

# AESO Bulk and Regional Rate Design and Modernized DOS Rate Design Application

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## Executive Summary

- 1 This is the application of the Independent System Operator (ISO), operating as the Alberta Electric System Operator (AESO), for approval of the methodology (i.e., design) that it proposes to use to recover the bulk and regional portions of the AESO's revenue requirement through customer rates.
- 2 The bulk and regional rate design, reflected in Rate Demand Transmission Service (Rate DTS), currently relates to the recovery of wires costs for both the bulk and regional portions of the Alberta transmission system. These costs represent approximately 75% of wires costs and 60% of the AESO's total revenue requirement. The rate design aims to recover these costs based on the principles of cost causation. The Alberta Utilities Commission (AUC or Commission) has found that rates based on cost causation will provide appropriate price signals, be fair, objective, and equitable, and minimize inter-customer subsidies.<sup>1</sup>
- 3 The current bulk and regional rate design (the Current Rate Design) was established nearly 15 years ago on the premise that the majority of transmission costs are driven by system peak load.<sup>2</sup> Accordingly, the Current Rate Design recovers a large proportion of costs through the monthly coincident peak charge (12CP). In Proceeding 22942, the Commission proceeding for the 2018 ISO Tariff Application, the Commission received submissions regarding the 12CP methodology, and directed the AESO to "continue the consultation process with respect to the 12CP issue, the regional tariff design, and the bulk tariff design."<sup>3</sup>
- 4 As transmission reinforcements have increased the wires costs that the ISO tariff must recover, it has become evident that costs are disproportionately allocated to the 12CP billing determinant under the Current Rate Design. For example, costs that have been driven by the requirement to allow for the flow of in-merit energy on the transmission system are allocated in a manner that is not aligned with cost causation principles. This has resulted in bulk and regional rates that are no longer cost reflective and, as a result, do not provide appropriate price signals to customers. A change to the rate design is therefore required.
- 5 NERA Economic Consulting (NERA) has provided its expert opinion to the AESO in relation to the development of a more cost-reflective bulk and regional rate design (the Proposed Rate Design).<sup>4</sup> The Proposed Rate Design was developed through an in-depth, methodical review of the planning and cost drivers for the transmission system.
- 6 This Application seeks Commission approval of the Proposed Rate Design, which the AESO submits will better reflect the costs that have been incurred and will continue to be incurred to support the flow of in-merit energy on the transmission system. While the Proposed Rate Design continues to recover a

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<sup>1</sup> The application of these principles to the AESO's rate design was extensively discussed in both Decision 2005-096 at PDF pages 19-20 with respect to the 2005-2006 ISO tariff application and in Decision 2007-106 at PDF page 20 regarding the 2007 ISO tariff application. Paragraph numbers have not been provided for Decision 2005-096 and Decision 2007-106 reflecting the AUC eFiling versions of the decisions, which do not contain paragraph numbers.

<sup>2</sup> Decision 2005-096 at PDF page 32.

<sup>3</sup> Decision 22942-D02-2019 at PDF page 25, para 74, Direction 1. The Commission further directed the AESO to "investigate and apply, if appropriate, the [Dual Use Customers] DUC's recommendations 1, 5 and 6 in its consultative process." In that proceeding, AltaLink Management (AltaLink) submitted that the 12CP method rate design was made over ten years ago and the market and market drivers have changed, see Exhibit 22942-X0089 at PDF page 4, para 14.

<sup>4</sup> The Proposed Rate Design has been referred to by other names over the development process. NERA refers to the Proposed Rate Design as the Recommended Rate Design and materials in Appendices B and C referred to it as the Preferred Rate Design.

proportion of costs through the 12CP charge, it moderates the overreliance on 12CP and takes a more balanced approach that recognizes other significant cost drivers.

- 7 This application also sets out the AESO's proposed tariff treatment for energy storage. While the AESO considered several options for energy storage treatment under the ISO tariff,<sup>5</sup> it proposes that storage should be treated in the same way as other technologies and users of the transmission system. By re-examining Demand Opportunity Service (Rate DOS) with a modernized lens, the AESO has determined that storage and other technologies alike, along with ratepayers more generally, would receive increased value if loads are provided additional flexibility in how they manage their electricity withdrawals from the transmission system.
- 8 Accordingly, this Application proposes a modernized Demand Opportunity Service (Modernized DOS) rate design. Modernized DOS will allow market participants, including but not limited to energy storage participants, additional flexibility in how they manage their loads. At the same time, Modernized DOS will provide value to all ratepayers by using capacity that would otherwise go unused, resulting in a reduction in overall transmission rates.
- 9 The AESO consulted extensively with stakeholders throughout the development of the Proposed Rate Design and Modernized DOS, holding a total of eight stakeholder sessions, two technical sessions, and targeted mitigation sessions over the course of a year and a half. Throughout this time the AESO presented materials, sought feedback both in person and in writing, requested proposals from stakeholders, and provided additional materials including bill impact tools, additional analyses, explanatory documents, and requested data.<sup>6</sup> While the AESO recognized early in the process that stakeholders had differing views regarding the tariff design, it has leveraged the engagement process to build a more thorough mutual understanding of the Proposed Rate Design and clarify the scope of unresolved issues, in order to drive as much efficiency as possible into the proceeding process. As a result, this Application includes a proposed issues list to assist the Commission in determining the scope of the proceeding.
- 10 While the Commission has consistently held that rates should be designed to recover costs in the manner in which they are caused,<sup>7</sup> it has also recognized that, depending on the severity of the impact, it can be appropriate to mitigate the resulting impact for a distinct period of time.<sup>8</sup> The AESO has identified a small number of stakeholders that it anticipates will be highly impacted by the transition to the Proposed Rate Design. In the wake of the pandemic and accompanying recession, the AESO recognizes that economic activity and recovery across the province are a key focus, such that businesses should be supported through the transition to the Proposed Rate Design. The AESO is of the view that a transitional mitigation period is important in these circumstances.
- 11 The AESO used an innovative, targeted engagement process to consult with highly impacted stakeholders on a mitigation proposal. The purpose of the mitigation proposal is to allow the highly impacted stakeholders to adjust to the new rates over a period of time, with the aim of transitioning their operations to the Proposed Rate Design over the long term. While the AESO was unable to reach a formal Memorandum of Agreement (MOA) with these impacted stakeholders, the AESO considers its mitigation proposal to be an appropriate and balanced approach to the transition, as it was developed based on a set of clear principles over the course of numerous targeted engagement sessions and discussions.

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<sup>5</sup> Appendix B Part 1 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 1 Presentation (March 13, 2020) at slide 65.

<sup>6</sup> See section 2 of this application and Appendix B.

<sup>7</sup> Decision 2005-096 at PDF page 20, Decision 2007-106 at PDF page 20, Decision 2010-606 at PDF page 15, para 41.

<sup>8</sup> Decision 2005-096 at PDF page 20. Decision 2007-106 at PDF pages 20-21.

12 Overall, the Proposed Rate Design described in this application will ensure that customers pay transmission charges that reflect cost causation and the long-term costs of using the transmission system going forward, which is particularly important as the interconnected electric system evolves to encompass new uses and technologies. In addition, Modernized DOS will allow all market participants the opportunity to use the grid in a more flexible way and through the use of different technologies, while providing additional value to all Rate DTS ratepayers. Taken together, these changes will improve economic efficiency over the long term through a combination of more cost reflective tariff charges, cost allocation that is updated to reflect the long-term costs of using the transmission system, and additional rate options for market participants to use the transmission system with new technology.

## 1. Introduction

### 1.1 Organization of Application

13 This application is organized into sections as follows:

- 1 **Introduction** — section 1 provides background on the application, sets out the proposed scope and process and specifies the relief requested.
- 2 **Consultation** — section 2 provides an overview of stakeholder consultation concerning the bulk and regional rate redesign and energy storage, prior to filing this application, and sets out a proposed issues list.
- 3 **Proposed Rate Design** – section 3 discusses the case for change and details the AESO’s proposed changes to the AESO’s bulk and regional rate design.
- 4 **Energy Storage** – section 4 sets out the AESO’s proposed treatment of energy storage treatment under the ISO tariff.
- 5 **DOS Modernization** – section 5 provides an explanation of the AESO’s proposed modernization of Rate DOS.
- 6 **Impacts of Proposed Rate Design on Other Rates** – section 6 provides an overview of resulting changes to other rates resulting from the Proposed Rate Design.
- 7 **Implementation** – section 7 provides an overview of changes proposed to implement the Proposed Rate Design
- 8 **Conclusion**
- A-V **Appendices** — the appendices to the application are provided in support of the proposed amendments to the ISO tariff rate design.

### 1.2 Overview

14 Pursuant to sections 30 and 119 of the *Electric Utilities Act*, SA 2003, c E 5.1 (the Act or *EUA*), the AESO seeks approval from the Commission of amendments to its ISO tariff.

15 The AESO is a not-for-profit statutory corporation established pursuant to the Act.<sup>9</sup> As part of its statutory responsibilities, the AESO performs the following functions, among others:

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<sup>9</sup> *Electric Utilities Act*, SA 2003, c E-5.1 (*EUA*) s 7.



- Facilitates the operation of electricity markets in a manner that is fair and open and gives all electricity market participants wishing to participate in those electricity markets and to exchange electric energy a reasonable chance to do so;
- Determines the order of dispatch of electric energy and ancillary services in Alberta;
- Provides system access on the transmission system and prepares an ISO tariff;
- Directs the safe, reliable and economic operation of the interconnected electric system; and
- Assesses the future needs of electricity market participants and plans the capability of the transmission system to meet those needs.<sup>10</sup>

16 To promote a more agile and adaptable approach as the tariff evolves, the AESO has proposed to address changes to tariff provisions with the Commission using a modular approach, rather than a comprehensive tariff filing as it has in the past. As approved by the Commission in Decision 25175-D02-2020, the AESO is submitting its tariff in separate modules.<sup>11</sup> The modules identified to address the Commission’s Directions from Decision 22942-D02-2019 include:

- Bulk and regional rate design;
- Point-of-delivery (POD) cost function, investment policy and optional facilities;
- Criteria for system versus connection projects and “grey area” costs; and
- Other Directions (Decision 22942) including power factor deficiency, contract level adjustment provisions, system access service request (SASR) provisions, and line relocation principles.

17 This proceeding is intended to consider the bulk and regional rate design, including Modernized DOS.<sup>12</sup> On that basis, and pursuant to section 14.3 of AUC Rule 001, *Rules of Practice*, the AESO proposes that the following issues be specifically included by the Commission within the scope of this proceeding:

- a) amendments to the design of Rate DTS (the Proposed Rate Design) including:<sup>13</sup>
  - i) the methodology to classify between demand and energy related transmission system costs;
  - ii) the simplified method to functionalize demand related costs based on voltage;
  - iii) the allocation of bulk demand related costs between coincident and non-coincident demand;

<sup>10</sup> *Ibid*, s 17.

<sup>11</sup> Decision 25175-D02-2020 at PDF page 13-16, paras 46-59.

<sup>12</sup> *Ibid*.

<sup>13</sup> Amendments to Rate DTS will result in consequential changes to Rate FTS, Rate XOS, Rate XOM, and Rate DOS.

- iv) the recovery of the above costs from the related billing determinants;
- v) calculating the coincident peak on hourly intervals and calculating the 12CP charge on a five-year monthly average basis.
- b) classification and functionalization values for use in the development of ISO tariff rates for select years;
- c) amendments to Rate DOS, *Demand Opportunity Service* (Modernized DOS);
- d) mitigation of rate impact for certain customers resulting from the Proposed Rate Design; and
- e) proposals related to the implementation of the Proposed Rate Design.

18 The AESO submits that all other matters are outside of the scope of this proceeding, including the following:

- a) the AESO's revenue requirement;
- b) changes to the methodologies for calculating rates other than Rate DTS;<sup>14</sup>
- c) changes to the terms and conditions of the ISO tariff, other than those associated with Modernized DOS or implementation of the Proposed Rate Design;
- d) changes to the actual bulk and regional rates, which will be addressed in the AESO's annual tariff update filing following approval of the rate design;<sup>15</sup>
- e) transmission system need identification;
- f) the AESO's planning practices not connected to rate design issues;
- g) the adjusted metering practice;
- h) legal owner of electric distribution system (DFO) customer contribution policy;
- i) distribution-connected generation (DCG) credits developed through DFO tariffs;
- j) substation fraction being set to one for DFO PODs;
- k) the AESO's discretion to adjust contract capacity;
- l) DFO tariff design;
- m) speculation about government policy shifts;

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<sup>14</sup> Amendments to Rate DTS will result in consequential changes to Rate XOS, Rate XOM, and Rate DOS.

<sup>15</sup> Once the design has been approved, the AESO will file a separate application for approval of rates based on the revenue requirement and forecast billing determinants identified at that time.

n) any issues identified by the AESO in Proceeding 25175 as being part of Phase 2 or Phase 3 of the comprehensive tariff application; and

o) other Directions from Decision 22942-02-2019, which will be addressed in later modules.

19 The various elements of the Proposed Rate Design described in this application were developed in tandem and are intended to provide a long-term and durable foundation for how transmission costs are recovered through rates. The Proposed Rate Design is put forward as an integrated whole. The AESO provides a detailed description of certain design alternatives that were considered and rejected, including the connected rationale, to provide the Commission with the information necessary to understand why these alternatives were not pursued.

### 1.3 Legislative Requirements

20 The AESO files this Application in accordance with the requirements set out in the Act and the *Transmission Regulation*, Alta Reg 86/2007(*Transmission Regulation*).

