Alberta Utilities Commission

Milner Power Inc.

Complaints Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology

ATCO Power Ltd.

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Phase 2 Module C

December 18, 2017

Alberta Utilities Commission
Decision 790-D06-2017
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1 Introduction and background

1. In this decision, the Alberta Utilities Commission approves a methodology for the calculation of final loss factors, for the period between January 1, 2006 and December 31, 2016 (the historical period). The Commission also determines to whom revised invoices for line loss charges or credits for the historical period are to be issued.

2. For the reasons set out below, the Commission approves the Modified Module B methodology for calculating loss factors for the historical period. The Commission directs the Alberta Electric System Operator (AESO) to re-issue invoices for loss charges or credits to those parties that held Supply Transmission Service (STS) contracts when the charges or credits were first incurred.

1.1 Line losses and calculating loss factors

3. When electricity generated by a power plant (generating unit) is transmitted across a transmission line, not all of that electricity will reach consumers (load). Some of it will be lost as heat along the way. The difference between the amount of energy put onto the system and the lesser amount of energy ultimately received for consumption is referred to as transmission line losses (line losses). In Alberta, the owner of the generating unit that produced the electricity, or the owner of the output of that generating unit through a Power Purchase Arrangement (PPA), pays the cost of this lost energy.

4. The AESO manages and recovers the costs of line losses from the owners of generating units through its tariff. While the AESO can accurately measure system-wide losses sustained over time, assigning or attributing those losses to individual generating units on a cost causal basis is a challenging and complex task. This is because line losses for each generating unit are influenced by a number of related factors, including: the amount of electricity produced by all other generating units, their locations relative to load and to each other, the amount of load on the system at any time, and the capacity of the transmission line(s) linking generating units to the rest of the system.[1]

[1] Decision 2012-104: Milner Power Inc., Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss, Factor Methodology, Application 1606494, Proceeding 790 April 16, 2012, pages 4-9.

5. While some electricity produced by every generating unit is lost in transit, some generating units are responsible for more line losses than other generating units. The following simple example illustrates this. A new generating unit is built within five kilometres of a large load centre and it produces enough electricity to serve the centre's needs. Before the new generating unit was built, the closest generating unit serving the centre was located 200 kilometres away. The new generator has two separate but related effects on line losses. First, because the new generating unit is located very close to the centre, relatively little energy is lost on the short transmission line between the generating unit and the centre. Second, because the centre is now served by the new generating unit, the line losses associated with transmitting electricity for 200 kilometres from the next closest generator are avoided. In this example, the avoided line losses (savings) far exceed the new generator's line losses, with the result that overall system line losses are now lower.

6. The challenge facing the AESO in recovering the costs of line losses is to ensure that the line loss costs paid by each generating unit reasonably reflect the losses caused by or avoided (saved), by each unit. To address this complex problem, the AESO uses a methodology (or model) to determine line losses for each generating unit rather than attempting to physically measure line losses for each unit. The methodology generates a loss factor for each unit. That loss factor, in turn, is used to determine whether a generating unit adds to or reduces system-wide losses on a net basis. Generating units that cause losses on a net basis are issued an invoice whereas generating units that reduce (i.e., save or avoid) losses are given credits.

1.2 The unlawful line loss rule

7. The genesis of this proceeding dates to 2005 when the AESO proposed a new methodology for calculating line losses. The following is a very brief summary of the events since that time. To assist the reader, a full chronology can be found in Section 2 of AUC Decision 790-D02-2015,[2] and is reproduced in Appendix 3 of this decision.

8. In 2005, the AESO proposed to implement a new methodology for calculating loss factors in what became known as the "Line Loss Rule".[3] Milner Power Inc. (Milner) filed a complaint about the Line Loss Rule on the basis that it did not comply with certain sections of the *Transmission Regulation*. The Alberta Energy and Utilities Board (EUB), the Commission's predecessor, dismissed Milner's complaint, but that decision was successfully appealed to the Alberta Court of Appeal. The court directed the Commission to reconsider whether the Line Loss Rule contravened Section 19 (now Section 31) of the *Transmission Regulation*, as alleged by Milner.

9. The Commission set up a two-phase process to re-hear Milner's complaint: Phase 1 to consider if the Line Loss Rule contravened the *Transmission Regulation*, and Phase 2 (if necessary) to determine the remedy if a contravention was found. In Phase 1, a majority of the

[2] Decision 790-D02-2015: Milner Power Inc., Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, ATCO Power Ltd., Complaint regarding the ISO, Transmission Loss Factor Rule and Loss Factor Methodology, Applications 1606494, 1608563 and 1608709, Proceeding 790, January 20, 2015.

[3] All references to the 'Line Loss Rule' in this decision mean the rule that was in place as adjusted from time to time during the period from January 1, 2006 to December 31, 2016.

assigned panel found that the Line Loss Rule contravened Section 19 and upheld Milner's initial complaint as valid. An AUC review panel upheld that decision.[4]

10. The Commission decided to hear Phase 2 in three modules. In Module A, the Commission considered whether it could order a remedy to address unlawful payments made pursuant to the Line Loss Rule and concluded that it had the jurisdiction to make such an order.[5] The Commission also determined that the unlawful rates were interim.[6]

11. In Module B, the Commission heard proposals for a new line loss methodology to replace the Line Loss Rule, and ultimately approved a methodology for determining loss factors on a go forward basis starting on January 1, 2017, that became known as the Module B methodology.

12. In this, the final module (Module C) of this proceeding, the Commission is tasked with selecting what methodology should be used for determining loss factors for the historical period and deciding to whom the AESO must re-issue invoices (for charges or credits) for that period.

1.3 Request for delay

13. On November 13, 2017, a group of seven participants[7] in Proceeding 790 wrote to the Commission asking that the Commission delay the issuance of its decision in Module C to no later than January 9, 2018, to allow those participants and others to explore whether an agreement can be reached to settle outstanding issues in that proceeding. Powerex Corp. (Powerex), ENMAX Energy Corporation (ENMAX) and the AESO took no position on the request. The Balancing Pool and the Office of the Utilities Consumer Advocate (UCA) opposed the request.

14. After due consideration, the Commission decided to provide the requesting parties a reasonable period of time to conclude their negotiations, while also providing market participants with certainty as to when the issues in Module C would be resolved and advised that it would issue its decision on December 18, 2017.

1.4 Scope of the Module C proceeding

15. On August 8, 2014, the Commission directed that Phase 2 of Proceeding 790 be divided into three modules, with the purpose of Module C being to determine financial compensation and the parties entitled to receive or required to pay monetary compensation.[8]

16. On January 28, 2016, the Commission issued a Notice of Proceeding for Module C, and set a schedule to receive statements of intent to participate. The Commission also requested submissions and reply submissions from parties regarding the list of issues they considered it

[4] Decision 2014-110: April 16, 2014.
[5] Decision 790-D02-2015: January 20, 2015.
[6] Decision 790-D02-2015: January 20, 2015, paragraph 8.
[7] ATCO Power Canada Ltd., Capital Power Corporation, the City of Medicine Hat, Milner Power Inc., Suncor Energy Inc., TransAlta Corporation and TransCanada Energy Ltd. (the requesting parties).
[8] Exhibit 0524.01, AUC Letter re issues list and schedule for Phase 2, August 8, 2014.

necessary to resolve in Module C, their position regarding those issues, and the process they considered the Commission should follow to determine any relief or remedy to be granted.[9]

17. On April 21, 2016, the Commission ruled it would hear submissions from parties regarding several preliminary issues as outlined in the Commission's ruling, and set a schedule for submissions from parties regarding those matters.[10] This led the Commission to issue Decision 790-D04-2016 on September 28, 2016, regarding the preliminary matters in Module C.

18. On October 24, 2016, Powerex submitted a motion asking the Commission to set a process schedule for interested parties to advance methodologies for the calculation of line loss factors for the historical period. On November 9, 2016, Milner submitted a motion proposing a methodology for calculating line loss factors for the historical period and asked the Commission to adopt that methodology on an interim or final basis.

19. On December 1, 2016, the Commission issued its ruling on the Powerex and Milner motions. The Commission granted the Powerex motion in part and ruled that the issues raised in the Milner motion would be considered as part of the broader process for completing Module C. On December 20, 2016, the Commission held a round table meeting with parties to Proceeding 790 to discuss how to best address collection and payment issues, as well as to set a schedule for considering alternative methodologies to finalize line loss factors for the historical period.

20. In a letter dated August 8, 2014, the Commission held that the purpose of Module C was to determine the amounts of, and the parties entitled to receive or pay, financial compensation.[11] At the December 20, 2016 round table meeting, the AESO advised parties that it would invoice current STS contract holders for final line loss charges for the historical period, pursuant to the Independent System Operator (ISO) tariff. This raised the prospect that the parties that had previously been held responsible for line losses during the historical period might not be the parties receiving revised invoices from the AESO for final line loss charges. Several parties noted that separate, standalone legal contracts typically govern the terms and conditions of the purchase and sale of generating assets. As such, one would need to turn to these private contracts to determine who is ultimately responsible for paying the revised tariff rates: the vendor (or assignor) on the one hand, or the purchaser (or assignee) on the other.[12]

21. The Commission refined its description of the purpose of Module C on June 6, 2017:

> Specifically, in Module C, the Commission must decide, amongst other things, to which parties (and for what amounts) the AESO must issue revised invoices for line loss charges related to the historical period. In the Commission's view, the issue of who may ultimately be responsible for the payment of (or be entitled to the receipt of refunds for)

[9] Exhibit 790-X3000, AUC Notice of proceeding for Module C, January 28, 2016.
[10] Exhibit 790-X3028, AUC ruling on scope and process for Module C, April 21, 2016.
[11] Exhibit 0524.01, AUC Letter re issues list and schedule for Phase 2, August 8, 2014.
[12] Exhibit 790-X3132, 790 Technical Meeting Notes Dec 20 2016, January 23, 2017, page 26.

> those line loss charges is a different matter, and is not a question that it can or should determine in this proceeding.[13]

22. Accordingly, the primary questions for the Commission's determination in this decision, with respect to the historical period, are:

(a) Which methodology to apply to the historical period.

(b) Which parties should, at first instance, receive invoices for the final line loss rates.

(c) What should the process be for collection and payment of the amounts resulting from those final rates.

2 Which methodology to apply to the historical period

23. On January 25, 2017, the Commission issued a summary of the views expressed by attendees at the December 20, 2016 round table meeting regarding potential methodologies, and set a process for completing Module C. The Commission confirmed that only the following three methodologies were discussed at the round table meeting, and only these three would be considered further:

(a) The Milner methodology.

(b) The Old AESO methodology.

(c) The Modified Module B methodology.[14]

24. Each of those methodologies, and the parties' views regarding them, are summarized below. The AESO stated that it does not directly support or oppose any of the three methodologies.[15] It added, however, that it could implement any of these methodologies subject to certain qualifications, as discussed in more detail below.

2.1 The Milner methodology

25. The Milner methodology refers to the proposed method for calculating loss factors put forward by Milner on November 9, 2016, in exhibit 790-X3099. At paragraph 26 of that exhibit, Milner stated that its methodology:

- Uses an incremental loss factor (ILF) methodology for calculating raw loss factors using the Load Flow approach.
- Specifies the location of a 'generating facility,' as the location of each metering point identifier (MPID) for a generating unit or group of generating units.

[13] Exhibit 790-X3331, AUC ruling on TransAlta motion re Balancing Pool, June 6, 2017, paragraph 9.
[14] Exhibit 790-X3134, AUC ruling on Mod C process and schedule, January 25, 2017.
[15] Exhibit 790-X3441, AESO Argument, July 28, 2017, paragraph 6.

- Performs the ILF calculations by keeping load constant when a generation facility is (notionally) removed from the system and scaling up (i.e., notionally re-dispatching) other specific generation facilities to rebalance the system.
- Uses the actual energy market merit order data for each of the 8,760 hours of the year.
- Should be implementable across all loss factor customers in significantly less time than that which is currently estimated by the AESO to apply its Module B methodology for calculating loss factors going forward to the 2006 through 2016 period.

26. Milner stated that its methodology would use energy market merit order data from each of the 8,760 hours of the year, but would not perform a load flow analysis and loss factor calculations for each hour of the year. Milner stated that instead it proposed to analyze the 8,760 hours of energy market merit order data each year, and integrate the data into a form that could be utilized with the AESO's previous approach of using 12 loss factor base cases for each of the historical years.[16]

27. To integrate the data from each of the 8,760 hours into 12 base cases, Milner proposed to use a "generation replacement vector."[17] Milner submitted that a generation replacement vector would be used to determine what other generation should be dispatched when a generator was notionally removed in each of the 12 base cases in a given year.[18]

28. ATCO Power Canada Ltd. (ATCO Power) and Powerex supported the use of the Milner methodology. In its evidence, ATCO Power stated that "nothing in Milner's Proposed Methodology raises a concern that the resulting loss factors would not be representative or that they would be non-compliant with legislative requirements."[19] Powerex submitted that if the Milner methodology required no additional process relative to the Old AESO methodology, then the Milner methodology should be preferred because it best reflects the Commission's preference for adjusting the merit order instead of load.[20]

29. Milner submitted that it considers all three of the methodologies to be legally compliant and suitable for the purposes of estimating historical differences in loss factors, and that any of the three methodologies could be used to calculate the new line loss factors, which are then used to determine the financial losses and gains by market participants during the historical period.[21] Milner's expert witness, Dr. John MacCormack, echoed the view that all three methodologies are

[16] Exhibit 790-X3099, John MacCormack Dragan Brankovich Interim Application, November 9, 2016, paragraph 27.
[17] Exhibit 790-X3099, John MacCormack Dragan Brankovich Interim Application, November 9, 2016, paragraph 31.
[18] Exhibit 790-X3099, John MacCormack Dragan Brankovich Interim Application, November 9, 2016, paragraph 32.
[19] Exhibit 790-X3162, ATCO – Written Submissions, February 24, 2017, paragraph 39.
[20] Exhibit 790-X3152, Powerex's Submissions, February 24, 2017, paragraph 71.
[21] Exhibit 790-X3157, Milner Power Inc. submissions on methodologies, February 24, 2017, paragraph 4.

compliant. However, he also submitted that he preferred the Old AESO methodology over both the Milner and Modified Module B approaches.[22]

> It is my view that all three methodologies under consideration are technically compliant with the applicable legislation. The Milner methodology is superior to the Module B methodology because it integrates material aspects of the Module B methodology while avoiding the vast increases in computation time and complexity associated with modeling 8760 scenarios each year. The Milner methodology is nonetheless inferior to the Old AESO methodology. While simpler than the Module B methodology, the Milner methodology is still more complex than the Old AESO methodology. Further the Milner methodology is subject to: (a) still unresolved issues of the adequacy of offer data over all historic periods, (b) has not had the scrutiny of the Old AESO methodology and, (c) it has not yet been implemented by the AESO. As I have stated, all of these reasons indicate that the AESO could implement the Old AESO methodology with the minimum of delay.

