Decision **26911-D01-2022**

Alberta Utilities Commission

Alberta Electric System Operator

Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application

November 10, 2022

Alberta Utilities Commission
Decision 26911-D01-2022
Alberta Electric System Operator
Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application
Proceeding 26911

November 10, 2022

Published by the:
Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Telephone: 310-4AUC (310-4282 in Alberta)
1-833-511-4AUC (1-833-511-4282 outside Alberta)
Email: info@auc.ab.ca
Website: www.auc.ab.ca

The Commission may, within 60 days of the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

Contents

List of figures

List of tables

Alberta Utilities Commission
Calgary, Alberta

Alberta Electric System Operator
Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application — **Decision 26911-D01-2022**
Proceeding 26911

1 Executive summary

1. In this decision, the Alberta Utilities Commission denies the Alberta Electric System Operator's (AESO) rate design application.

2. The AESO's current bulk and regional rate design (current rate design) was approved over 15 years ago. The AESO's proposed bulk and regional rate design (proposed rate design) constituted a significant departure from past applications. In the AESO's view, the current rate design is no longer valid because it does not recognize that an increasing amount of transmission investment is being driven by investments to accommodate the flow of in-merit energy.[1] Additionally, the AESO raised concerns that some customers are able to avoid charges that were previously thought to be unavoidable, reducing the amount of money recovered from these customers to pay for transmission system costs.

3. Most customers[2] take service under Rate DTS (demand transmission service), which is the rate charged to those who withdraw energy from the transmission system; however, customers may be eligible to use other rates such as Rate DOS, which is a demand opportunity service rate, and Rates XOS (export opportunity service) and XOM (export opportunity merchant service), which are opportunity service rates available to exporters of electricity from Alberta. In addition to changes to the current rate design, the AESO proposed substantial changes to Rate DOS (modernized DOS or M-DOS), which it believed would facilitate the use of spare transmission system capacity and result in incremental revenue to help pay for transmission system costs. The AESO's proposed rate design impacted how charges are calculated under Rates XOS and XOM. In addition, the AESO proposed revisions to payment in lieu of notice (PILON) provisions in its terms and conditions, and proposed a mitigation strategy for customers materially impacted by the proposed rate design.

4. Many stakeholders, representing a range of interests, participated in this proceeding. Notably, none supported the AESO's proposed rate design. The primary concerns highlighted by stakeholders were the AESO's approach to the rate design, the relevance of the monthly coincident peak (12 CP) billing determinant, and modernized DOS' application to energy storage (ES) resources.

[1] The phrase "accommodate the flow of in-merit energy" was used by the AESO in its application. In this decision, the following terms/concepts are used interchangeably to reflect the legislative requirements in sections 15(1)(e) and (f) of the *Transmission Regulation*: accommodating the flow of in-merit energy, integrating generation, and avoidance of congestion.

[2] In this decision "customer" refers to those AESO customers who withdraw energy from the transmission system and not to other customers of the AESO. Additionally, in this decision, "consumers" and "load customers" are used interchangeably, and also refer to customers who withdraw energy from the transmission system.

5. In the Commission's view, the bulk and regional rate design should incent the most efficient and cost-effective use of the transmission system already in place, with a view to forestalling further transmission build[3] and costs to the greatest degree possible. However, within the current framework this may be possible only to a modest degree, particularly in the short term. The Commission is limited by legislative requirements in approving just and reasonable rates so that, in general, only consumers pay for the costs of the transmission system, and rates in the Independent System Operator (ISO) tariff cannot vary as a result of the location of a consumer on the transmission system. Consumers, in turn, cannot effectively influence most transmission costs, especially those costs incurred to integrate generation. Recognizing these constraints, the Commission is extremely limited in its ability to direct effective price signals to consumers. Past Commission decisions attributed primacy to cost causation to inform the AESO tariff rate design; this emphasis, which the AESO applied in its proposed rate design, is not currently appropriate.

6. The Commission considers that the proposed rate design includes a number of inappropriate price signals to consumers including: (i) charges based on average cost causation (which does not reflect their locational dependence or when they were caused) and so invalidates the relationship between the costs and consumption; (ii) an avoidable 12 CP charge to collect historical or "sunk" transmission costs; and (iii) greatly increased all-hours energy charges to collect sunk transmission costs, which penalize the most efficient users of the system[4] and may encourage system avoidance[5] by them and dissuade the use of surplus off-peak capacity.[6] Inappropriate signals result in a rate design that may not be durable, predictable or stable.

7. The Commission finds that the focus of cost recovery must shift from broadly relying on cost causation principles to inform the development of price signals and fair rates, to a more narrow application of cost causation focused on the efficient use of surplus off-peak transmission capacity as well as fairness in sunk cost recovery. The Commission finds that the rate design should, to the degree possible, recover costs in a manner that minimizes inappropriate price signals, particularly those that enable avoiding payment for the sunk costs of the system, and that encourages use of surplus off-peak system capacity. The Commission also considers that in order for the rate design to be fair, consumers who benefit from using the transmission system should contribute to recovering its costs, and consumers who benefit similarly should contribute similarly. The Commission provides guidance in this decision as to how to satisfy these efficiency and fairness objectives.

8. The Commission has denied modernized DOS. In the Commission's view, there is a significant risk that increased use of Rate DOS under the AESO's proposed modernized DOS approach could cannibalize Rate DTS use. The Commission also declines to implement an energy-storage specific opportunity service rate at this time, as requested by certain interveners. The AESO has been asked to consider an off-peak billing capacity rate structure intended to enhance off-peak usage, which customers such as ES resources may be able to access.

[3] The Commission is referring to transmission built to serve load reliably, and not to transmission built to integrate generation as required by legislation.

[4] Exhibit 26911-X0587.01, FortisAlberta evidence, PDF pages 16-17, paragraphs 32-33; Transcript, Volume 11, page 2037, line 21, to page 2039, line 1.

[5] Transcript, Volume 11, page 1870, line 14 to page 1874, line 23.

[6] Transcript, Volume 7, page 1273, lines 7-15.

9. Given the AESO's proposed rate design is denied, there is no change to how rates are calculated under Rates XOS and XOM at this time. The Commission does provide guidance regarding the principles that underpin Rates XOS and XOM, in anticipation that these rates will be re-examined in the future.

10. The Commission grants the AESO's request to revise the PILON waiver applicability to sites that have not increased contract capacity in the last five years.

11. The Commission does not make any findings on the AESO's proposed mitigation strategy because the proposed rate design is denied.

12. The AESO noted that substantial modification of its proposed rate design may have unanticipated consequences and requested that if the Commission does not substantially approve its proposed rate design as filed, the Commission provide guidance and direction to the AESO to consider and review before any new rate design is implemented.[7] The Commission attributes significant weight to this request. The Commission finds it practical and reasonable to continue the current rate design at this time. The Commission requires the AESO to file a new rate design application by January 31, 2025, that reflects the guidance, findings and directions provided in this decision.

13. The Commission thanks the AESO and all stakeholders for the significant time and effort put in by these parties in relation to this proceeding. The Commission's views have been informed by the AESO's application, the alternative rate design proposals and the evidence put forward by parties. As a result of this extensive process, the key elements of the tariff are now well understood by all parties, and this understanding will provide a sound foundation to reassess core rate design elements for the forthcoming rate design refiling.

14. Throughout this decision, the Commission provides guidance and its views on what rate design aspects should be included in the AESO's next rate design application. The Commission also expresses interest in exploring innovative processes in developing and adjudicating the AESO's next rate design application. The Commission is open to supporting some type of Commission-assisted process, if parties would find that helpful, to provide a venue for open dialogue and to help resolve issues in a more timely way.

2 Introduction

15. The AESO is an independent, not-for-profit public agency that performs many functions, including facilitating the operation of electricity markets, and planning the transmission system as well as directing its safe, reliable and economic operation. One of the AESO's roles is to connect customers to the transmission system; the AESO is the sole provider of access to the transmission system in Alberta.

16. As the ISO for Alberta, the AESO is responsible for preparing the ISO tariff and applying to the Commission for approval of the ISO tariff.[8] The Commission, when considering the ISO tariff application, must ensure that the "tariff is just and reasonable, not unduly preferential,

[7] Exhibit 26911-X0001.03, AESO application, PDF pages 108-109, paragraph 391.

[8] Sections 30 and 119 of the *Electric Utilities Act* state that the AESO must prepare and receive Commission approval of its ISO tariff rates and terms and conditions.

arbitrary or unjustly discriminatory or inconsistent with or in contravention of [the *Electric Utilities Act*] or any other enactment or any law."[9] The AESO has the burden of proof to show that the ISO tariff is just and reasonable.[10]

17. The ISO tariff consists of the rates and terms and conditions that apply to customers who receive system access service from the transmission system. The ISO tariff is set in two phases.

18. In the first phase, or a Phase 1, the Commission determines the AESO's total costs and expenses[11] (revenue requirement). The AESO's revenue requirement is reviewed in other proceedings, and is therefore outside the scope of this proceeding.[12]

19. On October 15, 2021, the AESO filed its Phase 2 tariff application; that application is the subject of this proceeding. In the second phase, or a Phase 2, the Commission determines the methodology to allocate the total revenue requirement to customers, and how to structure the charges (i.e., rate design), so that the AESO can collect its entire revenue requirement.[13] The ISO tariff comprises several rates. The two most commonly used rates are Rate STS (supply transmission service), used for injecting energy into the transmission system, and Rate DTS, used for withdrawing energy from the transmission system. Rate DTS comprises four components: bulk, regional, point of delivery charges, and ancillary services charges.[14] Bulk and regional costs are the largest component of Rate DTS and represent approximately 75 per cent of Alberta's transmission wires costs and 60 per cent of the AESO's total revenue requirement.[15] The Commission also approves the AESO's terms and conditions in a Phase 2 proceeding.

20. The Commission, in discharging its duty to set just and reasonable rates, takes into account a number of rate design principles in a Phase 2 proceeding, which may be assigned more or less importance depending on the circumstances.

21. The Commission is mindful that the statutory scheme includes specific requirements regarding the AESO's role and responsibilities and the ISO tariff. Some of the legislative requirements at issue in this proceeding include the requirements that: (i) the AESO plans and makes arrangements for a substantially congestion-free transmission system;[16] (ii) load customers pay for most of the costs of the transmission system (colloquially referred to as "load pays for wires");"[17] and (iii) rates in the ISO tariff do not vary for owners of electric distribution systems, customers who are industrial systems, or a person who has made an arrangement under

---

[9] *Electric Utilities Act*, Section 121(2).

[10] *Electric Utilities Act*, Section 121(1).

[11] Generally, there are four principle categories of costs and expenses incurred by the AESO that are included in its tariff: (i) the AESO's own administrative costs; (ii) ancillary services costs; (iii) transmission line losses; and (iv) costs related to transmission wires (payable under a transmission facility owner (TFO) tariff).

[12] See Decision 22942-D02-2019: Alberta Electric System Operator, 2018 ISO Tariff Application, Proceeding 22942, September 22, 2019, Section 3.1, paragraphs 44-48, for a more fulsome discussion of how the AESO's revenue requirement is considered in various AUC proceedings.

[13] *Electric Utilities Act*, Section 14(1)(3) "The Independent System Operator must be managed on that, on an annual basis, no profit or loss results from its operation."

[14] Point-of-delivery and ancillary services charges are not considered in this decision.

[15] Exhibit 26911-X0001.03, AESO application, PDF page 6, paragraph 2.

[16] *Transmission Regulation,* sections 15(1)(e) and (f).

[17] *Transmission Regulation,* Section 47.

Section 101(2) of the *Electric Utilities Act* as a result of the location of those systems or persons on the transmission system (colloquially referred to as the "postage stamp principle").[18]

22. This decision provides the Commission's determinations on the AESO's Phase 2 application. In the sections that follow, the Commission discusses the issues identified in greater detail and provides its findings on each issue. The Commission reviewed the entire record in coming to this decision; lack of reference to a matter addressed in evidence or argument does not mean that it was not considered.

23. A summary of important procedural steps, including consultation sessions held by the AESO can be found in Appendix 4.