21 In accordance with section 16 of the Act, the AESO must carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.<sup>16</sup>

22 Pursuant to section 29 of the Act, the AESO must provide system access service on the transmission system “in a manner that gives all electricity market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so”.<sup>17</sup>

23 The AESO’s transmission responsibilities also require the AESO to plan a transmission system that:

- forecasts the needs of Alberta, and “must anticipate future demand for electricity, generation capability and appropriate reserves required to meet forecast load so that transmission facilities can be planned to be available in a timely manner to accommodate the forecast load and new generation capability;”<sup>18</sup>
- “satisfies reliability standards;”<sup>19</sup> and
- “is sufficiently robust to allow for transmission of 100% of anticipated in-merit electric energy...when all transmission facilities are in service, is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in-merit electric energy ... can occur when operating under abnormal operating conditions.”<sup>20</sup>

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<sup>16</sup> *EUA*, s 16.

<sup>17</sup> *Ibid*, s 29.

<sup>18</sup> *Transmission Regulation*, Alta Reg 86/2007 (*Treg*), s 8(a).

<sup>19</sup> *Ibid*, s 15(a).

<sup>20</sup> *Ibid*, s 15(e)(ii).

24 The AESO must prepare and receive Commission approval of its ISO tariff rates and terms and conditions in accordance with sections 30 and 119 of the Act, which provide:

**ISO tariff**

30(1) *The Independent System Operator must submit to the Commission, for approval under Part 9, a single tariff setting out*

(a) *the rates to be charged by the Independent System Operator for each class of system access service, and*

(b) *the terms and conditions that apply to each class of system access service provided by the Independent System Operator to persons connected to the transmission system.*

(2) *The rates to be charged by the Independent System Operator for each class of service must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Independent System Operator...*

**Preparation of tariffs**

119(4) *The Independent System Operator must prepare a tariff relating to the transmission system in accordance with Part 2 and apply to the Commission for approval of the tariff.*

25 The ISO tariff, which sets out the rates to be charged for, and the terms and conditions that apply to, each class of system access service provided by the AESO, is generally composed of two elements: (i) costs and expenses; and (ii) the proposed allocation of costs and expenses to rate classes (rate design).<sup>21</sup>

26 These requirements specific to ISO tariffs are in addition to the general requirements applicable to all tariffs submitted to the Commission for approval. Section 121 of the Act requires that the Commission, when considering whether to approve a tariff application, ensure that:

(i) the tariff is just and reasonable, and

(ii) not unduly preferential, arbitrary or unjustly discriminatory or inconsistent with or in contravention of the Act or any other enactment or any law.<sup>22</sup>

27 Further, the Act provides that rates set out in the ISO tariff cannot differ based on the location of load on the transmission system, which is generally referred to as the “postage stamp rule”:

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<sup>21</sup> Decision 22942-D02-2019 at PDF page 19, para 44.

<sup>22</sup> *EUA*, s 121.

30(3) *The rates set out in the tariff*

*(a) shall not be different for owners of electric distribution systems, customers who are individual systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system [...]*

28 The ISO tariff only recovers transmission system costs from load customers pursuant to section 47 of the *Transmission Regulation*.<sup>23</sup>

29 As a result of the above, and in accordance with the *Transmission Regulation* and the Act, the ISO tariff has been structured to allocate all costs of the transmission system, except for losses<sup>24</sup> and revenue offsets (such as revenue collected from opportunity service rates), to Rate DTS.

## 1.4 The AESO's Proposed Process

### 1.4.1 Overview of Process

30 The AESO proposes the following process with a view to achieving a streamlined and efficient regulatory proceeding that leverages the outcomes of the AESO's stakeholder engagement process. Like the Commission,<sup>25</sup> the AESO is actively evolving its processes to better promote regulatory efficiency and reduce proceeding time. As described throughout this application, the AESO made efforts to improve the efficiency of this proceeding through the stakeholder engagement process by seeking to ensure a mutual understanding of its design with stakeholders, identifying and narrowing issues through written and oral feedback, using a third-party facilitator to encourage effective pre-hearing discussions, and setting up a targeted engagement process regarding mitigation.

31 The AESO views the proposed proceeding process as most efficiently meeting the need for the Commission to balance regulatory efficiency with receiving sufficient information to make an informed decision, and the needs of interveners for procedural fairness. This is explained in more detail for specific procedural steps below. The AESO would also be in favour of leveraging opportunities to reduce proceeding time as appropriate, such as instituting page limits and information requests where appropriate, timelines on cross examination and pre-scheduling motions.

### 1.4.2 Process Schedule

32 The AESO has included a Proposed Process Schedule as Appendix A.

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<sup>23</sup> *TReg*, s 47 (a)(i).

<sup>24</sup> *Ibid*, ss 33(1), 34.

<sup>25</sup> See, for example, Commission Bulletin 2020-17: "AUC creates independent, expert committee to assist in improving efficiency of rates proceedings"; Commission Bulletin 2020-33: "Process improvements to AUC rate proceedings"; the Report of the AUC Procedures and Processes Review Committee, dated August 14, 2020; and Commission Rule 001, *Rules of Practice*, as amended on April 27, 2021 (AUC Rule 001).

33 The AESO anticipates new rates becoming effective in January 2024. The proposed process schedule suggests that a Commission decision may be issued before the end of 2022. The AESO expects a compliance filing process to follow in 2023, followed by a rates update application in Q4 of 2023 to reflect the updated rates.

#### 1.4.3 Confidential Treatment of Data

34 This application requests confidential treatment of customer site data relied on within the September 24, 2021 report entitled “AESO Bulk and Regional Tariff Design: Expert Report” (the NERA Report) attached as Appendix D. The AESO routinely keeps this type of data confidential pursuant to ISO Rule 103.1. The AESO also considers this data to be commercially sensitive. Accordingly, the AESO submits that the Commission should carefully consider the impacts of releasing this data.

35 In this case the AESO could not identify a feasible method to aggregate the data to address confidentiality issues and maintain the granularity required to replicate the analysis. The AESO will provide the confidential un-aggregated data to the Commission and only those hearing participants who execute the standard Commission undertaking and assume the associated duties to protect this data. As well, and if it is determined to be of value, the AESO could provide hearing participants, on request, the data in an aggregated form that addresses confidentiality and commercial sensitivity.

36 Customers and other interveners may have additional views about the commercial sensitivity of this data. Under the schedule proposed in Appendix A, parties’ submissions on confidential treatment would be due at the same time as Statements of Intent to Participate and Issues List submissions.

#### 1.4.4 Information Requests

37 The AESO’s proposed process includes:

- one round of information requests to the AESO from the Commission and interveners; and
- one round of information requests to any interveners that choose to file evidence from the AESO, the Commission and other interveners.

38 In accordance with the process schedule attached as Appendix A, the AESO proposes that the Commission’s information requests be issued four business days in advance of intervener information requests (i.e., Monday November 22 and Friday November 26) in order to allow interveners the opportunity to narrow and focus their requests as much as possible in accordance with both the issues list and the Commission’s requests. In addition, and pursuant to the Commission’s authority to issue directions on procedure pursuant to AUC section 14.5 Rule 001, *Rules of Practice*, the AESO is proposing that information requests be limited to no more than 50 per party, including sub-parts.

39 The AESO views a single round of limited information requests from interveners as appropriate, particularly in the context of the extensive stakeholder consultation undertaken by the AESO prior to the filing of this Application. As noted in section 2 herein, the AESO held multiple stakeholder sessions, which, specific to the Proposed Rate Design, included:

- a) Session 5, on March 25, 2021, wherein the AESO and NERA presented the Proposed Rate Design to stakeholders, answered stakeholders’ questions live, and received written feedback from stakeholders and Commission staff following the session;
- b) Technical Session II, on March 31, 2021, to assist stakeholders in understanding the impacts of the Proposed Rate Design on their invoices;

- c) Session 6A, on June 3, 2021, wherein the AESO and NERA addressed stakeholder feedback from Session 5 on the Proposed Rate Design, responded to certain questions received from Commission staff on the Proposed Rate Design, answered stakeholders' questions live, and received written feedback from stakeholders following the session; and
- d) Session 6B, on June 24, 2021, wherein the AESO provided an overview to stakeholders on the outstanding concerns and next steps for the Proposed Rate Design.

40 In addition, the AESO released information items to address questions and requests received throughout the course of the engagement.<sup>26</sup>

41 As noted in AUC Rule 001, the objective of information requests is to (a) clarify documentary evidence; (b) simplify the issues; (c) permit a full and satisfactory understanding of the matters to be considered; and (d) expedite the proceeding.<sup>27</sup> Through its consultation efforts, the AESO has met these objectives as they apply to how the Proposed Rate Design works, why it was designed that way, and its impact. The result of those efforts is that interveners should be able to, at this time, ask targeted, in-scope questions of the AESO without the need for multiple rounds of requests.<sup>28</sup>

#### 1.4.5 *Written and Oral Evidence*

42 In accordance with the requirements of AUC Rule 001, the AESO proposes that the majority of the evidentiary record in this proceeding be conducted via a written process.<sup>29</sup>

43 At this early stage,<sup>30</sup> the AESO requests that a limited portion of the evidentiary record take place through an oral process. It does so on the basis that:

- a) the AESO believes the Commission and interveners would benefit from hearing NERA's reasoning underlying the Proposed Rate Design as well as NERA and the AESO's understanding of the primary issues in the proceeding as they remain at that point in time; and
- b) the AESO understands that interveners may want to test NERA's assumptions, understandings and ultimate conclusions on the remaining areas of contention via cross-examination, as oral questioning may, at times, be more effective than a written process.

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<sup>26</sup> See for example, the following materials in Appendix B Part 3: Historical Hourly by Region Load Data Rate DTS, DOS and FTS 2016-2020; Historical Peak-Load and Gen by Area Data 2015-2020; DOS Bid Examples in Energy Market; Historical Coincident Metered Demand versus 15-Minute Comparison; Estimated Bill Impact Analysis by DFOs (FortisAlberta, ENMAX and EPCOR); and Tool for Estimating Rate Calculations; Illustrative Tool for 5-Year Average 12-CP.

<sup>27</sup> AUC Rule 001, s 26.1.

<sup>28</sup> As noted in AUC Rule 001, s 26.2: "An information request must ... if there is a finalized list of issues in a rates proceeding, only contain questions that directly relate to an issue identified by the Commission in the directions on procedure established under Section 14.4."

<sup>29</sup> AUC Rule 001, s 36.2.

<sup>30</sup> *Ibid*, s 36.3.

44 The scope of the oral portion of the hearing<sup>31</sup> would be limited to only those issues that remain largely contested after the filing of the AESO's rebuttal evidence. The AESO proposes that the Commission impose strict time limits on cross-examination, and that cross-examination questions align with a pre-determined issues list.

#### 1.4.6 **Argument**

45 The AESO submits that argument should take place through written submissions, with page limits as determined to be appropriate. The Proposed Rate Design, and the nature of this proceeding, is technical and complex. Precision in describing the concepts, data analysis, evidence, and opposing views is of utmost importance to make sure that sufficient and accurate information is before the Commission. This is particularly the case given the expected volume of evidence that will constitute the proceeding record. Given those factors, the resolution of the proceeding is more likely to be "fair, expeditious and efficient" if argument and reply argument are conducted in writing.<sup>32</sup>

46 Following close of written argument, should the Commission have outstanding questions or require further submissions, the Commission can elect to hold an oral hearing in which only the Commission may ask questions of the parties.

#### 1.4.7 **Commission Settlement Processes**

47 The AESO understands that the Commission is looking to use new, progressive approaches in proceedings to encourage regulatory efficiency and effectiveness, including through the use of mandated mediated and/or negotiated settlements,<sup>33</sup> particularly in contested applications.<sup>34</sup>

48 While the AESO supports the Commission's initiatives to achieve efficiencies, this proceeding is not the appropriate forum for a mandated settlement process. This is due, in part, to the following impediments present in this proceeding that prevent an effective mediated and/or negotiated settlement process:

- a) the proceeding is anticipated to have numerous registered interveners with divergent and, at times, opposing interests, evidence, and/or impacts, even as between those interveners that are aligned against the Proposed Rate Design;<sup>35</sup>
- b) as noted in section 2.3 herein, fundamental disagreements are expected between the AESO and certain interveners as to:

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<sup>31</sup> *Ibid*, s 36.6.

<sup>32</sup> *Ibid*, s 48.2. The AESO notes that directions from the Commission on scope, format, content, and page limits can be spoken to at a later date once the evidentiary record has been finalized, as per AUC Rule 001, s 48.3.

<sup>33</sup> See Proceeding 26207, "AUC Letter Mediated Settlement Process" at Exhibit 26207-X0069 at PDF page 1, para 5.

<sup>34</sup> John J Marshall, Q.C. Professional Corporation, *Report of Committee on Mediated Settlements to Alberta Utilities Commission*, (November 13, 2020) at PDF pages 3-4, para 4 (Mediated Settlement Report).

<sup>35</sup> For example, the AESO's Stakeholder Session 5 was attended by more than 82 organizations. See Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021) at slide 9.