30. Capital Power Corporation (Capital Power) and the City of Medicine Hat did not support the use of the Milner methodology and submitted that it would provide no expediency benefits. In evidence, Capital Power concluded that Milner's proposal could not be found to be compliant at this time and that an oral hearing would be required to assess its compliance.[23] The City of Medicine Hat submitted that there did not appear to be any basis to justify the adoption of either the Old AESO methodology or the Milner methodology on the grounds that one or the other would expedite the financial settlement process.[24]

31. Both TransCanada Energy Ltd. (TCE) and TransAlta Corporation (TransAlta) argued that the Milner methodology should be rejected because not enough details about it were available and, as a result, parties were unable to fully assess whether it is compliant.[25] [26]

32. The AESO stated that it had not replicated the calculations used by Milner to determine the generation replacement vectors and noted that the vectors remained to be calculated for several generating units for each loss factor year.[27]

2.2 The Old AESO methodology

33. The AESO, as part of its compliance filing in Module B in this proceeding, submitted a proposed methodology on December 4, 2014 in exhibit 0563.02, which has since come to be called the Old AESO methodology. The AESO summarized this methodology as using load flow analysis for 12 base cases with load reduced to balance the system.[28]

34. The Commission considered and did not accept the AESO's proposed methodology on a forward-looking basis in Decision 790-D03-2015. It stated in that decision that "scaling down

22 Exhibit 790-X3290, Evidentiary submissions of Dr. MacCormack Module C, May 8, 2017, page 12.
23 Exhibit 790-X3155, CPC Module C Submissions, February 24, 2017, paragraph 123.
24 Exhibit 790-X3146, CMH Mod C Submission, February 24, 2017, paragraph 8.
25 Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 83.
26 Exhibit 790-X3438, TransAlta Argument Module C, July 28, 2017, paragraph 94.
27 Exhibit 790-X3137, AESO Additional Information on Module C Scenarios, January 31, 2017, paragraph 32.
28 Exhibit 790-X3137, AESO Additional Information on Module C Scenarios, January 31 2017, paragraph 11.

load to rebalance the system introduces a conceptual problem in terms of what is being measured in that it does not reflect what actually occurs on the system when a generating facility is, in fact, removed."[29] The Commission further stated that while scaling down load does not in itself violate the *Transmission Regulation*, because the curtailment of load is hypothetical, the modelling results would be improved by better representing actual system conditions.[30]

35. Regarding the use of 12 base cases (again, on a going-forward basis) in Decision 790-D03-2015, the Commission stated that the 12 representative base cases may be improved upon to render a more robust 'but-for' approach, and that the merit order would be a practical and reasonable method of effecting system rebalancing when calculating loss factors while holding load constant under an ILF methodology.[31]

36. ATCO Power, Milner, TCE and, to some extent, Powerex all supported the use of the Old AESO methodology for calculating loss factors on a historical basis. ATCO Power argued that the Old AESO methodology should be preferred as it can be verified by participants,[32] and it is compliant given the interchangeability of load and generation when considering a single bus.[33] Milner's expert witness, Dr. MacCormack, stated in his evidence that the Old AESO methodology has a proven track record, has been shown to produce loss factors accurately and in a timely manner, and that other parties have been able to reasonably replicate its results.[34]

37. TCE submitted that the Old AESO methodology is the preferred choice for calculating line loss factors for the historical period as it is the only methodology that satisfies the requirements for accuracy and expediency, as well as being the only methodology that can be verified by other parties.[35] Powerex submitted that the primary virtue of the Old AESO methodology is its ability to quickly replace an illegal interim rate with a legal final rate,[36] and that using this methodology will bring these proceedings to a close most expeditiously, and result in the implementation of a just and reasonable rate.[37]

38. Capital Power, the City of Medicine Hat and TransAlta opposed the use of the Old AESO methodology. Capital Power submitted that the distinction between the competing ILF methodologies to either use load scaling, or to hold load constant while re-dispatching generation, is critical and cannot be diminished or overlooked because it was integral to the determination of a compliant forward-looking methodology in Module B.[38]

39. The City of Medicine Hat submitted that there is no theoretical basis to expect that a loss factor methodology that integrates 8,760 base cases into 12 base cases (as in the Old AESO and Milner methods) will accurately replicate the annual loss factor resulting from calculating and

29 Decision 790-D03-2015: November 26, 2015, paragraph 137.
30 Decision 790-D03-2015: November 26, 2015, paragraph 139.
31 Decision 790-D03-2015: November 26, 2015, paragraphs 157-158.
32 Exhibit 790-X3445, ATCO Power Canada Ltd. Argument, July 28, 2017, paragraph 4.
33 Exhibit 790-X3445, ATCO Power Canada Ltd. Argument, July 28, 2017, paragraph 23.
34 Exhibit 790-X3290, Evidentiary submissions of Dr. MacCormack Module C, May 8, 2017, page 4.
35 Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 5.
36 Exhibit 790-X3152, Powerex's Submission, February 24, 2017, paragraph 71.
37 Exhibit 790-X3429, Powerex Argument, July 28, 2017, paragraph 45
38 Exhibit 790-X3287, CPC Module C Evidentiary Submission, May 8, 2017, paragraph 14.

volume-weighting 8,760 hourly raw loss factors.[39] The City of Medicine Hat further submitted that the use of fewer than 8,760 base cases should not be approved without first understanding the degree of distortion arising from this notional simplification.[40]

40. TransAlta argued that the Old AESO methodology is not compliant because it does not accurately reflect contribution, as it does not measure the full value of losses saved or caused by each generator, and because it simulates an abnormal operating condition when it scales load to balance the system.[41]

41. The AESO stated that if the Old AESO methodology were to be implemented, it would require directions on (1) whether incremental loss factors should be calculated each time MLF/2[42] loss factors are calculated, or whether they should be based only on the final MLF/2 loss factor calculations for each year, and (2) whether a minimum dispatch of 1.00 megawatt (MW) is to be applied or whether that provision of the Old AESO methodology is to be ignored. The AESO further noted that if the Old AESO methodology were to use actual (as opposed to forecast) data, then four actual system topologies would need to be developed for the calculations.[43]

2.3 The Modified Module B methodology

42. In Decision 790-D02-2015, the Commission determined that the MLF/2 methodology was unlawful. In Module B, the Commission determined that the MLF/2 methodology should be replaced on a going forward basis with an ILF methodology. The ILF methodology approved in Decision 790-D03-2015 became known as the Module B methodology. The Modified Module B methodology is the Module B line loss factor methodology approved in Decision 790-D03-2015 for future periods, modified for the historical period pursuant to Decision 790-D04-2016.

43. In Decision 790-D03-2015, the Commission directed changes to the Line Loss Rule (ISO rules Section 501.10) on a prospective basis. These changes included:

(a) Replacing the previous rule with an ILF methodology for calculating raw loss factors using the Load Flow approach.

(b) Specifying that the location of a generation facility will be the location of each MPID for a generating unit or group of generating units.

(c) Allowing generators that own or control generating facilities to aggregate or disaggregate their generating facilities at the same location.

(d) Keeping load constant when a generation facility is notionally removed from the system and scaling up other specific generation facilities to rebalance the system.

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39 Exhibit 790-X3146, CMH Mod C Submission, February 24, 2017, paragraph 19.
40 Exhibit 790-X3146, CMH Mod C Submission, February 24, 2017, paragraph 23.
41 Exhibit 790-X3438, TransAlta Argument Module C, July 28, 2017, paragraph 61.
42 The term marginal loss factor (MLF) refers to the last loss caused by the last unit of power generated.
43 Exhibit 790-X3395, AESO Module C Reply Comments and Request for Directions, June 19, 2017, paragraphs 2-7.

(e) Instead of using 12 base cases, the 8,760 energy market merit orders would be used during the process of calculating forecast loss factors.

44. The Commission further directed in Decision 790-D04-2016 that any methodology to be used for the historical period must exclude aggregation and use actual data rather than forecast data when calculating loss factors. The Modified Module B methodology gives effect to this direction.

45. In this proceeding, Capital Power, the City of Medicine Hat and TransAlta supported the Modified Module B methodology. Capital Power submitted that the Modified Module B methodology is the only compliant and accurate methodology on the record,[44] and the only one that accords with the Commission's findings both in Module B and the preliminary issues decision in Module C.[45] The City of Medicine Hat argued that the Modified Module B methodology is compliant and reasonable for final settlement, conditional on the implementation of the Module B methodology on a prospective basis "in a reasonable manner without material flaws."[46]

46. TransAlta submitted that the Module B methodology approved in Decision 790-D03-2015 is the only methodology in this proceeding approved by the Commission. It further argued that the proposed modifications to the Module B methodology have also been the subject of a ruling by the Commission. Therefore, TransAlta recommended that the Modified Module B methodology should be the focus of the AESO's efforts to calculate retroactive loss factors in Module C. TransAlta also submitted that a procedural mechanism should be in place for addressing potential non-compliance issues that may only become evident upon review of the results.[47]

47. ATCO Power, Milner, TCE and, to a lesser extent, Powerex either opposed the Modified Module B methodology or favoured other methodologies. ATCO Power submitted that the Modified Module B methodology is not the only potentially compliant methodology and that the resemblance of the Modified Module B methodology to the going-forward Module B methodology is no reason to prefer it over other compliant methodologies.[48]

48. Milner submitted that it is beyond question that the Modified Module B methodology is lawful and fully suitable as a basis to calculate loss factors and financial recompense for the historical period.[49] However, Milner preferred the Old AESO methodology and argued that a major problem with the Modified Module B approach is that it will be a 'black box' to most market participants. Milner further submitted that a significant number of the base case ILF calculations under the Module B methodology do not solve.[50]

[44] Exhibit 790-X3155, CPC Module C Submissions, February 24, 2017, paragraph 123.
[45] Exhibit 790-X3442, Module C Argument of Capital Power Corporation, July 28, 2017, paragraph 9.
[46] Exhibit 790-X3430, CMH Argument Module C, July 28, 2017, paragraphs 44-45.
[47] Exhibit 790-X3150, TransAlta Submissions re Module C, February 24, 2017, paragraphs 10-11.
[48] Exhibit 790-X3162, ATCO – Written Submissions, February 24, 2017, paragraph 21.
[49] Exhibit 790-X3157, Milner Power Inc. submissions on methodologies, February 24, 2017, paragraph 14.
[50] Exhibit 790-X3460, Milner Power Inc. Main Reply Argument, August 18, 2017, paragraphs 50-51.

49. TCE stated in its final argument that the complexity of the Modified Module B methodology not only increases the likelihood of errors, it also makes it less likely that errors will be identified, diagnosed or resolved.[51] Powerex submitted that the Old AESO methodology has material benefits in terms of expediency and timeliness, but that the Modified Module B methodology would arguably better serve Bonbright's fairness criteria if it allowed costs to be assigned more accurately to those that cause those costs.[52]

50. The majority of parties[53] submitted that the Modified Module B methodology is compliant, whether or not it was their preferred approach. An exception was ENMAX, which submitted that no methodology that is a variation of an ILF methodology approved in Module B is compliant.[54] However, ENMAX also submitted that if the Commission finds all three methodologies under consideration to be compliant, then the Commission should prefer the Modified Module B methodology. It also argued that 8,760 base cases should be preferred to 12 base cases.[55]

2.4 Commission findings regarding which methodology to apply to the historical period

51. Each of the three above-mentioned methodologies was discussed by participants at the Commission's Module C round table meeting on December 20, 2016. During that meeting, participants agreed that while compliance and expediency are both important considerations in evaluating each methodology, expediency can only be considered once compliance has been established.[56]

2.4.1 Compliance with the statutory scheme

52. To be compliant a methodology must be consistent with the relevant provisions of the *Electric Utilities Act* and satisfy the requirements set out in Section 31 (formerly Section 19) of the *Transmission Regulation*.

53. The AESO's duty to manage and recover line losses is set out in Section 17(e) of the *Electric Utilities Act*. Section 30(4) of that act provides that the AESO may recover the costs of line losses from market participants by including those costs in its tariff or by establishing and charging fees for those costs. Section 121(2) of the *Electric Utilities Act* requires the Commission to ensure that the ISO tariff is consistent with the statutory scheme, just and reasonable and not unduly preferential, and is not arbitrary nor unjustly discriminatory. A further underlying requirement arising from Section 5 of the *Electric Utilities Act* is that the approved

[51] Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 78.
[52] Exhibit 790-X3280, Powerex's Submission relating to Position of others, May 8, 2017, paragraph 8.
[53] Exhibit 790-X3287, CPC Module C Evidentiary Submission, May 8, 2017, paragraph 5; exhibit 790-X3150, TransAlta Submissions re Module C, February 24, 2017, paragraph 10; exhibit 790-X3146, CMH Mod C Submission, February 24, 2017, paragraph 9; exhibit 790-X3157, Milner Power Inc. submissions on methodologies, February 24, 2017, paragraph 14; exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 89.
[54] Exhibit 790-X3436, EEC 790 Module C Argument, July 28, 2017, paragraph 8.
[55] Exhibit 790-X3436, EEC 790 Module C Argument, July 28, 2017, paragraphs 65 and 70.
[56] Exhibit 790-X3134, AUC ruling on Mod C process and schedule, January 25, 2017, paragraph 14.

ISO tariff must be consistent with the fair, efficient and openly competitive operation of the market.

54. Section 31 of the *Transmission Regulation* provides express direction with respect to the development of a line loss rule. This section makes it clear that such a rule must satisfy a number of criteria, including that:

(a) It must reasonably recover the cost of transmission line losses.

(b) It must be determined for each location on the transmission system as if no abnormal operating conditions exist.

(c) It must be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load.

55. The Old AESO methodology and the Module B methodology were closely scrutinized by the Commission in the Module B proceeding. In this proceeding, the Commission considered variants of these two methodologies.

56. The Commission ultimately approved the Module B methodology in Decision 790-D03-2015 and subsequently found that the AESO's new transmission loss factor rule, which implements that methodology, complies with the requirements of the *Electric Utilities Act* and the *Transmission Regulation*.[57]

57. When Module C commenced, the Commission considered, as a preliminary matter, what modifications to the Module B methodology would be required to calculate loss factors for the historical period. The Commission determined that few changes to the methodology were required. Most notably, the Commission disallowed aggregation of generating units and directed the use of historical merit orders. The Commission is satisfied that these amendments have not rendered the Modified Module B methodology non-compliant with the statutory scheme, and notes that no party has taken such a position, save ENMAX (which continues to favour its superposition approach – a methodology that was previously rejected by the Commission as being non-compliant and which is not under consideration in Module C).

58. While the Commission rejected the Old AESO methodology in favour of the Module B methodology in Decision 790-D03-2015, it did not rule that the Old AESO methodology was non-compliant with the statutory scheme. Rather, the Commission found that the Module B methodology, which is based on generation re-dispatch rather than load scaling, better represents the actual operation of the Alberta Interconnected Electric System (AIES). The Commission also observed that while load scaling would constitute an abnormal operating condition, this would not in itself render the Old AESO methodology non-compliant:

[57] Decision 790-D05-2016: Milner Power Inc., Complaints Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, ATCO Power Ltd., Complaint Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, Phase 2, Module B, Compliance Filing, Proceeding 790, Applications 1606494, 1608563 and 1608709, November 30, 2016, paragraph 1.

> …the Commission is not suggesting that using distributed load as the swingbus to rebalance the system in order to calculate raw line loss factors under an ILF methodology would in itself violate Section 31(2)(c) of the *Transmission Regulation*. This is because the process of calculating raw line loss factors under an ILF methodology involves no actual curtailment of supply and no actual rebalancing of the system, whether by load scaling or output re-dispatch. The exercise is entirely hypothetical. No generating facility is actually being removed from the system in order to conduct a 'but-for' analysis.[58]

59. Similarly, the Commission did not find that the Old AESO methodology's use of 12 base cases renders it non-compliant. In the Commission's view, the use of 12 representative base cases, rather than the 8,760 used in the Module B methodology, is not inconsistent with subsection 31(2)(d) of the *Transmission Regulation*, which requires that the loss factor in each location be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load.

60. The Commission understands the Milner methodology to be a hybrid of the Module B methodology and the Old AESO methodology. It adopts the merit order re-dispatch approach from the Module B methodology, but uses 12 base cases derived from the 8,760 base cases, rather than the 8,760 base cases themselves. The Commission finds that the Milner methodology may also be compliant with the statutory scheme because it is premised on normal operating conditions and appears capable of providing a loss factor for each location that would be representative of the impact on average system losses by each respective generating unit or group of generating units relative to load. However, the Commission is concerned that the Milner methodology was only recently developed and, accordingly, the AESO has no meaningful experience with it. Additionally, Milner has not shared its scripts for the methodology with any other party, making replication and verification of results challenging.

2.4.2 The preferred methodology

61. Having decided that all three methodologies comply or may be capable of complying with the statutory scheme, the Commission must determine which methodology it should direct the AESO to implement for the historical period. The Commission finds that three criteria are relevant: consistency, expediency (i.e., timeliness) and verifiability (i.e., replicability). In this context, consistency means the degree to which each methodology is able to reasonably represent (or emulate) what would happen on the AIES when a generating unit unexpectedly comes off line. Expediency relates to the time necessary to successfully implement each methodology. The need for verifiability is self-explanatory; market participants must be able to reasonably verify (i.e., replicate) the AESO's loss factor calculations.

62. In Decision 790-D04-2016, the Commission acknowledged that generators may have made different decisions under a different line loss rule and methodology but found that it would neither be "reasonable nor feasible to attempt to look back and accurately model what parties

[58] Decision 790-D03-2015: Milner Power Inc., Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, ATCO Power Ltd., Complaint regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, Applications 1606494, 1608563 and 1608709, Proceeding 790, Phase 2, Module B, November 26, 2015, paragraph 139.

would have done in terms of aggregation and offer blocks since January 1, 2006." The Commission found that such an exercise would be "speculative and likely to be influenced by hindsight."[59] Rather, the Commission found that loss volumes and costs are best apportioned by using information about the actual operation of generating facilities as inputs into the approved methodology.