3 Bulk and regional rate design

3.1 Summary

24. For the reasons below, the Commission denies the AESO's proposed rate design, and the alternative rate designs proposed by interveners. In this section, the Commission refers to bulk and regional rate design as "rate design."

25. The AESO based its proposed rate design on cost causation principles. Given the legislative constraints and practical realities of Alberta's transmission system, the Commission considers that the AESO is severely constrained in its ability to develop a rate design that allocates system costs according to their causes and thus to send useful price signals or to fairly recover those costs on that basis. The Commission considers that it is only to a very limited extent that cost causation can be practically applied, namely, respecting those system costs that are affected by a consumer's behaviour independent of their location on the system. Recognizing this, the Commission finds that the rate design should to the degree possible, recover costs in a manner that minimizes price signals that discourage incremental use of surplus off-peak system capacity. Additionally, the Commission considers that the fairness of the rate design is enhanced by not using pricing structures that enable avoiding paying for the costs of the system so that consumers who benefit from using the transmission system contribute to recovering its costs, and consumers who benefit similarly, contribute similarly.

26. The Commission is concerned with the price signals that the proposed rate design would send to consumers. More particularly, the Commission considers that the proposed rate design: (i) assigns charges to consumption based on average cost causation (which does not reflect their locational dependence or when they were caused) and so invalidates the relationship between the costs and consumption; (ii) continues to use an avoidable 12 CP charge to collect historical or "sunk" transmission costs; and (iii) uses greatly increased all-hours energy charges to collect sunk transmission costs that penalizes the most efficient users of the system and may dissuade the use of surplus off-peak capacity.

27. The AESO requested that if the Commission does not substantially approve the proposed rate design, the Commission should provide the AESO with guidance and direct it to consider and review the directed changes before implementing any new rate design.[19] The Commission

[18] *Electric Utilities Act*, Section 30(3).
[19] Exhibit 26911-X0001.03, AESO application, PDF pages 108-109, paragraph 391.

has directed the AESO to refile its bulk and regional rate design by January 31, 2025, to reflect the guidance, findings and directions provided in this decision. Additionally, the Commission finds it just and reasonable for the AESO to maintain its current rate design at this time.

3.2 Background

28. The bulk and regional system is the part of the transmission system used to transfer power between and within regions of Alberta. The parts of the transmission system operating at 240 kilovolt (kV) and above are considered the bulk system, and the parts of the transmission system operating above 25 kV and below 240 kV are considered the regional system. The AESO's Rate DTS recovers costs for both the bulk and regional portions of Alberta's transmission system. Currently, the bulk and regional portions of the transmission system costs represent 75 per cent of transmission wires costs and 60 per cent of the AESO's total revenue requirement.[20] The rate design allocates the revenue requirement to consumers based on usage characteristics such as their contract capacity,[21] their peak consumption and their total consumption. These and other characteristics related to individual usage are referred to as billing determinants and determine what a consumer pays for transmission system access service.

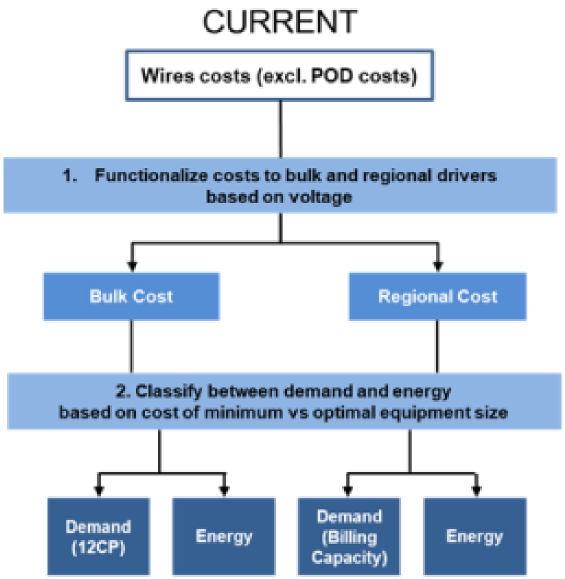
3.2.1 AESO's current rate design

29. The Commission's predecessor (the Alberta Energy and Utilities Board or EUB) first approved the current rate design in Decision 2005-096,[22] over 15 years ago. The current rate design is based on a cost-of-service study that splits transmission system costs between costs required to: (i) serve demand, which are recovered using billing determinants that reflect demand; and (ii) deliver energy, which are recovered through energy-based charges.

30. The current rate design is illustrated in Figure 1.

[20] Exhibit 26911-X0001.03, AESO application, PDF page 6, paragraph 2.
[21] Defined as peak demand or supply capability in megawatts (MW).
[22] Decision 2005-096: Alberta Electric System Operator (AESO), 2005/2006 General Tariff Application, Application 1363012, August 28, 2005.

Figure 1. AESO's current rate design[23]



31. As a first step, the current rate design distinguishes between costs of meeting the highest system demand (the bulk system) and those that are associated with meeting regional needs (the regional system) using transmission voltage as a proxy.[24] Next, costs are classified as being demand or energy related using a minimum system approach. The purpose of this is to assign the costs of the theoretical minimum transmission system that is capable of serving load to demand, and assign costs incurred beyond the theoretical minimum transmission system to energy.[25] This results in four categories of costs that are recovered through the billing determinants noted in the figure above. The largest portion, bulk demand related costs,[26] are recovered using the 12 CP billing determinant. Consumers pay the 12 CP charge based on their metered demand during the time of coincident peak.[27] The remaining costs are regional demand costs, which are recovered through a billing capacity charge,[28] and bulk and regional energy costs, which are recovered through flat energy charges.

23 Exhibit 26911-X0001.03, AESO application, PDF page 33, paragraph 108.
24 Exhibit 26911-X0001.03, AESO application, PDF page 32, paragraph 105. This is done by voltage where bulk assets are functionalized at 240 kV and above and regional assets at below 240 kV but above 25 kV. The ratio of bulk, regional and point-of-delivery assets is then calculated using net book value for a single historical year based on actual TFO cost data and calculated for future years based on forecasts. Also see Exhibit 26911-X0048, Appendix N – 2013 LEI [London Economics International] cost causation study, sections 8-10.
25 Exhibit 26911-X0048, Appendix N – 2013 LEI cost causation study, PDF page 70.
26 Exhibit 26911-X1265, AESO argument, PDF page 21, paragraph 56. The AESO stated that when point-of-delivery costs are excluded, approximately two-thirds of transmission costs are recovered using the 12 CP charge.
27 The AESO determines coincident peak by calculating when metered demand at the point-of-delivery is the highest in each month, when averaged over a single 15-minute interval.
28 The AESO's Consolidated Authoritative Document Glossary defines billing capacity at a point of delivery as the highest of: (i) the highest 15-minute metered demand in the settlement period; (ii) 90% of the highest metered demand in the 24-month period including and ending with the settlement period, but excluding any months during which commissioning occurs; or (iii) 90% of the contract capacity or, when the settlement period contains a transaction under Rate DOS, 100% of the contract capacity.

32. In Decision 2005-096, the EUB approved the current rate design considering that the bulk system is primarily constructed and sized, and costs incurred, to meet the peak load of the system (the combined maximum use of all loads);[29] rates should be in keeping with cost causation, with other ratemaking principles being complementary to this principle;[30] and that a rate design that recovers a large proportion of costs through the monthly 12 CP charge, which is a measure related to consumption during the system peak, would provide an appropriate price signal in the circumstances.

33. The EUB reaffirmed the current rate design in Decision 2007-106.[31] In that decision, the EUB reiterated that cost causation remained the primary consideration when evaluating a rate design proposal.[32] The EUB explained it was interested in the real price signal being received by real customers.[33] The EUB's decision to approve the 12 CP billing determinant was based on evidence that the 12 CP would incent customers to shift loads to non-peak hours, but not necessarily avoid the peak entirely. The EUB found that "clearly it is not possible for a customer to generally simply turn the power off and completely avoid the hour of system peak …"[34]

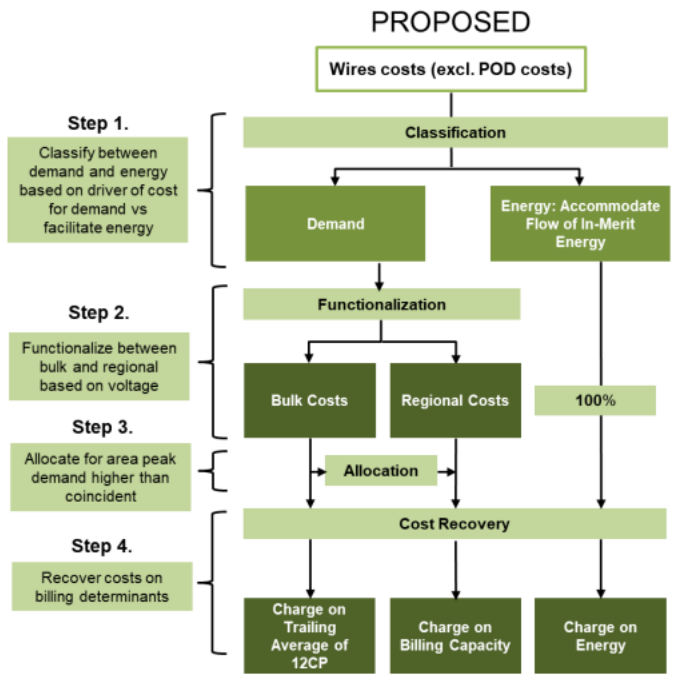
3.2.2 AESO proposed rate design

34. The Commission previously directed the AESO to review its current rate design, and address identified concerns, in its next comprehensive tariff application, which is the subject of the current proceeding.[35] The AESO developed its proposed rate design with assistance from NERA Economic Consulting (NERA), and adopted the proposed rate design recommended by NERA.[36]

35. Notably, in the proposed rate design, NERA developed a new minimum system methodology to classify transmission costs between drivers of costs. NERA recommended classifying costs prior to functionalizing those costs, on the basis that demand-related costs vary in purpose or function according to bulk and regional system needs, but that costs relating to accommodating the flow of in-merit energy do not.[37] The proposed rate design is illustrated in the figure below.

29 Decision 2005-096, PDF page 32.
30 Decision 2005-096, PDF page 32.
31 Decision 2007-106: Alberta Electric System Operator, 2007 General Tariff Application, Application 1485517, December 21, 2007, PDF pages 30, 40 and 66.
32 Decision 2007-106, PDF page 14.
33 Decision 2007-106, PDF page 40.
34 Decision 2007-106, PDF page 40.
35 In Decision 22942-D02-2019, paragraphs 12-21, 74 and 1211, the Commission directed the AESO to address concerns associated with its 12 CP charge and tariff considerations relating to the provision of transmission service to energy storage providers in its next comprehensive tariff application.
36 Exhibit 26911-X0001.03, AESO application, PDF page 22, paragraph 64. The AESO agreed with and adopted the proposed rate design as recommended by NERA.
37 Exhibit 26911-X0001.03, AESO application, PDF page 46, paragraph 145.

Figure 2. NERA's proposed rate design[38]



36. As a first step, NERA proposed using the minimum system methodology it developed to classify costs as being related to serving demand or accommodating the flow of in-merit energy. NERA's minimum system methodology uses the ratio of annual peak net load to peak net generation in a planning area to allocate the transmission system costs in that area. In those areas where peak net load exceeded peak net generation, the entirety of the costs were assigned to demand. In areas where the net peak generation exceeded the net peak load, only that portion of the area transmission costs equal to the ratio of the peak net load to the peak net generation were assigned to demand, with the remainder assigned to accommodating the flow of in-merit energy.[39]

37. NERA proposed to continue to use transmission voltage as the primary proxy for functionalizing demand-related costs into bulk and regional groups, because voltage reflects the function of lines in the transmission system. However, NERA also recognized that the bulk system may need to be larger than is required to meet coincident peak if individual areas have peaks at different times, and allocated some costs from bulk to regional to reflect that some bulk system costs are attributable to non-coincident peaks in demand.

