Alberta Electric System Operator 2019 ISO tariff update

Date: November 6, 2018
Prepared by: Alberta Electric System Operator
Prepared for: Alberta Utilities Commission

Classification: Public

Alberta Electric System Operator, Calgary Place, 2500, 330 – 5th Avenue SW Calgary, AB T2P 0L4
Phone: 403-539-2450 Fax: 403-539-2949 www.aeso.ca @theaeso

Table of Contents

Tables

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 2019 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 2019 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 2018 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 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 tariff application was filed on September 14, 2017, and revised on August 17, 2018 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 27, 2017, by which the AESO sought approval from the Commission for the 2018 ISO tariff.[6] The Commission approved the current form of the 2018 ISO tariff, effective January 1, 2018, by way of Decision 23065-D01-2017[7] on a final basis. The 2018 ISO tariff approved in that decision reflected costs and billing determinants for the 2018 calendar year. The AESO is now filing this annual tariff update application to reflect costs and billing determinants for the 2019 calendar year.

[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 23065-D01-2017.

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 2019; (ii) rate, rider, and maximum investment level amounts using the rate calculation methodology already approved by the Commission in Decision 3473-D01-2015;[8] and (iii) the investment amounts first approved in Decision 3473-D01-2015,[9] updated in Decision 21302-D01-2016,[10] then updated in Decision 22093-D02-2017,[11] and then updated in Decision 23065-D01-2017,[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 2019 bulk system, regional system and point of delivery cost functionalization and classification as part of its 2018 ISO tariff application, filed on August 17, 2018 and currently being considered by the Commission in Proceeding 22942.[13] A supplementary 2019 ISO tariff update application may in the future be required, depending on the Commission's decision regarding the 2018 ISO tariff Application.

8 Additionally, the AESO is consulting with stakeholders on tariff design for bulk and regional costs and the AESO has been directed by the Commission to file an application regarding the results of this stakeholder consultation by the end of the first quarter of 2020.[14] Therefore, it is unlikely that a Commission decision will require a supplementary 2019 ISO tariff update application resulting from this consultation.

1.2 Organization

9 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 **2019 Forecast Revenue Requirement** — Summarizes the AESO's forecast revenue requirement for 2019, including costs that have been approved either 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 **2019 Tariff Update** — Discusses the calculation of rate levels based on the 2019 forecast revenue requirement, 2019 wires costs functionalization and classification approved in Commission Decision 2013-421,[15] and 2019 forecast billing determinants.

4 **2019 Maximum Investment Levels Update** — Discusses the calculation of 2019 maximum investment levels using the 2019 escalation factor.

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

10 This application also includes the following appendices:

A **AESO 2019 Business Plan and Budget Proposal** — Document prepared by AESO management in consultation with stakeholders, as proposed on October 31, 2018, containing the AESO's proposed

[8] See footnote 4.
[9] See footnote 4.
[10] See footnote 6.
[11] See footnote 7.
[12] See footnote 7.
[13] Exhibit 22942-X0163 at para 59
[14] Exhibit 22942-X0156 at para 67
[15] 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.

2019 business initiatives and proposed 2019 budgets and forecasts for ancillary services costs, transmission line losses costs, and administrative costs.

B **2019 Rate Calculations** — Microsoft Excel workbook which calculates the updated dollar and percentage of pool price amounts for the 2019 rates, based on the same methodology used for the AESO's currently approved rates.

C **2019 Escalation Factor and Investment Levels** — Microsoft Excel workbook which calculates the composite inflation index and escalation factor used to update maximum investment levels.

D **2019 Rates, Riders, and Section 8 of the ISO Tariff** — The proposed 2019 rates, riders, and section 8 that incorporate the 2019 updated amounts included as Appendices B and C to this application.

E **2019 Rates, Riders, and Section 8 of the ISO Tariff (blackline)** — The blackline version of the proposed 2019 rates, riders, and section 8 that incorporate the 2019 updated amounts included as Appendices B and C to this application.

1.3 Relief Requested

11 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 B to this application, and (ii) the proposed 2019 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 D to this application, which incorporates the updated amounts.

12 The AESO respectfully requests that this application be approved effective January 1, 2019. If the timing of this application does not permit the granting of final approval prior to January 1, 2019, 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, 2018 as this is the last approval date that will allow the AESO to implement the proposed tariff updates effective January 1, 2019 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,[16] 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.