63. For the reasons set out below, the Commission has decided to direct the AESO to calculate loss factors for the historical period using the Modified Module B methodology. Of the three major criteria considered and relied upon by the Commission to distinguish among, and evaluate the merits of, the three competing methodologies, the most important proved to be the first criterion, namely, consistency. Compared to the other two methodologies, the Modified Module B methodology best produces loss factors that reasonably represent (or emulate) what would happen on the AIES when a generating unit unexpectedly comes off line. Relying on the information provided by the AESO with respect to the second criterion, that is, expediency, the Commission found no material or substantive difference in the estimated implementation time for each of the three methodologies. With respect to the third criterion, while some parties were of the view that differences exist in the extent to which market participants might be able to verify or replicate the results of each methodology, the Commission was not persuaded that these anticipated differences would persist with successive iterations, especially for the two methodologies with which parties were least familiar. This is particularly the case once additional measures are implemented by the AESO as discussed in more detail in paragraph 74 below. Accordingly, the Commission finds that the verifiability or replicability criterion provides insufficient basis to distinguish between the merits of the three methodologies.

2.4.3 Consistency

64. As noted above, the Commission finds that the Modified Module B methodology best satisfies the consistency criterion. This finding is premised on the fact that the Modified Module B methodology emulates most closely the actual operation of the AIES when a generating unit unexpectedly comes off line, because it holds load constant and rebalances the system by re-dispatching generation using the actual merit order for each hour in the historical period, and measures the resultant change in losses to determine a loss factor for each location that is representative of the impact of the generating unit on average system losses relative to load.

65. The Commission is satisfied that the Modified Module B methodology's reliance on historical data and merit orders reduces the risk of misrepresenting a generator's contribution to losses as compared to the Old AESO methodology and the Milner methodology. The Commission finds that the averaging necessary to generate the 12 base cases used by both methodologies can materially affect the degree to which the loss factors fairly represent a generator's impact relative to load. The Commission observes that the small number of base cases used in the Old AESO and Milner methodologies is susceptible to sampling errors. Further, the Commission finds that the averaging cannot capture and reflect generator volatility as effectively and accurately as the use of the 8,760 base cases in the Modified Module B methodology.

[59] Decision 790-D04-2016: September 28, 2016, paragraph 89.

66. The Old AESO methodology notionally removes a generating unit and then rebalances the system by reducing load across the system to measure the resultant change in losses. While reductions in load may very occasionally be used to address outages, it would not happen across the system and would not reflect a normal operating condition. The Commission finds that load scaling as recast in Dr. Baldick's 'thought experiment', is still load scaling and is not reflective of the normal operation of the AIES.

67. The Milner methodology proposes to use a generation replacement vector to simulate merit order re-dispatch rather than the merit order itself. The generation replacement vector does not include all generating units in the merit order and instead relies on a selected group of 35 generating units. Rather than replace the removed generating unit's output with output from the next generating unit(s) in the merit order, the lost output is incrementally re-allocated to the selected subset of generating units.

68. The Commission sees no merit in adopting this methodology. It suffers from the averaging concerns associated with using 12 bases cases and it uses a subset of 35 generating units for the generating replacement vector rather than using the actual merit order to re-dispatch output.

69. All three of the methodologies proposed in Module C are ILF based and, as a result, are consistent with the Commission's findings in Decision 790-D03-2015. However, the Commission finds that the Modified Module B methodology exhibits modelling attributes that are materially superior to those of either the Old AESO or Milner methodologies. In particular, of the three competing methodologies, the Modified Module B methodology most closely emulates the operation of the AIES.

2.4.4 Expediency

70. Regarding expediency or timeliness, the Commission finds that the AESO's estimates for implementation timing are reasonable in the circumstances. The AESO's evidence is that, under an accelerated scenario, each of the proposed methodologies could be implemented within 13 months.[60]

71. Several parties expressed concerns that the AESO's timing projections for implementing the Module B methodology for the go-forward period have been consistently optimistic and suggest that this favours the implementation of the Old AESO methodology. The Commission recognizes that implementation of any of the proposed methodologies could potentially be subject to delays arising from unforeseen or unanticipated challenges. However, the Commission accepts as both reasonable and impartial, the testimony of Mr. Martin, that once issues associated with the (forward-looking) Module B methodology are resolved, there would be a low likelihood

[60] Exhibit 790-X3374, Undertaking provided by John Martin to ATCO Power Canada Ltd, June 12, 2017, and Exhibit 790-X3137, AESO Additional Information Regarding Module C Methodologies Under Discussion, January 31, 2017, page 8.

for additional issues emerging with respect to implementing the Modified Module B methodology for the historical period.[61]

72. Given that all three of the methodologies can be implemented within a similar time frame, no methodology is materially favored from the perspective of expediency.

2.4.5 Verifiability

73. The Commission is satisfied that it will be possible to reasonably verify loss factors for each of the proposed methodologies, if not immediately, then without undue delay once implementation by the AESO begins.

74. The Commission considers it likely that, at least initially, it will be easiest to verify loss factors generated by the Old AESO methodology because it is less complex, involves fewer calculations than either the Milner methodology or the Modified Module B methodology, and all parties already have some experience with it.[62]

75. The Commission acknowledges that the Modified Module B methodology uses more input data and involves more calculations than the other methodologies being considered. The Commission also recognizes that not all of the input data for the Modified Module B methodology can be shared with market participants because of confidentiality concerns. Notwithstanding these factors, the Commission finds that confidence in the loss factors generated through the Modified Module B process can be reasonably assured with a compliance process that includes the following measures.

(a) A post approval compliance process that will allow market participants to provide feedback to the AESO before and after it files its methodology in response to the Commission's directions in this decision.

(b) Following the completion of the AESO's modelling for producing loss factors for the historical period, the AESO will begin a staggered, year by year release of loss factors leading to a final settlement, affording market participants an opportunity to review and assess loss factors on a yearly basis.

(c) An audit process that will allow market participants to verify results using a limited number of hours. Errors identified in the audit process can then be reported back to the AESO.

76. Although the Milner methodology is in the developmental stage and has not been fully tested, the Commission is similarly confident that it would be possible for market participants to reasonably replicate or verify outcomes under this methodology using the process steps outlined above.

61 Transcript, Volume 1, June 12, 2017, page 73.
62 For example, the Commission accepts, in this respect, TCE's evidence that it was able to verify the Old AESO methodology as part of the Module B process as stated in exhibits 790-X0175 and 790-X0302.

2.4.6 Conclusion: The Modified Module B methodology is the preferred methodology

77. The Commission is satisfied that the Modified Module B, Old AESO and Milner methodologies all comply with, or may be capable of complying with, the statutory scheme. The Commission is also satisfied that there is little to distinguish the three competing methodologies on the basis of expediency and verifiability. However, whenever a generating unit is notionally removed from the system, the Modified Module B methodology holds load constant and rebalances the system by re-dispatching generation using the actual merit order for each hour in the historical period, and measures the resultant change in losses to determine a loss factor for each location that is representative of the impact of the generating unit on average system losses relative to load. Hence, the Modified Module B methodology is the preferred methodology for producing loss factors for the historical period, because it is best able to reasonably represent (or emulate) what would actually happen on the AIES. This is important because the purpose of an ILF line loss factor methodology is to calculate system wide line losses with and without the presence of each generating unit on the system and, thus, the contribution of each generating unit to average system losses.

78. Accordingly, the Commission finds that the Modified Module B methodology should be adopted by the AESO for the historical period in place of the MLF/2 loss factor methodology underpinning the unlawful Line Loss Rule. Given the forgoing, the Commission is satisfied that determining loss factors for the historical period using the Modified Module B methodology will result in rates that are (1) consistent with the statutory scheme, (2) just and reasonable, and (3) not unduly preferential, arbitrary or unjustly discriminatory.

3 Who should receive revised invoices, current or original STS contract holders?

3.1 Introduction

79. In this section, the Commission determines which market participants should be invoiced for line losses calculated using the Modified Module B methodology for the historical period.

80. In Decision 790-D02-2015, the Commission found that those portions of the ISO tariff relating to line loss charges were interim since January 1, 2006 and that the Commission has the jurisdiction to grant a tariff-based remedy. In Decision 790-D04-2016, the Commission confirmed that any recalculation or re-assignment of line loss charges for the historical period would be done under the ISO tariff.

81. Invoices under the ISO tariff are issued to market participants that hold STS contracts with the AESO. The subject of a significant debate in the Module C proceeding was whether the revised invoices should be issued to the party that held the STS contract with the AESO at the time the losses or credits were incurred or whether the charges or credits should be borne or received by the current holder of the STS contract. The Commission understands that there has been relatively little turnover in STS contracts during the historical period.[63] As a result, in most

[63] Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraphs 8-11.

instances, no question arises as to who should be issued a revised invoice or credit: the original and current STS contract holder is the same. However, in some instances, most notably related to output governed by PPAs, the STS holders have changed during or after the historical period.

82. During the Commission's round table meeting on December 20, 2016, parties were sharply divided on this issue.[64] On February 8, 2017, the Commission specifically invited parties to make submissions on whether the AESO should bill current or previous contract holders. The Commission stated that this issue would be addressed as part of its overall deliberations in Module C without need for a separate process.[65]

3.2 Proponents of invoicing current STS contract holders

83. The AESO submitted that STS agreements are entered into between the AESO and market participants and are explicitly subject to the terms and conditions of the ISO tariff. In the AESO's view, all adjustments for loss factor charges during the historical period must be applied to the account of an STS agreement assignee in accordance with subsection 2(2) of Section 15 of the ISO tariff.[66]

84. Subsection 2(2) of Section 15 of the ISO tariff states:

> 2(1) A market participant may assign its agreement for system access service or any rights under it to another market participant who is eligible for the system access service available under such agreement and the ISO tariff, but only with the consent of the ISO, such consent not to be unreasonably withheld.
>
> (2) The ISO must apply to the account of the assignee all rights and obligations associated with the system access service when a system access service agreement for Rate DTS, Demand Transmission Service, Rate FTS, Fort Nelson Demand Transmission Service, or Rate STS, Supply Transmission Service, has been assigned in accordance with subsection 2(1) above, including any and all retrospective adjustments due to deferral account reconciliation or any other adjustments.

85. The AESO submitted that STS agreements are assigned between market participants pursuant to Assignment, Assumption and Novation (AA&N) agreements. The AESO stated that AA&N agreements cannot alter or affect the requirements of the ISO tariff because (1) under the terms of the AA&N agreement, an STS assignee agrees to be bound by the terms of the STS agreement, which is subject to the terms and conditions of the ISO tariff, and (2) by accepting the assignment of an STS agreement, an assignee agrees to be bound by the ISO tariff pursuant to subsection 1(1) of Section 1 of the ISO tariff. Therefore, according to the AESO, in the event of any conflict between the provisions of an AA&N agreement and the ISO tariff, the tariff takes precedence and governs the rights and obligations of the AESO and an assignee with respect to adjustments for loss factor charges during the historical period.[67]

[64] Exhibit 790-X3132, 790 Technical Meeting Notes Dec 20 2016, January 23, 2017, page 26.
[65] Exhibit 790-X3140, AUC response to ATCO clarification request, February 8, 2017.
[66] Exhibit 790-X3148, LT AUC re Module C Adjustments, February 24, 2017, paragraphs 4 and 7.
[67] Exhibit 790-X3148, LT AUC re Module C Adjustments, February 24, 2017, paragraphs 10-11.

86. The AESO explained that while it would send the invoice to the current Rate STS holder for all adjustments, the final allocation of such adjustments as between the current and prior STS holder is a commercial matter that can be determined between the parties in agreements respecting the sale of generation assets. The AESO considered that this is consistent with the EUB findings in Decision 2003-054: [68]

> The Board considers that the onus is on owners of generators/PPA holders and DTS customers to include commercial arrangements for STS/DTS amounts owing or refunds that apply to a prior period in any buy/sell agreements. [69]

87. The AESO submitted that parties who entered into Rate STS assignment agreements from 2006 to 2016 should be taken to be aware of the EUB's findings regarding the assignment provision. If parties wished to allocate, between themselves, line loss charges or refunds in a manner different from that required by the assignment provisions of the ISO tariff, the parties could have provided for that in private commercial agreements separate from the AESO's form of assignment agreement. The AESO suggested that attempts to interpret the tariff assignment provisions differently in Module C could undermine the terms of separate commercial agreements made between former and current holders of Rate STS agreements.[70]

88. The AESO pointed out that bilateral purchase and sale agreements establish the rights and obligations of vendors and purchasers, and cannot alter or affect the requirements of the ISO tariff. It added that bilateral agreements would not alter the AESO's obligation to invoice a purchaser for loss factor charge adjustments if the purchaser is assigned the vendor's STS agreement.[71]

89. The AESO submitted that the current STS contract holder is accountable for adjustments to prior periods only if the STS contract has been assigned to that party. In cases where the STS contract has been terminated, the holder of the STS contract at the time of termination is accountable for adjustments to prior periods. The AESO also explained that it is possible, although rare, for a service to be transferred to a new party without the existing contract being assigned. Where a contract was not assigned, adjustments for periods prior to the transfer would be to the account of the previous contract holder and adjustments for periods after the transfer would be to the account of the current contract holder.[72]

90. Assignment is not available for system access services provided under Rates export opportunity service (XOS), import opportunity service (IOS), or demand opportunity service (DOS).[73]

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68 Exhibit 790-X3282, AESO Response to Module C Submissions and IR Responses, May 8, 2017, paragraph 39.
69 EUB Decision 2003-054: Alberta Electric System Operator, Aquila Networks Canada (Alberta) Ltd., and ATCO Electric Ltd., Article 24 Refund Omnibus Proceeding, Refund to AESO Customers, Refund to DISCO End-Use Customers, Application No. 1244140, July 8, 2003, page 20.
70 Exhibit 790-X3282, AESO Response to Module C Submissions and IR Responses, May 8, 2017, paragraph 40.
71 Exhibit 790-X3148, LT AUC re Module C Adjustments, February 24, 2017, paragraph 9.
72 Exhibit 790-X3180, AESO Preliminary Comments re Feb 24 Submissions, March 14, 2017, paragraph 12.
73 Exhibit 790-X3043, AESO Reply Submission re Module C Issues, June 30, 2017, paragraph 8.

91. Capital Power, the City of Medicine Hat, ENMAX and TCE all submitted that Section 15 of the ISO tariff dictates that adjustments to historical line loss charges and credits should be invoiced to current STS contract holders.