38. The AESO argued that a new rate design was necessary because the drivers of transmission system costs have changed over time. Specifically, the AESO submitted that the drivers of bulk transmission investments are not limited to coincident peak demand, but also include investments to accommodate the flow of in-merit energy. In the AESO's view, because the current rate design does not reflect this cost driver, 12 CP is overstating the costs associated with using the transmission system at peak times. In addition, the AESO submitted that some customers are avoiding the 12 CP charge, resulting in costs shifting to other customers that cannot avoid 12 CP, without a corresponding reduction in system costs. The AESO confirmed

38 Exhibit 26911-X0001.03, AESO application, PDF page 47, paragraph 146.
39 Exhibit 26911-X0001.03, AESO application, PDF page 50, paragraph 153.

that this behaviour was contributing to the significant increase in the 12 CP charge. The AESO submitted that the lack of recognition of the additional cost driver sends an inefficient price signal that results in costs no longer being allocated based on cost causation.[40]

39. The AESO submitted that the proposed rate design is based on cost causation, and considers there are two main cost drivers of transmission in Alberta: the need to meet peak demand, and the need to accommodate the flow of in-merit energy. NERA proposed to recover bulk system demand-related costs through a 12 CP charge, regional system demand related costs though a billing capacity charge, and costs related to the accommodation of in-merit energy through an all-hours energy charge. The proposed rate design resulted in lower 12 CP and billing capacity charges and a higher energy charge when compared to the AESO's current rate design, as shown below.

Table 1. Summary of allocations to billing determinants under the current rate design and proposed rate design[41]

Billing determinant	Current rate design	Proposed rate design
	(%)	
12 CP	49.8	29.4
Billing capacity	22.7	17.3
Energy	6.1	31.9

40. The AESO and several other parties advocated for a need to change the current rate design however, no party supported the proposed rate design. In the AESO's view, this was due to the different outcomes preferred by the different parties, with each endorsing a rate design that resulted in fewer costs being allocated to that party.[42] However, even some parties who stood to benefit from the AESO's proposed rate design opposed it.[43]

3.3 Evaluation of the proposed rate design

3.3.1 Ratemaking principles

41. The Commission, in discharging its duty to set just and reasonable rates, takes into account a number of rate design principles in a Phase 2 proceeding. These principles may be assigned more or less importance depending on the circumstances. The Commission and the EUB have previously referenced a set of principles adapted from James C. Bonbright's *Principles of Public Utility Rates*[44] in assessing prior AESO Phase 2 applications. These principles are:

1. Recovery of revenue requirement.

2. Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service.

---

[40] Exhibit 26911-X0001.03, AESO application, PDF pages 34-36, paragraphs 114-120.
[41] Exhibit 26911-X0001.03, AESO application, PDF pages 60-61, paragraph 180. For clarity, columns do not add to 100 because the point-of-delivery allocations have been excluded.
[42] Exhibit 26911-X0001.03, AESO application, PDF page 8, paragraph 7.
[43] Transcript, Volume 11, page 1870, line 14 to page 1874, line 23.
[44] Decision 2007-106, PDF page 20.

3. Fairness, objectivity and equity that avoids undue discrimination and minimizes inter-customer subsidies.

4. Stability and predictability of rates and revenue.

5. Practicality, such that rates are appropriately simple, convenient, understandable, acceptable and billable.[45]

42. The Commission acknowledges that the proposed rate design responds to the significant weight that the Commission has historically placed on cost causation as the primary consideration when evaluating rate design. In decisions 2005-096 and 2007-106, the EUB used cost causation as the primary consideration when evaluating the AESO's rate design.[46] This was because, at the time, EUB considered rates based on cost causation to provide appropriate price signals, to be fair, objective and equitable, and to minimize or eliminate inter-customer subsidies.

43. However, as discussed in the subsections below, the Commission finds that circumstances today are materially different than in the past, and that this warrants a re-evaluation of the weight placed on cost causation considerations. The Commission explains why cost causation considerations are necessarily limited to those aspects of consumer behaviour that affect system costs independent of location. Cost causation therefore plays a much more limited role than in the past in motivating the efficient use of the transmission system and in fairly allocating its costs in order to achieve just and reasonable rates.

3.3.1.1 Efficiency considerations

44. Here, the Commission evaluates the considerations of efficient behaviour and efficient use of the transmission system. The proposed rate design is based on a cost-of-service study that split transmission system costs between those associated with the delivery of energy, and those associated with serving peak demand. There are a large amount of sunk transmission system costs in Alberta that need to be recovered.[47]

45. Starting with the costs associated with the delivery of energy, which the AESO characterized as being driven by the need to accommodate the flow of in-merit energy, parties broadly agreed that a substantial portion of the costs of the recent transmission buildout were and continue to be driven by factors other than load growth. In particular, the Commission accepts that much of the increase in transmission system costs since 2007 has been driven by government policies, including the commitment to build critical transmission infrastructure and policies intended to reduce greenhouse gas emissions, that have resulted in a substantial increase in generation integration costs. Alberta transmission system costs have increased 326.6 per cent since 2007, while consumer load growth over the same period was only 7.6 per cent.[48]

46. Regarding the need for generation integration, the AESO argued that the proposed rate design accurately reflects the transmission infrastructure costs incurred to accommodate the flow of in-merit energy and that this cost reflectivity is necessary to encourage efficient consumption decisions throughout the transition towards greater electrification and decarbonization of the

[45] See, for example, EUB Decision 2007-106, PDF pages 18-19.
[46] Decision 2005-096, PDF page 21; Decision 2007-106, PDF page 20.
[47] Exhibit 26911-X1168, AESO Subject to Check 1-7, PDF page 2.
[48] Exhibit 26911-X1168, AESO Subject to Check 1-7, PDF page 2.

electricity system.[49] In contrast, interveners generally agreed that there is no direct causal relationship between these costs and consumer use of the transmission system. The Commission agrees with AltaLink Management Ltd.'s argument that while accommodating the flow of in-merit energy can be a driver of transmission investment for planning purposes, "*load has no control over costs associated with generation* and therefore cannot affect those costs in response to a price signal."[50] (emphasis in original)

47. Although the Commission is constrained by the legislated requirement that load must pay for wires, it is clear to the Commission that changes in consumption have not caused the costs of generation integration and as a result cost causation principles are not relevant. Accordingly, the Commission considers that the rate design should not attempt to provide price signals to consumers (consumption signals) that are based upon the cost of accommodating the flow of in-merit energy.

48. Turning to costs that are associated with serving peak demand, the Commission received evidence that efficient consumption incentives should ideally be based on the marginal costs associated with marginal increases in consumption.[51] The Commission accepts that such an approach would align with economic theory and understands that by collecting marginal costs through billing determinants that reflect their marginal changes in consumption, consumers could internalize the transmission costs associated with their consumption decisions which would motivate them to choose the least overall cost supply options.

49. It has become increasingly apparent that the postage stamp principle results in a non-locational tariff that cannot signal to consumers the marginal cost of transmission at their location. In light of that limitation, some participants[52] stated that providing an average marginal cost based signal would nevertheless promote more efficient outcomes than not providing any marginal signal. The AESO argued against that position stating that, in the Alberta context, an average marginal cost-based signal would not enhance efficiency, would raise fairness concerns and would be impractical to implement.[53] [54]

50. The Commission observes that an average marginal cost based signal would provide incentives that are too strong in areas where the marginal cost is low and too weak in areas where the marginal cost is high. Consumers that are provided with a signal that is too high, compared to the marginal cost at their location, would be motivated to avoid consumption, even though the marginal cost of supplying them, and therefore the value provided by their avoidance of consumption, is low. From the perspective of the overall transmission system, such inefficient choices would offset efficient choices to avoid consumption in areas where actual marginal costs are high. Depending on the amount of load and its cost responsiveness in the respective areas, the average marginal cost signal could result in inefficient outcomes overall.

---

49 Exhibit 26911-X1265, AESO argument, PDF page 20, paragraph 51.
50 Exhibit 26911-X1278, AltaLink reply argument, PDF page 10, paragraph 17.
51 Exhibit 26911-X0013, Appendix D – Attachment 4A, PDF page 4, paragraph 4.
52 Exhibit 26911-X0578, E3 evidence of Dr. Orans on behalf of AltaLink, PDF page 26; Mr. Pfeifenberger on behalf of Capital Power, Transcript, Volume 10, page 1772, lines 23-25 and page 1774, lines 1-2; Exhibit 26911-X1255, ATCO Electric argument, PDF page 7, paragraph 13; and Mr. Zarumba on behalf of ATCO Electric, Transcript, Volume 9, page 1554, lines 8-12.
53 Exhibit 26911-X0013, Appendix D – Attachment 4A, PDF page 5, paragraphs 6-7.
54 Exhibit 26911-X1265, AESO argument, PDF pages 71-72, paragraph 231.

51. Therefore, the Commission is not convinced that an average marginal cost based signal would reliably enhance efficiency. As NERA stated, marginal costs are likely to vary broadly and include both positive and negative costs.[55] The Commission concludes that, in general, any signal that falls within the range of marginal costs on the transmission system could enhance or detract from efficiency, depending on the circumstances. NERA's evidence illustrated potential marginal costs in areas of the transmission system and the range of forecast load growth in those areas. Using NERA's illustrative example, the Commission considers that the resulting average marginal cost would represent several relatively low cost areas and a single very high cost area.[56] This furthered the Commission's concern that an average marginal cost based signal may exacerbate inefficient outcomes overall.

52. The AESO argued that the inability of a non-locational tariff to provide signals that accurately reflect marginal costs militated in favour of basing cost signals on total system costs (the embedded cost) as was done in the proposed rate design, and that the resulting embedded cost based signal would support long-term efficient outcomes.[57] In support of this claim, the AESO stated that in the long term, an increasing amount of transmission system costs are variable and therefore it is important to provide appropriate, cost based consumption signals that support the efficient development of the transmission system.

53. In the Commission's view, the AESO's embedded cost approach could only support long-term efficient outcomes if, in the long term, locational marginal costs could be expected to approximate the embedded cost. No compelling evidence was provided to suggest that this is likely. Nor does the Commission consider that this is likely to happen, recognizing, for example, the wide variations in population density, generation and industrial development across Alberta. For this reason, the Commission finds that the long-term, embedded cost cannot usefully signal long-term locational marginal costs, and therefore suffers from the same fundamental limitation of being unable to provide efficient locational charges as the shorter term, average marginal cost.

54. The Commission is therefore not convinced that long-term efficiencies would be gained by providing an embedded cost based signal that is in all respects except its greater size, equivalent to an average marginal cost based signal. Further, the Commission is concerned that the increased magnitude of an embedded cost signal would amplify the risk that its locational inaccuracy would promote inefficient consumption decisions in the short-term. This could lead to a rate design that is not stable, predictable or durable.

55. Based on the considerations above, the Commission finds that a non-locational tariff is unable to provide efficient consumption signals where the relationship between consumption and cost depends heavily on location. The Commission also finds that because average marginal cost, embedded cost or embedded cost split between peak demand based charges and energy based charges, would also not vary by location, this limitation of a non-locational tariff cannot be cured by providing signals based on any of these alternatives.

56. Based on the analysis above, cost causation principles cannot be applied to i) costs associated with generation integration, because load has no control over those costs and cannot affect them, or ii) costs associated with serving peak demand, because those costs depend on location. In the Commission's view, there are almost no practical applications for cost causation

55 Exhibit 26911-X1023, Appendix A – NERA rebuttal evidence, PDF page 93, Table 4 and paragraphs 218-221.
56 Exhibit 26911-X1023, Appendix A – NERA rebuttal evidence, PDF page 93, Table 4 and paragraphs 218-221.
57 Exhibit 26911-X0013, Appendix D – Attachment 4A, PDF page 6, paragraph 10.

principles remaining except for the use of surplus off-peak capacity. The Commission understands that this surplus capacity is broadly available on the system[58] and expects that its increased use will not cause significant costs and is consistent with the efficient use of the system. Cost causation principles suggest that use of this capacity should not attract significant charges. Accordingly, the Commission considers that use of surplus off-peak capacity need not be priced to recover costs and instead should be priced according to fairness principles discussed below.

