delivery charge has been updated in this application, the AESO has correspondingly updated the primary service credit as provided in Table 3-1 below. The primary service credit amounts determined in Table 3-1 are reflected in Rate PSC of the proposed 2018 ISO tariff included in Appendix E to this application.

Table 3-1 – Calculation of 2018 Primary Service Credit

Rate Component	Rate DTS Charge	PSC Factor	Rate PSC Credit
Substation fraction	\$8,635.00/month	79%	\$6,822.00/month
First (7.5 × substation fraction) MW of billing capacity	\$3,496.00/MW	79%	\$2,762.00/MW
Next (9.5 × substation fraction) MW of billing capacity	\$2,190.00/MW	79%	\$1,730.00/MW
Next (23 × substation fraction) MW of billing capacity	\$1,527.00/MW	79%	\$1,206.00/MW
All remaining MW of billing capacity	\$989.00/MW	100%	\$989.00/MW

3.1.2 Regulated Generating Unit Connection Costs in Rate STS, Supply Transmission Service

56 The AESO most recently provided the derivation of the regulated generating unit connection costs (“RGUCC”) charge in an attachment to the AESO’s response to information request AUC-AESO-009 in its 2014 ISO tariff application proceeding.[30] That attachment included a calculation of the RGUCC charge for each calendar year to 2020, based on the original determinations of the Alberta Energy and Utilities Board (referred to below) which established the RGUCC. In general, RGUCC charges decrease every year reflecting the on-going amortization of connection costs over the lives of the previously-regulated generating units.

57 The RGUCC charge calculation was reviewed in Decision 2007-106 in connection with the AESO’s 2007 general tariff application, where the Alberta Energy and Utilities Board stated that “The Board has reviewed this calculation and considers the AESO RGUCC appears to be reasonable.”[31] A value of \$75.28/MW was included for the 2018 RGUCC in the attachment to the response to information request AUC-AESO-009 in the AESO’s 2014 ISO tariff application proceeding.

58 The regulated generating unit connection cost charge has accordingly been updated to \$75.00/MW in Rate STS in the proposed 2018 ISO tariff included as Appendix E to this application, being the 2018 value rounded to the nearest dollar.

3.1.4 Rider J, Wind Forecasting Service Cost Recovery Rider

59 As the AESO explained in its 2014 ISO tariff application, Rider J, *Wind Forecasting Service Cost Recovery Rider*, charges 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.[32] Since first being implemented in 2011, Rider J is expected to recover in 2018 all costs of the contracted wind forecasting service incurred to date.

[30] Exhibit 0109.03.AESO-2718, Attachment AUC-AESO-009.
[31] Decision 2007-106, Alberta Electric System Operator 2007 General Tariff Application, issued December 21, 2007, at page 76.
[32] Exhibit 0026.00.AESO-2718, at paras 124-126.

60 On a cumulative forecast basis, the AESO will undercollect $59,063 by the end of 2017. The wind forecasting service annual cost forecast for 2018 is $304,560. Annual wind powered generation metered energy forecast for 2017 is 4.1 million MWh, a decrease of about 0.2 million MWh from 2016. Annual wind power generation metered energy forecast for 2018 is approximately 4.1 million MWh which is the 2017 forecast amount. The AESO proposes to set the Rider J charge at $0.09/MWh.

61 The increase from $0.05/MWh in the currently approved 2017 ISO tariff to $0.09/MWh results from a combination of refunding the cumulative overcollection of $115.7 million at the end of 2015 and the decrease in expected 2017 forecast wind power generation metered energy from 2016. Table 3-2 below illustrates the changes from year to year to achieve approximately zero balance at the end of 2018.

Table 3-2 – Wind Forecasting Service Cumulative Balance

Line		Actual							Forecast	
No.	Description	2010	2011	2012	2013[1]	2014	2015	2016[2]	2017	2018
1	Contracted wind forecasting service ($000)	$300.3	$338.4	$338.4	$338.4	$304.6	$304.6	$304.6	$304.6	$304.6
2	Volumes (GWh)	-	1,228	2,555	3,245	4,830	4,093	4,301	4,121	4,121
3	Rider J Charge ($/MWh)	-	0.13	0.14	0.15 / 0.12	0.12	0.12	0.06 / 0.05	0.05	0.09
4	Revenue ($000)	-	159.6	357.7	452.2	579.7	491.1	228.3	206.0	370.9
5	Annual (undercollection) / overcollection ($000)	(300.2)	(178.8)	19.3	113.8	275.1	186.6	(76.3)	(98.5)	66.4
6	Cumulative Balance ($000)	(300.2)	(479.1)	(459.8)	(346.0)	(70.9)	115.7	39.4	(59.0)	7.3

[1] Rider J charge in 2013 was $0.15/MWh for January 1 to September 30 and $0.12/MWh for October 1 to December 31.