- i) whether the methodology for the bulk and regional tariff need be revised at all; and
- ii) if the methodology needs to be revised, in what way and based on what information, including multiple variations thereof;

where either decision will impact all Alberta ratepayers, not just those interveners opposed to a new tariff design;

- c) the Proposed Rate Design itself is an integrated design, where each element is intertwined and dependent on the other elements, such that any prospective “settlement” would be premised on an all or nothing basis;
- d) through its consultation process, the issues relating to the Modernized DOS proposal have been narrowed and the remaining issues require adjudication (i.e., load factor);
- e) the mitigation approach, being the one area appropriate for a settlement resolution, has already been discussed with the assistance of a third party facilitator via the AESO’s mitigation consultation process; while the issue was not resolved the AESO is of the view that all possible efficiencies were gained in the course of that process;
- f) a mediator may not be well placed to determine any of the above, given that such issues are highly technical, and substantially about the public interest and what is just and reasonable; and
- g) the Commission has indicated in other proceedings that it may not submit information requests in a mediated process, thereby creating an inability of the Commission, if a settlement process was initiated at the front-end of the proceeding, to obtain information it deems pertinent to determining the public interest.<sup>36</sup>

49 The potential inability to achieve a consensus resolution to the tariff’s methodology has already been noted by the Commission:

7. In light of what appear to be fundamental differences in views of parties in support of and opposed to significant changes to the AESO’s current bulk and regional rate design, a consensus approach to bulk and regional tariff design issues may not be achievable. Given this, the Commission urges the AESO to exercise reasonable judgement in using additional time to consult with various stakeholders on rate changes prior to filing an application. Furthermore, given the Commission’s view that a full consensus on a proposed rate design is unlikely, the Commission finds that the revised deadline for the AESO to file its bulk and regional tariff application must be more defined.<sup>37</sup> [emphasis added]

50 As a result, in these circumstances, the use of settlement mechanisms will not achieve a more streamlined, cost-effective and timely process. Instead, it is “apparent that because of positions taken by parties

<sup>36</sup> Exhibit 26207-X0078 at PDF page 2, para 8.

<sup>37</sup> Commission Ruling on the AESO’s extension request, Exhibit 25175-X0142.

adverse in interest, mediation may be challenging”<sup>38</sup> and that the very the nature of the proceeding has “considerable public policy implications”<sup>39</sup> requiring an open, transparent, and fulsome hearing.

51 Alternatively, should the Commission order that a mediated and/or negotiated settlement process take place, the AESO requests that the Commission set firm and short timelines (i.e., a maximum of three weeks) for negotiations after information request responses have been provided by interveners to the AESO and the Commission.

## 1.5 Relief Requested

52 Based on the entirety of the information provided with this application, the AESO requests approval of:

- a) the AESO’s Proposed Rate Design including:
  - i) the methodology to classify between demand and energy related transmission system costs;
  - ii) the simplified method to functionalize demand related costs based on voltage;
  - iii) the allocation of bulk demand related costs between coincident and non-coincident demand;
  - iv) the recovery of the above costs from the related billing determinants;
  - v) calculating the coincident peak on hourly intervals and calculating the 12CP charge on a five-year monthly average basis;
- b) classification and functionalization values for use in development of 2024, 2025 & 2026 ISO tariff rates, specifically:
  - i) energy and demand classification, as described in section 3.5.2;
  - ii) functionalization of demand related costs to be recovered on coincident metered demand and to be recovered on billing capacity based on percentages, as described in section 3.5.3;
- c) the proposed amendments to Rate DOS as described in section 5;
- d) confirming tariff treatment of energy storage pursuant to the Decision 22942-D02-2019;<sup>40</sup>

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<sup>38</sup> Mediated Settlement Report at PDF page 4, para 4.

<sup>39</sup> *Ibid.*

<sup>40</sup> See Decision 22942-D02-2019, paras 1210-2011. The AESO will proceed with further changes to applicable authoritative documents following completion of the Energy Storage Roadmap consultation process and related proceedings; however, the AESO does not anticipate any further changes to the Commission’s findings regarding the ISO Tariff treatment of energy storage in Decision 22942-D02-2019.

- e) the AESO's mitigation proposal for significantly impacted customers, as described in section 3.9;
- f) the implementation proposals, including:
  - i) temporary relief to payment-in-lieu of notice (PILON) to enable the proposed contract adjustment period, as described in section 7.1;
  - ii) revision to existing PILON waiver, as described in section 7.1;
  - iii) process for future updates to classification and functionalization values, as described in section 7.1;
- g) changes to ISO Tariff Rates Sheets, terms and conditions and Appendix A identified in Appendices S, T and U to implement the above changes;
- h) confirmation from the Commission that the AESO has adequately responded to the Commission's outstanding directions relating to the transmission system rate design;<sup>41</sup> and
- i) such other relief as the Commission deems appropriate.

53 For the reasons outlined below, the AESO submits that the proposed ISO tariff amendments, as described in items (a) – (i) above (the Proposed Tariff Amendments), meet the applicable legislative tests, and respectfully requests that they be approved by the Commission. The Proposed Tariff Amendments are set out in Appendix Q of this application. Appendices S-U include blackline comparisons of the Proposed Tariff Amendments to the current versions as approved by the Commission.

## 2. Consultation

### 2.1 Overview and Objectives of Consultation

54 The AESO conducted extensive stakeholder consultation as part of developing the Proposed Rate Design presented in this application. The Bulk and Regional Tariff Consultation (B&R Consultation) took place from March 2020 to September 2021.

55 Consistent with the AESO's Stakeholder Engagement Framework, the primary objectives of consultation were the following:

- a) to help the AESO develop a rate design that meets the needs of all Albertans by better understanding stakeholder perspectives and concerns;
- b) to give stakeholders a meaningful opportunity to contribute to the rate design;
- c) to foster stakeholder understanding of the AESO's reasons for revising the current ISO tariff and the concepts and methodologies underlying the AESO's Proposed Rate Design; and

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<sup>41</sup> See Decision 22942-D02-2019, at PDF page 25, para 74, Direction 1.

- d) to work toward a shared understanding of design objectives and principles, while also identifying areas of ongoing disagreement among stakeholders.<sup>42</sup>

56 A primary goal of the consultation was to give stakeholders a meaningful opportunity to participate in the design process and to foster mutual understanding of sometimes conflicting views. The AESO recognized that stakeholders often have fundamentally different perspectives and interests that cannot be reconciled, as such consensus is not always achievable.<sup>43</sup> Consultation also gave stakeholders an opportunity to understand and begin to assess the Proposed Rate Design prior to this proceeding. By fostering informed discussion and (where possible) narrowing issues in the proceeding, the AESO's consultation process supported regulatory efficiency.

57 The AESO's consultation process was guided by principles of transparency, inclusiveness, and effectiveness. Stakeholders were encouraged to actively engage in discussion, ask questions, and propose their own rate designs for discussion. Information and feedback received from stakeholders throughout the consultation assisted the AESO in developing the Proposed Rate Design. Where appropriate, the AESO refers to stakeholder consultation in the relevant sections of this application but does not repeat all comments and exchanges that took place. All consultation materials, including stakeholder presentations and comments, can be found on the AESO website at [www.aeso.ca](http://www.aeso.ca) under the Stakeholder Engagement > Rules, standards and tariff consultations > Bulk and Regional Tariff Design, and at Appendices B and C of this application.

## 2.2 Consultation Process

58 The AESO's consultation on the bulk and regional rate design began following Direction 1 from the Commission in Decision 22942-D02-2019 "to continue the consultation process with respect to the 12 CP issue, the regional tariff design and the bulk design and to investigate and apply if appropriate, the DUC's recommendations 1, 5, and 6 in its consultative process."<sup>44</sup>

### 2.2.1 B&R Consultation

59 The AESO initiated the B&R Consultation in March 2020. After an interruption due to the COVID-19 pandemic, the AESO resumed consultation in September 2020. The specific design objectives which guided the development of the Proposed Rate Design were as follows (the B&R Objectives):

- Reflect Cost Responsibility (meaning, a tariff that meets cost causation principles);
- Efficient Price Signals (meaning, a tariff that allocates costs in a way that reflects cost causation and reflects the long-term costs of using the transmission system);

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<sup>42</sup> AESO "Stakeholder Engagement Framework" (February 2020), available at <https://www.aeso.ca/assets/downloads/Stakeholder-Engagement-Framework-Report-FINAL.pdf>, also see Appendix B Part 1 - AESO Bulk and Regional Tariff Design Session 1 Presentation (March 13, 2020) at slide 9.

<sup>43</sup> As recognized by the Commission in Exhibit 25175-X0142 at PDF page 2, para 7.

<sup>44</sup> Decision 22942-D02-2019 at PDF page 25, para 74.

- Minimal Disruption (meaning, rates that would not result in significant changes, and would provide significantly impacted consumers appropriate time to adjust to new rates);
- Simplicity (meaning, a tariff that is understandable, easy to implement and operate, and sends clear price signals); and
- Innovation & Flexibility (meaning, a tariff that provides optionality and flexibility to customers in their use of the transmission system while not shifting costs onto other customers).<sup>45</sup>

60 Between March 2020 and June 2021, the AESO hosted eight general consultation sessions and two technical information sessions. The AESO also established a parallel consultation stream focused on mitigation for those stakeholders who would be most impacted by the Proposed Rate Design (for further information on this process, refer to section 3.9 of the application).

61 Over the course of the consultation sessions, a total of 117 stakeholder organizations were engaged. Stakeholders were actively involved in providing input throughout the process. Seven stakeholder proposals were presented by 14 stakeholders and 180 comment matrices were received. Diverse stakeholders from across the industry participated including representatives of transmission-connected loads, small distribution-connected consumers, industrial systems, industry associations, energy storage owners, generators, DFOs, transmission facility owners (TFOs), exporters, and importers.

62 Throughout Stakeholder Sessions 1 to 4 (March to December 2020), the AESO and stakeholders discussed a wide range of possible tariff designs in response to the issues identified through the B&R Consultation process, including the widespread, though not universal, concern with a perceived overreliance of the Current Rate Design on the 12CP price signal. The AESO put forward a number of preliminary design ideas and illustrative models incorporating different possible rate structures, including modified versions of coincident peak billing (120 CP), non-coincident peak (NCP) billing, billing capacity charges, fixed contribution rates, charges tied to time of region or area peaks, and energy charges.<sup>46</sup> A number of stakeholders put forward their own rate design proposals, which also varied widely from proposals largely based on maintaining the status quo, marginal rate designs, designs emphasizing NCP and regional coincident demand.<sup>47</sup> Sessions 1 to 4 also saw discussion of a number of possibilities for the tariff treatment of energy storage, including presentations both by the AESO and by stakeholders.<sup>48</sup>

63 Above all, the discussion throughout Sessions 1 to 4 brought home the need to ground the AESO's Proposed Rate Design on a robust and well-researched understanding of cost causation in Alberta's transmission system which prevailed as a common principle amongst stakeholders. In order to best explore

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<sup>45</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021) at slide 17.

<sup>46</sup> Appendix B Part 1 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 1 Presentation (March 13, 2020); AESO, Bulk and Regional Tariff Design Session 2 Presentation (September 24, 2020).

<sup>47</sup> Appendix B Part 2 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 3 Presentation (November 5, 2020).

<sup>48</sup> Appendix B Part 2- AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 2 Presentation (September 24, 2020); AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 3 Presentation (November 5, 2020).

cost causation-based designs and their potential impact in Alberta, the AESO determined an independent transmission tariff rate expert should be retained.

64 The AESO retained NERA, independent tariff design experts, to assist in formulating an appropriate rate design recommendation. In addition to experience with the embedded rate design approach currently used in Alberta, NERA also has valuable experience with marginal rate design, a type of design that was novel to Alberta but had been contemplated by stakeholders. NERA reviewed data and conducted analysis to develop an appropriate rate design (which, for the reasons set out in this application is an embedded rate design). The AESO agreed with and adopted the Proposed Rate Design, as recommended by NERA, which was presented to stakeholders in Stakeholder Session 5 on March 25, 2021. NERA attended and was questioned live by stakeholders on the design.

65 Bill impact tools were provided in advance of Stakeholder Session 5. During the session, the AESO presented on how the Proposed Rate Design and related mitigation options would result in a minimally disruptive transition for customers.

66 Following this session, the AESO held a second technical information session on March 31, 2021 to help stakeholders understand the bill impact tools and how they could be used to evaluate the impacts of the Proposed Rate Design and potential mitigation options to their transmission connected sites.<sup>49</sup>

67 The discussion in Sessions 1-4 around energy storage tariff treatment included options for non-firm rates, with Rate DOS identified as one such rate.<sup>50</sup> In Session 5, the AESO presented the idea of modernizing Rate DOS. Through consultation the AESO determined it was appropriate to modernize Rate DOS and expand eligibility, encouraging greater opportunities for revenue maximization and improving the administration of the service. Although not specifically designed for energy storage resources, the altered eligibility for Rate DOS provides a technologically agnostic opportunity for energy storage resources to use this opportunity service given their flexible nature.<sup>51</sup>

68 While initially scheduled as a single session 6, the AESO decided to hold two sessions, 6A and 6B, to provide additional clarity, build mutual understanding and address stakeholder concerns regarding the Proposed Rate Design.

69 NERA attended Session 6A on June 3, 2021, during which NERA and the AESO answered questions, presented additional information and sought stakeholder feedback on the AESO's Proposed Rate Design. The AESO responded to stakeholder feedback and presented analysis regarding the potential response to the economic incentives for self-supply provided in the Proposed Rate Design, as well as the short-term impact of the Proposed Rate Design on the energy market.

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<sup>49</sup> The AESO also posted information from select DFOs to assist DFO customers in understanding impacts to their sites: EPCOR, Preferred Rate Design Bill Impact (May 3, 2021); ENMAX, Preferred Rate Design Bill Impact (April 21, 2021); FortisAlberta, Estimated Bill Impacts to FortisAlberta DTS rate classes/ customers of AESO Preferred DTS Rate Design (Appendix B Part 3).

<sup>50</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5B Presentation (May 20, 2021) at slides 40-41.

<sup>51</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021).