[16] 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 2019 Forecast Revenue Requirement

13 The AESO's revenue requirement consists of costs related to wires, ancillary services, transmission line losses, and the AESO's own administration (which includes other industry costs and general and administrative costs). The AESO's forecast costs for 2019 are detailed in column A of Table 2-1. For comparison, Table 2-1 includes costs in the AESO 2019 Business Plan and Budget Proposal (Dated October 31, 2018) for 2019 (included as Appendix A to this application), updated forecast costs for 2018,[17] forecast costs for 2018,[18] and the updated forecast costs for 2017 and 2016, in columns B, C, D, and E, respectively.

Table 2-1 – 2019 Forecast, 2018 Updated Forecast, 2017 and 2016 Recorded Cost Components

Cost Component	2019 Forecast ($ 000 000) A	2018 Updated Forecast ($ 000 000) B	2018 Forecast ($ 000 000) C	2017 Updated Forecast ($ 000 000) D	2016 Recorded ($ 000 000) E
Wires	1,834.6	1,713.3	1,720.3	1,734.0	1,724.4
Ancillary services	313.8	179.2	179.2	118.9	93.2
Losses	126.1	96.8	96.8	74.1	41.3
Administrative	97.6	100.8	100.8	98.7	100.4
Revenue Requirement	**2,372.1**	**2,090.2**	**2,097.1**	**2,025.6**	**1,959.3**

Note: Numbers may not add due to rounding

14 The 2018 updated forecast costs (column B) represent a decrease of $6.9 million (or 0.3%) over the 2018 forecast costs (column C) included in the 2018 ISO tariff update application. The decrease results from a forecast decrease of $6.9 million (or 0.4%) in wires costs.

15 The 2019 forecast costs (column A) represent an increase of $275.0 million (or 13.1%) over the 2018 forecast costs (column C). The increase results from forecasted increase of $114.3 million (or 6.6%) in wires costs, $134.6 million (or 75.1%) in ancillary services costs, and $29.3 million (or 30.3%) in losses costs.

2.1 AESO Board Approval of Costs

16 The AESO is not seeking approval in this application of its 2019 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 *2019 Business Plan and Budget Proposal* dated October 31, 2018, included as Appendix A to this application.

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

18 (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 2019 Business Plan and Budget Proposal (Dated October 31, 2018) included as Appendix A to this application reflected TFO tariffs applied for or approved by the Commission at the time the AESO budget was prepared at the same time as this application, as discussed in more detail below.)

---

[17] 2018 Updated Forecast includes 2017 forecast costs and updated wires costs reflecting recent TFO filings, compliance filings and decisions for 2018.
[18] 2018 Forecast reflects amounts applied for in AESO's 2018 ISO tariff update application, approved in Decision 23065-D01-2017, issued April 28, 2017.

19 (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.

20 (c) Losses costs reflect recovery of the prudent costs of transmission line losses under subsection 30(4) of the 8ct.

21 (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*.

22 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.

23 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.

24 As part of the AESO Budget Review Process for its 2019 budget, AESO management consulted with stakeholders in a planning process that had been first established with stakeholders in 2005. AESO management proposed the *2019 Business Plan and Budget Proposal* to the AESO Board on October 31, 2018. This document (included as Appendix A 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 2019. The *2019 Business Plan and Budget Proposal* was also provided to stakeholders and posted on the AESO website.

25 The AESO's 2019 forecast ancillary services, losses and administrative costs are not approved at the time of this application, though approval by the AESO Board is expected in December 2018. The Budget Review Process moved through the first round of consultation with preliminary 2019 forecasts costs provided to stakeholders on October 10, 2018. The AESO, as described in Appendix L of the AESO's 2018 ISO tariff application[19], early tariff update applications are required to reduce amounts collected through Rider C, Deferral Account Reconciliation Rider, and to reduce deferral account reconciliation balances. As wires costs are approximately 80% of the total revenue requirement to be collected through the ISO tariff, timely ISO tariff update applications are required to minimize deferral account reconciliation balances.

26 The AESO proposes to notify the Commission in December 2018 within this proceeding after the Budget Review Process is complete and the AESO board has approved the *2019 Business Plan and Budget Proposal* along with any differences between from the costs proposed in this application and those approved by the AESO Board.