92. Capital Power submitted that the issue of which party the AESO is required to invoice must be kept separate from the issue of ultimate liability for line loss charges as between commercial counterparties. It stated that the question of ultimate liability is entirely a commercial matter between those parties and is subject to the jurisdiction of the Alberta courts, rather than the Commission.[74] Capital Power further submitted that arguments related to cost causation do not withstand scrutiny, as the very purpose of Section 15(2) of the ISO tariff appears to depart from a pure, cost causation-based allocation of historical liabilities, and that the clear intent of that section is to allow the AESO to look to the current holder of an STS agreement to meet all tariff-based obligations associated with its asset.[75]

93. The City of Medicine Hat submitted that in paragraph 50 of the Commission's preliminary issues decision (790-D04-2016), the Commission stated that it "considers that the provisions in the ISO tariff and ISO rules provide the AESO with mechanisms to pursue payment from, or reimbursement to, market participants." The City of Medicine Hat interpreted this decision to mean that the reissuance of line loss charges will be accomplished in accordance with the provisions of the ISO tariff, which includes the provisions in Section 15 that assign all prior rights and obligations for system access service.[76]

94. ENMAX submitted that regardless of changes to the AA&N agreements over the years, the STS contracts have always been explicitly subject to the terms and conditions of the ISO tariff, including Section 15(2). ENMAX added that while this means that the assignee under an AA&N agreement is explicitly subject to the terms of the ISO tariff, the assignor is not, since it no longer takes system access service from the AESO under the STS contract.[77]

95. TCE argued that ignoring the agreed upon terms found in valid and subsisting AA&N agreements, and making the holder of prior STS contracts responsible for retroactive losses that have been assigned pursuant to the ISO tariff and AA&N agreements would be patently unfair.[78]

3.3 Proponents of invoicing <u>original</u> STS contract holders

96. The Balancing Pool was a proponent of invoicing previous STS contract holders for historical line loss charges. The Balancing Pool explained that, since the beginning of 2016, many of the PPA units it did not initially hold were returned to it pursuant to provisions set out in the PPAs. This has resulted in the Balancing Pool assuming offer control for those PPA units as

[74] Exhibit 790-X3310, Reply Submission of Capital Power, May 26, 2017, paragraph 47.
[75] Exhibit 790-X3310, Reply Submission of Capital Power, May 26, 2017, paragraphs 66-67.
[76] Exhibit 790-X3146, CMH Mod C Submission Method and Settlement, February 24, 2017, paragraph 49.
[77] Exhibit 790-X3436, EEC 790 Module C Argument, July 28, 2017, paragraphs 49-50.
[78] Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 119.

buyer, and becoming the current holder of the STS contracts for 3,900 MW of coal-fired generation, most of which was not under the Balancing Pool's control for the historical period.[79]

97. The Balancing Pool explained that, in accordance with the terms of the *Balancing Pool Regulation*, it is the party that backstops the PPAs.[80] Given its mandate and legislative duties, it must accept responsibility for these units and assume the role of buyer, including becoming an assignee of the STS contracts.[81] The Balancing Pool suggested that, taking into consideration the size and complexity of the record in this proceeding,[82] parties on both sides of the related asset transactions could not have been expected to identify, assess or quantify the potential charges or refunds, and certainly would not have been able to reflect them accurately in any associated agreements.[83]

98. The Balancing Pool pointed out that a determination of who to bill for historical line losses as between current and previous STS contract holders has the potential to significantly impact both itself and, ultimately, all consumers in Alberta, largely due to the PPAs that have been returned to it.[84] The Balancing Pool argued that it has a unique interest in this proceeding for three reasons: (1) it holds a significant percentage of the STS contracts at issue, (2) it bears very little historical liability, and (3) its funds are consumer funds.[85] The Balancing Pool stated that:

> This confluence of factors means that depending on the outcome of the Commission's deliberations, Alberta's electricity consumers could be at risk for tens of millions of dollars of line loss charges, virtually all of which were incurred before the Balancing Pool was required by statute to accept the STS Contracts of the Historic PPAs and at a time when the Balancing Pool and its stakeholders were not entitled to, and did not enjoy, the benefits of being an STS Contract Holder.[86]

99. The Balancing Pool submitted that the purpose of Module C is not to create new or additional historical line loss charges but, rather, to determine the proper methodology for the calculation of historical line loss charges and to ensure that the resulting charges and credits are properly and fairly allocated.[87] It further submitted that it is integral to the "principle of re-distribution" that only those parties holding STS contracts at the time that historical line losses were incurred should be eligible for charges and credits, and that to allocate charges to parties

[79] Exhibit 790-X3144, Balancing Pool submission, February 24, 2017, page 1.
[80] Exhibit 790-X3144, Balancing Pool submission, February 24, 2017, page 13.
[81] Exhibit 790-X3144, Balancing Pool submission, February 24, 2017, page 13.
[82] Exhibit 790-X3144, Balancing Pool submission, February 24, 2017, page 2.
[83] Exhibit 790-X3144, Balancing Pool submission, February 24, 2017, page 11.
[84] Exhibit 790-X3144, Balancing Pool submission, February 24, 2017, pages 1 and 2.
[85] Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 11.
[86] Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 12.
[87] Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 14.

that did not participate is equal to the creation of new charges and is contrary to the principles in Module C.[88]

100. The Balancing Pool highlighted that subsection 31(1)(a) of the *Transmission Regulation* requires the ISO to make rules to reasonably recover the costs of transmission line losses based on respective locations and contributions to transmission line losses.[89] The Balancing Pool argued that this means that a reasonable recovery of line losses has been statutorily defined to mean an outcome that is tied to location and contribution. A result in which liability is not tied to contribution is contrary to these principles.[90] The Balancing Pool further argued that principles of cost causation and intergenerational equity require that current STS contract holders not be burdened with the costs or risks associated with services consumed by past STS contract holders.[91] The Balancing Pool submitted that the only outcome that is consistent with all relevant principles is the one in which the AESO invoices each market participant for all historical line loss charges and credits that accrued while that market participant was an STS contract holder.[92]

101. Regarding the issue of bilateral agreements, the Balancing Pool submitted that the possibility that parties may have contracted amongst themselves to address indemnification with respect to historical line loss charges should have no effect on which party is liable to the AESO. The Balancing Pool said that it agrees with the Commission’s distinction (in exhibit 790-X3331) between the party that the AESO will invoice and the party who may ultimately bear responsibility for historical line loss charges as being between STS contract assignors and assignees, and that it should be irrelevant to the Commission’s deliberations whether assignors and assignees have chosen to enter into separate agreements.[93]

102. In addition, the Alberta Direct Connect Consumers Association (ADC), ATCO Power, the Industrial Power Consumers Association of Alberta (IPCAA), Milner, TransAlta and the UCA supported the position that previous STS contract holders should be invoiced for historical line loss charges and credits. The ADC and IPCAA recommended that the Commission direct the AESO to apply payments and collections to the STS contract holder of record for the historical period to protect consumers.[94] [95]

103. ATCO Power submitted that the ISO tariff does not prescribe how the AESO is to deal with differences arising from the finalization of the unjust and unreasonable interim line loss charges. Further, the assignor retains the responsibility to pay the finalized rates once the interim

88 Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 17. The Balancing Pool here refers to the principle of re-distribution to be similar to the term ‘zero sum game’ used in paragraph 6 of Decision 790-D02-2015.
89 Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 20.
90 Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 22.
91 Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraphs 23-27.
92 Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 42.
93 Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraphs 33-35.
94 Exhibit 790-X3158, ADC letter on Ruling on Process Direction for Module C, February 24, 2017.
95 Exhibit 790-X3145, IPCAA Submission on Payment/Collection Process, February 24, 2017.

rate is replaced with a final just and reasonable rate. In ATCO Power's view, this is the only way that the AESO can ensure that it has charged just and reasonable rates.[96]

104. ATCO Power also stated that the fact that Rate STS is referred to in subsection 15.2(2) does not lead to the "reasonable interpretation" that the finalization of interim line loss charges is included in subsection 15.2(2).[97] ATCO Power further submitted that subsection 15.2(2) does not extend to the replacement of an unlawful interim tariff rate by a just and reasonable final rate that complies with legislation. ATCO Power explained that the AESO's basic obligation requires that it ensure that all market participants have been charged just and reasonable rates for the service they received, which means that the final rates have to be charged to the participant that actually received the service at the time.[98] Milner stated that it generally supported ATCO Power's submissions.[99]

105. TransAlta submitted that the *Transmission Regulation* requires the AESO to reasonably recover the cost of transmission line losses based on "respective locations and contributions." According to TransAlta, charges levied on units for output that they did not offer during past periods means that those units did not "contribute" to those line losses during the retroactive period as required by the *Transmission Regulation*.[100]

106. TransAlta agreed that subsection 15(2) of the ISO tariff is just and reasonable in the circumstances for which it was designed; those circumstances being the normal course transactions where counterparties have contemplated trailing costs as part of their commercial arrangements. However, TransAlta submitted that an 11-year retroactive adjustment of line loss charges is not a normal course trailing cost.[101]

107. TransAlta argued that the AA&N agreements are private contracts. It stated that while those contracts may ultimately dictate which entity may be liable for retroactive line loss charges, the issue of who the AESO should bill is a completely different question that must be driven by policy considerations that are evident in the *Electric Utilities Act* and the *Transmission Regulation*, and not by wording of a section of the ISO tariff that was not designed for this situation.[102]

108. The UCA was primarily concerned with whether current or previous STS contract holders should be billed for historical line loss charges and the related considerations of fairness, cost causation and intergenerational equity.[103] The UCA also submitted that, having regard to the plain language and punctuation of subsection 15.2(2) of the ISO tariff, there are at least two possible, reasonable interpretations of the words "all rights and obligations ... including any and

[96] Exhibit 790-X3293, ATCO – Submissions relating to the positions of other parties, May 8, 2017, paragraph 12.
[97] Exhibit 790-X3312, ATCO Power Canada Ltd. - Rebuttal Submissions, May 26, 2017, paragraph 10.
[98] Exhibit 790-X3312, ATCO Power Canada Ltd. - Rebuttal Submissions, May 26, 2017, paragraph 29.
[99] Exhibit 790-X3157, Milner Power Inc. submissions on methodologies, February 24, 2017, paragraph 46.
[100] Exhibit 790-X3438, TransAlta Argument Module C, July 28, 2017, paragraph 131-132.
[101] Exhibit 790-X3438, TransAlta Argument Module C, July 28, 2017, paragraph 123-124.
[102] Exhibit 790-X3438, TransAlta Argument Module C, July 28, 2017, paragraph 134.
[103] Exhibit 790-X3308, UCA Reply Submission, May 26, 2017, page 1.

all retrospective adjustments due to deferral account reconciliation or any other adjustments." These interpretations are as follows:

> Option 1 (AESO Interpretation): all rights and obligations ... including any and all (1) retrospective adjustments due to deferral account reconciliation, OR (2) retrospective adjustments due to any other adjustments <u>of any sort whatsoever</u>.
>
> Option 2 (ATCO Interpretation): all rights and obligations ... including any and all retrospective adjustments due to (1) deferral account reconciliation, OR (2) any other adjustments of a nature <u>similar to deferral account reconciliation</u>. [104]

3.4 Commission findings: Invoices must be issued to the STS contract holder at the time when the losses occurred

3.4.1 The statutory scheme

109. The ISO tariff is part of the overall statutory scheme that governs the provision of electricity to Albertans from generation to distribution. That tariff, including Section 15, which lies at the heart of this dispute, cannot be read in isolation. Rather, the ISO tariff must be interpreted in a manner consistent with the governing legislation. The starting point for this exercise is the *Electric Utilities Act*. Section 5 of that act sets out its purposes, which include:

> (c) to provide for rules so that an efficient market for electricity based on fair and open competition can develop in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of government-owned participants or any other participant;
>
> (d) to continue a flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces;

110. Section 17 of the *Electric Utilities Act* sets out the duties of the AESO. Under subsection 17(e) the AESO is required to "manage and recover the costs of transmission line losses."

111. Section 30 of the *Electric Utilities Act* requires the AESO to prepare and submit a tariff to the AUC for approval. Section 30(4) provides that the AESO may recover the costs of transmission line losses by including those costs in that tariff. Section 31 requires market participants who obtain system access service to pay the AESO the rates prescribed in the ISO tariff and comply with the terms and conditions of that tariff.

112. Section 121 of the *Electric Utilities Act* sets out the matters the Commission must consider when deciding on a tariff application, including the AESO's tariff. That section requires the Commission to ensure that each approved tariff is just and reasonable and that each approved tariff is not unduly preferential, arbitrary or unjustly discriminatory or inconsistent with the statutory scheme.

[104] Exhibit 790-X3435, UCA Argument, July 28, 2017, paragraph 29.

113. The *Transmission Regulation* is also relevant to the Commission's analysis. Subsection 31(1)(a) requires the AESO to make rules to reasonably recover the cost of transmission line losses. Subsection 31(1)(e) makes it clear that owners of generating units, importers, exporters and other opportunity service customers subject to loss factors are charged or receive a credit so that they pay the actual cost of transmission line losses. Finally, Section 34 of the *Transmission Regulation* provides that the cost of transmission line losses must be reasonably recovered from the owners of generating units, importers, exporters and other opportunity service customers subject to loss factors through the ISO tariff.

114. Read simply, Section 17 of the *Electric Utilities Act* obliges the AESO to recover the costs associated with line losses. Section 30(4) of that act, in conjunction with Section 34 of the *Transmission Regulation*, directs the AESO to recover the costs of transmission line losses through the ISO tariff from four classes of market participants: the owners of generating units, importers, exporters and other opportunity service customers subject to loss factors. Section 121 of the *Electric Utilities Act* sets out what the Commission must consider when deciding on the ISO tariff, including the line loss component. Finally, underlying this scheme is the overriding goal of an efficient energy market based on fair and open competition in which no party can enjoy an unfair advantage that could distort the market or the Alberta electric industry.

3.4.2 The Commission's interpretation in past decisions

115. The Commission has considered these and related provisions in past decisions in this proceeding; those interpretations must also inform its decision regarding whether to invoice current STS holders or those of record when the line losses occurred.

116. The Commission found in Decision 2012-104 that the previous unlawful Line Loss Rule did not comply with the *Transmission Regulation* because it employed a methodology that disadvantaged loss savers and did not properly charge loss creators.[105] The Commission then considered the application of cost causation in relation to line losses and stated:

> In rate design, the principle of cost-causation requires that there be no undue discrimination between ratepayers in the same class. Those who cause high costs should pay for the high costs and those whose costs are lower should pay less. Translated into the line loss rule, this would mean that, at the very least, loss causers should pay while loss savers should receive a credit. When those who lower line losses are actually charged while those causing losses are charged much less than their contribution, this not only is unduly discriminatory, but unjust.[106]

117. In Decision 790-D02-2015, the Commission found that the line loss charge components of the ISO tariff have been unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory and inconsistent with Alberta legislation since January 1, 2006. The Commission further found that the Line Loss Rule and the line loss components of the ISO tariff were subject to a negative disallowance scheme, and were automatically considered interim and have

[105] Decision 2012-104: April 16, 2012, paragraph 94.
[106] Decision 2012-104: April 16, 2012, paragraph 97.

remained effectively interim since they went into effect on January 1, 2006.[107] In that same decision, the Commission found that "[t]o inflict financial harm without just cause on one group of competitors, while bestowing on another group of competitors financial benefits to which it has no just claim, is to interfere with the efficient market for electricity based on fair and open competition as required by Section 5 of the *Electric Utilities Act*."[108] The Commission later stated:

> Finally, the Commission remains sensitive to the following concern expressed by the courts. That is, the overall scheme of legislation governing regulatory ratemaking should not be interpreted in a manner that creates incentives for parties to act opportunistically where a finding has been made that existing rates are unjust and unreasonable. In particular, in so far as negative disallowance schemes are concerned, it would run contrary to the very purpose of such schemes were it possible for parties that benefit from unjust and unreasonable rates to permanently (and unjustly) capture for their benefit, at the expense of injured parties, the rewards attending regulatory delay.[109]

3.4.3 Section 15(2) of the ISO tariff

118. Section 15(2) of the ISO tariff addresses assignments between market participants. The Commission has reproduced Section 15(2) again to assist the reader.

> 2(1) A market participant may assign its agreement for system access service or any rights under it to another market participant who is eligible for the system access service available under such agreement and the ISO tariff, but only with the consent of the ISO, such consent not to be unreasonably withheld.
>
> (2) The ISO must apply to the account of the assignee all rights and obligations associated with the system access service when a system access service agreement for Rate DTS, Demand Transmission Service, Rate FTS, Fort Nelson Demand Transmission Service, or Rate STS, Supply Transmission Service, has been assigned in accordance with subsection 2(1) above, including any and all retrospective adjustments due to deferral account reconciliation or any other adjustments.

119. The Commission considers that the purpose of Section 15(2) is to provide the AESO and market participants with certainty about the effects of assignments in the normal course. From a policy perspective, it is reasonable that assignees are required to assume responsibility for obligations associated with the facilities they have acquired. It is also reasonable that the AESO have a single, readily identifiable and convenient point of contact for all market participants receiving system access service.

120. Section 15(2) appears to make assignees responsible for the rights and obligations of predecessor STS contract holders including "retrospective adjustments due to deferral account reconciliations" or any other adjustments. Examples of the types of "other adjustments" contemplated in Section 15(2) are found in Section 13(5), which specifically allows for

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[107] Decision 790-D02-2015: January 20, 2015, paragraph 8.
[108] Decision 790-D02-2015: January 20, 2015, paragraph 226.
[109] Decision 790-D02-2015: January 20, 2015, paragraph 259.

adjustments to a market participant's statement of account for system access service for unavailable or incomplete meter data, inaccurate estimates of meter data, or reconciliations with updated estimates of meter data. Read in this context, the Commission considers that the types of adjustments contemplated in Section 15(2) appear to be adjustments necessary to true up or update lawful rates that are just and reasonable.

121. The Commission finds the AA&N agreements to be of little assistance when deciding whether to invoice current or original STS contract holders because those agreements are subject to the terms of the ISO tariff, which, in turn, is subordinate to the Commission's statutory obligation to safeguard the fair, efficient and openly competitive operation of the market and to ensure that rates are just and reasonable. To the extent that there are inconsistencies between the tariff and the AA&N agreements and the Commission's statutory obligations, the statutory obligations must prevail.

122. To satisfy the Commission's statutory obligations to safeguard the fair, efficient and openly competitive operation of the market and to ensure that rates are just and reasonable, invoices for final rates to replace interim rates must be issued to the original cost causers and cost savers, not only because they were competitors of each other, but because they were the parties unjustly and unduly advantaged or disadvantaged by the unlawful interim rates. Because Section 15(2) contemplates adjustments to a lawful tariff in the normal course, applying it in these circumstances cannot achieve this objective. The Commission finds that Section 15(2) does not apply in these singular circumstances.