70 The AESO also shared the list of questions submitted by Commission staff during the stakeholder consultation process with all stakeholders and addressed the key themes raised in the questions.<sup>52</sup> These questions fell into six categories, as follows:

- a) Design Objectives;
- b) Breakdown of Bulk and Regional Transmission Costs;
- c) Proposed Design;
- d) Load Growth;
- e) 12CP Demand as a Driver of Bulk and Regional Transmission Costs; and,
- f) Storage.<sup>53</sup>

71 Session 6B was held June 24, 2021 and focused on the areas of targeted mitigation outcomes and addressing stakeholder feedback on the proposal for Modernized DOS.<sup>54</sup>

### 2.2.2 *Engagement with Stakeholder Feedback*

72 Stakeholder feedback influenced the development of the Proposed Rate Design throughout the consultation. Stakeholder proposals in Session 3 included a range of alternatives based on two fundamental approaches to cost allocation: embedded cost and marginal cost. Stakeholder feedback on these approaches in Session 4 prompted consideration of the marginal approach and reexamination of the cost causation study.

73 Stakeholder questions from Sessions 5 and 6 highlighted key areas of concern, including the approach to the allocation between demand and energy, the flat energy charge, the five-year average 12CP and the expected implications of the Proposed Rate Design to self-supply decisions. Further information was shared relating to these concerns through the presentation of NERA's May 25th "Estimating Customer Response to Our Recommended Bulk and Regional Tariff Design" report (Self-Supply Report)<sup>55</sup> in Session 6A, and responses to questions arising from that report and its underlying analysis. Additional information was provided to stakeholders with respect to the data behind the rate calculations (including examples of rate calculations) to solicit greater stakeholder feedback on specific areas in which stakeholders had identified concerns.

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<sup>52</sup> Appendix B Part 3 - Letter to Stakeholders re: AUC Staff Letter and List of Questions issued to AESO on April 7, 2021.

<sup>53</sup> Appendix B Part 3 - Letter to Stakeholders re: AUC Staff Letter and List of Questions issued to AESO on April 7, 2021.

<sup>54</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 6A Presentation (June 3, 2021); AESO Bulk and Regional Tariff Design Session 6B Presentation (June 24, 2021).

<sup>55</sup> Appendix D - NERA, AESO Bulk and Regional Tariff Design: Expert Report (referred to as the NERA Report), Attachment 4A.



74 The AESO evaluated certain alternative design options raised by stakeholders during the consultation process. The AESO considered whether any elements of the Proposed Rate Design warranted amendment. Key feedback themes included:

1. Amendments to the flat energy charge;
2. Removal of the five-year trailing average to the 12CP charge (the 5-Year Average 12CP Charge); and
3. Amendments to the methodology of calculating costs attributable to demand and facilitating the flow of in-merit energy.

75 The AESO determined that options 1 and 3 present significant risks to the integrity of the AESO's Proposed Rate Design as a whole and significantly alter the design from a cost causation perspective. Option 2 presents less risk to the Proposed Rate Design and could be implemented but would result in a rate design that is less cost reflective.

76 Overall, the above changes to the Proposed Rate Design would each cause the ISO tariff to be less cost reflective to varying degrees such that, in the AESO's view, none of these alternative options improve the Proposed Rate Design. Appendix O includes a summary of the three options, stakeholder feedback, and the AESO's responses.

77 Stakeholder feedback informed changes to the AESO's proposed Modernized DOS approach. Following Session 5B, several stakeholders commented on the business case assessment, drawing attention to concerns around disclosing sensitive economic information and the administrative burden of preparing and assessing cases. Taking these concerns into account the AESO developed an alternative process of representation and audit, as described in section 5.3.4 of this application.

### 2.2.3 Targeted Mitigation Consultation

78 Targeted mitigation sessions were held from March to June 2021 to engage with the six most significantly impacted parties. Significantly impacted parties were defined as those with an estimated transmission cost increases of 10 per cent or greater as a result of implementing the Proposed Rate Design.<sup>56</sup> The AESO sought to reach an agreement acceptable to the impacted parties and the broader stakeholder group, in order to meet the AESO's objective of minimal disruption and drive efficiencies in the proceeding. Significantly impacted customers preferred a permanent mitigation solution, such as an interruptible rate class or legacy treatment.<sup>57</sup> The AESO considered these proposals to be inconsistent with the legislative framework. While agreement was not ultimately reached, the AESO is of the view that the targeted mitigation discussions nonetheless resulted in the development of a robust mitigation proposal, as described in section 3.9 of this application. The AESO shared the outcomes of the mitigation sessions to the broader stakeholder group during Session 6B.<sup>58</sup>

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<sup>56</sup> The process for identifying significantly impacted parties is described in section 3.8 of the application.

<sup>57</sup> Appendix C - AESO Summary Targeted Mitigation 1:1 Meetings (April 22, 2021).

<sup>58</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 6B Presentation (June 24, 2021).



#### 2.2.4 Additional Consultation

79 The AESO provided additional opportunities for stakeholders to build understanding and provide their feedback, beyond the main B&R Consultation sessions. The AESO released and updated its Estimating Rate Calculations Tool to include updated rate estimates for additional years for Rate DTS, Rate DOS and Export Opportunity Service (Rate XOS) rates under the Proposed Rate Design following Session 6B. Stakeholders provided feedback via email.<sup>59</sup>

80 In September 2021, the AESO conducted further consultation on the draft rate sheets, revised terms and conditions and proposed draft DOS proforma agreement. The intent of this further consultation was to ensure stakeholders had visibility of these documents and the opportunity to comment on whether they reflected the Proposed Tariff Amendments as communicated throughout the consultation. Based on the comments received, the AESO revised some of the provisions to improve clarity and to better align the provisions with the design. The AESO also reversed a change to the operating reserve charge in the rate sheet for Rate XOS and Export Opportunity Merchant Service (Rate XOM) in response to stakeholder comments.

81 The consultation for this application has been extensive, detailed and transparent. In alignment with the importance and expected impact of this file, there was broad industry attention and involvement. Stakeholders actively contributed throughout the process, proposing alternative rate designs, and voicing perspectives and concerns through live sessions and post-session written feedback. Throughout the process, stakeholders and the AESO built a shared understanding and identified areas of alignment and misalignment, facilitating the development of an issues list and allowing for a more focused proceeding.

82 Where appropriate, stakeholder consultation and feedback are referred to in the relevant sections of this application, and the documentation of the consultation process can be found in Appendices B and C. Stakeholder participation and feedback helped the AESO understand parties' perspectives, assess the priority of different issues, ensure tariff rate design and energy storage alternatives were adequately explored, and develop a sound underlying rationale for various aspects of the Proposed Rate Design, all of which, in the AESO's view, ultimately resulted in appropriate and robust proposals in this application.

### 2.3 Issues List

83 Throughout the course of the consultation process, the AESO sought to identify and narrow the key issues to be addressed during this proceeding. The diversity of stakeholders was reflected in the spectrum of views expressed. Perspectives on each specific issue varied widely, with some stakeholders preferring the status quo and others advocating for new approaches and/or smaller discrete changes to address specific concerns, rather than considering a more holistic design aligned with the public interest.

84 The AESO considered the range of risks and issues raised by stakeholders who came from differing perspectives, exploring a broad suite of options. At a macro level:

- one group expressed the view that no changes are required to the Current Rate Design,

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<sup>59</sup> Appendix B Part 3 - AESO Stakeholder Comments on the AESO's Estimating Rate Calculations (July 16, 2021).

- a second group was of the view that 12CP should be eliminated and more costs recovered on a billing capacity charge; and
- a number of stakeholders expressed concerns, driven by varied reasoning, on the increase to the energy charge.

85 The Proposed Rate Design considers these diverse stakeholder perspectives, responding to the need for a change to a more cost reflective rate design while maintaining or modifying elements of the Current Rate Design.

86 As described in sections 2.2.2 of this application and Appendix B, the AESO has considered and responded to the key themes and specific concerns raised throughout the stakeholder process and identified the following key issues to be resolved during the regulatory process:

#### Proposed Rate Design:

- Is the Current Rate Design misaligned with cost causation principles by recovering costs associated with the flow of in-merit energy through the 12-CP mechanism?
- Should transmission costs driven by facilitating in-merit flow of energy be classified separately from demand-driven costs?
  - If so, is the proposed minimum system approach the appropriate method to classify these costs?
- Do the Proposed Rate Design cost categories and billing determinants accurately allocate costs attributable to the different uses and cost drivers of the transmission system?
  - If so, does the Proposed Rate Design reasonably reflect the application of cost causation principles within Alberta's regulatory framework?
- Overall, is the Proposed Rate Design just and reasonable and not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of any enactment or law?

#### Mitigation:

- What are the conditions under which the Proposed Rate Design would not apply to all customers and are those conditions met? If so, are the rate impact threshold, mitigation mechanisms and timelines proposed sufficiently fair and pragmatic to support a minimally disruptive transition to the Proposed Rate Design?

#### Energy Storage

- Should energy storage be charged in a manner that is consistent with other users of the transmission system?

#### Modernized DOS

- Is retaining a DOS opportunity service useful?
- Are Modernized DOS bidding mechanics workable for users?

- Will each of the representation and maximum load factor mechanisms prevent DTS cannibalization?

The AESO's views on each of these issues are set out in detail herein.

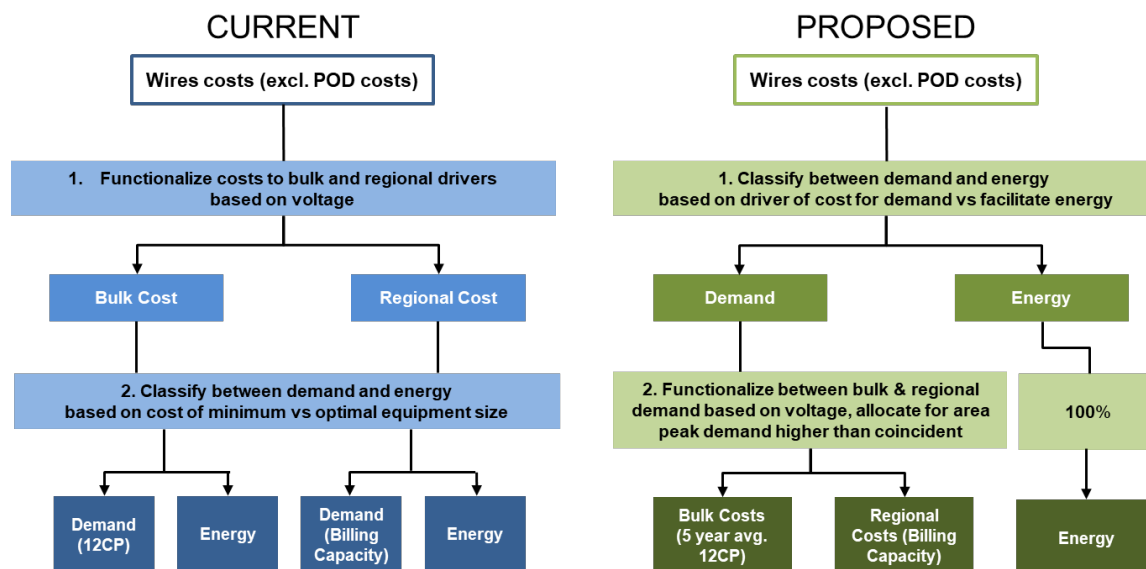
### 3. Proposed Rate Design

#### 3.1 Introduction and Overview of Proposed Rate Design

87 A cost causation-based tariff design means customers are charged based on how their use of the system drives transmission costs over the long term. In contrast to the Current Rate Design, the Proposed Rate Design better reflects actual use and transmission cost drivers by recognizing costs incurred as a result of demand (through the 12CP and billing capacity billing determinants) and costs incurred to accommodate the flow of in-merit energy (through the energy billing determinant). This amendment appropriately recognizes the AESO's legislative responsibilities to plan a transmission system that accommodates anticipated in-merit electric energy.

88 The Proposed Rate Design represents a significant shift in how transmission costs are recovered under the ISO tariff. It has been developed after considerable examination and assessment by the AESO, including stakeholder consultation, and advice from leading transmission tariff design experts. It is a design grounded in cost causation that classifies costs relating to demand and costs to accommodate the flow of in-merit energy. Demand related costs are functionalized between bulk and regional functions based on voltage, with the majority of bulk demand related costs allocated and recovered through a five-year trailing average 12CP billing determinant (the remaining bulk demand related costs are recovered through the billing capacity billing determinant), and regional demand related costs recovered through the billing capacity billing determinant. Costs classified to accommodate the flow of in-merit energy are recovered through a flat energy charge. By recognizing these cost drivers within the Proposed Rate Design and amending the billing determinants to align more closely with principles of cost causation, the Proposed Rate Design represents a robust, flexible and enduring rate design over the long term.

89 The Proposed Rate Design is detailed in section 3.5 of this application. However, the chart below provides a comparison of the differences between the Current and Proposed Rate Designs:



90 The Proposed Rate Design results in lower 12CP and billing capacity charges and higher energy use charges as compared to the Current Rate Design under the current use of the transmission system. The rate design will adapt based on how the transmission system continues to be used in the future. Additional details relating to the implementation of all rates impacted by the Proposed Rate Design, including changes to terms and conditions of service, are further discussed in section 7 of the application.

### 3.2 Transmission System Planning

91 The planning process is an important consideration in understanding cost causation for the development of the Proposed Rate Design. Transmission costs are recovered under the Proposed Rate Design in a way that corresponds to the reasons for which they are incurred through the planning process, and not based on real time stress conditions on the system that may occur because of transmission outages and contingencies.