[19] Exhibit X0008, paras 28-32

27 Additional information on the AESO's business priorities and budget for 2019 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 ▶ 2019.

2.2 Wires Costs

28 The 2019 forecast costs for wires are $1,834.6 million and represent approximately 77.0% of the AESO's transmission revenue requirement. Wires costs include primarily wires-related costs of TFOs as well as two small non-wires costs.

29 The AESO has determined the 2019 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,[20] approved in Decision 2010-606, referred to in Decision 2014-242[21] and updated in Decision 22093-D02-2017:[22]

> *(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.*

30 As discussed in greater detail below, applications have been filed for several 2019 TFO tariffs. Therefore, in accordance with the foregoing approach, the AESO has forecast the 2019 wires costs in Table 2-1 to reflect these approvals and applications.

31 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

---

[20] 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.
[21] Decision 2014-242, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, issued August 21, 2014, at para 43.
[22] Decision 22093-D02-2017 at para 37.

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]

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

[23] Exhibit 0026.00.AESO-2718, at para 58.

Table 2-2 – AESO 2019 Forecast Revenue Requirement ($ 000 000)

Line No.	Description	2019 Forecast A	2018 Updated Forecast B	2018 Forecast C	2017 Updated Forecast D	2016 Recorded E
	WIRES					
	TFO Wires-Related Costs					
1	AltaLink	875.6	887.8	892.1	866.2	834.1
2	ATCO Electric	692.3	619.7	625.4	664.8	690.7
3	Isolated Generation	(4.1)	(3.1)	(3.1)	(1.7)	(1.3)
4	Subtotal ATCO Costs	688.1	616.6	622.3	663.1	689.4
5	ENMAX Power Corporation	81.2	81.2	80.1	79.7	74.8
6	EPCOR Distribution & Transmission	106.2	100.0	99.3	98.6	100.0
7	City of Lethbridge	7.1	7.1	7.1	7.1	6.3
8	TransAlta Utilities Corporation	6.7	6.1	4.9	4.9	6.1
9	City of Red Deer	4.9	4.3	4.3	4.3	3.9
10	FortisAlberta (Farm Transmission)	4.7	4.7	4.7	4.7	4.8
11	Alberta PowerLine	55.4	-	-	-	-
12	**Subtotal TFO Wires-Related Costs**	**1,830.0**	**1,728.6**	**1,723.9**	**1,706.3**	**1,561.5**
	Non-Wires Costs					
13	Invitation to Bid on Credits (IBOC)	2.1	1.9	1.9	1.9	1.8
14	Location Based Credit Standing Offer (LBC SO)	2.5	3.5	3.5	3.5	3.2
15	**Subtotal IBOC/LBC SO Costs**	**4.6**	**5.4**	**5.4**	**5.4**	**5.0**
16	**TOTAL WIRES COSTS**	**1,834.6**	**1,713.3**	**1,720.3**	**1,734.0**	**1,724.4**
	ANCILLARY SERVICES					
	Operating Reserves					
	Active					
17	Regulating	68.5	37.6	37.6	21.3	29.4
18	Spinning	102.7	55.7	55.7	33.8	16.1
19	Supplemental	68.0	32.2	32.2	13.7	7.2
20	**Subtotal Active Reserves**	**239.2**	**125.5**	**125.5**	**68.8**	**52.6**
	Standby					
21	Regulating	7.1	4.6	4.6	5.2	8.1
22	Spinning	18.3	12.9	12.9	11.2	4.8
23	Supplemental	9.0	4.9	4.9	3.4	1.2
24	**Subtotal Standby Reserves**	**34.4**	**22.4**	**22.4**	**19.8**	**14.1**
25	Trading Fees and Other Related Charges	(3.0)	(1.2)	(1.2)	(0.5)	(0.3)
26	**Subtotal Operating Reserves**	**270.6**	**146.6**	**146.6**	**88.2**	**66.4**
	Other Ancillary Services					
27	Black Start	2.3	4.3	4.3	2.1	2.1
28	Transmission Must Run (TMR)	3.4	5.3	5.3	4.8	0.7
29	Load Shed Service for Imports (LSSi)	32.8	17.3	17.3	18.1	18.2
30	Reliability Services from BC	2.9	2.9	2.9	2.9	2.9
31	Transmission Constraint Rebalancing (TCR)	0.1	0.1	0.1	0.1	0.0
32	Poplar Hill	1.7	2.8	2.8	2.8	2.8
33	Interruptible Load Remedial Action Scheme (ILRAS)	-	-	-	-	-
34	Generator Load Remedial Action Scheme	-	-	-	-	-
35	**Subtotal Other Ancillary Services**	**43.2**	**32.6**	**32.6**	**30.7**	**26.8**
36	**TOTAL ANCILLARY SERVICES**	**313.8**	**179.2**	**179.2**	**118.9**	**93.2**