123. Previous STS contract holders either contributed to lines losses or to line loss savings, paid interim rates that were subsequently determined to be neither just nor reasonable, and should now be invoiced for final rates that are just and reasonable. The Commission agrees with ATCO Power's submission that:

> …each market participant has the right to be charged, and similarly has the obligation to pay, just and reasonable rates. Finalization of interim rates, as in the current case, ensures this. The current issue is not about special treatment for losses. Transferring fundamental rights with respect to interim rates is simply not contemplated by the ISO Tariff.[110]

124. While the previous Line Loss Rule itself was determined to be unlawful, and the related line loss charges were determined to be interim, no party to this proceeding has suggested that the invoices for those line loss charges were issued to the wrong party during the historical period. In ordering that a compliant line loss rule replace an unlawful rule during the historical period, and that a just and reasonable rate replace an unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory interim rate, the Commission must proceed on the basis that the invoices for the interim rates were issued to the correct parties, and that the invoices for the final rates should be issued to the same parties.

125. The Commission cannot emphasize enough that, but for the unlawful Line Loss Rule, the predecessor STS holders associated with historical line losses would have been responsible for the costs of those line losses. From the Commission's perspective, it would be contrary to the

[110] Exhibit 790-X3293, ATCO – Submissions relating to the positions of other parties, May 8, 2017, paragraph 17.

principle of cost causation and unjust and unreasonable, to allow predecessor STS contract holders to avoid responsibility for the losses they caused by not invoicing them for lawful final rates. Further, interpreting Section 15(2) as requiring that current STS contract holders be initially invoiced in these circumstances could be perceived as creating an incentive for opportunistic behavior which, as noted above, the courts have frowned upon in the past. As argued by the Balancing Pool:

> The re-distribution of historical line losses cannot be permitted to become a high-stakes game of "hot potato" in which the party holding the STS Contract when the music stops is liable to the AESO for eleven years of line loss charges.[111]

126. The Commission finds that invoicing current STS holders for charges or credits for the line losses of predecessor STS holders could create unfair advantages for some market participants that could potentially distort both the market and the structure of the industry. The Commission notes, in this regard, that the effect of invoicing current STS holders could potentially do that which the Commission previously found to be impermissible, i.e., to bestow on a group of competitors financial benefits to which they may have no just claim. In the Commission's view, this could potentially interfere with the efficient market for electricity based on fair and open competition as required by Section 5 of the *Electric Utilities Act*. This is not to say that market participants are not free to contractually shift liabilities for past unlawful rates they were charged. Rather, it simply recognizes that such transactions fall outside the statutory scheme and the Commission's purview.

127. The remedy for an interim rate that has been determined to be neither just nor reasonable, is to issue a lawful final rate in its place. However, such remedy is imperiled if the final invoices are not issued to the right market participants. Disadvantaged loss savers and undercharged loss causers are treated justly and reasonably if they receive final invoices that correct the competitive injustice wrought by unlawful interim charges. This is consistent with the Commission's express intention throughout this proceeding. Subject to the ongoing caveat in this decision that the Commission is only determining which market participants the AESO must invoice, and that the ultimate responsibility for payment may rest with others pursuant to separate commercial agreements, the Commission finds it is just and reasonable to issue final invoices to the same party that received the original (currently interim) invoices for line losses during the historical period.

128. In response to the AESO's request set out as Direction 10 in its final argument, the Commission confirms that its determination on the applicability of subsection 15(2) as set out above applies only to the historical period. The Commission further confirms that this determination applies only to the correction of line loss charges and credits for system access service provided under Rate STS and not to any corrections arising from system access service provided under Rate demand transmission service (DTS) or Rate Fort Nelson demand transmission service (FTS).

[111] Exhibit 790-X3433, Balancing Pool Argument, July 28, 2017, paragraph 5.

4 The method for and timing of collection and reimbursement

129. The AESO explained that, pursuant to Section 33(1) of the *Transmission Regulation*, the AESO applies charges and credits under the ISO tariff to reasonably recover the actual cost of losses on an annual basis. If the actual cost of losses is over-recovered or under-recovered in one year, then, pursuant to Section 33(2) of the *Transmission Regulation*, the over-recovery or under-recovery must be refunded or collected in the next year or subsequent years.[112] The AESO suggested that the most straightforward and efficient method for the collection and reimbursement of funds over the historical period would be by way of retroactive adjustments to charges assessed under the ISO tariff. This would involve a recalculation of bills and the issuance of new statements of account. The AESO explained that its transmission settlement system (TSS) is capable of correcting the applicable bills and reissuing invoices for any settlement period back to January 1, 2006.[113] The AESO further explained that the TSS is currently unable to issue invoices to the original STS contract holders and it would need time to modify the system. However, the AESO stated that it did not expect the modifications to be a barrier should the Commission direct the AESO to invoice the original STS contract holders.[114]

130. The Commission agrees with the AESO that the most straightforward and efficient approach for the collection and reimbursement of funds for the historical period would be by way of retroactive adjustments to charges assessed under the ISO tariff. The Commission finds that settlement under Module C will involve the AESO recalculating the bills for the historical period using the Modified Module B methodology and issuing new statements of account. The determination of which parties the new statements of account should be addressed to is dealt with in Section 3.4.3.

4.1 Sequence of collection and reimbursement

131. The AESO explained that rebilling all services for each year will take several days to process and may need to be spread over more than one settlement period to avoid conflict with the AESO's on-going settlement process.[115]

132. Discussion at the round table meeting contemplated two approaches for the collection and reimbursement of historical line losses:

(a) A single, net settlement approach with one net charge collected or reimbursed to market participants only after all loss factors have been calculated for the historical period (single settlement).

(b) A pay-as-you-go settlement approach, with a charge or reimbursement made to market participants once the loss factors had been calculated for one or more years and repeated sequentially until all historical years have been settled (pay-as-you-go settlement).

[112] Exhibit 790-X3030, AESO Description of Losses Cost Recovery Methodology, May 12, 2016, paragraph 4.
[113] Exhibit 790-X3032, AESO Submission on module C issues, June 9, 2016, paragraph 20.
[114] Exhibit 790-X3180, AESO Preliminary comments on submissions filed February 24, 2017, paragraph 10.
[115] Exhibit 790-X3030, AESO Description of Losses Cost Recovery Methodology, May 12, 2016, paragraph 33.

133. The AESO indicated that both approaches would require a second process to address any trailing amounts resulting from the AESO's inability to collect from or reimburse certain market participants. This is discussed further in Section 4.9.

134. The AESO identified three potential options for collection and reimbursement of loss factor charges and credits for the historical period and, in its argument, requested direction from the Commission on which option (or other alternative) to implement. The three options proposed by the AESO included:[116]

- Option 1 - Simultaneous collection and refund: Shortfalls will not be known until after refunds are paid. Payment plans for collections might require the use of a credit facility following simultaneous refunds.

- Option 2 - Collection before refund: Payment due date delays would delay refunds as well. No shortfalls, as refunds will equal payments received.

- Option 3 – Refund before collection: No delay in refunds. This option would require a credit facility to manage due date delays between refund and collection. Shortfalls would not be known until 60 to 90 days after refunds are issued.

135. The AESO suggested that collection and reimbursement be implemented on a simultaneous basis, consistent with the AESO's normal practice.[117] The AESO also pointed out that if a due date delay was approved for amounts owing, then simultaneous collection and refund would mean that payment of refunds would also be delayed for a similar period of 60 to 90 days.[118]

136. The AESO stated in testimony that a single settlement process would be simpler and more efficient.[119] The single settlement process nets charges and reimbursements to each individual market participant, and it avoids potentially charging a market participant for one year and then later issuing a refund to the same market participant for another year.[120]

137. The AESO explained that it contemplates calculating each year sequentially and then posting the results in advance of issuing any new statements of account. The AESO pointed out that under the single settlement approach, stakeholders will have the opportunity to review loss factors that are posted as they become available during the calculation process and prior to single settlement. By comparison, under the pay-as-you-go settlement approach, new statements of account will be issued following calculation of each year's loss factors, and may allow less time for stakeholders to review posted loss factors before the new statements of account are issued.

[116] Exhibit 790-X3441, AESO Argument July 28, 2017, paragraph 16.
[117] Exhibit 790-X3395, AESO Module C Reply Comments and Request for Directions, June 19, 2017, paragraph 9(c).
[118] Exhibit 790-X3177, AESO Comments on Immediate Resettlement, March 10, 2017, paragraph 24(a). In testimony, Mr. Martin confirmed that the principles and comments with respect to interim settlement, found in Exhibit 790-X3177, also apply to final settlement. Transcript, Volume 2, June 13, 2017, page 289, lines 11-15.
[119] Transcript, Volume 1, June 12, 2017, page 56, lines 15-17.
[120] Exhibit 790-X3137, AESO Additional Information on Module C Scenarios, January 31, 2017, paragraph 14.

However, if the payment due date is delayed, as proposed by the AESO, stakeholders will have that extra time to review loss factors before needing to pay an invoice.[121]

138. A number of parties supported the AESO's preference for the single settlement approach, including Capital Power, ENMAX and TransAlta. Other parties, including ATCO Power, City of Medicine Hat, Milner, Powerex and TCE supported a pay-as-you-go settlement approach, with new statements of account issued for each historical year, once the information becomes known.

139. The parties in favour of the single settlement approach argued that, because the AESO will release the line loss results for each year of the historical period as they become available, the advance notice will allow parties who have been undercharged over the historical period to plan for repayment. It would also provide parties the opportunity to review the AESO's line loss results to check for any issues with the calculations prior to being invoiced for payment. Capital Power argued that, in the alternative, under the pay-as-you-go approach, parties may potentially be exposed to multiple cost shocks, which in turn have the potential to cause cash flow disruptions.[122] TransAlta argued that the single settlement option would provide parties the time needed to check for technical issues in the calculations and to confirm that the results can pass "reality and plausibility checks."[123] ENMAX indicated that its preliminary modelling has demonstrated significant variability over the historical period due to the fact that ENMAX's asset portfolio has changed over this period.[124] Capital Power and ENMAX both expressed concern that there is a risk under the pay-as-you-go settlement approach that certain generators may not be available or able to repay amounts initially refunded to them should those amounts need to be returned in later years.[125]

140. The parties in favour of the pay-as-you-go settlement approach generally preferred it because it would allow settlement to begin significantly earlier than under the single settlement approach. It was argued by a number of parties that the AESO should be required to rectify, as expeditiously as possible, the fact that some parties have overpaid line loss charges, potentially as far back as 2006, and continue to carry this burden. ATCO Power submitted that there is no justification for deferring settlement for the entire historical period when the relevant data for just and reasonable line loss charges for a particular year becomes available.[126] Milner submitted that parties owed money will face greater cash flow problems if payments are not made each year.[127]

141. Both ATCO Power and the City of Medicine Hat argued that the pay-as-you-go approach could accommodate stakeholder consultations and the verification of loss factors on a year-by-year basis.[128] ATCO Power submitted that there is no evidence on the record to suggest

[121] Exhibit 790-X3441, AESO, Argument July 28, 2017, paragraph 39.
[122] Exhibit 790-X3442, Capital Power, Argument July 28, 2017, paragraph 141.
[123] Exhibit 790-X3438, TransAlta, Argument July 28, 2017, paragraph 136.
[124] Exhibit 790-X3436, ENMAX, Argument July 28, 2017, paragraph 14.
[125] Exhibit 790-X3436, ENMAX, Argument July 28, 2017, paragraph 21.
[126] Exhibit 790-X3445, ATCO Power, Argument July 28, 2017, paragraphs 100-102.
[127] Exhibit 790-X3460, Milner, Reply Argument August 18, 2017, paragraph 182.
[128] Exhibit 790-X3445, ATCO Power, Argument July 28, 2017, paragraph 101; and exhibit X3430, CMH Argument Module C, July 28, 2017, paragraph 110.

that historical loss charges will threaten the ongoing viability and cash flow of a generator,[129] and it disagreed with ENMAX that there would be significant variability from year-to-year. Instead, it argued that because line loss charges will be based on location relative to load under a compliant methodology, alternating credits and charges throughout the historical period are unlikely.[130] Milner disputed that single settlement is better from a cash flow perspective, arguing instead that those parties required to make payments are better able, from a cash flow perspective, to absorb a series of smaller payments over time rather than a single large payment.[131]

142. With respect to the three options for collection and reimbursement of loss factor charges and credits for the historical period, generally parties supported the AESO's Option 1, simultaneous collection and refund. No alternatives were put forward, but two parties objected to a collection option that would delay reimbursement to those market participants that had overpaid line loss charges over the historical period. Milner suggested that any further delay in repayment would only add to the financial hardship of these parties[132] and strongly supported Option 3, which provides for refunds before collections.[133] Similarly, Powerex submitted that Option 3 is the only acceptable option.[134]

4.1.1 Commission findings

143. The Commission directs the AESO to implement the single settlement approach for the historical period with simultaneous collection and reimbursement. The Commission also directs the AESO to release the yearly line loss results and the updated line loss charges for each year as they become available. The results must include the updated line loss charges for the specific year and cumulative results for each party. The Commission accepts that one or more secondary processes may be needed to address any trailing amounts resulting from the AESO's inability to collect from or reimburse certain market participants. This is addressed further in Section 4.5 of this decision.

144. The Commission agrees that parties should have an opportunity to review the yearly line loss results calculated using the Modified Module B methodology. The single settlement approach will provide parties with the opportunity to review the results for each year, before new statements of account are issued. The Commission expects that the yearly line loss calculations will become routine after some initial debugging of the Modified Module B methodology by the AESO, but considers it will be most efficient, from an administrative perspective, to wait until all years are calculated before issuing a final statement of account for the full historical period. The Commission recognizes that, of all the options considered, the single settlement approach will delay refunds the longest. The Commission discusses steps to help address the longer timeline in Section 4.2 of this decision.

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129 Exhibit 790-X3445, ATCO Power, Argument July 28, 2017, paragraph 104.
130 Exhibit 790-X3445, ATCO Power, Argument July 28, 2017, paragraph 106.
131 Exhibit 790-X3460, Milner, Reply Argument August 18, 2017, paragraph 185.
132 Exhibit 790-X3460, Milner, Reply Argument August 18, 2017, paragraph 28.
133 Exhibit 790-X3443, Milner, Argument July 28, 2017, paragraph 151.
134 Exhibit 790-X3429, Powerex, Argument July 28, 2017, paragraph 47.

145. It is not clear from the evidence in this proceeding whether there will be significant variability in the revised yearly line loss charges for any one market participant. ENMAX has submitted that its modelling indicates there will be significant variability, at least for ENMAX, whereas ATCO Power has suggested that, because the line loss charges will be based on location relative to load under a compliant methodology, market participants should not experience alternating charges and credits as the updated yearly line loss amounts are finalized. Given this uncertainty, the Commission is not prepared to direct an approach that could result in a market participant that overpaid during the historical period being required to pay again under the pay-as-you-go approach, even though that market participant may ultimately be a net beneficiary once all calculations have been completed.

146. The Commission also considers that collection (including the possible repayment of amounts already refunded) under the pay-as-you-go approach could impose an additional administrative burden on the AESO if it is required to deal with payment defaults. The Commission agrees with TransAlta and Capital Power that, under the single settlement approach, parties would be aware of their accumulating statement of account and would have time to plan for payment. The extra time would also assist the AESO in establishing credit facilities and payment plans, if necessary.

4.2 Interest

147. In Decision 790-D04-2016, the Commission found that "it is just and reasonable to consider the time value of money dating back to January 1, 2006 and that awarding (and charging) interest is a practical and just and reasonable method of doing so."[135] Further, the Commission determined that "it would be reasonable to set the rate of interest equal to the Bank of Canada's Bank Rate plus one and one half per cent to be applied from the date on which the recalculated loss factors become effective to January 1, 2006 consistent with the guidance provided in sections 3(2)(d) and 3(2)(e) of AUC Rule 023."[136]

148. In response to questioning by Commission counsel, Mr. Martin suggested that while the AESO did not require further direction from the Commission with respect to the charging and awarding of interest associated with historical line loss charges, it might be helpful to market participants if more specifics were provided. Mr. Martin proposed that, when it issues statements of account to market participants, there would be an accompanying document setting out the monthly amounts and showing the interest attributed to each of the monthly amounts so that market participants would understand how the interest was calculated.[137]

4.2.1 Commission findings

149. Further to the Commission's finding in Decision 790-D04-2016, that directs the AESO to award (charge) interest, equal to the Bank of Canada rate plus one and one half per cent, the Commission directs the AESO to set out the interest attributed to the monthly amounts for each

[135] Decision 790-D04-2016: September 28, 2016, paragraph 78.
[136] Decision 790-D04-2016: September 28, 2016, paragraph 80.
[137] Transcript, Volume 2, June 13, 2017, page 293, lines 2-11.

market participant when it issues updated statements of account for the historical line loss charges.