92 The AESO's planning process ensures that the transmission system meets a number of criteria, including regulations and the Alberta reliability standards. For example, the *Transmission Regulation* requires the transmission system to accommodate all in-merit flows of energy under system normal (i.e., no contingency) conditions in all hours of the year. While the need for transmission development evolves over time, the planning criteria used by the AESO have remained relatively consistent since 2006.<sup>60</sup>

93 The need for transmission reinforcement is driven by a range of plausible combinations of expected load location and level, expected generation location and dispatch, as well as contingency conditions to ensure the transmission system can meet reliability standards and facilitate the flow of in-merit energy. The main inputs into the AESO's transmission system planning are load forecasts and generator dispatch forecasts, which are used to develop study conditions that are evaluated in transmission system models:

- a) Load Forecasts: The AESO creates and analyzes various hourly forecasts of load (including load location and level) which are described in the Long-term Outlook.<sup>61</sup> Load forecasts are created using POD level data and are typically based on five years of historical data.<sup>62</sup> The POD level data is aggregated into coincident load forecasts at various levels (such as planning area and planning region) which account for the diversity of load profiles.
- b) Generator Dispatch Forecasts: The AESO considers historical generator output and market simulations to forecast hourly generation dispatch levels for existing and forecast generation, also described in the Long-term Outlook.
  - For conventional generation, low and high generation dispatch scenarios are assessed using market simulations, historical data and generation development scenarios.

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<sup>60</sup> Appendix B Part 1 - AESO System Planning Report Transmission Tariff Work Group (referred to as the P1 Report), at PDF page 875.

<sup>61</sup> Appendix B Part 1 - P1 Report, at PDF page 874.

<sup>62</sup> Appendix K - AESO 2021 Long-term Outlook (referred to as the 2021 Long-term Outlook), at PDF page 16.

- For variable, non-dispatchable sources (i.e.: wind and solar generation), the AESO assesses the stressed low and high generation conditions for the specific areas under investigation using market simulations and expected resource profiles.<sup>63</sup>

c) Study conditions: The AESO uses the above forecasts in its various transmission planning studies based on a range of study cases to ensure resiliency and flexibility of transmission plans, and to ensure that transmission planning criteria are met. These studies consider the need to accommodate the flow of in-merit generation under system normal conditions in all hours, and the need to reliably serve load in all hours, including peak hours.<sup>64</sup> For example, planning for bulk transmission system accounts for seasonal peaks, light and shoulder load system conditions. These system planning studies model system coincident load conditions (and not the sum of individual customer highest loads).<sup>65</sup>

94 The AESO's planning process delineates between local and system related drivers of transmission. From a planning perspective, local or regional systems are designed to serve both load and generation within a region, whereas the bulk system is designed to enable power flow exchanges across the entire transmission system.<sup>66</sup> The load forecasts that would be considered in planning for different transmission system needs are different in each case: coincident system peak is studied in relation to bulk transmission reinforcements, while the local load profile is studied when considering the need for regional transmission reinforcement.

95 Through the planning process, the need for transmission reinforcement is identified where reliability and planning requirements exceed the capability of the existing system. Conditions that indicate a need for transmission investment can include a specific reasonably expected stressful combination of load location and level, generation location and dispatch, as well as contingency conditions.<sup>67</sup>

96 Often a combination of factors drives the need for transmission, such as forecast peak demand and forecast generation dispatch. Other combinations of factors can contribute to a need for transmission. For example, the output from non-dispatchable renewable generating assets does not follow system loading conditions. If higher output from these assets coincides with lighter load conditions, the combination of factors may increase power flows on certain transmission paths and thereby contribute to the need for transmission reinforcement.<sup>68</sup>

97 Once the need for transmission reinforcement is determined, the AESO considers a number of different transmission alternatives to serve the transmission need, including alternatives that can meet the defined need at different voltage levels. Alternatives are evaluated based on technical performance, cost, and land, environmental and social impact.<sup>69</sup> The need for transmission reinforcements are identified pursuant to a

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<sup>63</sup> Appendix B Part 1 - P1 Report, at page 875.

<sup>64</sup> Appendix B Part 1 - P1 Report, at PDF pages 875 and 877.

<sup>65</sup> Appendix B Part 1 - P1 Report, at PDF page 877.

<sup>66</sup> Appendix B Part 1 - P1 Report, at PDF page 878.

<sup>67</sup> Appendix B Part 1 - P1 Report, at PDF page 876.

<sup>68</sup> Appendix B Part 1 - P1 Report, at PDF page 878.

<sup>69</sup> Appendix B Part 1 - P1 Report, at PDF page 876.

holistic approach of planning for transmission capacity needs, regardless of the technical solution proposed by the AESO with respect to line voltage.

### 3.3 Rate Design Principles

98 The rate design presented in this section of the application is founded on the rate design principles that have been articulated by the Commission in numerous decisions.

99 In its 2005-2006 ISO tariff application, the AESO adopted five rate design principles:

- (i) recovery of the total revenue requirement;
- (ii) provision of appropriate price signals;
- (iii) fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
- (iv) stability and predictability of rates and revenue; and
- (v) practicality, such that rates are appropriately simple, convenient, understandable, acceptable, and billable.<sup>70</sup>

100 The application of these principles to the AESO's rate design was extensively discussed in both Decision 2005-096 and in Decision 2007-106. In those decisions, the predecessor to the Commission (the Energy and Utilities Board (the EUB or Board)) determined that:

- a) The first principle - recovery of the total revenue requirement - would be satisfied by any rate design that, on a forecast basis, recovered the applied-for revenue requirement.
- b) The second and third principles - appropriate price signals and fairness, objectivity and equity - were considered to be satisfied by rates that recover costs in the manner in which they are caused. That is, rates based on cost causation should provide appropriate price signals, should be fair, objective, and equitable, and should minimize or eliminate inter-customer subsidies. Cost causation therefore is the *primary consideration* when evaluating a rate design proposal.
- c) The remaining two principles – stability and predictability, and practicality - should be given secondary consideration. That is, there should be little need to be concerned with stability, predictability and practicality if rates reflect cost causation, barring unusual regulatory events such as regulatory lag or dramatic changes in cost structure.<sup>71</sup>

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<sup>70</sup> Decision 2005-096, at PDF page 19.

<sup>71</sup> The rate design principles adopted by the Commission align with and informed the AESO's B&R Objectives. Specifically, the principle of cost causation aligns with the AESO's "Reflect Cost Responsibility" and "Efficient Price Signals" as the Commission has accepted that where a tariff reflects cost responsibility, proper price signals will be sent. "Minimal disruption" "Innovation and Flexibility" and "Simplicity" align with the secondary rate design principles of stability and predictability.

101 In considering the 2010 ISO tariff application in Decision 2010-606, the Commission reaffirmed that, after the principle of full recovery of the revenue requirement, cost causation should generally prevail over the above noted secondary considerations when assessing the AESO's ISO tariff rate design.

102 In recommending the Proposed Rate Design, the AESO was cognizant of and adherent to the Commission's recurrent description of rate design principles, placing the most weight on the need for a tariff to reflect cost causation. In particular, the AESO has relied on the NERA Report which sets out recommended improvements to the Current Rate Design that better meets cost causation principles. Further, and described in this application, implementation of the Proposed Rate Design will result in appropriate price signals and in a fair, objective and equitable allocation of transmission system costs.

103 Finally, the Commission has found that, while rate shock remains a valid consideration in the design of any rate, it is a secondary consideration that should only be addressed as a separate stand-alone issue after cost causation has been determined.<sup>72</sup> The AESO has included in this application a proposal to mitigate the impacts resulting from its Proposed Rate Design for a small number of highly impacted loads.

### 3.4 Case for Change

#### 3.4.1 Current Rate Design

104 The following high-level summary of the Current Rate Design methodology is provided for the purpose of contextualizing the Proposed Rate Design.

105 The first step of the Current Rate Design primarily distinguishes between costs associated with meeting coincident peak load (bulk system costs) and those costs associated with meeting local system needs (regional system costs).<sup>73</sup> Transmission assets are distinguished by voltage, where bulk assets are functionalized at 240 kV and above and regional assets at below 240 kV,<sup>74</sup> after which the net book values<sup>75</sup> of each category of asset are used to determine the ratio of bulk, regional, and POD transmission costs. This calculation is completed for a single historical year based on actual TFO cost data and calculated for future years based on forecasts (including estimates of depreciation and forecasted capital additions expected to energize in the future).<sup>76</sup>

106 Having divided transmission system costs between bulk and regional functions, the Current Rate Design then classifies costs in each category between demand and energy through a minimum system approach. Broadly speaking, the minimum system classification process occurs in two steps: first, representative assets are assumed for a minimum system (to meet total load) and then for an optimal system (to reduce energy losses) at bulk and regional voltages.<sup>77</sup> The ratios of the estimated costs of representative assets

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<sup>72</sup> Decision 2007-106, at PDF page 68.

<sup>73</sup> Decision 2014-242, at PDF page 19, para 76.

<sup>74</sup> And above 25 kV.

<sup>75</sup> Net book values of transmission and substation assets provided to the AESO by TFOs. See section 3.5.4 of this application.

<sup>76</sup> Appendix N - London Economics International, *Alberta Transmission System Cost Causation Study* (referred to as the LEI Report), at PDF pages 44-45.

<sup>77</sup> Appendix N - LEI Report, at PDF pages 68-73.

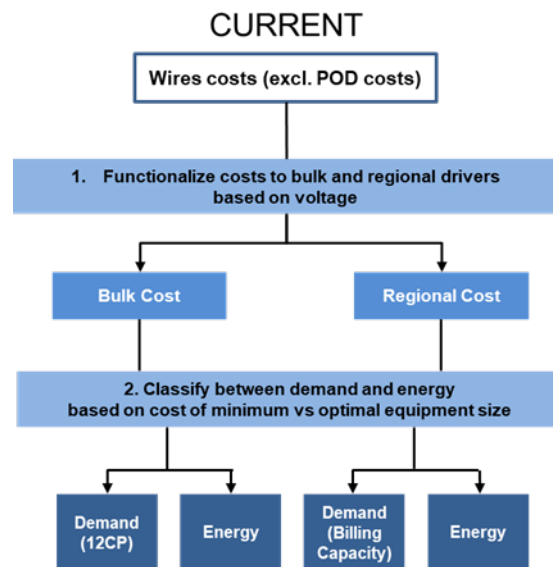


determine the respective portion of the minimum and optimal systems at each voltage level, which are used to classify costs between demand and energy, respectively.

107 After costs are functionalized and classified, four categories of costs result: bulk demand related costs, bulk energy related costs, regional demand related costs, and regional energy related costs. The Current Rate Design recovers these costs from the following billing determinants:

- bulk demand related costs are recovered through a 12CP charge (a demand charge), on the basis that these costs relate to meeting coincident peak demand on the system (as costs driven by the combined maximum use of all loads);
- regional demand related costs are recovered through a billing capacity charge (a demand charge), on the basis that these costs relate to meeting local non-coincident peak demand (as costs relate to serving the ability of customer to use power in a local region);
- bulk energy and regional energy related costs are recovered through flat energy charges, on the basis these costs relate to minimizing energy losses on the transmission system (as costs relate to the use of energy).<sup>78</sup>

108 The steps in the Current Rate Design described above are depicted in the following graphic:



### 3.4.2 Overview of Case for Change

109 The Current Rate Design was approved by the EUB in Decision 2005-096. The Board considered stakeholder proposals for the recovery of bulk transmission costs on coincident metered demand charges

<sup>78</sup> Appendix N - LEI Report, at PDF page 68.



on the basis that “the bulk system is largely constructed and sized, and costs incurred, to meet the peak load of the system”.<sup>79</sup>

110 The EUB accepted these submissions, approving the 12CP methodology because it aligned with principles of cost causation and would therefore send appropriate price signals to customers. The EUB held that a rate design in which “costs are being recovered in the matter in which they are caused” adhered to cost causation principles, whereas rate designs that failed to do so led to inter-customer subsidies.<sup>80</sup>

111 The EUB upheld recovering bulk transmission costs through a 12CP charge in Decision 2007-106, relying on the following findings:

- The transmission system is planned for peak load;
- Peak load is the primary cause of maximum transmission stress;
- It follows that peak load is the cause and primary driver for bulk system costs;
- As peak load is the primary driver for bulk system costs, peak load should be the primary basis on which costs are allocated;
- It is clearly “not possible for a customer to generally simply turn the power off and completely avoid the hour of system peak”; and
- Transmission wires costs are largely fixed in nature and most appropriately recovered primarily through demand charges.<sup>81</sup>

112 Consistent with these findings, the Current Rate Design primarily recovers transmission costs (excluding POD costs) from demand billing determinants, approximately two thirds of which are recovered from a charge levied on 12CP. Less than of 10% of transmission costs are recovered from an energy charge.<sup>82</sup>

113 Alberta’s transmission system and electricity market have evolved over the past 15 years. Both the composition and location of generators across the province have changed. Coal plants have been phased out or converted to natural gas generation and variable renewable generation sources have increased significantly. The transmission system has simultaneously undergone substantial reinforcement, including transmission investment costs of approximately \$13 billion.<sup>83</sup> The ability of load to avoid transmission charges by responding to the 12CP price signal, thought to not be possible in 2005, has increased significantly (as further detailed at paras 130 – 136).

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<sup>79</sup> Decision 2005-096, at PDF page 32.

<sup>80</sup> Decision 2005-096, at PDF page 20.

<sup>81</sup> Decision 2007-106, at PDF pages 30, 40, and 66.

<sup>82</sup> See para 180, Table 3-3 of this application.

<sup>83</sup> Appendix B Part 1 - AESO Bulk and Regional Tariff Design Session 1 (March 13, 2020) Driver and Costs – Historical and 2017 LTP System Projects.