Table 2-2 – AESO 2019 Forecast Revenue Requirement ($ 000 000) (continued)

Line No.	Description	2019 Forecast A	2018 Forecast Budget B	2018 Updated Forecast C	2017 Updated Forecast D	2016 Recorded E
	LOSSES					
37	Pool Payment	126.1	96.8	96.8	74.1	41.3
38	**TOTAL LOSSES COSTS**	**126.1**	**96.8**	**96.8**	**74.1**	**41.3**
	OTHER INDUSTRY COSTS					
39	Regulatory Process Costs	0.9	0.5	0.5	0.8	0.4
40	Western Electricity Coordination Council (WECC)	2.4	2.2	2.2	2.2	2.4
41	Share of Commission Costs	12.2	12.8	12.8	12.6	12.1
42	**TOTAL OTHER INDUSTRY COSTS**	**15.5**	**15.5**	**15.5**	**15.6**	**14.9**
	GENERAL AND ADMINISTRATIVE COSTS					
	Administrative Costs					
43	Staff and Benefits	44.4	49.0	49.0	47.7	49.4
44	Contract Services and Consultants	5.7	4.4	4.4	5.9	4.9
45	Administration	2.4	3.2	3.2	3.0	3.2
46	Facilities	5.5	5.4	5.4	5.2	5.1
47	Computer and Telecom Services and Maintenance	8.2	8.6	8.6	8.3	7.3
48	**Subtotal Administrative Costs**	**65.8**	**70.6**	**70.6**	**70.1**	**69.9**
	General Costs					
49	Market System Replacement	-	-	-	-	-
50	Interest	0.7	0.7	0.7	0.3	0.1
51	Amortization and Depreciation	15.6	14.1	14.1	12.7	15.5
52	**Subtotal General Costs**	**16.3**	**14.8**	**14.8**	**13.0**	**15.6**
53	**TOTAL G&A COSTS**	**82.1**	**85.4**	**85.4**	**83.1**	**85.5**
54	**TOTAL G&A AND OTHER INDUSTRY COSTS**	**97.6**	**100.8**	**100.8**	**98.7**	**100.4**
55	**TOTAL REVENUE REQUIREMENT**	**2,372.1**	**2,090.2**	**2,067.1**	**2,025.6**	**1,959.3**

Notes: Totals may not add due to rounding

33 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.

34 AltaLink has filed for approval of $870.8 million to the Commission for approval of 2019 TFO tariff costs. AltaLink received final approval of 2018 TFO tariff costs of $887.8 million in Decision 23074-D01-2017. The AESO has included 72% of the applied for decrease of $17.0 million and has accordingly included $875.6 million as the forecast TFO tariff costs for AltaLink for 2019.

Lines 2-4 ATCO Electric Ltd.

35 ATCO Electric filed for approval of $699.5 million to the Commission for approval of 2019 TFO tariff costs. 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 included 72% of the applied for increase of $26.0 million and has accordingly included $692.3 million as the forecast TFO tariff costs for ATCO Electric for 2019.

36 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 $4.1 million for 2019, based on 2017 and 2018 recorded volumes for isolated communities and the 2019 forecast pool price.

37 The 2019 net forecast TFO tariff costs for ATCO Electric are $688.1 million.

Line 5 ENMAX Power Corporation

38 ENMAX has not yet applied to the Commission for approval of 2019 TFO tariff costs but has initiated a proceeding for their 2018-2020 general tariff application[24] with no filed exhibits to date. ENMAX received final approval of 2017 TFO tariff costs of $81.2 million in Decision 23315-D01-2018. The AESO has accordingly included $81.2 million as the forecast TFO tariff costs for ENMAX for 2019.

Line 6 EPCOR Distribution & Transmission Inc.