3.3.1.2 Fairness considerations

57. The AESO argued that the proposed rate design was cost reflective and that as a result it avoided creating inter-customer subsidies and supported just and reasonable rates.[59] As discussed above, the Commission considers that it is only with respect to those system costs that are affected by consumers' behaviour independent of their location on the system, that cost causation principles can inform the efficiency and fairness of the design. The Commission also considers it fair that consumers who benefit from using the transmission system should contribute to recovering its costs, and that consumers who benefit similarly should contribute similarly.

58. The Commission considers that cost shifting caused by changes in consumption that are intended to avoid paying for the sunk costs of the transmission system results in an unfair allocation of costs. Accordingly, the Commission considers that in order to promote the fairness of the tariff, system costs should be recovered using billing determinants that are not readily avoidable.

59. As discussed in the sections above, the Commission finds that the rate making principle of cost causation is necessarily constrained to those aspects of consumer behaviour that affect system costs independent of location. The utility of a traditional cost causation analysis or cost-of-service study where conclusions depend on drawing average causal relationships across the transmission system is similarly limited. As a result, the Commission did not attribute weight to NERA's cost-of-service study and declines to opine on the methodology upon which it is based or the resulting cost allocations. Should the AESO determine that some type of cost-of-service study is useful in informing its next rate design, then the AESO should consider providing an analysis or verification of its study against historical actual costs.

3.3.2 Examination of aspects of the proposed rate design

60. In this section of the decision, the Commission examines specific aspects of the proposed rate design with regard to efficiency and fairness.

3.3.2.1 Avoidance of 12 CP charges by consumers that rely on the system for all or a majority of their electrical supply

61. The suitability of 12 CP as a billing determinant in the current and proposed rate designs was a substantial issue in this proceeding. As noted above, it is used to recover approximately 50 per cent of bulk and regional transmission costs in the current rate design and was proposed to recover approximately 30 per cent of bulk and regional costs in the proposed rate design. Participants raised concerns that consumers who rely on the transmission system for all or a majority of their electrical supply as well as standby consumers, avoid paying for some of the

58 See Exhibit 26911-X1265, AESO argument, PDF page 90, paragraph 292.
59 Exhibit 26911-X1265, AESO argument, PDF page 10, paragraph 13.

costs of the system as a result of avoidance of 12 CP charges. The Commission considers that different considerations apply to how these two different groups of consumers are charged and addresses the former in this section and the latter in Section 3.3.2.5.

62. The AESO provided evidence showing the increasing avoidance of 12 CP consumption over the past decade by customers who rely on the transmission system for all or a majority of their electrical supply.[60]

63. The AESO stated that the proposed rate design was based on how transmission costs are incurred through the AESO's planning process and not based on real-time stress conditions on the transmission system that may occur because of transmission outages and contingencies.[61] The AESO also stated that its planning process ensures that the system meets a number of criteria that include the Alberta reliability standards which, the Commission understands, include analysis at CP load conditions.

64. Ali Al-Jabir on behalf of the Alberta Direct Connect Consumers Association (ADC), stated that 12 CP remains the key planning criteria for bulk transmission costs. The coincident peak allocation method recognizes the fact that transmission planning is based on ensuring that there is sufficient transmission capacity in place to meet the maximum simultaneous peak demand imposed by customers on the transmission system. A coincident peak allocation method properly recognizes this cost causative factor that gives rise to the incurrence of fixed transmission costs.[62]

65. Colette Chekerda on behalf of the ADC confirmed that consumers that respond to the 12 CP signal typically curtail their production for 20 to 30 hours a month to avoid paying 12 CP charges.[63]

66. Based on the evidence from the AESO and interveners, the Commission finds that 12 CP is readily avoidable by certain consumers.

67. The Commission understands that the Alberta reliability standards require that transmission system performance be tested under all forecast demand levels of which system coincident peak is often the most onerous. For that reason some parties maintained that demand during the coincident peak causes transmission investments to support system reliability and therefore that 12 CP avoidance reduces the need for such transmission investments. The Commission accepts the AESO's evidence however that system stress events that lead to unreliability are uncorrelated with coincident peak.[64]

68. The Commission considers that because the period during which consumers respond to the 12 CP price signal spans such a small percentage of time, and because transmission system stress events are uncorrelated with coincident peaks, the probability that system stress events will overlap with these periods is also small. Therefore, consumer load curtailment in response to 12 CP charges would not materially impact system reliability; neither could it materially reduce

60 Exhibit 26911-X0001.03, AESO application, PDF page 44, Figure 3-4.
61 Exhibit 26911-X0001.03, AESO application, PDF page 28, paragraph 91.
62 Exhibit 26911-X0521, BAI evidence on behalf of ADC, PDF page 10.
63 Transcript, Volume 8, page 1410, lines 7-21; Exhibit 26911-X0526, ADC policy evidence, PDF pages 18-24.
64 Transcript, Volume 6, page 979, lines 14-20.

the need for future transmission builds in furtherance of system reliability or result in transmission system cost savings.

69. The Commission concludes that load curtailment in response to the 12 CP serves primarily to allow avoidance of payment for the sunk costs of the transmission system. Accordingly, the Commission considers that the AESO should avoid the use of 12 CP in Rate DTS in its next rate design application. Instead, the AESO should propose billing determinants that more broadly reflect on-peak consumption and are more difficult for consumers to avoid.

70. In order to develop these billing determinants, the AESO should consider providing an analysis examining the relationship between incremental consumption in on- and off-peak periods and system reliability.

71. The Commission has found that 12 CP avoidance does not reduce costs and therefore it follows that 12 CP avoidance results in cost shifting from those consumers who can avoid the 12 CP to those who cannot.

72. Based on the AESO's evidence that the magnitude of 12 CP cost shifts is increasing, the Commission observes that this behaviour, in conjunction with the increase in 12 CP charges[65] that has occurred, has exacerbated the transmission costs that are shifted each year to other consumers. The Commission estimates that this has increased from approximately $20 million in 2015 to approximately $70 million in 2020.[66]

73. The Commission considers that while this magnitude of cost shifting is currently relatively small compared to the overall bulk and regional revenue requirement, its upward trend justifies addressing it in the AESO's next rate design application.

3.3.2.2 Avoidability of billing determinants

74. In addition to the approximately 30 per cent of costs that were proposed to be recovered through 12 CP based charges, approximately 30 per cent of costs were proposed to be recovered through energy based charges in the proposed rate design.

75. The Commission heard concerns that both the 12 CP charges and energy charges could be readily avoidable especially by consumers with behind-the-fence generation[67] and that the resulting incentive to self-supply to avoid paying for sunk transmission costs could distort the energy market.[68] The Commission also heard that all billing determinants are avoidable to some degree.

76. The Commission agrees that the use of billing determinants that are relatively difficult to avoid to recover the sunk costs of the system would discourage changes in consumption intended to avoid those charges, and would both discourage inefficient consumer behaviour and reduce the unfair shifting of costs. The Commission considers the AESO should not use readily

[65] Exhibit 26911-X0001.03, AESO application, PDF page 36, paragraph 120.
[66] This estimate was developed by summing the product of each of the DTS Contract Capacities with the average of their ranges of response provided in Figure 3-4 (Exhibit 26911-X0001.03, AESO application, PDF page 44) multiplied by the then current DTS charge.
[67] Exhibit 26911-X1260, AML argument, PDF page 32, paragraph 81.
[68] Exhibit 26911-X1264, Capital Power argument, PDF page 15, paragraph 32.

avoidable billing determinants for the purpose of recovering sunk costs in its next rate design application. The Commission considers that the relative ease with which different billing determinants allow charges to be avoided might be measured by comparing the ratio of the effort required per amount of charge avoided, for the different billing determinants.

3.3.2.3 Use of surplus off-peak transmission system capacity

77. The Commission heard arguments in support of the view that, the transmission system has surplus capacity during off-peak periods. The Commission agrees and understands that this situation is widespread and does not depend on location. Accordingly, the Commission considers that the rate design should provide signals that motivate the efficient use of this surplus off-peak capacity and assist in paying for the fixed costs of the system.

78. For example, representatives of energy storage providers testified that under the current rate design, Rate DTS is not economically feasible for stand-alone storage facilities. As a result, the Commission considers that the potential benefits of their use of this surplus off-peak capacity and assistance in paying for the fixed costs of the system are therefore precluded. The Commission understands that under the current rate design, stand-alone storage providers subject to Rate DTS would be primarily charged based on their billing capacity.

79. The Commission notes that the structure of the current billing capacity charge, which was proposed to remain unchanged in the proposed rate design, was not examined during this proceeding. The Commission is concerned that the structure of billing capacity charges intended to recover the sunk costs of the regional transmission system should not, to the degree possible, dissuade incremental economic activity that could take advantage of surplus off-peak transmission system capacity and contribute to sunk cost recovery. The Commission considers that providing an alternative billing capacity charge structure that distinguishes between on-peak and off-peak consumption may address the Commission’s concerns in this regard. This may result in a more useful rate structure for energy storage providers and other customers that are able to take advantage of it.

80. As noted above, the Commission understands that surplus off-peak capacity is broadly available on the system and therefore anticipates that increased use of that capacity is unlikely to cause significant incremental transmission costs to be incurred. The Commission therefore considers that making that capacity available at a lower cost than on-peak capacity would not raise concerns with the fairness of the rate design.

81. The Commission considers that the availability of an alternative off-peak billing capacity rate structure may beneficially enable the use of surplus off-peak capacity and that the AESO should consider implementing such an alternative in a manner that would: (a) be available to all consumers; (b) provide a more cost-effective option for off-peak system use; (c) allow occasional, short term, on-peak system use at an incremental cost; and (d) be economically unattractive for sustained on-peak use such that it is not suitable for use for standby service. The Commission considers that this alternative rate structure could potentially be refiled with the Commission on a stand-alone basis earlier than the rest of its next rate design application, as discussed further by the Commission below.

82. The Commission considers that encouraging the use of surplus off-peak capacity may discourage high load factor consumers from self-supplying and encourage incremental use of the system and that behaviours such as these will support the efficient use of the system. The

Commission acknowledges, however, that reduced off-peak charges may also encourage load shifting from on-peak periods to off-peak periods. The Commission considers that the use of billing determinants that are difficult to avoid could mitigate this risk but also considers that load shifting should be considered in developing on- and off-peak rates.

3.3.2.4 Proposed all-hours energy charge

83. The proposed rate design included an all-hours energy charge that was used to recover approximately 30 per cent of the costs of the bulk and regional transmission system. The AESO defended the use of an all-hours charge on the basis that the costs that it was designed to recover related to the avoidance of congestion that could occur at any time.[69]

84. However, as discussed above, the Commission has found that the application of cost causation principles to costs that consumers cannot influence is not useful. Instead the Commission considers that a fair allocation of these costs is more usefully informed by consideration of how the benefits associated with them accrue to consumers.

85. The Commission understands that the principal theoretical benefit to consumers of congestion avoidance is the resulting increase in competitiveness of the power pool which is manifested as competitive pressure on energy prices. The Commission expects therefore that consumers benefit from congestion relief in proportion to their consumption of energy during periods when competition is most critical, which occur most often during on-peak periods.

86. In order to support suitable billing determinants for the allocation of system costs to consumption during on- and off-peak periods, the AESO should develop an analysis examining the relationship between the benefits of reduced congestion and consumption during high and low load use periods in its next rate design application.

87. Again, the Commission considers that the use of billing determinants that are difficult to avoid would reduce cost shifting resulting from charge avoidance, further promoting the fairness of the rate design. The Commission observes that many parties advocated for non-coincident peak billing determinants which they argued would be more difficult to avoid than energy based charges.

3.3.2.5 Standby charges

88. Under the current rate design, customers that normally supply their own electricity needs but rely on the system for backup are charged for its availability based on their billing capacity, under Rate DTS. This is colloquially known as the standby charge. The proposed rate design would result in the billing capacity charge being slightly reduced.