4.3 Consideration given to outstanding appeals

150. TransAlta stated that it filed applications for leave to appeal the Commission's findings in Module A and Module B of this proceeding and that it will seek a stay of any orders that the Commission may make in this decision with respect to payments related to final historical line loss factors, pending resolution of its Module A appeal.[138]

151. Capital Power has maintained its position throughout Module C that no retroactive payments can or should be made until Module A is finally resolved in the appellate courts. It argued that if payments were made before that time and were reversed later, it would cause prejudice to parties and needless process, which would further delay final resolution of this proceeding.[139]

152. ENMAX stated that it has filed a permission to appeal application with the Alberta Court of Appeal with respect to the Commission's Module A decision and an application for permission to appeal with respect to the Commission's Module B decision. ENMAX submitted that it would be unreasonable to permit the AESO to begin billing for retrospective adjustments until all of the outstanding permission to appeal and review and variance applications have been determined. It argued that the outcome of the leave to appeal applications could have significant implications for the retrospective adjustments, including whether the Commission has the jurisdiction to order such adjustments.[140] ENMAX pointed out that, if these applications are successful, and a subsequent appeal regarding the Commission's jurisdiction is allowed, there will be no retrospective adjustments for the historical period.[141]

4.3.1 Commission findings

153. For the reasons set out above, the Commission directs the AESO to adopt a single settlement approach in which the final statement of account will not be issued until the AESO has calculated loss charges and credits for the full historical period. This approach provides registered parties with an opportunity to pursue review or appeal remedies with the Commission and the Court of Appeal. Both the review and appeal processes include mechanisms for the granting of a suspension or stay of the operation of some or all of the Commission's orders and directions in this proceeding. The Commission finds that parties seeking such remedies should pursue them in the proper forum following the issuance of this decision. Accordingly, the Commission is not prepared to direct a delay in the billing for retrospective adjustments pending resolution of the various outstanding review and permission to appeal applications.

[138] Exhibit 790-X3438, TransAlta, Argument July 28, 2017, paragraph 138.
[139] Exhibit 790-X3442, Capital Power, Argument July 28, 2017, paragraph 4.
[140] Exhibit 790-X3436, ENMAX, Argument July 28, 2017, paragraph 18.
[141] Exhibit 790-X3436, ENMAX, Argument July 28, 2017, paragraph 19.

4.4 Accelerated settlement

154. As discussed earlier in this decision, parties considered both compliance and expediency to be important considerations in evaluating and selecting a methodology to be applied to the historical period. The Commission acknowledges the desire of parties that are owed money for the historical period to minimize any further delay in receiving payment.

155. The AESO was asked at various times throughout Module C to comment on the implementation timeline.[142] In response, the AESO estimated timelines for normal and accelerated implementation of each methodology. The AESO explained that implementing settlement under the Modified Module B methodology with single settlement could be accomplished using its existing resources, in the normal course of business. However, to accelerate settlement would involve additional cost, because the AESO would need to assign additional resources. The AESO estimated the additional cost to accelerate the settlement process at $400,000.[143]

156. The AESO estimated that it would take nine months less to implement the single settlement approach using the Modified Module B methodology with an accelerated process.[144]

4.4.1 Commission findings

157. Earlier in this decision, the Commission determined that settlement should be undertaken using the single settlement approach rather than the pay-as-you-go approach. However, in selecting the single settlement approach, reimbursement, even partial yearly refunds, will be delayed. The Commission recognizes the protracted nature of Proceeding 790 and the importance placed on expediency for Module C. In light of this, the Commission considers that it is reasonable and in the public interest to incur the additional cost to expedite calculation of the line loss charges for the historical period. Accordingly, the Commission directs the AESO to assign the necessary resources to implement the accelerated single settlement approach it has proposed.

4.5 Recovery of incremental costs for accelerated settlement

158. The AESO requested that, in the event the Commission directs it to implement Module C settlement on an accelerated basis, the Commission provide clarity regarding the recovery of material additional costs incurred through such a process. The AESO suggested that the additional costs be allocated to the energy market function to be recovered through the energy market trading fee.[145]

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[142] The AESO addressed implementation timeline in exhibits: 790-X3137, 790-X3177, 790-X3359, 790-X3374 and 790-X3380.

[143] Exhibit 790-X3137, AESO Additional Information on Module C Scenarios, January 31, 2017, paragraph 39.

[144] Exhibit 790-X3380, AESO UT to TransCanada, June 13, 2017.

[145] Exhibit 790-X3395, AESO Module C Reply Comments and Request for Directions, June 19, 2017, paragraph 9(b).

159. The AESO suggested that the additional costs could be tracked and recovered as part of the costs of settlement. It identified four options for the recovery of incremental costs:[146]

(a) Include the costs as a cost of losses.

(b) Recover the costs through the ISO tariff.

(c) Recover the costs through the energy market trading fee.

(d) Recover the costs through some other fee or charge.

160. The AESO submitted that recovery through either the ISO tariff or the energy market trading fee would be the most practical and efficient alternative because neither requires modifications to the AESO's information or billing systems.

161. The AESO explained that recovery through the ISO tariff would generally result in costs being attributed to market participants through rate DTS and rate FTS. On the other hand, recovery through the energy market trading fee would result in costs being attributed to transactions with the power pool as a dollar per megawatt-hour (MWh) charge, which would involve both generation and load market participants. The AESO stated its preference for recovery through the energy market trading fee at the hearing:

> the AESO considers it more appropriate to recover the costs associated with accelerated settlement from all energy market participants rather than solely from load.[147]

162. Parties either did not comment or generally agreed with the AESO's recommendation to use the ISO tariff or the energy market trading fee to recover the additional costs for an accelerated settlement process. The City of Medicine Hat supported recovery through the energy market trading fee and submitted that "[a]ny such fee is likely to be of an inconsequential magnitude per MWh. (e.g. $500,000/60,000 GWh = $0.008/MWh).[148]

4.5.1 Commission findings

163. The Commission directs the AESO to track its additional costs to implement an accelerated settlement process and to recover the incremental cost through the energy market trading fee. While the Commission is hesitant to attribute a portion of these additional costs to load market participants through the energy market trading fee, the Commission recognizes that it is the most practical solution since it would not impose further costs on the AESO to modify its information and billing systems, as would be the case were the Commission to direct recovery as a cost of losses, or recovery through some other fee or charge. The Commission also agrees with

[146] Exhibit 790-X3441, AESO Argument, paragraph 12.
[147] Transcript, Volume 6, June 20, 2017, page 870.
[148] Exhibit 790-X3430, City of Medicine Hat, Argument July 28, 2017, paragraph 117.

the City of Medicine Hat that recovery of the incremental cost as a dollar per MWh charge is likely to be immaterial.

4.6 Payment due date delay

164. The AESO explained that in cases where an invoice for payment was not previously known, it is common business practice to allow 60 to 90 days before payment is due. The AESO suggested that some parties may require additional time to arrange funds for the payment of the revised statement of account and requested that the Commission provide a direction to permit a due date delay for payment of Module C settlement invoices.

165. The AESO explained that during its normal settlement process, it issues preliminary statements to market participants on the fifth business day of the following month. It issues final statements on the fifteenth business day and requires cash settlement of accounts on the twentieth business day of the following month.[149] The AESO recommended that financial settlement be delayed by two months beyond the due date that would otherwise apply to a tariff invoice it has issued.

166. Parties agreed with the payment due date delay proposed by the AESO.

4.6.1 Commission findings

167. The Commission considers that the proposed 60 day due date delay, as described and recommended by the AESO, is reasonable, especially in light of the fact that the single settlement option was approved. The Commission acknowledges that under the simultaneous collection and refund option, the payment of refunds would be correspondingly delayed.

4.7 Credit facility and optional payment plan

168. Total line loss charges subject to adjustment are roughly $1.6 billion over the historical period.[150] Once line loss charges have been recalculated for all eleven years, a market participant may face a substantial payment owing. According to the AESO, in some cases, the amount owing could be substantial enough to adversely affect the cash flow or harm the financial stability of some market participants. In these circumstances, the AESO expects that a due date delay may not provide enough relief and market participants will request a longer-term payment plan. The AESO considers that offering a payment plan is preferable where the financial stability of the market participant is compromised and the alternative is to default on the amount owing.[151]

169. The AESO requested that the Commission direct a payment plan be made available to market participants should it be needed. In response to this direction, the AESO would proceed to:

[149] Exhibit 790-X3030, AESO Description of Losses Cost Recovery Methodology, May 12, 2016, paragraph 15.
[150] Exhibit 790-X3155, CPC Module C Submissions on Methodology and Settlement Matters, February 24, 2017, paragraph 10.
[151] Exhibit 790-X3177, AESO Comments on Immediate Resettlement, paragraph 21.

(a) Confer with financial institutions and advisors to develop proposed terms of the payment plan and eligibility criteria.

(b) File the proposed structure, terms, and eligibility criteria with the Commission for approval prior to issuing any invoices under Module C.[152]

170. The AESO submitted that it may be required to arrange credit facilities to manage shortfall balances caused by any delays between refunds and collections, or arising from payment plans or payment defaults. The AESO estimates that it would need two to three months to arrange the credit facility.[153]

171. Parties were mostly silent on the need for additional credit facilities and whether the AESO should offer a payment plan. TCE submitted that it is reasonable for the AESO to utilize its existing credit facilities,[154] and Milner commented that the AESO likely didn't need a direction from the Commission to confer with financial institutions, but if a direction is given, it should be given as soon as practicable.[155]

4.7.1 Commission findings

172. In Decision 790-D04-2016, the Commission found that, if a market participant is faced with a settlement invoice that would compromise ongoing viability, it would be reasonable for the market participant to work collaboratively with the AESO to explore available mechanisms that would mitigate adverse financial impacts, while still allowing for the charges to be paid.[156]

173. The Commission also recognized in Decision 790-D04-2016 that the AESO already has considerable leeway to negotiate or impose terms for any deferred payment relating to a just and reasonable tariff charge under ISO rules Section 103.7: *Financial Default and Remedies* and ISO rules Section 103.3: *Financial Security Requirements*.[157]

174. The Commission supports the AESO's efforts to put in place the credit facilities and payment options it considers necessary for the smooth implementation of the settlement process. The Commission considers that incurring an incremental cost to put in place additional credit facilities and a payment plan is reasonable, if it helps to avoid imposing material financial impacts on market participants or helps to avoid payment defaults. The Commission continues to encourage market participants to work collaboratively with the AESO to explore available mechanisms that would mitigate adverse financial impacts, while still allowing for charges to be paid.

152 Exhibit 790-X3441, AESO Argument, July 28, 2017, paragraph 24.
153 Exhibit 790-X3177, AESO Comments on Immediate Resettlement, paragraph 21.
154 Exhibit 790-X3446, TCE Argument July 28, 2017, paragraph 144.
155 Exhibit 790-X3443, Milner, Argument July 28, 2017, paragraph 152.
156 Decision 790-D04-2016: September 28, 2016, paragraph 61.
157 Decision 790-D04-2016: September 28, 2016, paragraphs 55-56.

175. The Commission directs the AESO to develop the structure, terms and eligibility criteria for its proposed payment plan, and file it with the compliance filing to this decision as directed below.

4.8 Collection of credit facility administration and interest costs

176. The AESO requested a direction from the Commission regarding the recovery of administration costs related to a credit facility required to manage shortfall balances throughout the settlement process.

177. The AESO also requested a direction from the Commission regarding the recovery of interest costs incurred for the credit facility. This would not include interest costs that are associated with a payment plan. These costs would be paid by the market participant. However, it would include interest costs associated with carrying balances due to timing differences between refunds and collections and as a result of payment defaults. Those interest costs cannot be attributed to a particular market participant.

178. The AESO proposed that these incremental administration and interest costs be recovered through the energy market trading fee.[158]

4.8.1 Commission findings

179. The Commission approves recovery of any incremental administration costs and the interest costs associated with credit facilities specifically put in place to manage shortfall balances throughout the settlement process through the energy market trading fee. The Commission considers this is the most practical way to recover these costs since it does not impose further costs on the AESO to modify its billing systems, as would be the case were the AESO to recover the costs through a new fee or charge. The Commission also considers that recovery of these incremental costs, as a dollar per MWh charge, is likely to be immaterial.

4.9 Collection of payment default shortfalls

180. The AESO considered three alternatives for collection of payment default shortfalls:[159]

(a) Collection through reduced refunds to market participants, which would only impact market participants who received refunds through the Module C settlement process.

(b) Collection through adjustment of loss factors using Rider E, or a similar mechanism, which would effectively include any payment default shortfalls as a "cost of losses" to be recovered. This alternative could either:

- Impact all market participants receiving either charges or refunds for the historical period through the Module C settlement process; or

[158] Exhibit 790-X3441, AESO Argument July 28, 2017, paragraph 9, Direction 6.
[159] Exhibit 790-X3177, AESO Comments on Immediate Resettlement, paragraphs 29-32.

- Impact all market participants receiving loss charges and credits on a going-forward basis over a defined duration.

(c) Collection through a separate fee assessed against some or all market participants on a going-forward basis over a defined duration.

181. The AESO requested that the Commission provide a direction regarding the process for collection of payment default shortfalls arising in response to a default on a settlement invoice or a default on payments made under a payment plan. The AESO recommended that such payment default shortfalls be collected through Rider E, consistent with the AESO's normal practice. In describing the AESO's consideration of the alternatives, Mr. Martin explained "… it seemed like Rider E was a relatively easy and available way to accomplish it that aligned with legislation. So we didn't put too much attention on other methodologies."[160]

182. Rider E is used to adjust loss factors to ensure that the actual cost of losses is reasonably recovered through charges and credits. The AESO must determine a calibration factor each quarter to recover or refund differences between the forecast and actual cost of losses.[161] The AESO explained that Rider E is also currently used for retroactive adjustments to loss charges or credits, such as data changes to metered volumes after final settlement; corrections to metering errors; or, in the event of an error in the billing of a losses charge to a service.[162] In each of these cases, if the change affects the cost of losses, any resulting variance is recovered over all services to which loss factors apply as part of the next Rider E adjustment.

183. The AESO submitted that it is necessary for the Commission to define the process for collection of payment default shortfalls to provide certainty for market participants, as well as to support the AESO's ability to secure credit facilities.[163]

184. In Decision 790-D04-2016, the Commission was not prepared to approve the use of Rider E to recover any mismatches between collections and refunds because the full extent of any mismatch was unknown. The Commission indicated that it would make a determination on how to deal with mismatches once it had more information on the extent of any mismatch, but also acknowledged that the full extent of any mismatch will only be known after the AESO settles the charges and credits for each calendar year.