39 EPCOR has filed for approval of $108.8 million to the Commission for approval of 2019 TFO tariff costs. EPCOR received final approval of 2017 TFO tariff costs of $99.3 million in Decision 22163-D01-2016. The AESO has included 72% of the applied for increase of $9.5 million and has accordingly included $106.2 million as the forecast TFO tariff costs for EPCOR for 2019.

Line 7 City of Lethbridge

40 The City of Lethbridge has not yet applied to the Commission for approval of 2019 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 City of Lethbridge has applied to the Commission for 2018 TFO tariff costs of $7.1 million on an interim basis.The AESO has accordingly included $7.1 million as the forecast TFO tariff costs for City of Lethbridge for 2019.

Line 8 TransAlta Corporation

41 TransAlta has not yet applied to the Commission for approval of 2019 TFO tariff costs. TransAlta applied for approval of 2018 TFO tariff costs of $7.0 million. TransAlta received final approval for 2016 TFO tariff costs of $6.1 million in Decision 23175-D01-2017. The AESO has included 72% of the applied for increase of $0.9 million and has accordingly included $6.7 million as the forecast TFO tariff costs for TransAlta for 2019.

Line 9 City of Red Deer

42 The City of Red Deer has filed for approval of $5.1 million to the Commission for approval of 2019 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 included 72% of the applied for increase of $0.8 million and has accordingly included $4.9 million as the forecast TFO tariff costs for City of Red Deer for 2019.

Line 10 FortisAlberta Inc. (Farm Transmission)

43 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 filed for approval of $4.8 million to the Commission for approval of 2019 farm transmission costs. FortisAlberta received final approval for 2017 farm transmission costs of $4.7 million in Decision 21980-D01-2016. The AESO has included 72% of the applied for increase of $0.1 million and has accordingly included $4.7 million as the forecast TFO tariff costs for FortisAlberta for 2019.

[24] Proceeding 23966

Line 11 Alberta PowerLine

44 Decision 23161-D01-2018, issued on January 28, 2018, considered the project agreement between the AESO and Alberta PowerLine L.P. ("Alberta PowerLine") for the Fort McMurray West 500-kilovolt (kV) Transmission ("WFMAC") project to be prudent. The anticipated energization date for the WFMAC project is June 2019. The AESO has accordingly included the first seven monthly payments identified in Schedule 11 of the application[25] in Proceeding 23161 as 2019 wires costs for Alberta PowerLine.

Lines 13-15 Non-Wires Costs

45 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 $4.6 million cost for the two programs was forecast by the AESO in conjunction with ancillary services costs and included in the AESO *2019 Business Plan and Budget Proposal* (Dated October 31, 2018) included as Appendix A to this application.

2.3 Ancillary Services Costs

46 The forecast 2019 costs for ancillary services are $313.8 million and represent approximately 13% 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.[26]

47 Ancillary services costs are primarily a function of volume forecasts and market-based commodity pricing forecasts. The 2019 forecast costs for ancillary services were based on a forecast average pool price of $57.52/MWh.

2.4 Losses Costs

48 The 2019 forecast costs for transmission line losses are $126.1 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.

49 Losses costs are a function of volume forecasts and market-based commodity pricing forecasts. The 2019 forecast costs for losses were based on a forecast average pool price of $57.52/MWh.

---

[25] Proceeding 23161,X0001
[26] AESO Consolidated Authoritative Document Glossary

2.5 Administrative Costs

50 The 2019 forecast cost for administration is $97.6 million and represents approximately 4% of the AESO's transmission revenue requirement.

51 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;*

52 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 *2019 Business Plan and Budget Proposal* (Dated October 31, 2018) provided as Appendix A to this application[27] 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.

[27] Appendix A, AESO 2019 Business Plan and Budget Proposal (Dated October 31, 2018), page 7 of 96.

3 2019 Tariff Update

53 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[28] 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[29] as the template for the 2018 rate calculations, updated to reflect the transmission constraint rebalancing charge approved in Decision 20623-D01-2015[30]. The 2018 rate calculations are included as Appendix B to this application, in Tables B-1 through B-16.

54 The rate calculations use the following inputs:

(a) the 2019 forecast revenue requirement discussed in section 2 of this application;

(b) the functionalization of wires costs approved for 2016 in Decision 2013-421;[31] and

(c) the 2019 forecast billing determinants prepared by the AESO.