89. Some participants raised the concern that, because these self-suppliers are charged based on billing capacity, they largely avoid paying for the costs of the bulk transmission system and consequently transfer the burden of recovering a portion of sunk costs to other consumers. Based on his estimate of the current average marginal cost, Dr. Orans on behalf of AltaLink, estimated that $256 million of costs[70] are shifted each year (by self-suppliers) under the current rate design and noted that this amount will continue to grow if the current rate design is not changed.[71] The

[69] Exhibit 26911-X1265, AESO argument, PDF page 19, paragraph 46.
[70] Exhibit 26911-X0580.01, E3 evidence on behalf of AltaLink, Attachment 2 – cost shift calculations.
[71] Exhibit 26911-X0578, E3 evidence on behalf of AltaLink, PDF pages 21-22.

AESO refuted concerns with cost shifting by self-suppliers and countered that in many cases, transmission system enhancements were avoided as a result of consumers' decisions to self-supply.[72]

90. While parties generally agreed that the current average marginal cost of transmission in Alberta is low relative to the level it has been in the past,[73] the Commission does not consider that a robust estimate of this cost was presented. Further, the Commission does not consider that past avoided costs associated with particular self-supply decisions can be accurately estimated using the current estimate of average marginal cost. The Commission is therefore not convinced that the estimated cost shift provided by AltaLink is accurate.

91. As noted above, the proposed rate design is based on cost causation principles which, as a result of the non-locational tariff, the Commission does not consider can be applied accurately to costs that vary with location. The Commission is not convinced that the proposed rate design is able to fairly or efficiently allocate costs caused or avoided by standby users or to properly send signals in relation to efficiency and fairness. Rather, the Commission considers that fairness in the circumstances is informed by the value of service received.

92. The Commission accepts the applicability to standby service of Richard Stout's statement on behalf of the Office of the Utilities Consumer Advocate (UCA), in relation to Rate DOS, that:

> … customers who are operating a behind-the-fence generator in a major viable process, the -- and the generator fails, has an unplanned outage, then taking grid power at that instant is a very high -- has a very high value to them.[74]

93. No evidence was provided that supported the current or proposed standby charges relative to the benefits obtained from the service. More particularly, the Commission notes that standby users face lower supply risk and avoid costs that would otherwise be incurred to manage their supply risk as a result of the availability of the bulk transmission system but do not contribute significantly to recovering its costs. The Commission considers that the AESO should develop more robust standby rates that are reflective of the benefit received from this service. The AESO should provide evidence in support of the benefit reflected in the standby charges in its next rate design application.

3.4 Alternative rate design proposals

94. A number of stakeholders advanced alternative rate design proposals.[75] The Commission confirmed that alternative rate designs are within the scope of this proceeding.[76] In general, parties advocated for a marginal cost approach, greater reliance on non-coincident peak based charges instead of all hours energy based charges, and maintaining the current rate design.

[72] Exhibit 26911-X1265, AESO argument, PDF page, 39, paragraph 119.

[73] Exhibit 26911-X0001.03, AESO application, PDF page 62, paragraph 189; Exhibit 26911-X0587, E3 evidence on behalf of AltaLink, PDF pages 20-21; Exhibit 26911-X0582, Mr. Zarumba evidence on behalf of ATCO Electric, PDF page 10.

[74] Transcript, Volume 13, page 2306, lines 13-17.

[75] AltaLink, ATCO Electric and Suncor advanced marginal cost methodologies while Fortis and UCA/CCA/CWSAA advanced embedded cost methodologies.

[76] Exhibit 26911-X0746, AUC ruling on motion from CCA, UCA and CWSAA, PDF page 2, paragraph 7.

95. The Commission does not approve any alternative rate design proposal in this decision. Throughout this decision, the Commission has provided guidance and its views on what rate design aspects should be included in the AESO's next rate design application. In some cases, the Commission's views have been informed by the alternative rate design proposals and evidence put forward by parties. However, the Commission has attributed significant weight to the AESO's request, that if the Commission does not substantially approve the proposed rate design, that the Commission provide the AESO with guidance and direct it to consider and review the directed changes before implementing any new rate design.[77]

3.5 Conclusion regarding bulk and regional rate design

96. The AESO is directed to refile its bulk and regional rate design application, considering the Commission's guidance, findings and directions, by January 31, 2025.

97. The Commission considers it just and reasonable to continue the current rate design at this time. The Commission considers that the magnitude of cost shifting that is currently occurring as a result of the avoidance of the 12 CP charge is not sufficiently large to render the current rate design unjust or unreasonable in the interim.[78] Additionally, the Commission agrees that it is practical and reasonable to maintain the 12 CP charge while the AESO considers possible changes to its rate design.[79] Further, the Commission considers that maintaining the current rate design reduces administrative burden and provides all parties with predictability and stability.

4 Proposed demand opportunity service modernization

4.1 Is M-DOS reasonable?

98. The AESO described the existing Rate DOS as a non-firm rate that allows additional use of available transmission capacity that would not otherwise be used.[80] For the proposed modernized DOS (M-DOS), the AESO proposed the following substantive changes to Rate DOS:

- A streamlined standardized application process by:
    - eliminating the requirement for a market participant to reapply for the opportunity service each year, and
    - replacing the requirement for a business case with a standardized representation.[81]

- The consolidation of the Rate DOS 1 Hour and the Rate DOS 7 Minute rate classes into a single rate class to be called Dispatchable Rate DOS.[82]

- Updates to the charges under Dispatchable Rate DOS (as compared to Rate DOS 7 minute) and to the Rate DOS Term rate class.[83]

77 Exhibit 26911-X0001.03, AESO application, PDF pages 108-109, paragraph 391.
78 Paragraph 72 above found the magnitude of cost shift was in the order of $70 million in 2020.
79 Exhibit 26911-X1254, Suncor argument, PDF pages 22-23, paragraphs 82-83.
80 Exhibit 26911-X0001.03, AESO application, PDF page 90, paragraph 308.
81 Exhibit 26911-X0001.03, AESO application, PDF page 93, paragraph 318(a).
82 Exhibit 26911-X0001.03, AESO application, PDF page 93, paragraph 318(b).
83 Exhibit 26911-X0001.03, AESO application, PDF page 93, paragraph 318(b).

- The introduction of new provisions to manage usage through energy market bids and merit order operations.[84]

- The introduction of the maximum annual load factor (MALF) mechanism. The MALF mechanism is a set of proposed new settlement provisions designed to limit market participant utilization of M-DOS to a 20 per cent maximum annual load factor.[85]

- Revisions to audit and disqualification provisions to allow the effective monitoring and auditing of market participants using the opportunity service. The AESO explained that the primary purpose of these provisions is to prevent the cannibalization of Rate DTS.[86]

99. The AESO included a proposed M-DOS version of the Rate DOS rate sheet[87] and updated certain terms and conditions[88] in its application.[89]

100. A number of parties criticized aspects of the M-DOS proposal, especially the proposed 20 per cent level of the MALF. Parties who opposed the AESO's M-DOS proposal altogether include the Consumers' Coalition of Alberta (CCA),[90] the Canada West Ski Area Association (CWSAA)[91] and the UCA.[92]

101. For the reasons that follow, the Commission finds that the AESO's M-DOS proposal is not just and reasonable as currently proposed, and is therefore denied.

102. The AESO explained that at the time the AESO filed the application, three market participants were utilizing Rate DOS,[93] and over the past 14 years, only 64 market participants have used the rate. Its proposed M-DOS would remove barriers to entry to the rate so more market participants could utilize spare transmission capacity that would not otherwise be used. It submitted that by lowering barriers to the use of Rate DOS, and in particular enabling use of the rate by energy storage developers, spare transmission system capacity could be used to offset some of the costs that would otherwise be collected in full from transmission system ratepayers.[94]

103. The Commission is not persuaded that the current Rate DOS is underutilized due to excessive barriers, or that its low utilization rate means that it is not fulfilling its intended purpose. In the Commission's view, because the charge associated with an opportunity service rate is so much lower than the charge applied under Rate DTS, there is an incentive for a market

84 Exhibit 26911-X0001.03, AESO application, PDF page 93, paragraph 318(b).
85 Exhibit 26911-X0001.03, AESO application, PDF page 93, paragraph 318(c). Under the MALF mechanism, Dispatchable Rate DOS utilization would be limited to 20 per cent of the market participant's Rate DOS contract capacity multiplied by the number of hours in the following 12-month period. Amounts in excess of this limitation would be charged a much higher rate called the Rate DOS DTS surcharge rate.
86 Exhibit 26911-X0001.03, AESO application, PDF page 93, paragraph 318(d).
87 Exhibit 26911-X0055, Appendix U - Blackline Rate DOS.
88 Exhibit 26911-X0053.01, Appendix S – Blackline terms and conditions, PDF pages 24-29.
89 The AESO provided a high-level overview of notable changes to the existing Rate DOS and proposed M-DOS terms and conditions (Exhibit 26911-X0001.03, AESO application, PDF pages 94-95, Table 5-1).
90 Exhibit 26911-X1250, CCA argument, PDF page 44, paragraph 123.
91 Exhibit 26911-X1246, CWSAA argument, PDF page 21.
92 Exhibit 26911-X1249, UCA argument, PDF pages 22-23, paragraphs 72-78.
93 Exhibit 26911-X0001.03, AESO application, PDF page 90, paragraph 308.
94 Exhibit 26911-X1265, AESO argument, PDF page 91, paragraph 298.

participant to utilize the DOS rate if they can. Rather, a more plausible explanation for the low utilization of DOS rates is the fact that, in order to qualify for Rate DOS, the market participant must clearly demonstrate that if charged the full Rate DTS amount, the market participant would not use the system at all, and therefore no rate revenue would be generated. The fact that only a small number of market participants have historically and currently utilized Rate DOS is not, of itself, a cause for concern, or demonstrative that barriers to using the rate are too onerous.

104. The Commission considers that if the AESO's proposal were approved more market participants would use Rate DOS. This is because the charge associated with an opportunity service rate is so much lower than the charge applied under Rate DTS. However, the Commission is concerned that such additional M-DOS usage would put upward pressure on Rate DTS due to market participants reducing their Rate DTS contract capacity in favour of Rate DOS contract capacity. In the Commission's view, the cannibalization risk is significant.

105. The Commission asked the AESO whether its M-DOS rate would be unsuccessful if the aggregate value of M-DOS revenues plus Rate DTS revenues is lower than revenues that would be generated under current Rate DTS and current Rate DOS. The AESO responded:

> The AESO does not agree that the measure of success should be based on the aggregate value of Modernized DOS revenue plus Rate DTS revenue compared to the aggregate value of current Rate DOS revenue plus Rate DTS revenue.
>
> In the AESO's view, this is not an appropriate measure of success because the revenue requirement will remain unchanged. The revenue generated under Modernized DOS, like the current Rate DOS, is applied to reduce the costs under Rate DTS. As more revenue is generated from Modernized DOS, less revenue is required from Rate DTS. Therefore, it would not make sense to compare the aggregate value of Modernized DOS revenue plus Rate DTS revenue against the aggregate value of current Rate DOS revenue plus Rate DTS revenue. The AESO also notes that it proposes changes to Rate DTS as well as Rate DOS. As such, evaluating this measure of success would require assumptions about how market participants would have behaved had neither Rate DTS nor Rate DOS changed.[95]

106. The Commission accepts the AESO's caveat that the revenues generated through its proposed rate design and M-DOS rate are uncertain and will depend on assumptions about how market participants will react to the AESO's ISO tariff proposals and in respect of how they would have behaved if neither Rate DTS nor Rate DOS were changed. However, given the cannibalization potential, there should be strong evidence, and a high degree of certainty, that the overall result of the AESO's M-DOS proposals is a greater revenue offset of Rate DTS. The AESO did not provide this.