[2] Rider J charge in 2016 was $0.16/MWh for January 1 to March 31 and $0.05/MWh for April 1 to December 31.

62 The Rider J charge will increase accordingly to $0.09/MWh in the proposed 2018 ISO tariff included in Appendix E to this application. The AESO will continue to monitor and report this amount in future tariff applications and updates.

3.2 2018 Forecast Billing Determinants

63 The rate calculations for the 2018 rates update are based on the AESO's forecast of billing determinants for 2018. The AESO prepares a long-term load forecast in accordance with the Act and the *Transmission Regulation*. The load forecast most recently prepared by the AESO is set out in the *AESO 2017 Long-term Outlook*, which contains a 2018 load forecast.

64 The *AESO 2017 Long-term Outlook* includes a 20-year peak load and electricity consumption forecast for Alberta. The load forecast is generated from economic growth (gross domestic product or GDP) information, oilsands production forecasts, and population projections by select consumer sectors, with regional adjustments based on historical results and participant-driven growth expectations. The *AESO 2017 Long-term Outlook*, including its data file, is available on the AESO website at www.aeso.ca by following the path Grid ▶ Forecasting.

65 Billing determinants are calculated using historical and year-to-date ratios between DTS Energy and each individual billing determinant listed below in Table 3-2. The billing determinants used in the 2018 rate calculations are also provided in Table C-12 of Appendix C to this application.

66 Additionally, Table 3-2 below provides a comparison of the forecast billing determinants in this tariff update to those forecast for 2017. Coincident metered demand and energy billing determinants for the 2018 forecast have increased by 4.5% and 3.8% respectively compared to the 2017 forecast billing determinants, while number of DTS market participants has decreased by 0.5%. Billing capacity (which incorporates non-coincident metered demand, demand ratchets, and contract minimums) has increased by 3.0%, with a 0.1% increase in the first demand tier, an increase of 2.4% in the second demand tier, an increase of 2.3% in the third demand tier and an increase of 5.0% in the last demand tier.

Table 3-3 – 2018 and 2017 Forecast Billing Determinants

Rate DTS Billing Determinant	Units	2018 Forecast	2017 Forecast	Increase (Decrease)	
				Amount	%
Coincident Metered Demand	MW-months	97,697.5	93,476.3	4,221.2	4.5%
Billing Capacity					
• Total Billing Capacity	MW-months	156,984.4	152,426.2	4,558.2	3.0%
• First (7.5×SF) MW	MW-months	36,498.4	36,455.7	42.7	0.1%
• Next (9.5×SF) MW	MW-months	34,526.1	33,717.9	808.2	2.4%
• Next (23×SF) MW	MW-months	43,063.7	42,113.0	950.7	2.3%
• All Remaining MW	MW-months	42,896.3	40,863.0	2,033.3	5.0%
Highest Metered Demand	MW-months	122,370.3	117,123.7	5,246.6	4.5%
Metered Energy (All Hours)	GWh	61,303	59,068	2,235	3.8%
DTS Market Participants	customer-months	5,309.0	5,337.9	(28.9)	(0.5%)
Pool Price	$/MWh	42.58	40.99	$1.59	3.9%
Average Increase/(Decrease) Weighted by Revenue					**3.6%**

67 To further examine the reasonableness of the 2018 forecast billing determinants, Table 3-3 below provides a comparison of the forecast billing determinants in this ISO tariff update application to the 2015 and 2016 recorded billing determinants and the 2017 forecast billing determinants. The AESO considers that the increase in billing determinants forecast for 2018 is reasonable when compared to recorded billing determinants for the two prior years, recorded billing determinants for January to September 2017, and expectations for 2018 as discussed at the beginning of this section.