3.1 Specific Rate Changes

55 Where applicable, rates in the ISO tariff have been updated to reflect the 2019 forecast revenue requirement, 2019 wires costs functionalization, and 2019 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*.

56 The levels for each of the above rates have been calculated in accordance with Appendix B to this application. The updated rate sheets themselves are provided in the proposed 2019 ISO tariff included as Appendix D to this application.

57 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

58 Consistent with the calculation of the 2014 primary service credit, the 2019 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.

59 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

---

[28] See footnote 1.
[29] 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.
[30] See footnote 2.
[31] Proceeding 2718, Exhibit 0265.02.AESO-2718, Alberta Transmission System Cost Causation Study Update dated January 17, 2014, at page 7, Figure 6.

determined in Table 3-1 are reflected in Rate PSC of the proposed 2019 ISO tariff included in Appendix D to this application.

Table 3-1 – Calculation of 2019 Primary Service Credit

Rate Component	Rate DTS Charge	PSC Factor	Rate PSC Credit
Substation fraction	$9,062.00/month	79%	$7,159.00/month
First (7.5 × substation fraction) MW of billing capacity	$3,669.00/MW	79%	$2,899.00/MW
Next (9.5 × substation fraction) MW of billing capacity	$2,298.00/MW	79%	$1,815.00/MW
Next (23 × substation fraction) MW of billing capacity	$1,603.00/MW	79%	$1,266.00/MW
All remaining MW of billing capacity	$1,038.00/MW	100%	$1,038.00/MW

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

60 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.[32] 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.

61 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."[33] A value of $45.17/MW was included for the 2019 RGUCC in the attachment to the response to information request AUC-AESO-009 in the AESO's 2014 ISO tariff application proceeding.

62 The regulated generating unit connection cost charge has accordingly been updated to $45.00/MW in Rate STS in the proposed 2019 ISO tariff included as Appendix D to this application, being the 2019 value rounded to the nearest dollar.

3.1.4 Rider J, Wind Forecasting Service Cost Recovery Rider

63 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.[34] Since first being implemented in 2011, Rider J is expected to recover in 2019 all costs of the contracted wind forecasting service incurred to date.

64 On a cumulative forecast basis, the AESO will undercollect $41,704 by the end of 2018. The wind forecasting service annual cost forecast for 2019 is $304,560. Annual wind powered generation metered energy forecast for 2018 is 4.2 million MWh, a decrease of about 0.2 million MWh from 2017. Annual wind power generation

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

metered energy forecast for 2019 is approximately 4.2 million MWh which is the 2018 forecast amount. The AESO proposes to set the Rider J charge at $0.08/MWh.

65 The decrease from $0.09/MWh in the currently approved 2018 ISO tariff to $0.08/MWh results from the increase in expected 2018 forecast wind power generation metered energy. 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	2017	2018	2019
1	Contracted wind forecasting service ($000)	$300.3	$338.4	$338.4	$338.4	$304.6	$304.6	$304.6	$304.6	$304.6	$304.6
2	Volumes (GWh)	-	1,228	2,555	3,245	4,830	4,830	4,093	4,301	4,121	4,121
3	Rider J Charge ($/MWh)	-	0.13	0.14	0.15 / 0.12	0.12	0.12	0.06 / 0.05	0.05	0.09	0.08
4	Revenue ($000)	-	159.6	357.7	452.2	579.7	491.1	228.3	218.7	309.3	379.0
5	Annual (undercollection) / overcollection ($000)	(300.2)	(178.8)	19.3	113.8	275.1	186.6	(76.3)	(85.9)	4.7	32.3
6	**Cumulative Balance ($000)**	**(300.2)**	**(479.1)**	**(459.8)**	**(346.0)**	**(70.9)**	**115.7**	**39.4**	**(46.4)**	**(41.7)**	**(9.4)**

[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.

66 The Rider J charge will decrease accordingly to $0.08/MWh in the proposed 2019 ISO tariff included in Appendix D to this application. The AESO will continue to monitor and report this amount in future tariff applications and updates.

3.2 2019 Forecast Billing Determinants

67 The rate calculations for the 2019 rates update are based on the AESO’s forecast of billing determinants for 2019. 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 2019 load forecast.

68 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.

69 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 2019 rate calculations are also provided in Table B-12 of Appendix B to this application.