107. As part of its justification for its proposed M-DOS framework, the AESO advised that it had considered other types of non-firm rates. This included interruptible rates designed to promote savings in future transmission costs by utilizing interruptions to relieve constraints. The AESO preferred its proposed M-DOS rate to interruptible rates because its proposed M-DOS rate would promote the utilization of spare transmission system capacity that would not otherwise be used, would not need to be locationally restricted to be useful, and would comply with the postage stamp principle.[96] While the Commission agrees that M-DOS may be preferable to

[95] Exhibit 26911-X0263.05, PDF page 44, AESO-AUC-2021DEC06-012.
[96] Exhibit 26911-X1265, AESO argument, PDF page 90, paragraph 292.

interruptible rates in relation to these factors, the Commission does not consider that this provides sufficient rationale to adopt M-DOS in light of the Rate DTS cannibalization concerns discussed above in this section. Regardless, the Commission agrees with the following submission of Suncor, that any interruptible rate proposal should be part of a DTS rate redesign, rather than part of a DOS rate:

> Further, Suncor submits any decision on the Modernized Rate DOS component of the Application is premature, considering the deficiencies of the proposed rate for Demand Transmission Service (DTS). Alternative demand rates should be complimentary to Rate DTS; would be dependent on the final components and rates under Rate DTS; and should therefore be deferred to the next AESO tariff application.[97]

108. For the above reasons, the Commission does not find it just and reasonable to approve M-DOS. Until such time as the AESO proposes an alternative, the Commission finds it just and reasonable to continue with existing Rate DOS. The AESO did not ask the Commission to consider, if M-DOS were denied, whether various changes to the terms and conditions or rate levels of existing Rate DOS were just and reasonable on a stand-alone basis; accordingly, the Commission makes no findings in this regard.

4.2 Guidance on opportunity service rates

109. In anticipation that further changes to Rate DOS may be sought in the future, the Commission provides the following general guidance on how it views opportunity rates.

110. As a starting point, the Commission re-iterates that the presumption in Alberta is that customers withdrawing electricity from the system take service under Rate DTS. The Commission has historically endorsed the use of opportunity service rates as an exception to Rate DTS where doing so would allow the utilization of spare transmission capacity, and generate incremental revenue to reduce rates for firm customers. A well-designed opportunity service rate should not cannibalize Rate DTS revenues, because its use is limited to customers who could not economically take service under Rate DTS.

111. As part of its M-DOS proposal, the AESO proposed a number of changes to the terms and conditions for the current Rate DOS. These changes included the elimination of: (i) an annual business case requirement; (ii) the requirement that the use of Rate DOS must be in respect of a commercial business opportunity that is either temporary or occurring on a repeated short-term basis; and (iii) the requirement that the use of Rate DOS must be to replace an alternate source of energy.[98]

112. The Commission advises that it is receptive to the AESO proposing changes to its existing Rate DOS, as part of its next rate design application, if the AESO provides sufficient evidence to demonstrate that the increased use provides an overall net benefit to transmission system customers in the form of additional incremental revenue, such that Rate DTS can be offset to a greater degree. Some examples of changes that the Commission is interested in exploring include a more long-term type of opportunity service rate and individual opportunity service rates with terms and conditions tailored to particular customers. This may include consideration of an opportunity service rate for load retention. Regardless of any proposed changes, the Commission believes that the business case requirement (or similarly rigorous

[97] Exhibit 26911-X1254, Suncor argument, PDF pages 4-5, paragraph 6.
[98] Exhibit 26911-X0053.01, Appendix S – Blackline terms and conditions, PDF pages 24-25.

eligibility threshold) remains necessary to clearly demonstrate that its use is limited to customers who could not economically take service under Rate DTS.

4.3 Guidance on opportunity service rates for energy storage

113. The AESO has historically taken the view that energy storage (ES) resources are not eligible for Rate DOS.[99] In its application, the AESO confirmed that its view has shifted over time, and that the use of Rate DOS by ES resources may be consistent with the objectives and requirements for Rate DOS. The AESO proposed to make M-DOS available for energy storage, and maintained an energy storage specific opportunity service rate was not warranted.

114. CanREA[100] and ESC[101] both proposed that a separate class of opportunity service rate, called storage opportunity service (Rate SOS), should be created, with terms and conditions distinct from those proposed by the AESO for its M-DOS rate. The UCA,[102] the CCA[103] and the CWSAA[104] also generally supported a separate opportunity service rate for ES resources, distinct from M-DOS.

115. Because the Commission has denied the AESO's M-DOS proposal, M-DOS is not available to ES resource developers. The Commission has suggested that the AESO consider implementing an alternative billing capacity rate structure within Rate DTS that would provide a more cost-effective option for off-peak transmission system use that ES resources may be able to access and which could potentially be refiled with the Commission on a stand-alone basis earlier than its next rate design application. The Commission will therefore not direct the AESO to adopt an energy-storage specific opportunity service rate at this time.

116. The Commission recognizes that ES resource proponents emphasized the importance of facilitating investment in ES resources and advocated for the development of an energy storage tariff, or storage-specific provisions on an expedited basis. The Commission will consider parties' views on whether ES resources can be made economically viable within the proposed rate design at the time of the AESO's next rate design application.

117. In the event that the adoption of an off-peak billing capacity charge in a future redesign of Rate DTS would not, of itself, be sufficient to make ES resources economically viable, and should use of Rate DOS (or future iterations of it) continue to be impractical for ES resources, the Commission advises that it would be interested in exploring a distinct form of opportunity service rate that is targeted to the specific needs of potential investors in ES resources.

[99] Exhibit 26911-X0001.03, AESO application, PDF page 91, paragraph 311.
[100] Exhibit 26911-X0543, CanREA evidence, PDF pages 2-3, paragraph 5.
[101] Exhibit 26911-X0517, ESC evidence, PDF page 4, paragraph 6.
[102] Exhibit 26911-X0576.01, UCA evidence, PDF page 26, and Exhibit 26911-X1249, UCA argument, PDF page 24, paragraph 82.
[103] Exhibit 26911-X1250, CCA argument, PDF page 45, paragraph 128.
[104] Exhibit 26911-X1246, CWSAA argument, PDF page 22.

5 Rate XOS and Rate XOM

118. In the application, the AESO proposed changes to Rate XOS (export opportunity service)[105] and Rate XOM (export opportunity merchant service).[106]

119. Rates XOS and XOM each apply a primary charge levied in $/MWh. Both Rate XOS and Rate XOM also require that a charge be applied for any incremental operating reserves that the AESO may be required to procure in relation to an export transaction using either of those rates. In addition, both Rate XOS and Rate XOM apply a $500 transaction fee in respect of any month in which at least one export transaction occurs. However, whereas a line loss charge is applied for transactions under Rate XOS, no loss charge is applied to transactions under Rate XOM.

120. For the purpose of comparing the primary charge for Rates XOS and XOM under the ISO's existing tariff and the proposed tariff, the AESO used 2019 costs and rates as a base year. Under this comparison, the primary charge for Rates XOS and XOM would rise from $7.98/MWh[107] to $14.84/MWh.[108]

121. The AESO explained that to calculate the primary charge for Rates XOS and XOM, Rate DTS costs are first converted, by component, to $/MWh charges. Rates XOS and XOM are then allocated components of transmission costs which are attributable to those rates; specifically, the energy charge and the operating reserve charge.[109]

122. The AESO explained that the primary charges would continue to be calculated under the same methodology, but would reflect the proposed design for Rate DTS.[110] Because the AESO's proposed Rate DTS design increases the proportion of costs allocated to a MWh energy charge, this consequentially increases the size of the primary charges in Rates XOS and XOM.

123. TransCanada Energy, Capital Power Corporation, Heartland Generation Ltd. and TransAlta Corporation (the "Joint Parties") opposed the AESO's proposals in respect of Rates XOS and XOM.[111] The Joint Parties requested that the AESO be directed to continue to allocate variable and fixed costs to Rates XOS and XOM in accordance with the proportions set

---

105 Rate XOS applies to system access service provided to market participants who export electric energy from the interconnected electric system utilizing an intertie as it existed on August 12, 2004, as referred to in Section 16 of the *Transmission Regulation*. See Exhibit 26911-X0062, Appendix BB – Rate XOS current.

106 Rate XOM applies to system access service provided to market participants who export electric energy from the interconnected electric system utilizing a merchant intertie, defined in accordance with Section 27(4) of the *Transmission Regulation* as an intertie for which the cost of planning, designing, constructing, operating and interconnecting is paid by the person who proposed the intertie and other persons that directly benefit from the intertie. See Exhibit 26911-X0061, Appendix AA – Rate XOM current.

107 Exhibit 26911-X0160.03, Updated appendix G – 2019 test year current rate calculations, Tab "G-11 Other Rates," cell L37.

108 Exhibit 26911-X0159.03, Updated appendix F – 2019 test year proposed rate calculations, Tab "F-11 Other Rates," cell L37.

109 Exhibit 26911-X0001.03, AESO application, PDF page 102, paragraph 356.

110 Exhibit 26911-X0001.03, AESO application, PDF pages 101-102, paragraph 355.

111 Two erratas to the Joint Parties' evidence were subsequently filed on April 21, 2022, and on May 2, 2022. The final version of the Joint Parties' evidence submitted on May 2, 2022, was filed as Exhibit 26911-X0757.

out in EUB Decision 2007-106 and AUC Decision 2010-606,[112] and as reflected in current rates.[113]

5.1 How has the Rate XOS and Rate XOM design methodology evolved, and is the current proposal consistent with its underlying principles?

124. The AESO and the Joint Parties debated whether the relatively higher primary charge for the AESO's proposed Rates XOS and XOM should be regarded as a natural continuation of a methodology adopted in prior decisions, or a fundamental change in that methodology.

125. The AESO took the view that its proposed Rates XOS and XOM have not fundamentally changed, and instead only reflect the existing calculation methodology being applied to its proposed rate design.[114] The AESO also argued that since the current Rate DTS is no longer aligned with cost causation, market participants utilizing the current Rates XOS and XOM benefit from a cross-subsidy from other market participants.[115] In the AESO's view, a higher energy charge ($/MWh) is appropriately reflective of cost causation because energy consumption by exporters drives transmission costs, in the form of investments to accommodate the flow of in-merit energy.[116] The Joint Parties argued that the AESO's proposed Rates XOS and XOM represent a significant change in methodology because, in their view, the proposed rates reallocate fixed transmission system costs into the primary charge.[117]

126. The AESO and the Joint Parties debated whether the EUB, in establishing and refining Rate XOS, necessarily intended that costs deemed to be variable with energy for the purposes of DTS rate design should also be recovered as energy in the primary charge for export rates.

127. The Commission considers that the key finding of the EUB in Decision 2007-106 is that "opportunity service should be priced at no less than the incremental variable cost of providing the opportunity service, and that opportunity service rates should also reflect the value of the opportunity service to the customer."[118]

128. The Commission accepts the Joint Parties' view that the construct for export opportunity service rates set in Decision 2007-106 was that: (i) the service would be priced at no less than incremental variable costs;[119] and (ii) that the rate charged should make a value of service based contribution towards fixed transmission wires costs.[120] The Commission considers that this construct remains relevant today, and does not see a compelling reason to depart from it.

129. In determining what constitutes the incremental variable costs attributable to an exporter, the Commission considers that the correct perspective is costs directly and immediately created by an export energy flow. These costs are variable when viewed in the short term because they are attributable to a specific transaction or transactions, and are distinct from system costs that

[112] Decision 2010-606: Alberta Electric System Operator, 2010 ISO Tariff, Proceeding 530, Application 1605961, December 22, 2010.
[113] Exhibit 26911-X1258, Joint Parties argument, PDF pages 4-5, paragraph 4.
[114] Exhibit 26911-X1265, AESO argument, PDF pages 110-113, Section 12.3.1.
[115] Exhibit 26911-X0282.02, PDF page 10, AESO-MATL-2021DEC06-004(d), cited at Exhibit 26911-X1265, AESO argument, PDF page 111, paragraph 283.
[116] Exhibit 26911-X1280, AESO reply argument, PDF pages 41-42, paragraph 172.
[117] Exhibit 26911-X1258, Joint Parties argument, PDF page 18, paragraph 45.
[118] Decision 2007-106, PDF page 92.
[119] Decision 2007-106, page 86, cited at Exhibit 26911-X1258, Joint Parties argument, PDF page 12, paragraph 24.
[120] Decision 2007-106, page 87, cited at Exhibit 26911-X1258, Joint Parties argument, PDF page 12, paragraph 24.

may be variable when viewed in the long-run. For example, these costs include estimated transmission losses and the estimated cost of operating reserves that may be required to support an export energy flow. The Commission considers that the future charge for service under Rates XOS and XOM should also reflect the value of the benefit received by exporters and should seek to maximize the incremental transmission revenue associated with Rates XOS and XOM.