185. TransAlta preferred the AESO's first alternative, namely, that any shortfall be deducted on a pro-rata basis from parties who are to receive refunds as part of the Module C settlement process.[164]

186. The City of Medicine Hat supported the AESO's proposal for payment default shortfalls to be collected through Rider E.[165] Similarly, ATCO Power supported the AESO dealing with

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160 Transcript, Volume 2, June 13, 2017, page 292, lines 2-5.
161 ISO Tariff – Rider E, Losses Calibration Factor Rider, www.aeso.ca.
162 Exhibit 790-X3030, AESO Description of Losses Cost Recovery Methodology, May 12, 2016, paragraphs 29-31.
163 Exhibit 790-X3177, AESO Comments on Immediate Resettlement, March 10, 2016, paragraph 27.
164 Exhibit 790-X3438, TCE Argument, July 28, 2017, paragraph 143.

shortfalls and surpluses as part of the AESO's normal process, but only if it is not a significant amount. ATCO Power proposed that if the amount is greater than +/- 5 per cent, the AESO should be required to confirm the reasons for the large discrepancy and to provide parties with an opportunity to comment on the approach to be used to deal with the mismatch.[166]

187. Other parties, such as Capital Power and TCE, submitted that the treatment of mismatch amounts should align with the AESO's normal approach to bad debt. TCE submitted that subsection 8(1) of ISO rules Section 103.6, *ISO Fees and Charges*, permits the AESO to recover payment default shortfalls from pool participants[167] and it pointed out that subsections 8(6) and 8(7) of ISO rules Section 103.6 contain reasonable refund provisions whereas the Rider E mechanism does not.[168]

188. TCE submitted that Rider E should not be used to recover payment default shortfalls. It argued that the purpose of Rider E is to correct for forecast error between the anticipated cost of losses and the actual cost of losses, not to recover the outstanding financial obligations of market participants.[169] It explained that, if used for this purpose, Rider E would end up collecting or refunding the variance amount based on a generator's output at the time, which would amount to different treatment than for any other unpaid charge levied under the ISO tariff. TCE submitted that a select group of market participants would be unjustly discriminated against, in violation of Section 121 of the *Electric Utilities Act*.[170]

189. The AESO submitted that there is no reason to limit or to qualify the direction to the AESO regarding the collection of shortfalls. It argued that to do so would only create uncertainty and that the recovery of shortfalls must be clearly provided for by the Commission to enable the AESO to arrange a credit facility without unnecessary delay.[171]

190. With respect to TCE's proposal that any shortfall amounts be collected under subsection 8 of ISO rules Section 103.6, *ISO Fees and Charges*, the AESO argued that doing so would violate the principle of cost causation, because it would result in both load and generation market participants incurring the cost of shortfalls. By comparison, the AESO's proposal to collect shortfalls using Rider E would be consistent with the principle of cost causation because it would allocate costs to generation market participants only, and not to load participants. The AESO also pointed out that Section 103.6 of the ISO rules is a non-tariff mechanism and, therefore, using it to recover shortfalls would not be consistent with the Commission's finding that line loss charges for the historical period are a tariff matter.[172]

191. The AESO did not agree with TCE's contention that recovery using Rider E would amount to treatment different from any other unpaid charge levied under the ISO tariff. The

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165 Exhibit 790-X3430, City of Medicine Hat, Argument, July 28, 2017, paragraph 126.
166 Exhibit 790-X3445, ATCO Power Argument, July 28, 2017, paragraph 112.
167 Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 125.
168 Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 129.
169 Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 127.
170 Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 128.
171 Exhibit 790-X3454, AESO Argument, August 18, 2017, paragraph 16.
172 Exhibit 790-X3454, AESO Argument, August 18, 2017, paragraph 17.

AESO explained that unpaid charges under the ISO tariff are rare but have been collected through the deferral account adjustment Rider C, which has an effect similar to Rider E.[173]

4.9.1 Commission findings

192. The Commission found, in Section 4.1.1 of this decision, that one or more secondary settlement processes will be needed to address any trailing amounts resulting from the AESO's inability to collect from or reimburse certain market participants. The Commission also determined, in Section 3.4 of this decision, that it is just and reasonable to issue final invoices for historical period line losses to the market participants that held the original STS contracts. Consistent with these findings, the Commission considers that any charges and refunds related to payment default shortfalls should also be allocated to the market participants that held the original STS contracts.

193. Accordingly, the Commission directs the AESO to use its proposed option b(i) for collection of payment default shortfalls, which is collection through an adjustment of loss factors using Rider E, where any default shortfalls are recovered as a cost of losses. An adjustment of loss factors through Rider E is to be applied to all market participants receiving either charges or refunds for the historical period through the Module C settlement process.

194. The Commission recognizes that the magnitude of any shortfall or surplus resulting from the settlement process will not be known until the final invoices for charges and refunds have been issued and financially settled. Only then, and only after reasonable efforts have been made to collect unpaid charges, would the amount of any shortfall or surplus be known. Therefore, the Commission directs that the AESO exhaust all reasonable means to collect outstanding amounts before resorting to recovery through Rider E.

195. The Commission also recognizes that, because it has directed that invoices be issued to original STS contract holders, further payment default shortfalls may arise. Should this occur, the Commission directs that any subsequent payment default shortfalls be recovered as they become known, from market participants by way of Rider E on a going forward basis.

5 Compliance filing is required

196. Almost all parties to Module C agreed that some form of compliance process is necessary, but differed as to what it should encompass. At the same time, no party in Module C argued that a new rule must be implemented as part of that process. Indeed, the AESO[174], ENMAX[175] and TransAlta[176] all submitted that a new rule cannot be applied with retroactive effect under Section 25(9) of the current *Electric Utilities Act*.

[173] Exhibit 790-X3454, AESO Argument, August 18, 2017, paragraph 18.
[174] Exhibit 790-X3441, AESO Argument, July 28, 2017, paragraph 34.
[175] Exhibit 790-X3449, 790- Module C Reply Argument, August 18, 2017, paragraph 11.
[176] Exhibit 790-X3456, TransAlta Module C Reply, August 18, 2017, paragraph 87.

197. The majority of parties submitted that a written description, as part of a compliance filing, would be sufficient. The AESO stated in argument that:[177]

> Even if an ISO rule could be made, the AESO submits that regulatory efficiency and practical considerations weigh against such an approach. Rule-making would trigger the AESO's consultation process, necessitate a filing pursuant to section 20.2 of the EUA, and could lead to objections and further regulatory process to consider and determine the complaints. Given that the ISO rule would be in effect for only so long as it will take to calculate Historical Period loss factors, the AESO respectfully submits the potential regulatory effort involved does not warrant the making of an ISO rule.
>
> Instead, the AESO submits that the appropriate approach would be for the AESO to file a written description of the approved methodology in this proceeding together with the procedure the AESO will use to implement it.

198. TCE submitted that all that is necessary to conclude Proceeding 790 and to give effect to a remedy is for the Commission to issue a decision that provides the basis for the unlawful interim rates to be corrected and made final. TCE stated that this can be done by directing the AESO to create a procedure document and then a compliance filing process can be implemented in a manner similar to Module B.[178]

199. Milner submitted that all that is required is a reissuance of the line loss portion of the ISO tariff charges dating back to January 1, 2006, and that the Commission can do this by directing the AESO to set out the specifics of the methodology for approval by way of a refiling.[179]

200. In Module B, several parties requested that the Commission direct the AESO to engage in "intensive" and "additional" consultations to develop and test the prospective methodology. However, the Commission ruled that further consultations should be left to the AESO's discretion.[180]

201. In Module C, the majority of parties supported some form of consultation prior to a methodology being implemented for the historical period. The AESO submitted that it should determine the requirements for stakeholder engagement on a case-by-case basis, as the Commission allowed it to do in Module B.[181] Similarly, TransAlta submitted that the process should include the release of results on a year-by-year basis, with ongoing consultations with stakeholders as issues arise.[182]

202. Capital Power supported a more formal consultation process whereby:[183]

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177 Exhibit 790-X3441, AESO Argument, July 28, 2017, paragraphs 35-36.
178 Exhibit 790-X3446, TCE Argument, July 28, 2017, paragraph 137.
179 Exhibit 790-X3443, Milner Power Inc. Final Argument, July 28, 2017, paragraphs 122-123.
180 Decision 790-D03-2015: January 20, 2015, paragraph 181.
181 Exhibit 790-X3441, AESO Argument, July 28, 2017, paragraphs 37-42.
182 Exhibit 790-X3456, TransAlta Module C Reply, August 18, 2017, paragraph 51.
183 Exhibit 790-X3442, Module C Argument of Capital Power Corporation, July 28, 2017, paragraph 145.

(a) The AESO would commence a stakeholder session that is "qualitative" in nature, to allow parties to better understand the basic elements of the approved approach and how the AESO intends to respond to the Commission's directions.

(b) Similar to the prospective Module B process, the AESO would produce the Module C methodology and publish a "version 1" of its model (including its program, scripts, etc.).

(c) Parties would have the opportunity to review and provide feedback on that model.

(d) The AESO would make any necessary revisions and publish an updated "version 2" of the model, along with a sample set of results for the four years of the AESO's "Modern Database."

(e) A final version of the model would be filed with the Commission for approval. If the Commission directs any material changes, a second compliance process should be undertaken.

203. ENMAX submitted that as part of the compliance filing, the affected parties should be permitted to (1) assess whether the methodology complies with the Commission's direction, and (2) determine if the AESO's loss factor calculations are correct.[184]

5.1 Commission findings

204. The Commission previously found in Module A that, it is charged with the responsibility of ensuring that rates are just and reasonable during the entire period such rates are deemed by operation of law to be interim. The process of calculating or determining rates that satisfy this standard does not require that a new or changed line loss rule be put into effect during the historical period.[185]

205. Similarly, and consistent with that finding, the Commission agrees with the majority of parties in Module C that a new rule is not required to implement the necessary rate adjustments for the historical period. Further, as stated in Decision 790-D02-2015, the Commission has a legislative duty and authority to adjust the tariff line loss charges flowing from the unlawful Line Loss Rule so that they are consistent with the statutory scheme, just and reasonable, not unduly preferential, arbitrary or unjustly discriminatory.[186] Finalizing the previously interim line loss charges requires direction from the Commission, and not a new rule to take effect.

206. The Commission finds that a reasonable and efficient approach is for the AESO to submit a compliance filing for approval which documents the methodology and procedures that will be implemented to produce final line loss charges for the historical period, pursuant to the directions in this decision. The Commission anticipates that consultations by the AESO may be required as the compliance filing is being developed, and when the AESO recalculates the line loss charges

[184] Exhibit 790-X3449, 790- Module C Reply Argument, August 18, 2017, paragraph 13.
[185] Decision 790-D02-2015: January 20, 2015, paragraph 253.
[186] Decision 790-D02-2015: January 20, 2015, paragraph 240.

for each year of the historical period. However, the Commission leaves it to the AESO to determine the necessary level of consultation.

207. The Commission recognizes that recalculating line losses will occur over several months. The Commission agrees with TransAlta's proposal to make the results available to stakeholders as the AESO recalculates line loss charges for each year of the historical period and before a final true-up takes place, and directs the AESO to do so. This staged process will provide stakeholders with an opportunity to review the results for each year for possible errors, as those results become available.

6 Order

208. The Commission orders as follows:

(a) The AESO shall produce final loss factors for the historical period (from January 1, 2006 to December 31, 2016) using the Modified Module B methodology.

(b) Following such consultation with market participants as the AESO considers necessary in the public interest, the AESO shall submit a compliance filing for approval that specifies and describes how it will implement the Modified Module B methodology and related procedures.

(c) The AESO shall issue final invoices to the same parties that received the original (currently interim) invoices for line losses during the historical period.

(d) The AESO shall implement the single settlement approach for the historical period with simultaneous collection and reimbursement pursuant to the ISO tariff.

(e) The AESO shall assign the necessary resources to implement the accelerated single settlement approach and recover the incremental cost through the energy market trading fee.

(f) The AESO shall provide updated statements of account for the final line loss charges to market participants setting out the recalculated line losses charges for the historical period on a year by year basis as they become available, before a final true-up takes place.

(g) The AESO shall charge/award interest, equal to the Bank of Canada rate plus one and one half per cent; the AESO shall set out the interest attributed to the monthly amounts for each market participant as it calculates and makes available the updated statements of account for the final line loss charges.

(h) The AESO shall develop the structure, terms and eligibility criteria for its proposed payment plan and file it with the compliance filing to this decision.

(i) The AESO shall recover through the energy market trading fee any incremental administration costs and any interest costs incurred by the AESO associated with credit facilities specific to the settlement process.

(j) The AESO shall collect any payment default shortfall from all market participants paying charges or receiving refunds for the historical period through the Module C settlement process by way of an adjustment of loss factors using Rider E, where any default shortfalls are recovered as a cost of losses. The AESO shall collect by way of Rider E on a going forward basis, any subsequent payment default shortfalls, as they become known, from all market participants, regardless of whether the market participant received a charge or refund for the historical period.

Dated on December 18, 2017.

Alberta Utilities Commission

(*original signed by*)

Mark Kolesar
Vice-Chair

(*original signed by*)

Neil Jamieson
Commission Member

(*original signed by*)

Bohdan (Don) Romaniuk
Acting Commission Member[187]

[187] Mr. Romaniuk was nominated by the Lieutenant Governor in Council as a person who could be selected by the Chair of the Commission as an acting member of the Alberta Utilities Commission in Order In Council 306/2012 (the O.C.) dated October 3, 2012. The Chair of the Commission selected Mr. Romaniuk as an acting member for the purposes of Proceeding 790 in 2012, soon after the O.C. was issued. Section 4(2) of the *Alberta Utilities Commission Act* makes it clear that the Chair of the Commission can name a person as an acting member for "any period of time." While the term during which Mr. Romaniuk could be selected as an acting member for new proceedings expired on October 2, 2017, his selection as an acting member on Proceeding 790 continues until Proceeding 790 is complete.

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
Alberta Electric System Operator (AESO or ISO) Keith F. Miller – Stikeman Elliot LLP
ATCO Power Canada Ltd. (ATCO) Marie H. Buchinski – Bennett Jones LLP
The Balancing Pool Patrick Roche – DLA Piper (Canada) LLP Sharilyn Nagina – DLA Piper (Canada) LLP
Capital Power Corporation (Capital Power) Douglas Crowther – Dentons Canada LLP Bernard Roth – Dentons Canada LLP
City of Medicine Hat Roger Belland Rod Crockford
ENMAX Energy Corporation (ENMAX) Randy Stubbings David Wood – Torys LLP
Milner Power Inc. (Milner) Monte S. Forester Lewis L. Manning – Lawson Lundell Barristers & Solicitors
Office of the Utilities Consumer Advocate (UCA) Thomas Marriott – Brownlee LLP
Powerex Corp. (Powerex) Chris W. Sanderson – Lawson Lundell LLP
TransAlta Corporation (TransAlta) Laura-Marie Berg

Name of organization (abbreviation) counsel or representative
TransCanada Energy Ltd. (TransCanada) Mark Thompson David Farmer

Alberta Utilities Commission Commission panel Mark Kolesar, Vice-Chair Neil Jamieson, Commission Member Bohdan (Don) Romaniuk, Acting Commission Member Commission staff JP Mousseau, Commission Counsel Wayne MacKenzie Greg Andrews Tom Chan

Appendix 2 – Abbreviations

Abbreviation	Name in full
AA&N agreements	Assignment, Assumption and Novation agreements
ADC	Alberta Direct Connect Consumers Association
AESO	Alberta Electric System Operator
AIES	Alberta Interconnected Electric System
ATCO Power	ATCO Power Ltd.
AUC or Commission	Alberta Utilities Commission
Capital Power	Capital Power Corporation
DOS	demand opportunity service
DTS	demand transmission service
ENMAX	ENMAX Energy Corporation
EUB	The Alberta Energy and Utilities Board (the Commission's predecessor)
FTS	Fort Nelson demand transmission service
ILF	incremental loss factor
IOS	import opportunity service
IPCAA	Industrial Power Consumers Association of Alberta
ISO	Independent System Operator
Line Loss Rule	2005 to December 31, 2016 ISO rules Section 9.2: Transmission Loss Factors and Appendix 7: Transmission Loss Factor Methodology and Assumptions and/or ISO rules Section 501.10 Transmission Loss Factor Methodology and Requirements
Milner	Milner Power Inc.
MLF/2	marginal loss factor divide by two
MPID	metering point identifier
Powerex	Powerex Corp.
PPA	Power Purchase Arrangement
STS	supply transmission service
TransAlta	TransAlta Corporation
TCE or TransCanada	TransCanada Energy Ltd.
TSS	transmission settlement system
XOS	export opportunity service

Appendix 3 – Chronology

Chronology from paragraphs 9 – 41 of AUC Decision 790-D02-2015

9. The origin of this proceeding extends back to August 17, 2005, when Milner filed a complaint with the Commission's predecessor, the Alberta Energy and Utilities Board (EUB or the Board).[188] Milner's complaint was about the Line Loss Rule, which was due to take effect on January 1. 2006. This ISO rule was made pursuant to the 2004 *Transmission Regulation* and approved by the AESO's Executive Rules Committee in May 2005. Section 19 of this regulation prescribed new criteria for the determination of line loss factors assigned to generating units through ISO rule-making in place of the previous regime of line loss factors established through ISO tariff approval proceedings before the Board. [189]

10. Milner's complaint was filed pursuant to Section 25 of the 2003 *Electric Utilities Act* concerning the ISO Line Loss Rule and pursuant to Section 26 of the 2003 *Electric Utilities Act* concerning certain conduct of the AESO in failing to comply with Board directives and in implementing the Line Loss Rule. Milner's complaint sought the following relief under Section 25(6) of the 2003 *Electric Utilities Act*:

(a) Directing that the present complaint be set down for hearing in accordance with subsection 25(6) of the EUA and section 22 of the Rules of Practice;

(b) Directing the AESO to comply with all outstanding Board directives concerning the implementation of the AESO's loss factor methodology in accordance with subsection 8(1)(d) of the Transmission Regulation, AR 174/2004 (the "Regulation") and Board Decisions 2000-1, 2000-27, 2002-064 and 2002-104;

(c) Revoking or suspending the Rule in accordance with subsection 25(6)(b) of the EUA until the AESO complies with the Board's outstanding directives and until the Rule is replaced by a loss factor methodology which complies with the Regulation;

(d) Directing that the AESO replace its marginal loss factor methodology as set out in the Rule with an "average MW in" methodology or other loss factor methodology as approved by the Board in accordance with subsection 25(6)(b) of the EUA;

(e) Directing in accordance with subsection 25(6)(b) of the EUA that any loss factor methodology approved by the Board be phased in, so as to limit the variation in loss factors that any generator sees year to year to no more than one half of the average system losses as a percentage of total MW supplied;

(f) Directing that the AESO remove transmission must run ("TMR") MW dispatches from the AESO's Generic Stacking Order ("GSO") for the purposes of establishing loss factors, in compliance with subsection 1(1)(a) of the Regulation and pursuant to subsection 25(6)(b) of the EUA;

(g) Extending the AESO's present tariff based loss factor methodology from December 31, 2005, on a final basis, as necessary, in accordance with subsection 10(2) of the Alberta Energy and

188 Exhibit 2.01, Milner, Complaint Application, August 17, 2005.
189 Exhibit 533.02, AESO Line Loss Rule Consultation Record, September 5, 2014, pdf, page 17.