- 114 Transmission investments have been made over this period with a dual purpose: to meet demand and to accommodate the flow of in-merit energy on the transmission system.<sup>84</sup> However, the Current Rate Design primarily reflects only one of these purposes: meeting demand. As a result, the peak demand charge levied on 12CP overstates the costs associated with using the grid at peak times in the Current Rate Design, and the design fails to explicitly account for costs incurred to facilitate the flow of in-merit energy.<sup>85</sup>
- 115 There have been recent calls to re-examine the Current Rate Design's heavy reliance on 12CP. The AESO initiated the B&R Consultation following stakeholder submissions in Proceeding 22942 about cost shifting resulting from customers avoiding the 12CP charge, despite increased overall use of the transmission system.<sup>86</sup> In that proceeding, the Commission acknowledged "significant changes in the market" that have occurred since the introduction of the 12CP methodology within the Current Rate Design, which warranted re-examining the methodology.<sup>87</sup> The AESO similarly concluded that the 12CP price signal was driving increased behavior to reduce consumption during the 12CP hours without a corresponding reduction in system costs,<sup>88</sup> and further that the Current Rate Design was not sustainable.<sup>89</sup>
- 116 The NERA Report confirms these concerns about the Current Rate Design and identifies significant deficiencies in the design within the evolved transmission context:
- The Current Rate Design fails to properly align the drivers of transmission investment in Alberta as it classifies 93.4% of bulk system wires costs to be recovered from a charge levied on 12CP, irrespective of whether the transmission cost driver is load or accommodating the flow of in-merit energy;<sup>90</sup>
  - By not recognizing investments relating to accommodating the flow of in-merit energy (which occur at any time) and by recovering those costs on a 12CP charge, the Current Rate Design sends inefficient price signals by overstating the costs associated with using the grid at peak times, and does not meet principles of cost causation;<sup>91</sup>

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<sup>84</sup> Appendix B Part 1 - AESO Bulk and Regional Tariff Design Session 1 (March 13, 2020) Driver and Costs – Historical and 2017 LTP System Projects.

<sup>85</sup> Appendix D – NERA Report at PDF pages 42, 9, and 62, paras 96, 13, 159. While the Current Rate Design includes an energy charge, this charge, nor any other aspect of the Current Rate Design, account for transmission costs relating to accommodating the flow of in-merit energy.

<sup>86</sup> September 28, 2017 Letter to Commission in Proceeding 22942, Exhibit 22942-X0036.

<sup>87</sup> November 27, 2017 Commission Ruling on ADC's motion to exclude AltaLink in proceeding 22942, Exhibit 22942-X0089, at PDF pages 7-8, para 28.

<sup>88</sup> Appendix B Part 2 - AESO, Bulk and Regional Tariff Design Stakeholder Engagement Session 2 Presentation (September 24, 2020), at slide 24.

<sup>89</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Session 4 (December 10, 2020) Presentation, at slide 49.

<sup>90</sup> Appendix D - NERA Report, at PDF page 41, paras 92-94.

<sup>91</sup> Appendix D - NERA Report, at PDF page 42, para 96.

- The Current Rate Design has contributed, in part, to the significant increase in the 12CP charge;<sup>92</sup> and
- Response to the 12CP price signal under the Current Rate Design has led to inefficient self-supply or consumption decisions, as well as a compounding effect, in which the more customers respond and reduce their consumption during peak times, the higher the 12CP charge and the stronger the incentive for others to respond.<sup>93</sup>

117 Further, and as detailed below, some of the main findings underpinning the initial approval of the Current Rate Design no longer apply. Drivers of bulk transmission investment are not solely related to coincident peak demand and therefore should no longer be the primary basis to allocate costs. Additionally, customer response to 12CP has also increased, with some customers becoming increasingly successful at avoiding some or all peak use charges.

118 These changes necessitate amending the Current Rate Design to realign with principles of cost causation. In this Proceeding, the Commission has the opportunity to recognize the current and future drivers of transmission costs through the adoption of the Proposed Rate Design, better reflecting principles of cost causation and sending more efficient price signals.

### **Transmission Investments and Maximum Stress Do Not Solely Relate to Peak Demand**

119 From 2014 to 2019, significant costs were incurred to reinforce the transmission system, mostly related to additions to the bulk system.<sup>94</sup> Since 2007, growth in coincident metered demand has been relatively flat<sup>95</sup>, while total load as measured by billing capacity experienced steady growth.

120 As a result of stagnant coincident metered demand growth and significant increases in bulk transmission costs recovered through the 12CP billing determinant, the 12CP charge increased significantly<sup>96</sup> from \$1,233/MW/Month in January 2006 to \$11,085/MW/Month in January 2021. During this timeframe, the energy charge remained largely constant. Figures 3-1A and 3-1B below demonstrate the effect of load growth and transmission investment costs on the tariff charges (tariff charges are calculated in \$/MWh equivalents for comparison between different charges):

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<sup>92</sup> Appendix D - NERA Report, at PDF pages 41-42, paras 95-97.

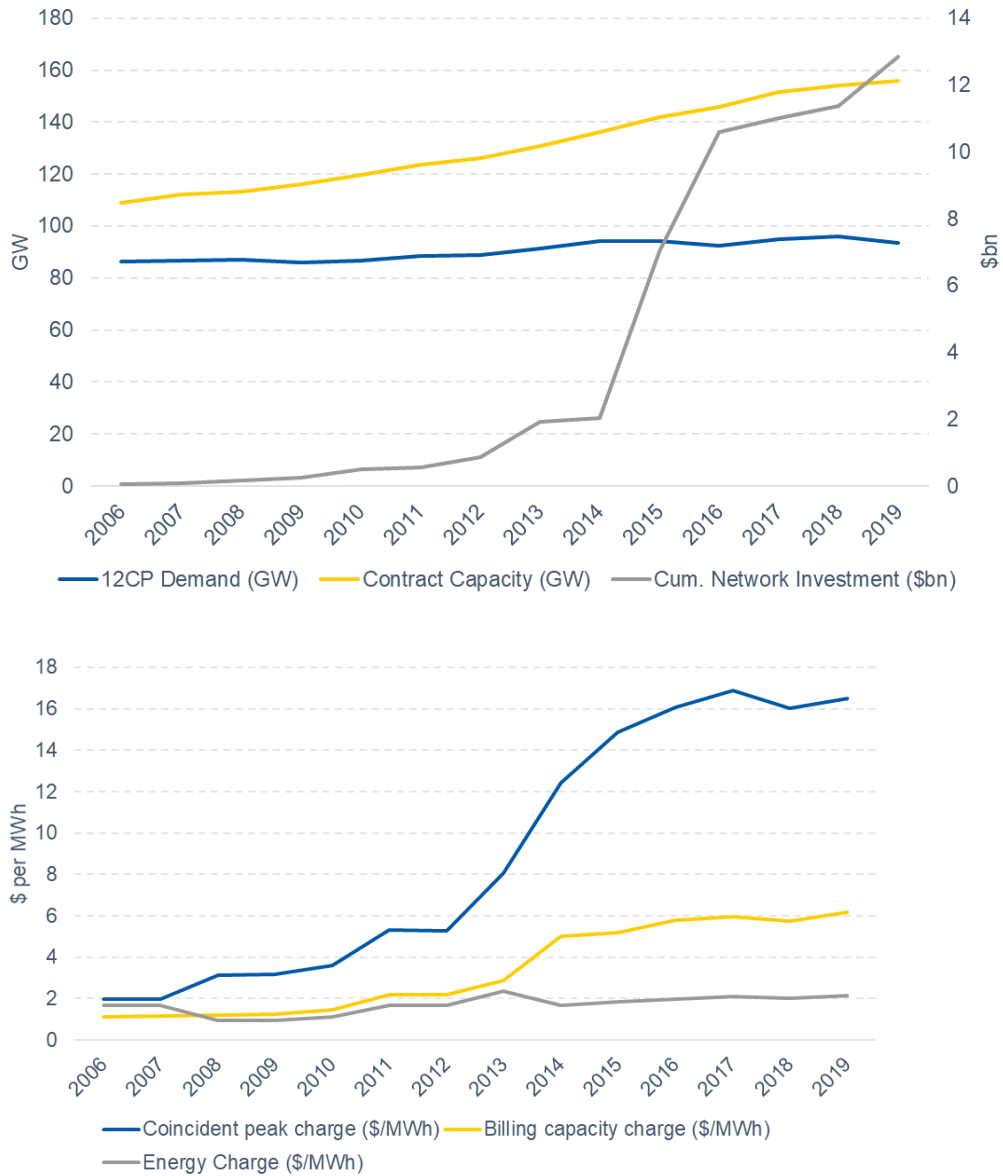
<sup>93</sup> Appendix D - NERA Report, at PDF page 42, para 97.

<sup>94</sup> Appendix B Part 1- P1 Report, at PDF page 879.

<sup>95</sup> Appendix I - AESO 2015 Revised Long-term Transmission Plan, at PDF page 2. "The AESO's 2014 LTO indicates that the provincial economy is expected to grow at a rate of 2.4 per cent annually until 2035". However, the Alberta economy experienced a decline, as outlined in the AESO 2017 Long-term Outlook, at PDF page 6 (see Appendix J).

<sup>96</sup> Appendix D - NERA Report, at PDF page 33, para 71.

Figures 3-1 A and B: Demand, Investment, and Tariffs, 2006-2019<sup>97</sup>



<sup>97</sup> Appendix D - NERA Report, at PDF page 34, Figure 5.

121 Figure 3-1A further demonstrates how transmission investments unrelated to growth in coincident metered demand have increased over this period, though not explicitly recognized under the Current Rate Design.

122 The fuel sources and the physical locations of power generation in Alberta have evolved since 2006, marked by a reduction of coal-based generation and influx of renewable sources.<sup>98</sup> It is expected that this trend will continue in the future, as all coal generation in the Province (currently comprising 27.6% of the overall installed generation capacity as of March 2021) will be retired or converted to gas generation by the early 2020s<sup>99</sup> in the Northwest, Edmonton, and Central planning regions. At the same time, renewable generation capacity is expected to increase significantly by 2024,<sup>100</sup> primarily within the South and Central planning regions. Table 3-1, demonstrates these forecasted changes to generation by fuel source and by planning region between 2018 and 2024:

*Table 3-1: Forecast Change in Generation Capacity Between 2018 and 2024 Across Planning Regions in Alberta (MW)<sup>101</sup>*

	Northwest	Northeast	Edmonton	Central	South	Calgary
Change to Total of Coal-fired and Converted Coal-to-gas Capacity	-144	0	0	-149	0	0
Change to Wind and Solar Capacity	0	0	0	248	1,327	0
<b>Total Change in Generation Capacity</b>	<b>-36</b>	<b>271</b>	<b>0</b>	<b>241</b>	<b>1,373</b>	<b>46</b>

Source: AESO 2020 Long-term Transmission Plan, January 2020.

123 Changes to generation capacity have altered the locational pattern of generation relative to demand and driven investment in the transmission system.<sup>102</sup> The AESO plans investments to account for the changing locational patterns of generation and load in order to accommodate the flow of in-merit energy. For example, the Southern Alberta Transmission Reinforcement was needed to accommodate integration of wind generation in southern Alberta, and the Provost to Edgerton and Nilrem to Vermillion transmission

<sup>98</sup> Appendix L - AESO 2020 Long-term Transmission Plan, January 2020, at PDF page 5.

<sup>99</sup> Appendix K - AESO 2021 Long-term Outlook, at PDF page 27.

<sup>100</sup> Appendix K - AESO 2021 Long-term Outlook, at PDF page 27.

<sup>101</sup> Appendix D - NERA Report, at PDF page 36, Table 4.

<sup>102</sup> Appendix D - NERA Report, at PDF page 37, para 79.

development was needed to facilitate additional generation collection capability (in addition to serving load).<sup>103</sup>

124 Transmission investments driven by the need to accommodate flows of in-merit energy are also anticipated to comprise a notable portion of future investments. The AESO's most recent Long-term Outlook forecasts that significant future generation investment is likely to continue the trend of locating in areas that are different from traditional generation locations including, for example, in areas where wind and solar potential are highest (which may not coincide with where load is located, or where transmission is currently in place).<sup>104</sup>

125 Due to the planning requirements in Alberta, investments are made to accommodate the changing flows of in-merit energy regardless of future changes in demand.<sup>105</sup> Because these costs are not explicitly recognized or accounted for under the Current Rate Design, most of the costs associated with accommodating the flows of in-merit energy are recovered through the 12CP charge, even though they are unrelated to peak demand.<sup>106</sup>

126 Analysis of high flows on bulk transmission lines as compared to 12CP hours also demonstrates that high utilization (meaning, flows within 10% of the peak flows on a line, which is indicative of the need for transmission investment),<sup>107</sup> is driven by factors other than just coincident peak demand. This analysis, conducted by NERA, is set out in the below Figures 3-2 A and B:

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<sup>103</sup> Decision 2009-126, at PDF pages 14-15, paras 42-44 and Decision 23429-D01-2019, at PDF page 45, para 180.