70 Additionally, Table 3-2 below provides a comparison of the forecast billing determinants in this tariff update to those forecast for 2018. Coincident metered demand and energy billing determinants for the 2019 forecast have increased by 2.9% and 2.0% respectively compared to the 2018 forecast billing determinants, while number of DTS market participants has decreased by 0.4%. Billing capacity (which incorporates

non-coincident metered demand, demand ratchets, and contract minimums) has increased by 2.9%, with a 0.2% increase in the first demand tier, an increase of 0.4% in the second demand tier, an increase of 1.3% in the third demand tier and an increase of 8.9% in the last demand tier.

Table 3-3 – 2019 and 2018 Forecast Billing Determinants

Rate DTS Billing Determinant	Units	2019 Forecast	2018 Forecast	Increase (Decrease)	
				Amount	%
Coincident Metered Demand	MW-months	100,531.6	97,697.5	4,221.2	2.9%
Billing Capacity					
• Total Billing Capacity	MW-months	161,544.6	156,984.4	4,558.2	2.9%
• First (7.5×SF) MW	MW-months	36,579.6	36,498.4	42.7	0.2%
• Next (9.5×SF) MW	MW-months	34,660.6	34,526.1	808.2	0.4%
• Next (23×SF) MW	MW-months	43,602.7	43,063.7	950.7	1.3%
• All Remaining MW	MW-months	46,701.7	42,896.3	2,033.3	8.9%
Highest Metered Demand	MW-months	127,416.5	122,370.3	5,246.6	4.1%
Metered Energy (All Hours)	GWh	62,524	61,303	2,235	2.0%
DTS Market Participants	customer-months	5,289.0	5,309.0	(28.9)	(0.4%)
Pool Price	$/MWh	57.52	42.58	$1.59	35.1%
Average Increase/(Decrease) Weighted by Revenue					**2.5%**

71 To further examine the reasonableness of the 2019 forecast billing determinants, Table 3-3 below provides a comparison of the forecast billing determinants in this ISO tariff update application to the 2016 and 2017 recorded billing determinants and the 2018 forecast billing determinants. The AESO considers that the increase in billing determinants forecast for 2019 is reasonable when compared to recorded billing determinants for the two prior years, recorded billing determinants for January to August 2018, and expectations for 2019 as discussed at the beginning of this section.

Table 3-4 – 2019 and 2018 Forecast, 2018, 2017 and 2016 Recorded Billing Determinants

Rate DTS Billing Determinants	Units	2019 Forecast	2018 Forecast	Jan – Aug 2018 Recorded	2017 Recorded	2016 Recorded
Coincident Metered Demand	MW-months	100,531.6	97,697.5	64,930.1	94,486.6	92,111.9
Billing Capacity (Total)	MW-months	161,544.6	156,984.4	105,324.2	155,274.4	151,464.1
Highest Metered Demand	MW-months	127,416.5	122,370.3	82,138.0	120,536.9	115,502.5
Metered Energy (All Hours)	GWh	62,524	61,303	40,657	60,010	58,504
Market Participants (Total)	customer-months	5,289.0	5,309.0	3,524.4	5,283.2	5,255.7

72 Overall, the AESO considers that the 2019 forecast provides an accurate estimate of billing determinants for the rate calculations in this application.

3.3 Bill Impacts

73 As noted in section 2 of this application, the AESO's 2019 forecast revenue requirement represents an increase of 13.1% from the 2018 forecast revenue requirement.

74 At the same time, billing determinants have also changed from the 2018 forecast on which currently-approved rates are based. As a result, the AESO's 2019 updated rates represents an overall increase of 5.7% from the 2018 rates currently in place, including an increase of 6.7% to Rate DTS, *Demand Transmission Service*, and a decrease of 9.7% to Rate STS, *Supply Transmission Service*.

75 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.

76 The decreases to the different components of Rate DTS are provided in Table 3-4 below. The Rate DTS increase of 6.7% represents a revenue-weighted average decrease over all components of Rate DTS.

77 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.