Utilities Board Act, RSA 2000, c. A-19.5 (the "AEUBA") and subsection 124(1)(a) of the EUA, until replaced as requested herein or as otherwise replaced or amended as directed by the Board;

(h) Where it appears to the Board to be just and proper, granting partial, further or other relief in addition to, or in substitution for that applied for, as fully and in all respects as if the present application had been for that partial, further or other relief, in accordance with subsection 10(3)(f) of the AEUBA.[190]

11. Section 25(6) of the 2003 *Electric Utilities Act* provided that the Board may order the ISO to revoke or change a provision of an ISO rule that, in the Board's opinion, is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the 2003 *Electric Utilities Act* or the regulations.[191]

12. The ground for Milner's complaint relevant to this proceeding was that the Line Loss Rule did not comply with sections 19(1)(a) and 19(2)(d) of the 2004 *Transmission Regulation.*[192]

13. On August 17, 2005, Milner also filed its ISO rule complaint in the then pending AESO 2005/2006 General Tariff Application (GTA) proceeding. Milner sought to intervene in that tariff proceeding to have the Board consider its Line Loss Rule complaint that the line loss charges under the tariff were contrary to the 2004 *Transmission Regulation,* and were unjust, unreasonable, unduly preferential, and arbitrarily or unjustly discriminatory.[193] The full text of Milner's August 17, 2005 complaint is attached as Appendix 5.

14. On August 28, 2005, the Board issued tariff Decision 2005-096: *Alberta Electric System Operator (AESO) 2005/2006 General Tariff Application*. Milner's application seeking consideration of its complaint in the AESO 2005/2006 GTA was not dealt with in the decision. Rather, the Board's ruling was addressed in the cover letter to Decision 2005-096. The Board stated:

> The Board acknowledges the receipt of a complaint from Milner Power (Milner) with respect to the AESO Rule regarding the development of loss factors to be effective January 1, 2006. In the complaint, on file with the Board as Application 1414213, Milner requested that the Board not relieve the AESO of its obligation to respond to certain directives from prior Board decisions. The Board notes that the date for submission of evidence in the GTA is well past. The Board is therefore not willing to consider the presentations of Milner within the context of the GTA Application.
>
> This determination is made, however, without prejudice to Milner's right to pursue its complaint pursuant to Section 25 of the *Electric Utilities Act* (the EUA or the Act). The Board is continuing to review Application 1414213 and will issue notice in due course with respect to the process to be followed.[194]

[190] Exhibit 2.1, Milner, Complaint Application, August 17, 2005, pages 2 and 3.
[191] Exhibit 2.1, Milner, Complaint Application, August 17, 2005, pages 1 and 2.
[192] Exhibit 2.1, Milner, Complaint Application, August 17, 2005, page 3.
[193] Exhibit 559.01, Milner Reply Argument, October 22, 2014, page 26, paragraph 112.
[194] AUC Proceeding 14250, Board Letter Aug 28, 05 – Cover Letter for Decision 2005-096, August 28, 2005.

15. On November 24, 2005, Milner filed an application with the Board for review and variance of Decision 2005-096. [195]

16. On December 30, 2005, the Board issued EUB Decision 2005-150: *Complaint Against the Proposed AESO Line Loss Rule* in which it summarily dismissed Milner's complaint. This decision also included a statement that the AESO was free to implement its Line Loss Rule effective January 1, 2006.

17. The first ISO tariff to include line loss charges based on the Line Loss Rule came into effect on January 1, 2006.[196]

18. On January 26, 2006, Milner applied to the Alberta Court of Appeal for leave to appeal Decision 2005-150 on five separate grounds.

19. On March 28, 2006, Milner applied to the Alberta Court of Queen's Bench seeking judicial review of Decision 2005-150 and also to compel the Board to include in the review record a November 28, 2005 Alberta Department of Energy "Role and Mandate Refinements for Alberta Electric Industry Implementing Agencies" policy paper. This application alleged apprehension of bias and lack of independence on the part of the Board panel deciding Decision 2005-150 and that it had improperly fettered its discretion by improperly considering and acceding to directives in this policy paper to defer to the AESO in matters said to be within the AESO's statutory mandate such as the Line Loss Rule.

20. On April 5, 2006 Milner's application seeking review and variance of Decision 2005-096 was denied by the Board.[197] Milner sought leave to appeal this decision to the Alberta Court of Appeal on two grounds.

21. On June 13, 2006, Milner's application to the Alberta Court of Queen's Bench seeking judicial review of Decision 2005-150 was heard.

22. On August 18, 2006, the application seeking judicial review was dismissed.[198] Milner appealed this dismissal to the Alberta Court of Appeal.

23. On April 11, 2007, the new *Transmission Regulation*, Alberta Regulation 86/2007(2007 *Transmission Regulation)* came into force. Sections 19(1)(a) and 19(2)(d) did not change (although they were renumbered as Sections 31(1)(a) and 31(2)(d), respectively), nor did the AESO change the marginal loss factor divided by two (MLF/2) methodology used to calculate transmission line loss factors under the ISO Line Loss Rule. Rather, the 2007 *Transmission Regulation* only changed the limits (collars) placed on line loss factors used to determine the charges and credits in the ISO tariff. The AESO updated the Line Loss Rule to comply with the change in the collars. However, the AESO did not file the Line Loss Rule containing the new

195 AUC Proceeding 14250, Review and variance application of Decision 2005-096, November 24, 2005.
196 AUC Decision 2005-096, August 28, 2005, page 1.
197 AUC Proceeding 14250, Denial letter of review and variance decision of 2005-096, April 5, 2006.
198 2006 ABQB 537.

collars with the Commission as an ISO rule pursuant to Section 20.2(1) of the 2003/07 *Electric Utilities Act*.[199] The effective date of the changes to the Line Loss Rule was January 1, 2009.

24. On April 20, 2007, the 2003 *Electric Utilities Act* was amended. Several new provisions came into force on January 1, 2008. One of the amendments was the repeal of Section 25 of the 2003 *Electric Utilities Act.* It contained the grounds for relief then specified in Section 25(6) where a complaint about an ISO rule had been made. New provisions dealing with objections to ISO rules before they come into effect were added to the Act as were new complaint provisions in a new Section 25 which, among other things, deals with complaints against ISO rules that are in effect. New grounds for complaints against ISO rules in effect and objections to ISO rules not yet in effect were substituted for the previous grounds applicable to complaints.[200] Some transitional provisions from the 2003 *Electric Utilities Act* to the 2003/07 *Electric Utilities Act* were also added.

25. On August 21, 2007, the Alberta Court of Appeal dismissed Milner's appeal of the dismissal of its application seeking judicial review of Decision 2005-150 while allowing further consideration by it of Milner's application for further document disclosure following determination of Milner's two applications seeking leave to appeal which was then still pending.[201]

26. On November 7, 2008, the Board filed with the Alberta Court of Appeal the record of proceedings required for the court's determination of Milner's applications seeking leave to appeal. In April and May 2009, the filing of memoranda of counsel regarding the leave to appeal applications followed.

27. On September 21, 2009, Milner was granted leave to appeal EUB Decision 2005-150 but was not granted leave to appeal the Board's denial of review and variance, which confirmed Decision 2005-096.[202]

28. On July 29, 2010, in *Milner Power Inc.* v. *Alberta (Energy and Utilities Board)*, 2010 ABCA 236 (*Milner*), the Court of Appeal of Alberta allowed Milner's appeal of the dismissal of its complaint against the ISO Line Loss Rule under Section 25 of the *Electric Utilities Act*. The court held that "[t]he Board's Decision 2005-150 is vacated and the matter is remitted to the Board to continue to further investigate or hold a hearing to determine whether there was a contravention of section 19 as alleged."[203]

Proceeding 790 and Decision 2012-104

[199] There appears to have been no requirement for the AESO to file this under section 20.2(1) of the 2003/07 *Electric Utilities Act* because of the transition provisions in Section 20.1 of that Act.

[200] For objections before a rule goes into effect, 2003/07 *Electric Utilities Act* Section 20.4(1)(a)(b)(c)(d) and for complaints about an ISO rule already in effect Section 25(1)(b)(i)(ii)(iii).

[201] *Milner Power Inc.* v. *Alberta (Energy and Utilities Board)*, 2007 ABCA 265.

[202] *Milner Power Inc.* v. *Alberta (Energy and Utilities Board),* 2009 ABCA 305.

[203] *Milner*, paragraph 61.

29. On September 20, 2010, the Commission issued a notice of proceeding designated as Proceeding 790.[204] In a letter dated February 28, 2011, the Commission bifurcated Proceeding 790 into two phases: the first phase to consider whether the 2005 Line Loss Rule contravened Section 19 of the 2004 *Transmission Regulation* and the second phase to determine the relief that might be granted should the complaint be upheld.[205]

30. The oral hearing respecting the first phase of Proceeding 790 was conducted from October 19 to October 22, 2011, and was followed by written argument. Decisions 2012-104 and 2012-105: *Complaint by Milner Power Inc. Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology – Transmission Must Run*[206] were issued by the Commission on April 16, 2012. In Decision 2012-104, the majority of the hearing panel determined that the complaint by Milner was valid and that the Commission would move to the next phase of the proceeding.[207]

Proceeding 1945 and Decision 2013-159

31. In June 2012, the Commission received four applications seeking review and variance of Commission Decision 2012-104, filed by the AESO, Capital Power Corporation (Capital Power), TransAlta Corporation (TransAlta) and TransCanada Energy Ltd. (TransCanada). The preliminary phase of these review and variance applications was designated as Proceeding 1945.

32. On June 11, 2012, Milner filed a second complaint with the Commission regarding changes to the Line Loss Rule that took effect on January 1, 2009. Milner requested that its original complaint filed on August 17, 2005 also apply with equal effect to any revisions of the Line Loss Rule beyond January 1, 2009. On July 30, 2012, ATCO Power Ltd. (ATCO Power) filed a similar ISO rule complaint.[208]

33. Effective October 10, 2012, the AESO filed ISO rules Section 501.10 with the Commission and removed ISO rule 9.2 as part of the AESO's Transition of Authoritative Documents Project. These changes were filed by the AESO on an expedited basis under Section 20.6 of the 2003/07 *Electric Utilities Act* in Application 1608876. The AESO's October 2, 2012 Notice of Filing respecting this rule stated that the changes were not intended to circumvent or dismiss the complaints submitted by Milner and ATCO Power against ISO rule 9.2. The AESO further stated that it wished to preserve the complaints by Milner and ATCO Power and requested the Commission to transfer the complaints to ISO Rules Section 501.10 upon removal of existing ISO rule 9.2. [209]

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204 Exhibit 64.01, AUC Notice of Proceeding, September 20, 2010.

205 Exhibit 110.01, AUC Ruling re Bifurcation, February 28, 2011.

206 The use of transmission must run generation when calculating loss factors was an issue in Proceeding 790. The Commission issued Decision 2012-105 regarding this issue, which the Commission considered is a separate issue from the methodology used to calculate loss factors.

207 AUC Decision 2012-104, April 16, 2012, page 33, paragraph 167.

208 The Milner and ATCO Power complaints from 2012 are filed as Application 1608563 and 1608709, respectively.

209 Exhibit 533.02, AESO Line Loss Consultation, September 5, 2014, pdf page 959.

34. On April 23, 2013, the Commission issued Decision 2013-159: *Decision on Preliminary Phase of Request for Review and Variance of AUC Decision 2012-104: Complaint by Milner Power Inc. regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology* (AUC Decision 2013-159) and granted a second stage consideration of review and variance of Decision 2012-104.[210] The resulting proceeding was designated as Proceeding 2581.[211]

Proceeding 2581 and Decision 2014-110

35. The Commission reviewed Decision 2012-104 in an oral hearing held from October 7 through October 18, 2013. Written argument followed.

36. On April 16, 2014, the Commission issued Decision 2014-110. It denied variance of Decision 2012-104 in any respect now relevant to Module A of this proceeding and found that the Line Loss Rule did not comply with the 2004 *Transmission Regulation* and was unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory and inconsistent with or in contravention of the 2003 *Electric Utilities Act*. The Commission then indicated it would proceed with the second phase of its consideration of Milner's complaint to determine the relief or remedy to be given.[212]

Current Proceeding 790, Phase 2, Module A

37. On April 24, 2014, the Commission established a schedule to receive submissions from parties regarding the relief or remedy that may be available in this proceeding.[213] In June 2014, the Commission received submissions from Milner, ATCO Power, Capital Power, TransAlta, TransCanada, the AESO, ENMAX Energy Corporation (ENMAX) and AltaGas Ltd. (AltaGas) regarding Phase 2 of this proceeding.

38. On July 4, 2014, the Commission issued a notice of proceeding for Phase 2 consideration of relief and remedy in this proceeding. In the notice, the Commission requested a statement of intent to participate by July 25, 2014 from any party that was not registered in this proceeding, or Proceeding 1945 or Proceeding 2581.[214] The Commission received one additional statement of intention to participate from Powerex Corp. (Powerex).

39. On August 8, 2014, the Commission released an issues list and proceeding schedule directing that Phase 2 of this proceeding be divided into three modules, two of which would run concurrently, and the last of which would proceed only if required, based on the outcome of the first two modules. The Commission directed that Module A encompass the 2012 complaints

210 AUC Decision 2013-159, April 23, 2013, page 16, paragraph 57.
211 Due to limitations in its electronic filing system, in order to initiate the second phase of the variance application the Commission created four new applications on May 3, 2013 relating to the review applicants: 1609554-1 – Capital Power, 1609555-1 – TransCanada, 1609556-1 – TransAlta, 1609557-1 – AESO.
212 AUC Decision 2014-110, April 16, 2014, paragraphs 147-148, page 44.
213 Exhibit 312.01, AUC Letter polling parties re Phase 2, April 24, 2014.
214 Exhibit 521.01, AUC Notice of Proceeding, July 4, 2014.

from Milner and ATCO Power[215] as well as Phase 2 of the original 2005 Milner complaint while addressing several issues of fact and law as specified in the Commission's letter.[216]

40. Module B was directed to address the development of a new line loss factor calculation methodology and line loss rule that meet the legislative requirements. On May 23, 2014, the AESO submitted that it anticipated it could design a methodology consistent with the findings in the Commission's decisions and the legislation.[217] In a subsequent submission on June 6, 2014, the AESO stated that it expected to be able to file its proposed new methodology within four months.[218] In a letter dated August 8, 2014, the Commission directed the AESO to file its proposed new rule and methodology in this proceeding by no later than December 4, 2014. It also invited submissions from all parties as to what order(s) the Commission should issue to the AESO pursuant to the *Electric Utilities Act* in relation to the proposed new rule.

41. Module C was directed to address determination of any financial compensation and the parties entitled to receive or required to pay monetary compensation. The Commission also indicated that Module C would be held only if required following the determinations made in Modules A and B. The Commission set a schedule of September 24, 2014 for written argument from all parties regarding issues identified for consideration in Module A of Phase 2 of this proceeding and what order(s) the Commission should issue to the AESO with respect to changes in the ISO Line Loss Rule, with reply from all parties due October 22, 2014.

215 Applications 1608563-1 and 1608709-1, respectively.
216 Exhibit 524.01, AUC Letter re issues list and schedule, August 8, 2014.
217 Exhibit 506.01, AESO process submission, May 23, 2014, page 4.
218 Exhibit 518.01, AESO process reply submission, June 6, 2014, page 1.