Table 3-4 – 2018 and 2017 Forecast, 2017, 2016 and 2015 Recorded Billing Determinants

Rate DTS Billing Determinants	Units	2018 Forecast	2017 Forecast	Jan – Sep 2017 Recorded	2016 Recorded	2015 Recorded
Coincident Metered Demand	MW-months	97,697.5	93,476.3	70,505.6	92,106.8	93,932.1

Billing Capacity (Total)	MW-months	156,984.4	152,426.2	116,035.3	151,547.8	150,192.2
Highest Metered Demand	MW-months	122,370.3	117,123.7	89,645.9	115,515.2	117,088.4
Metered Energy (All Hours)	GWh	61,303	59,068	44,415	58,503	58,942
Market Participants (Total)	customer-months	5,309.0	5,337.9	3,963.6	5,262.6	5,237.1

68 Overall, the AESO considers that the 2018 forecast provides an accurate estimate of billing determinants for the rate calculations in this application.

3.3 Bill Impacts

69 As noted in section 2 of this application, the AESO's 2018 forecast revenue requirement represents a decrease of 1.3% from the total forecast costs for 2017.

70 At the same time, billing determinants have also changed from the 2017 forecast on which currently-approved rates are based. As a result, the AESO's 2018 updated rates represents an overall decrease of 5.1% from the 2017 rates currently in place, including a decrease of 4.2% to Rate DTS, *Demand Transmission Service*, and a decrease of 19.7% to Rate STS, *Supply Transmission Service*.

71 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 the timeliness and accompanying accuracy of the recovery of costs from market participants.

72 The decreases to the different components of Rate DTS are provided in Table 3-4 below. The Rate DTS decrease of 4.2% represents a revenue-weighted average decrease over all components of Rate DTS.

73 Individual decreases 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.

74 To allow individual market participants to estimate the impact of the 2018 rates on their own Rate DTS bills, the AESO has included a bill impact estimator as Table C-16 in the rate calculations included as Appendix C to this application. The bill impact estimator calculates bills for a given set of billing inputs under both the current 2017 Rate DTS and the updated 2018 Rate DTS, to allow the impact of the rates update on an individual service to be estimated.

Table 3-5 – Increase (Decrease) for 2018 Rate DTS Components

Rate DTS Charge	Unit	Proposed (1 Jan 2018)	Current (1 Jan 2017)	Increase (Decrease)
Bulk System				
• Coincident Demand	$/MW	$10,177.00	$10,670.00	(4.6%)
• Energy	$/MWh	$1.20	$1.25	(4.0%)
Local System				
• Billing Capacity	$/MW billing	$2,281.00	$2,356.00	(3.2%)

• Energy	$/MWh	$0.84	$0.87	(3.4%)
Point of Delivery				
• Participant × SF	$/month	$8,635.00	$8,789.00	(1.8%)
• First (7.5 × SF) MW BC	$/MW	$3,496.00	$3,559.00	(1.8%)
• Next (9.5 × SF) MW BC	$/MW	$2,190.00	$2,229.00	(1.7%)
• Next (23 × SF) MW BC	$/MW	$1,527.00	$1,555.00	(1.8%)
• Remaining MW BC	$/MW	$989.00	$1,007.00	(1.8%)
Operating Reserve	% of Pool Price	6.44%	6.99%	(7.9%)
Transmission Constraint Rebalancing Charge	$/MWh	$0.002	$0.07	(97.1%)
Voltage Control	$/MWh	$0.09	$0.07	28.6%
Other System Support	$/MW	$46.00	$46.00	--
Net Change (revenue weighted)				(4.2%)

75 The changes to the different components of Rate STS are provided in Table 3-5 below. The Rate STS decrease of 19.7% represents a revenue-weighted average decrease over all components of the rate.

76 Individual decreases or increases experienced by market participants will vary, depending on the specific characteristics of a market participant's system access service including whether it includes a previously-regulated generating unit subject to the regulated generating unit ("RGU") connection costs charge.

Table 3-6 – Increase (Decrease) for 2018 Rate STS Components

Rate STS Charge	Unit	Proposed (1 Jan 2018)	Current (1 Jan 2017)	Increase (Decrease)
Losses	% of Pool Price	3.57%	4.44%	(19.6%)
RGU Connection Costs	$/MW	$75.00	$95.00	(21.1%)
Net Change (revenue weighted)				(19.7%)

77 In particular, the AESO notes that the loss factors provided in Table 3-5 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*, as specified in Rate STS. Section 501.10 of the ISO rules was confirmed by the Commission in Decision 790-D05-2016[33] in Proceeding 790, although the AESO notes that the losses charge remains as approved on an interim basis in Commission Decision 2014-242.[34]

[33] Decision 790-D05-2016, *Milner Power Inc. and ATCO Power Ltd. Complaints Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology* issued November 30, 2016, at para 1.
[34] Decision 2014-242, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, issued August 21, 2014, para 730.