130. The purposes, principles and attributes of Rate DTS and opportunity service rates are distinct. Exporters under Rates XOS and XOM utilize spare capacity on an as-available basis and are subject to curtailment risk that is not applied to firm load operating under Rate DTS. The AESO acknowledged that, unlike a firm service, exporters cannot depend on export opportunity service capacity being available.[121]

131. The Commission agrees with the Joint Parties that NERA's method to the design of Rates XOS and XOM results in an excessive primary charge for Rates XOS and XOM, because the energy charge component of the AESO's proposed rate design for Rate DTS is carried through mechanically, contrary to the opportunity rate principles stated above.

132. For the above reasons, the Commission denies the AESO's proposed changes to Rates XOS and XOM.

5.2 Does the Commission have sufficient data to determine an appropriate contribution towards fixed costs within Rates XOS and XOM?

133. Opportunity rates are intended to recover the incremental variable costs required to serve opportunity service customers, and make a contribution towards fixed costs that is based on the value of service provided to the customer (in this case, the exporter).

134. The Joint Parties filed evidence in this proceeding to substantiate their view that the AESO's proposal for Rates XOS and XOM would have required exporters to make an excessive contribution towards fixed costs, by reclassifying fixed costs as variable energy costs. However, the Commission notes that no party filed evidence specifically intended to examine whether the contribution to fixed costs by users of Rates XOS and XOM continues to reflect the value that export opportunity service provides.

135. The CWSAA, in expressing support for a separate storage opportunity rate, argued that both storage and exports should make a reasonable contribution to fixed transmission system costs, and that the amount should be optimized. CWSAA submitted that determining the optimum price would require economic analysis and a "nuanced and pragmatic approach based on market conditions and price spreads."[122]

136. The Joint Parties responded that CWSAA's approach for calculating "optimized" opportunity service rates was not raised during the evidentiary phase of the proceeding and is untested.[123] The Commission accepts that the focus of parties in this proceeding was to consider the AESO's proposal, rather than scrutinize whether and how the currently approved Rates XOS and XOM could be improved. However, the Commission notes that the level of contribution by exporters towards the fixed system costs has not been revisited since the 2007 and 2010 AESO

[121] Exhibit 26911-X1265, AESO argument, PDF page 110, paragraph 278.
[122] Exhibit 26911-X1246, CWSAA argument, PDF page 22.
[123] Exhibit 26911-X1281, Joint Parties reply argument, PDF pages 16-17, paragraphs 47-48.

tariff applications. The Commission is not directing any changes to Rate XOS and Rate XOM from the existing current rate at this time. However, the Commission is receptive to exploring whether the level of contribution to fixed costs of the transmission system made by export opportunity service users adequately reflects the value of service to those users, at the time of the AESO's next rate design application.

6 System access service contract change notification provisions

137. In this section of the Decision, the Commission addresses the AESO's proposal to make two changes to the PILON (payment in lieu of notice) provisions found in Section 5.3 of the tariff terms and conditions. The two changes pertain to reductions or terminations of contract capacity. The Commission also addresses requests by certain interveners for a Commission-directed study into "over contracting" practices, and to ensure that distribution facility owners (DFOs) flow-through PILON waivers to end-use customers.

138. The Commission denies the AESO's proposed revisions to the PILON provision in Section 5.3(7) that would provide market participants with the ability to adjust contract levels during a one-time contract adjustment period, following the introduction of the proposed DTS rate design. This is because the Commission denied the AESO's request to change its DTS rate design.

139. However, the AESO also proposed revising the PILON waiver applicability in Section 5.3(6) to sites that have not increased their contract capacity in the last five years, regardless of whether the Commission approved the proposed DTS rate design and the changes to Section 5.3(7).[124] This was based on the rationale that current PILON charges were a barrier to stakeholders providing the AESO with accurate information about their sites.[125] The AESO's recommended adjustment to Section 5.3(6), it submitted, would help ensure that accurate information is available to effectively plan the efficient use of the transmission system.[126] Without this change, the current PILON waiver eligibility would only apply to sites that demonstrate a need for a contract reduction because of energy efficiency improvements and that have had no increases to their contract capacity in the last 10 years.

140. To implement this change, the AESO proposed modifications to Section 5.3(6) of its terms and conditions to:

(i) eliminate a requirement that the market participant has taken system access service for at least 20 years;

(ii) eliminate provisions that provided that a proposed DTS contract reduction stemmed from a market participant's demand reduction initiative; and

(iii) change the minimum period since the market participant had last requested a contract capacity increase to five years rather than 10 years.[127]

124 Transcript, Volume 6, page 949, lines 20-25.
125 Exhibit 26911-X0001.03, AESO application, PDF page 104, paragraph 371; Transcript, Volume 6, page 950, lines 19-24.
126 Exhibit 26911-X0001.03, AESO application, PDF pages 104-105, paragraph 373.
127 Exhibit 26911-X0053.01, Appendix S – Blackline terms and conditions, PDF pages 14-15.

141. The AESO noted that, in accordance with Section 5.2 of its terms and conditions, if market participants reduced their contract capacity, they would have to pay back some or all of the money that the AESO funded to build the facilities to serve their original contract capacity.[128]

142. The ADC agreed that the PILON is a barrier to customers "right sizing" their DTS contracts, as it is costly and risky to get contract capacity reduced. In ADC's view, most customers will not pay a five-year PILON unless they plan to exit the grid, and providing notice five years in advance is undesirable as it is often difficult to predict future load changes, and it is unclear what happens if notice is provided and later withdrawn. The ADC submitted that setting contract capacity at correct levels would save Alberta ratepayers in the long-run by further delaying new transmission and distribution capacity.[129]

143. The Commission finds it just and reasonable to revise the PILON waiver applicability to sites that have not increased contract capacity in the last five years. Historically, concerns about PILON being a barrier to contract reductions have involved a debate over the trade-off between the PILON being a barrier to providing the AESO accurate information about the current energy requirements at their sites, and the concern that maintaining PILON penalties may be necessary to provide an incentive for market participants to contract accurately in the first place. The Commission accepts that the AESO's proposed changes to Section 5.3(6) will aid in incenting market participants to recontract at a level that reflects their current use of the system.

144. In addition, the Commission notes that it approved critical information requirements in Decision 22942-D02-2019, in part to incent new and current customers to provide accurate information regarding specific matters throughout the connection process. The Commission accepts the AESO's submission that the critical information requirements should work in conjunction with the PILON waiver revisions, which apply to customers that have been connected for a significant period of time, to enhance provision of accurate contract information to the AESO overall.[130]

145. The AESO is directed to file a compliance filing to reflect the approved changes to Section 5.3(6) of its PILON terms and conditions by January 15, 2023.

146. There is a need to balance PILON's negative effect as a barrier to contract adjustments which may free up transmission capacity, and PILON's benefit to act as an incentive for market participants to initially contract accurately. Accordingly, the Commission directs the AESO to monitor both initial contracting decisions and decisions reducing contract capacities as a result of the PILON relaxations approved in this decision in order to learn whether the relaxed PILON has had any effect on a market participant's incentive to accurately contract in its initial DTS contract. The ISO should file this information in an ISO tariff application after its next rate design application to be filed by January 31, 2025.

147. The ADC provided evidence that a number of PODs have contract capacity significantly in excess of the highest metered demand of the POD, and recommended that the Commission direct the AESO and the DFOs to undertake a study to assess the issue of over-contracting, in order to assist with identifying the spare capacity in the system.[131] DUC/IPCAA similarly

[128] Exhibit 26911-X0001.03, AESO application, PDF page 105, paragraph 378.
[129] Exhibit 26911-X0526, ADC policy evidence, PDF page 59.
[130] Transcript, Volume 6, page 951, lines 23-25 to page 952, lines 1-22.
[131] Exhibit 26911-X0526, ADC policy evidence, PDF page 58.

requested that the Commission direct the AESO and the DFOs to undertake a study on DTS over-contracting.[132] The ADC submitted that over-contracting may be caused by the fact that DFOs have entered into the DTS contract for those transmission-connected customers that have not obtained a waiver under Section 101(2) of the *Electric Utilities Act*. The ADC submitted that because DFOs have the ability to pass through costs, they may not be motivated to pursue DTS contract capacity reductions, and that they do not proactively contact their transmission-connected customers to make them aware of the costs they are incurring due to having a higher than required contract capacity.

148. The Commission declines to direct the AESO and DFOs to conduct a study to identify potential over contracting. The Commission notes that the ADC agreed[133] that it is ultimately the responsibility of the end-use customer and not the DFO to initiate changes to DTS contract capacity levels entered into by the DFOs on behalf of the end-use customer. While the ADC suggested that some transmission connected customers served by DFOs may not be aware of their DTS contract capacity particulars, in the Commission's view, it is the responsibility of the end-use customer, and not the DFO, to understand what drives their billing for transmission services flowed through from the ISO tariff. Further, given that the ADC confirmed[134] that it was its experience that DFOs would, when requested, assist in the preparation of a system access service request to modify the DTS contract capacity, the Commission is likewise not persuaded that any direction to DFOs with respect to the contract capacities of their transmission connected end-use customers is necessary.

149. As there is no evidence that DFOs would not accommodate an end-use customer request for contract changes, the Commission is not persuaded that there is a need to make any specific direction to DFOs to ensure that expanded access to a waiver of the current PILON provisions (Section 5.3(6)) is proactively used by the end-use customers of the DFOs.

7 Mitigation

150. The Commission considers that the rate impact of the proposed rate design is likely far greater than what the AESO submitted in its application because it did not consider resulting bill impacts to end-use distribution customers. For example, Fortis estimated that under the proposed rate design, approximately 7,000 of its sites would see a bill increase of greater than 10 per cent.[135] However, since the AESO's proposed rate design is denied, it is unnecessary to make any findings regarding mitigation of rate impacts to consumers at this time.

151. The Commission recognizes that some of the guidance, findings and directions in this decision in relation to the AESO's next rate design application have the potential to result in significant rate impacts or rate shock to specific customers. The Commission considers that mitigation will likely need to be addressed in connection with a new bulk and regional rate design proposal. The Commission advises that it is interested in exploring reasons for mitigation,

---

132 Exhibit 26911-X1257, DUC and IPCAA argument, PDF pages 28-29, paragraphs 124-129.
133 Exhibit 26911-X0773, PDF page 34, ADC-AUC-2022APR18-011(a).
134 Exhibit 26911-X0773, PDF page 35, ADC-AUC-2022APR18-011(b).
135 Exhibit 26911-X1256, FortisAlberta argument, PDF page 16, paragraph 45; Exhibit 26911-X0485, EDTI Cover Letter, PDF page 3; Exhibit 26911-X0493, 2022-03-11 EPC Cover Letter re AUC Ruling on IPCAA distribution customer information request, PDF page 3; Exhibit 26911-X0496, ATCO Electric – 2022 SAS Bill Estimator, 4.0-Bill Impacts, cell K27. Evidence received from DFOs, including FortisAlberta, estimated that over 15,000 customers would see an increase greater than 10 per cent.

which may include cost impacts, knock-on effects to regions and employment outcomes. The Commission is also amenable to exploring various methods of mitigation of rate design impacts, such as: load retention rates, long-term rate mitigation, gradual implementation of new rates, and other identified means of mitigation. In addition, the Commission intends to consider bill impacts to customers of the electric distribution utilities in connection with the next AESO rate design application and possibly distribution utility Phase 2's, and expects these utilities to provide relevant information on rate impacts and potential mitigation to their rates at that time.

8 Next steps

152. The AESO is directed to file a compliance filing to reflect the approved changes to Section 5.3(6) of its PILON terms and conditions by January 15, 2023.

153. The AESO is directed to update the Commission on how it proposes to deal with the remaining three ISO tariff modules to address the Commission's directions from Decision 22942-D02-2019,[136] by June 30, 2023.