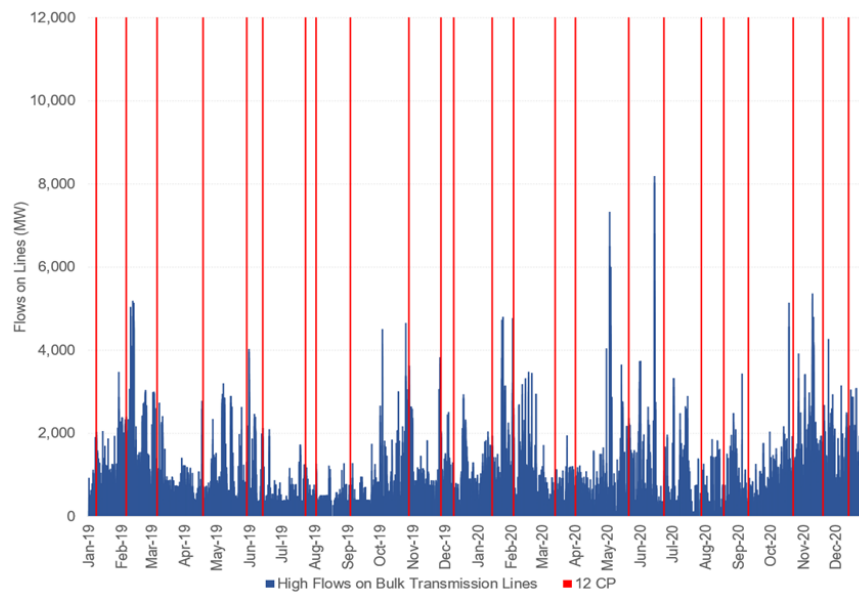
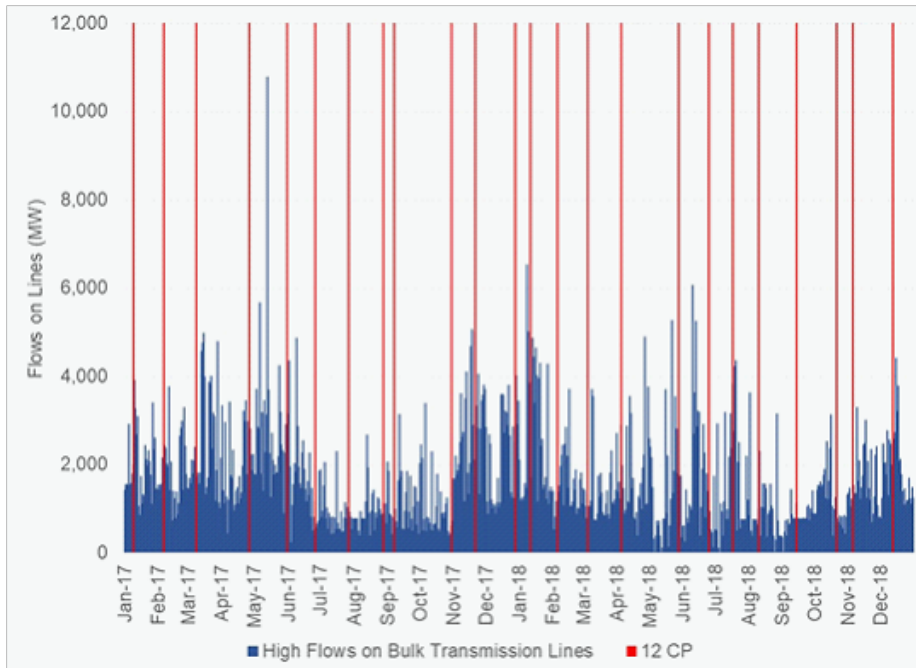
<sup>104</sup> Appendix K – AESO 2021 Long-term Outlook, at PDF page 24.

<sup>105</sup> Appendix D - NERA Report, at PDF page 58, para 147.

<sup>106</sup> Appendix D - NERA Report, at PDF page 41, para 94.

<sup>107</sup> Appendix D - NERA Report, at PDF pages 38 and 39, paras 85 and 90.

Figures 3-2 A and B: Hours of High Flows on Bulk Transmission Lines and 12CP (2017-20)<sup>108</sup>



<sup>108</sup> Appendix D - NERA Report, at PDF page 40, Figure 7.

127 This shows that the Current Rate Design's recovery of the majority of transmission costs from the 12CP charge does not align with how the need for transmission investment is driven in Alberta.<sup>109</sup>

### **Cost Causation Requires Lesser Emphasis on Coincident Peak Load to Allocate Costs**

128 By recovering the majority of costs from a 12CP charge, the Current Rate Design does not send price signals that reflect the drivers of investment on the transmission system. It has also led to an inefficient 12CP price signal by overstating the transmission costs associated with using the grid at times of coincident peak.<sup>110</sup>

129 This is because the need for investments required to accommodate the flow of in-merit energy is driven by system conditions that occur at times other than coincident system peak, such as in response to changes in generation dispatch (by example, during windy conditions).<sup>111</sup> By recovering the costs of these investments on a 12CP charge, the Current Rate Design does not send cost reflective price signals because the driver of costs is accommodating the flow of in-merit energy.<sup>112</sup>

130 As the 12CP charge has increased, so too has the incentive for loads to respond to the price signal (by reducing consumption during times that are expected to be coincident peak hours). Over the past ten years the proportion of load with the highest CP response levels has grown by 45%, from approximately 11% of total contract capacity in 2010 to approximately 16% of total contract capacity in 2020.<sup>113</sup> At the same time, the proportion of load that has not exhibited 12CP response has fallen from 70% to just over 60% of total contract capacity.

131 Figures 3-3 and 3-4 show the increased total proportion of contract capacity that is responsive to the 12CP price signal (CP Response) from 2010 to 2020. A low CP Response level indicates that the POD consumes at a level similar to its contract capacity at times of coincident peak. The bars measure the proportion of total contract capacity that fall within a certain CP Response category. The blue bars show the total proportion of contract capacity that is least responsive to coincident peak (0%-<20%); the purple bars show the total proportion of contract capacity with the highest levels of coincident peak response (60%-100%).

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<sup>109</sup> Appendix D - NERA Report, at PDF page 41, para 91.

<sup>110</sup> Appendix D - NERA Report, at PDF page 42, para 96.

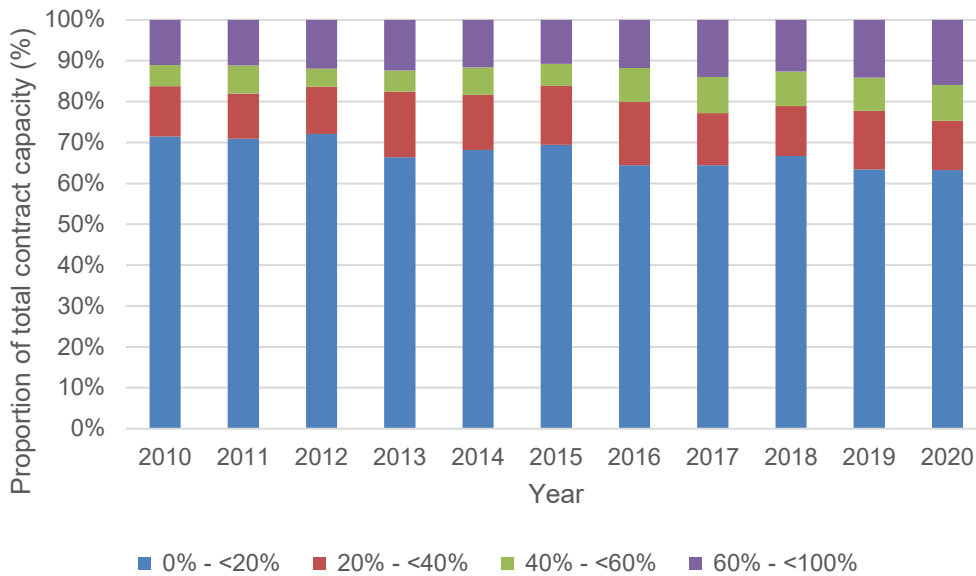
<sup>111</sup> Appendix D - NERA Report, at PDF page 42, para 96.

<sup>112</sup> Appendix D - NERA Report, at PDF page 42, para 96.

<sup>113</sup> CP Response is calculated as one minus the ratio of a POD's total consumption during CP hours relative to a POD's contract capacity.



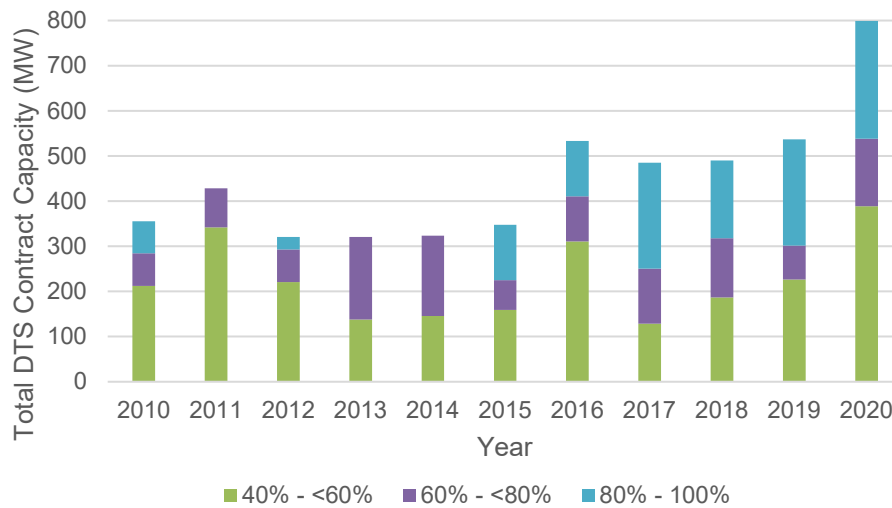
Figure 3-3: Total contract capacity by proportion of CP Response from 2010 to 2020



132 CP Response is likely to vary with average load factor because loads with a low load factor are on average less likely to consume at times of coincident peak, whereas loads with a higher load factor are on average more likely to consume at times of coincident peak. For this reason, Figure 3-4 shows the total capacity of loads with relatively high load factors and relatively high CP Response (specifically loads with both a load factor of 50% or more and a CP Response of 40% or more). The bars on the graph show the total contract capacity of loads in each CP Response category. For instance, the green bars show the total contract capacity for loads with a CP Response factor of between 40%-<60% (and a load factor above 50%).

133 The total contract capacity represented in the Figure has doubled from 2010 to 2020, from approximately 400 MW in 2010 to 800 MW in 2020. Further, the total contract capacity in the highest 12CP response range (80 – 100%) has grown to approximately 260 MW in 2020, from a low of 71 MW in 2010 (and zero in each of 2011, 2013, and 2014). The number of PODs included in the graph also increased from 15 in 2010 to 25 in 2020. This indicates the overall trend of increasing amounts of load responding to the 12CP price signal, whether in the form of new loads or existing loads becoming more responsive.

Figure 3-4: CP Response from customers with load factor of 50% or more from 2010 to 2020



- 134 Under the Current Rate Design, customers who accurately respond to the 12CP charge can avoid nearly half (48%) of the total transmission charges.<sup>114</sup> In avoiding these costs, 12CP responders reduce the charging base for the 12CP charge, which shifts transmission costs to customers who are less responsive or not responsive. This creates a compounding incentive for the less-responsive subset of customers to begin to respond to the higher 12CP charge, or responding customers to increase their response, as the incentive to avoid the 12CP charge continues to increase as more customers respond.<sup>115</sup>
- 135 The AESO is not suggesting those who respond to the 12CP price signal under the Current Rate Design are doing so inappropriately. Rather, due to the mechanics of the Current Rate Design, customers are responding to an inefficient price signal that overstates the extent to which use of the system during times of coincident peak drives transmission costs.
- 136 During the B&R Consultation, certain stakeholders suggested that the Current Rate Design did not require amendment, and that the Proposed Rate Design was a significant change to transmission rates.<sup>116</sup> The AESO considered this feedback, but remains of the view that updating the tariff now to be more cost

<sup>114</sup> Appendix B Part 3- AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021), at slide 32.

<sup>115</sup> Appendix D - NERA Report, at PDF pages 33 and 42, paras 72 and 97.

<sup>116</sup> Appendix B Part 2 - Industrial Power Consumer Association of Alberta (IPCAA), Alberta Direct Connect (ADC) & Dual Use Customers (DUC), Bulk and Regional Tariff Design Stakeholder Engagement Session 3: Stakeholder Proposal Presentation (November 5, 2020); and Appendix B Part 3 - IPCAA, Bulk and Regional Tariff Design Stakeholder engagement Session 5: Stakeholder Comment Matrix (April 15, 2021), question 1; ADC, Bulk and Regional Tariff Design Stakeholder engagement Session 5: Stakeholder Comment Matric (April 15, 2021) at, question 1.

reflective better implements the requirements under sections 121(2) and 30(2) of the Act.<sup>117</sup> Continuing the Current Rate Design will exacerbate the existing 12CP dynamic and feedback loop described in paragraph 134.

### 3.5 Proposed Rate Design

137 The Proposed Rate Design is a bespoke design reflective of Alberta's regulatory framework. It identifies transmission cost drivers and recovers transmission costs, including costs to accommodate the flow of in-merit energy, in a manner that better meets principles of cost causation. It maintains aspects of the Current Rate Design that continue to appropriately reflect transmission system planning and investment drivers, and it resolves the disproportionate recovery of costs from the 12CP billing determinant. The result is a tariff that sends more efficient price signals for consumers when using energy from the transmission system.

138 The Proposed Rate Design was designed through the advice of transmission rate design experts, and stakeholder consultation pursuant to which numerous alternative designs were presented to and considered by the AESO. However, the AESO concluded that the Proposed Rate Design as presented in this application represents the best and most cost reflective tariff for Alberta.

139 More specifically, the AESO retained NERA as independent transmission tariff design experts to design a tariff which aligned with the current regulatory framework, the B&R Objectives and principles of cost causation. The Proposed Rate Design was recommended to the AESO as meeting these criteria.