4 2018 Maximum Investment Levels Update

78 The tariff update approach described in section 1.1 of this application includes updating investment amounts approved in the most recent comprehensive tariff application reflecting an escalation factor based on a composite of specified recent inflation indices.

79 The AESO has accordingly updated the composite inflation index used for developing the point of delivery cost function to 2018, using additional Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta consumer price index. Table 4-1 below provides the composite inflation index values for 2014, 2015, 2016 and 2017, as included in the 2014 ISO tariff filing, 2015 ISO tariff update, 2016 ISO tariff update and the 2017 ISO tariff update, and for 2018 as updated in this application. Values prior to 2014 are excluded from Table 4-1 as they do not affect the escalation factor.

Table 4-1 – Escalation Factor for Composite Inflation Index

	Year	Basis	Present Value Factor
2014 Tariff Application	2014	Forecast	1.5727
2015 Tariff Update	2015	Forecast	1.5834
2016 Tariff Update	2016	Forecast	1.6201
2017 Tariff Update	2017	Forecast	1.6579
2018 Tariff Update	2018	Forecast	1.6230
2018 Escalation Factor (over 2014)	1.6230_{2018} / 1.5727_{2014} =		1.0320

80 The resulting escalation factor for updating the 2018 maximum investment levels in section 8 of the ISO tariff is 1.0320, which represents a small 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 D of this application.

81 The AESO has applied the resulting 1.0320 escalation factor to the 2014 Rate DTS maximum investment levels to determine the 2018 Rate DTS maximum investment levels, as summarized in Table 4-2 below. Table 4-2 also includes the calculation of the corresponding Rate PSC maximum investment levels for each year.

Table 4-2 – Calculation of 2018 Maximum Investment Levels

Tier	Rate DTS Investment	PSC Factor	Rate PSC Investment
2014 Maximum Investment Levels			
Substation fraction (for new points of delivery only)	$76 050/year	21%	$15 970/year
First (7.5 × substation fraction) MW of contract capacity	$30 800/MW/year	21%	$6 470/MW/year
Next (9.5 × substation fraction) MW of contract capacity	$19 300/MW/year	21%	$4 050/MW/year
Next (23 × substation fraction) MW of contract capacity	$13 450/MW/year	21%	$2 820/MW/year
All remaining MW of contract capacity	$8 700/MW/year	0%	$0/MW/year
2018 Escalation Factor (over 2014)	**1.0320**		
2018 Maximum Investment Levels			
Substation fraction (for new points of delivery only)	$78 500/year	21%	$16 480/year
First (7.5 × substation fraction) MW of contract capacity	$31 800/MW/year	21%	$6 680/MW/year
Next (9.5 × substation fraction) MW of contract capacity	$19 900/MW/year	21%	$4 180/MW/year
Next (23 × substation fraction) MW of contract capacity	$13 900/MW/year	21%	$2 920/MW/year
All remaining MW of contract capacity	$9 000/MW/year	0%	$0/MW/year

5 Conclusion

82 Based on all of the foregoing, the AESO submits that the tariff updates proposed in this application are just and reasonable, and comply with the update methodology approved by the Commission for the AESO's tariff. The AESO respectfully requests that the Commission approve this tariff update application, including (i) the updated amounts included as Appendix C to this application, and (ii) the proposed 2018 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J and Section 8 included as Appendix E to this application, effective January 1, 2018. If the timing of this application does not permit the granting of final approval prior to January 1, 2018, the AESO also requests that the Commission approve this application on an interim refundable basis effective as of that date. The AESO further requests that the Commission issue its approval (whether on an interim or final basis) on or before December 28, 2017, as this is the last approval date that will allow the proposed tariff updates to be implemented by the AESO effective January 1, 2018 on a prospective basis.

83 All of which is respectfully submitted this 27th day of October, 2017.

Alberta Electric System Operator

Per: *"Miranda Keating Erickson"*
Miranda Keating Erickson
Vice-President, Regulatory and External Affairs