154. The AESO is directed to refile its bulk and regional and Rate DOS rate design application considering the guidance, directions and findings provided in this decision, by January 31, 2025. The Commission is open to the AESO filing smaller stand-alone portions of its application earlier if the AESO is in a position to do so and considers that this may assist in implementing a revised rate design in a more timely manner.

155. In addition, the Commission considers that there has already been a significant amount of consultation and evidence on the issues discussed in this application, and that all parties have a sound foundation to reassess core rate design elements. Therefore, the Commission is interested in and would support alternative approaches to developing and adjudicating the AESO's next rate design application. The Commission is open to supporting some type of Commission assisted process, if parties would find that helpful, to provide a venue for open dialogue and to help resolve issues in a more timely way. This could include, as an example, a negotiated settlement process on all or part of the rate design.

9 Order

156. It is hereby ordered that:

(1) The Alberta Electric System Operator's current rate design continues until further order or decision of the Commission.

(2) The Alberta Electric System Operator shall file a compliance filing that reflects the findings and directions in this decision regarding payment in lieu of notice provisions in the ISO tariff terms and conditions by January 15, 2023.

[136] Exhibit 26911-X0001.03, AESO application, PDF page 9, paragraph 16.

(3) The Alberta Electric System Operator shall update the Commission on how it proposes to deal with the remaining three ISO tariff modules that address the Commission's directions from Decision 22942-D02-2019, by June 30, 2023.

(4) The Alberta Electric System Operator shall refile its Phase 2 ISO tariff application to reflect the guidance, findings and directions in this decision by January 31, 2025.

Dated on November 10, 2022.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Douglas A. Larder, KC
Vice-Chair

(original signed by)

Vera Slawinski
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
Alberta Electric System Operator (AESO or ISO) Norton Rose Fulbright LLP
Alberta Direct Connect Consumers Association (ADC) Ackroyd LLP
Alberta Forest Products Association
Alberta Newsprint Company
AltaLink Management Ltd. (AltaLink or AML) Borden, Ladner Gervais LLP
AltaSteel Ltd. Miller Thomson LLP
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP
BluEarth Renewables Inc.
British Columbia Hydro and Power Authority (BC Hydro) Lawson Lundell Barristers & Solicitors
Canadian Renewable Energy Association (CanREA)
Capital Power Corporation Dentons Canada LLP
ConocoPhillips Canada
Consumers' Coalition of Alberta (CCA) N. J. McKenzie Wachowich & Co.
Canada West Ski Area Association (CWSAA)
City of Lethbridge

Name of organization (abbreviation) Company name of counsel or representative
Desiderata Energy Consulting Inc Ackroyd LLP
Dual Use Coalition Ackroyd LLP
Dow Chemical Canada ULC (Dow) Dentons Canada LLP
Elemental Energy Renewables Inc.
Energy Associates International
Energy Storage Canada (ESC) Power Advisory LLC McCarthy Tetrault LLP
Elemental Energy Renewables Inc.
ENMAX Energy Corporation Regulatory Law Chambers
ENMAX Power Corporation (EPC)
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI)
ERCO Worldwide
FortisAlberta Inc. (Fortis) Osler, Hoskin & Harcourt LLP
Greengate Power Corporation
Heartland Generation Ltd. McLennan Ross Barristers & Solicitors
Industrial Power Consumers Association of Alberta (IPCAA)
Lionstooth Energy

Name of organization (abbreviation) **Company name of counsel or representative**
MATL Canada G.P. Inc.
Millar Western Forest Products Ltd.
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP
Powerex Corporation Lawson Lundell Barristers & Solicitors
Rural Municipalities of Alberta
RWE Canada Ltd.
Suncor Energy Inc. Stikeman Elliott LLP
The City of Red Deer
Town of High Prairie
Town of Edson
Town of Slave Lake
TransAlta Corporation (TransAlta)
TransCanada Energy Ltd.
URICA Asset Optimization (URICA)
Versorium Energy Ltd.
West Fraser Mills Ltd. Ackroyd LLP

Name of organization (abbreviation) Company name of counsel or representative
Woodlands County Council

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair D.A. Larder, KC, Vice-Chair V. Slawinski, Commission Member Commission staff J. Graham (Commission counsel) M. Anderson (Commission counsel) S. Karim C. Strasser J. Halls C. Fuchshuber T. Richards N. Morter

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
Alberta Forest Products Association R. Secord	B. Mulligan J. Dobner
Industrial Power Consumers Association of Alberta (IPCAA) and the Dual Use Customers (DUC) R. Secord D. Hildebrand	P. Sotkiewicz D. Hildebrand
Canada West Ski Areas Association (CWSAA) I. Maharaj	R. Cowburn
Canadian Renewable Energy Association (CanREA) M. Wenig	K. de Palezieux E. de Palezieux L. Olien
Energy Storage Canada (ESC) R. Goyal	T. Lusney
ENMAX Energy Corporation R. Twyman K. Dumanovski	C. Joy O. Tomiuk J. Frayer S. Mueller
ATCO Electric Ltd. D. Sheehan	R. Zarumba
Consumers' Coalition of Alberta (CCA) N. McKenzie	R. Retnanandan D. Levson D. Madsen
FortisAlberta Inc. (Fortis) J. Gormley C. Richards	M. Stroh R. Sharma
TC Energy, Capital Power, Heartland Generation, and TransAlta (Joint Parties) S. Kupi G. Fitch V. Light D. Farmer	M. Davis K. Glasier A. Yamamoto M. Thompson
Alberta Electric System Operator (AESO) G. Barnett G. Valacco (student-at-law) M. Keen L. Mason M. Manhas A. Baer	M. Keating Erickson N. LeBlanc S. Hall L. Olive M. Dawes R. Druce

Name of organization (abbreviation) Name of counsel or representative	Witnesses
Suncor Energy Ltd. D. Langen L. Lees A. Newmarch	H. Klinkenborg
Capital Power Corporation S. Kupi	M. Davis J. Pfeifenberger J. Tsoukalis
AltaLink Management Ltd. J. Liteplo K. McGlone J. Hulecki	R. Orans R. Boulton
Office of the Utilities Consumer Advocate (UCA) T. Marriott K. Rutherford	R. Stout M. Good S. Mason
Alberta Direct Connect Consumers Association (ADC) R. Secord	C. Chekerda A. Al-Jabir E. Soto C. Laird N. DeGelder S. Fehr

Alberta Utilities Commission C. Dahl Rees D.A. Larder, KC V. Slawinski J. Graham M. Anderson

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The AESO is directed to refile its bulk and regional rate design application, considering the Commission's guidance, findings and directions, by January 31, 2025. ... paragraph 96

2. The AESO is directed to file a compliance filing to reflect the approved changes to Section 5.3(6) of its PILON terms and conditions by January 15, 2023. .....paragraphs 145 and 152

3. There is a need to balance PILON's negative effect as a barrier to contract adjustments which may free up transmission capacity, and PILON's benefit to act as an incentive for market participants to initially contract accurately. Accordingly, the Commission directs the AESO to monitor both initial contracting decisions and decisions reducing contract capacities as a result of the PILON relaxations approved in this decision in order to learn whether the relaxed PILON has had any effect on a market participant's incentive to accurately contract in its initial DTS contract. The ISO should file this information in an ISO tariff application after its next rate design application to be filed by January 31, 2025.. paragraph 146

4. The AESO is directed to update the Commission on how it proposes to deal with the remaining three ISO tariff modules to address the Commission's directions from Decision 22942-D02-2019, by June 30, 2023. .... paragraph 153

5. The AESO is directed to refile its bulk and regional and Rate DOS rate design application considering the guidance, directions and findings provided in this decision, by January 31, 2025. The Commission is open to the AESO filing smaller stand-alone portions of its application earlier if the AESO is in a position to do so and considers that this may assist in implementing a revised rate design in a more timely manner. .... paragraph 154

Appendix 4 – Summary of important process steps

(return to text)

Date	Process step description
Proceeding 22942	
September 22, 2019	In the decision for Proceeding 22942, the Commission directs the AESO to continue the consultation process with respect to the 12 CP issue.
Consultation period	
February 13, 2020	Letter of Notice of Stakeholder Engagement Session on Bulk and Regional Tariff Design Session issued by the AESO.
March 13, 2020	Session 1. Webinar session of Bulk and Regional Tariff Design: AESO indicates its intention to file its application on September 30, 2020.
April 9, 2020	AESO indicates that it intends on postponing the work on the AESO tariff due to COVID-19; will request an extension from its September 30, 2020, filing date to the Commission.
September 24, 2020	Session 2 Webinar session of Bulk and Regional Tariff Design: AESO indicates its intention to file its application on September 30, 2020.
October 14, 2020	Technical Session 1.
November 5, 2020	Session 3.
November 30, 2020 **(Proceeding 25175)**	The Commission directs that the AESO's bulk and regional rate design application is to be filed by June 30, 2021.
December 10, 2020	Session 4.
March 25, 2021	Session 5.
March 31, 2021	Technical Session 2.
April 22, 2021	Targeted mitigation
May 12, 2021 **(Proceeding 25175)**	AESO files updated request and variance of June 30, 2021, filing deadline to October 15, 2021, or eight weeks after the AESO's last stakeholder session, whichever is later.
May 20, 2021	Session 5B (DOS).
June 1, 2021 **(Proceeding 25175)**	The Commission grants the AESO's request to file by October 15, 2021; the Commission rejects the eight weeks after the last stakeholder session if it is to be later than October 15, 2021.
June 3, 2021	Session 6A.
June 24, 2021	Session 6B.
Proceeding 26911	
October 15, 2021	The AESO files an application for bulk and regional rate design and modernized demand opportunity service.
October 18, 2021	The AESO files a motion seeking confidential treatment of certain information related to its tariff application.
October 19, 2021	The Commission opens the proceeding and issues notice.
November 2, 2021	Written submissions of concern or support for the application are due.
November 3, 2021	Deadline for the AESO to reply to IRs from the Commission regarding the treatment of confidential information.

Date	Process step description
November 17, 2021	Submissions by parties regarding the AESO's motion for confidentiality.
November 22, 2021	The Commission sets out its directions for the procedure for Proceeding 26911.
December 6, 2021	Information request (IR) round 1 to the AESO.
December 8, 2021	Final participation closing date.
January 11, 2022	The Town of High Prairie submits a late statement of intent to participate (SIP) and requests Proceeding 26911 to be paused until a thorough economic analysis is complete. The SIP is accepted and the request for suspension is declined.
January 19, 2022	IR response round 1 from the AESO.
January 24, 2022	The Commission directs the AESO to file the unredacted versions of the confidential information on the confidential portion of the record of this proceeding.
January 26, 2022	The AUC receives motions filed by parties on further and better IR responses from the AESO.
January 28, 2022	The AUC receives a late SIP by Woodlands County. The SIP is accepted.
February 3, 2022	Refiled motions on further and better IR responses from the AESO.
February 9, 2022	AESO response to motions.
February 11, 2022	The AUC receives and accepts a late SIP by the Rural Municipalities of Alberta. Additionally, receives a request for suspension of Proceeding 26911, which is denied.
February 14, 2022	Reply by parties who filed motions.
February 25, 2022	Commission ruling on motions.
March 4, 2022	Updated AESO IR Round 1 responses.
March 18, 2022	Intervener evidence is due.
April 18, 2022	IRs to interveners by the AESO, the Commission and other interveners.
April 27, 2022	TransAlta files a motion seeking confidential treatment of its IR response.
May 9, 2022	IR responses from interveners.
May 11, 2022	The AESO files a motion containing several requests.
May 16, 2022	Reply comments from the AESO.
May 31, 2022	Deadline for the AESO to file rebuttal evidence.
June 2, 2022	Comments due from the AESO regarding implications of Bill 22 on proposed application.
June 6, 2022	Counsel call organized by the AUC.
June 13-30, 2022	Oral hearing is held virtually.
July 15, 2022	Written argument.
July 29, 2022	Written reply argument.
August 12, 2022	Commission cancels oral argument and reply argument.