Table 3-5 – Increase (Decrease) for 2019 Rate DTS Components

Rate DTS Charge	Unit	Proposed (1 Jan 2019)	Current (1 Jan 2018)	Increase (Decrease)
Bulk System				
• Coincident Demand	$/MW	$10,524.00	$10,177.00	3.4%
• Energy	$/MWh	$1.26	$1.20	5.0%
Local System				
• Billing Capacity	$/MW billing	$2,359.00	$2,281.00	3.4%
• Energy	$/MWh	$0.87	$0.84	3.6%
Point of Delivery				
• Participant × SF	$/month	$9,062.00	$8,635.00	4.9%
• First (7.5 × SF) MW BC	$/MW	$3,669.00	$3,496.00	4.9%
• Next (9.5 × SF) MW BC	$/MW	$2,298.00	$2,190.00	4.9%
• Next (23 × SF) MW BC	$/MW	$1,603.00	$1,527.00	5.0%
• Remaining MW BC	$/MW	$1,038.00	$989.00	5.0%
Operating Reserve	% of Pool Price	8.50%	6.44%	32.0%
Transmission Constraint Rebalancing Charge	$/MWh	$0.002	$0.002	0.0%
Voltage Control	$/MWh	$0.05	$0.09	(44.4%)
Other System Support	$/MW	$36.00	$46.00	(21.7%)
Net Change (revenue weighted)				**6.7%**

78 To allow individual market participants to estimate the impact of the 2019 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 2018 Rate DTS and the updated 2019 Rate DTS, to allow the impact of the rates update on an individual service to be estimated.

79 The changes to the different components of Rate STS are provided in Table 3-5 below. The Rate STS decrease of 9.7% represents a revenue-weighted average decrease over all components of the rate.

80 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 2019 Rate STS Components

Rate STS Charge	Unit	Proposed (1 Jan 2019)	Current (1 Jan 2018)	Increase (Decrease)
Losses	% of Pool Price	3.26%	3.57%	(8.7%)
RGU Connection Costs	$/MW	$45.00	$75.00	(40.0%)
Net Change (revenue weighted)				**(9.7%)**

81 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[35] in Proceeding 790, although the AESO notes that the losses charge remains as approved on an interim basis in Commission Decision 2014-242.[36]

[35] 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.
[36] Decision 2014-242, Alberta Electric System Operator 2014 ISO Tariff Application and 2013 ISO Tariff Update, issued August 21, 2014, para 730.

4 2019 Maximum Investment Levels Update

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

83 The AESO has accordingly updated the composite inflation index used for developing the point of delivery cost function to 2019, 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, 2017 and 2018, as included in the 2014 ISO tariff filing, 2015 ISO tariff update, 2016 ISO tariff update, 2017 ISO tariff update and the 2018 ISO tariff update, and for 2019 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	1.6579
2019 Tariff Update	2019	Forecast	1.6518
2019 Escalation Factor (over 2014)	1.6518_{2019} / 1.5727_{2014} =		1.0503

84 The resulting escalation factor for updating the 2019 maximum investment levels in section 8 of the ISO tariff is 1.0503, which represents an increase to the 2019 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.

85 The AESO has applied the resulting 1.0503 escalation factor to the 2014 Rate DTS maximum investment levels to determine the 2019 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 2019 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
2019 Escalation Factor (over 2014)	**1.0503**		
2019 Maximum Investment Levels			
Substation fraction (for new points of delivery only)	$79 900/year	21%	$16 780/year
First (7.5 × substation fraction) MW of contract capacity	$32 350/MW/year	21%	$6 790/MW/year
Next (9.5 × substation fraction) MW of contract capacity	$20 250/MW/year	21%	$4 250/MW/year
Next (23 × substation fraction) MW of contract capacity	$14 150/MW/year	21%	$2 970/MW/year
All remaining MW of contract capacity	$9 150/MW/year	0%	$0/MW/year

5 Conclusion

86 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 B to this application, and (ii) the proposed 2019 ISO tariff Rate DTS, Rate FTS, Rate DOS, Rate XOS, Rate XOM, Rate PSC, Rate STS, Rider J and Section 8 included as Appendix D to this application, effective January 1, 2019. If the timing of this application does not permit the granting of final approval prior to January 1, 2019, 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, 2018, as this is the last approval date that will allow the proposed tariff updates to be implemented by the AESO effective January 1, 2019 on a prospective basis.

87 All of which is respectfully submitted this 6th day of November, 2018.

Alberta Electric System Operator

Per: *"Miranda Keating Erickson"*
Miranda Keating Erickson
Vice-President, Markets