140 The AESO conducted its own review of the Proposed Rate Design to ensure, among other things, rates charged under the ISO tariff:

- reflect costs reasonably attributable to each class of service;
- are just and reasonable; and
- are not unduly preferential, arbitrary, unjustly discriminatory or inconsistent with the Act.

141 The AESO commissioned the Self-Supply Report from NERA and analyzed the efficiency impact of the Proposed Rate Design on the wholesale energy market to further test the suitability of the design for the Alberta context. This analysis was presented to stakeholders in response to key feedback following presentation of the Proposed Rate Design.<sup>118</sup>

142 As it is satisfied with the anticipated impacts of the Proposed Rate Design (as detailed further in section 3.8 of this application) and finds that it meets the B&R Objectives, the AESO requests the Commission approve the Proposed Rate Design in its entirety.

143 The Proposed Rate Design recommended by NERA is set out in the NERA Report and provided as Appendix D to this application. Section 6 of the NERA Report explains the Proposed Rate Design in detail.

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<sup>117</sup> *EUA*, at ss 30(2) and 121(2).

<sup>118</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 6A Presentation (June 3, 2021).

144 This section summarizes the Proposed Rate Design methodology, as well as how the AESO and NERA developed the design.

### 3.5.1 Overview of Proposed Rate Design

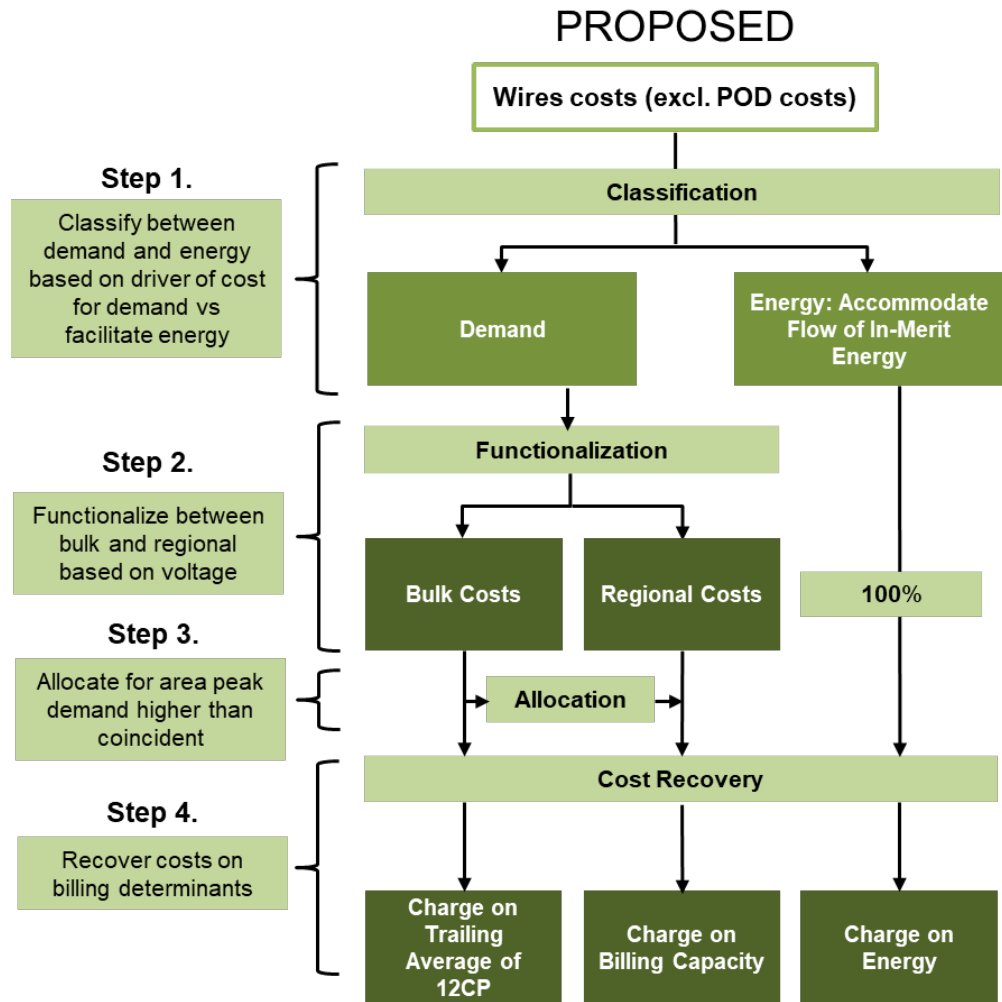
145 The AESO requested that NERA consider and advise on the Current Rate Design relative to alternative rate design approaches. After reviewing the Current Rate Design, NERA identified four key modifications to better reflect cost causation and improve the design:

1. Recognizing the dual purpose of transmission in Alberta (serving demand and accommodating the flow of in-merit energy) by classifying these costs *before* functionalizing. NERA observed that the first step under the Current Rate Design of functionalizing costs into bulk and regional costs by voltage was not reflective of the AESO's planning process where transmission reinforcement solutions are considered irrespective of voltage.<sup>119</sup> NERA therefore recommended classifying these costs *before* functionalizing, recognizing demand related costs vary in purpose by voltage, but costs relating to accommodating the flow of in-merit energy do not.
2. Utilizing a minimum system approach based on a more objective and data driven method of delineating between costs associated with demand and accommodating the flow of in-merit energy. NERA recommended using peak load and peak generation data in each planning area to estimate the size of the minimum and actual systems needed to accommodate peaks in each area.
3. Allocating bulk demand-driven costs between those associated with serving coincident peak demand and those associated with serving non-coincident peak demand within areas. NERA recommended a more cost reflective step of using net load data in planning areas to delineate between these demand related costs, recognizing that most (though not all) bulk system demand related costs are driven by coincident system peak.
4. Recovering bulk system costs associated with coincident peak demand using a charge that reflected a customer's average contribution to coincident peak demand over a longer time horizon. NERA recommended using a five-year trailing average 12CP charge to recover the majority of bulk demand-driven costs, recognizing that within the AESO transmission planning process, sustained high consumption at times of coincident peak is more likely to drive transmission costs than consumption in any single peak hour.

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<sup>119</sup> See para 97 of this application.

146 Each step of the Proposed Rate Design methodology is illustrated in the below table:

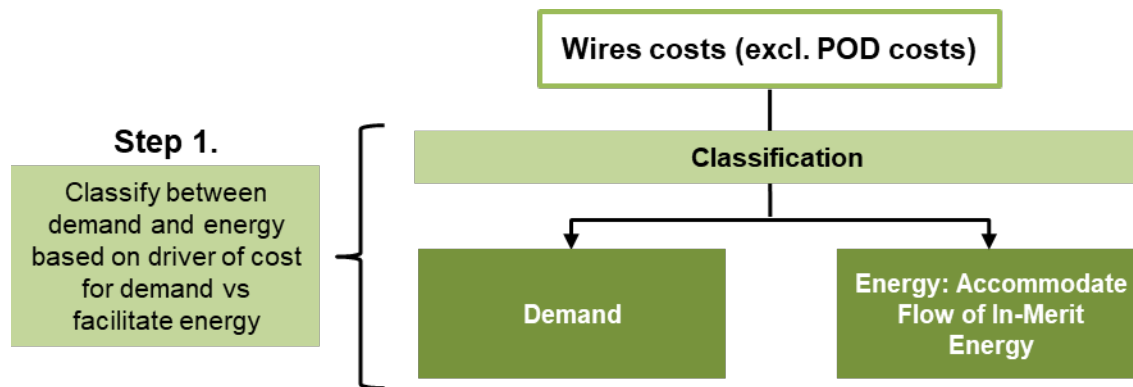


147 A high-level overview of the main steps within the Proposed Rate Design is set out below:

- i. Classify transmission costs between costs relating to demand and accommodating the flow of in-merit energy through a minimum system methodology;
- ii. Functionalize the pool of demand-driven costs based on the proportion of bulk and regional systems as delineated by a voltage level, where the proportion is based on the ratio of the net book value of bulk and regional assets;
- iii. Allocate bulk system, demand-driven costs between coincident and non-coincident demand drivers; and

- iv. Recover the resulting pool of costs from the following billing determinants:
- Recover bulk system costs associated with coincident peak demand from a charge levied on 12CP with a five-year trailing average;
  - Recover bulk system costs associated with non-coincident peak demand from a charge levied on billing capacity;
  - Recover regional system costs from a charge levied on billing capacity; and
  - Recover costs associated with accommodating the flow of in-merit energy from a flat, all hours energy charge.<sup>120</sup>

3.5.2 **Step 1: Classify Costs Between Demand and Accommodating the Flow of In-Merit Energy Costs Prior to Functionalization**



148 To meet the requirements under section 15 of the *Transmission Regulation*, the AESO plans the transmission system to accommodate flows of in-merit energy in all hours of the year.<sup>121</sup> Transmission costs that are incurred to meet this requirement are driven by use of the system at times other than just times of coincident peak. As previously detailed, these costs are not explicitly recognized within the Current Rate Design, which instead treats these costs as demand-driven, and primarily recovers them through demand charges (i.e., 12CP and billing capacity).<sup>122</sup>

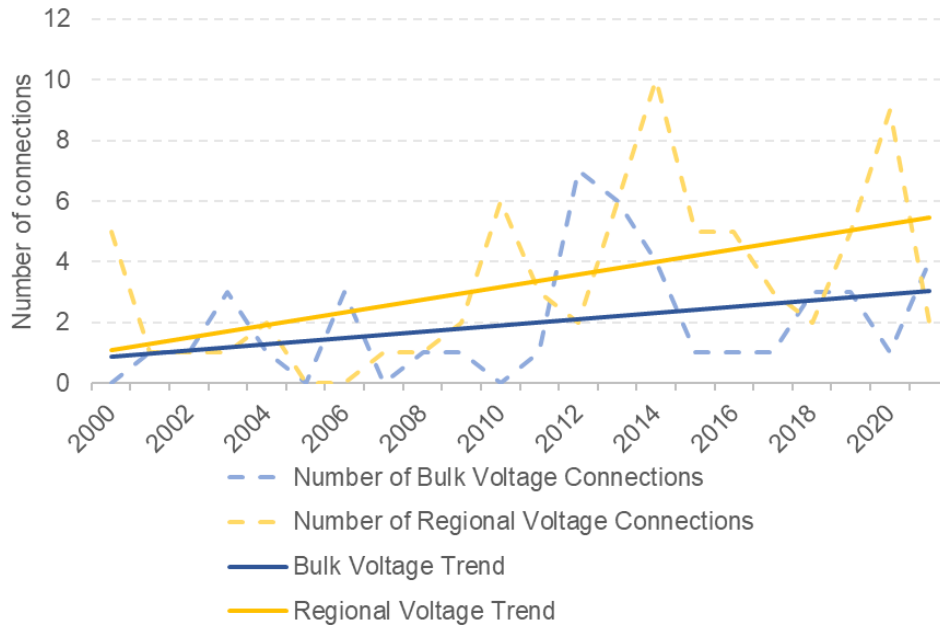
<sup>120</sup> Appendix D - NERA Report, at PDF pages 93 – 97, section 7.1.

<sup>121</sup> *TReg*, s 15.

<sup>122</sup> More specifically, under the Current Rate Design methodology, costs relating to accommodating the flow of in-merit energy are a) functionalized between bulk and regional system costs based on the net book value of the underlining asset distinguished by voltage, and b) allocated between demand and energy using the minimum system methodology under which the type and cost of transmission asset is assumed based on an optimal and minimal system, irrespective of the reason for why the costs were incurred.

149 Transmission facilities above and below 240kV can serve the function of accommodating the flow of in-merit energy, as indicated by the increasing trend of generators connecting at voltages below 240kV<sup>123</sup> evidenced by Figure 3-5:

*Figure 3-5: Generation connections per year at regional system voltages are rising faster than connections per year at bulk system voltages<sup>124</sup>*



Source: See Attachment 5F; NERA analysis of AESO Connection Data.

150 Classifying costs between demand and energy better reflects the fact that the planning process develops alternatives to meet defined needs regardless of the voltage level of the alternative selected. Further, transmission investments occur to accommodate the flow of in-merit energy at both bulk and regional voltage levels. By classifying costs between demand and energy before functionalizing based on voltage, the Proposed Rate Design better reflects how the use of the transmission system drives transmission costs.<sup>125</sup>

**Minimum System Methodology**

151 The recommended minimum system approach to classify costs as relating to either demand or accommodating the flow of in-merit energy better reflects cost causation than under the Current Rate Design. The proposed approach estimates the portion of transmission system costs (excluding POD costs)

<sup>123</sup> Appendix D - NERA Report, at PDF pages 61-62, paras 153-154.

<sup>124</sup> Appendix D - NERA Report, at PDF page 61, Figure 8.

<sup>125</sup> Appendix D - NERA Report, at PDF page 62, paras 155-157.

that are required to serve peak load in Alberta (the minimum system) and the additional costs required above the minimum system to accommodate the flow of in-merit energy.<sup>126</sup>

152 The methodology uses historical load and generation data that the AESO relies on to develop forecasts used in its transmission planning process.<sup>127</sup>

153 The minimum and actual transmission system in Alberta is calculated by planning area as follows:

- The maximum hourly metered net load in a planning area is identified during a reference year in MW, as a proxy for the size of the minimum system required in a planning area to serve peak load:

A = Maximum hourly metered net load in planning area in reference year (MW)

- The maximum hourly generation during a reference year in MW is identified, as a proxy for the size of the transmission system required to accommodate the flows of in-merit energy:

B = Maximum hourly metered net generation in planning area in reference year (MW)

- In planning areas where  $A > B$ , the minimum system is the same size as the actual system. The transmission system in that planning area to meet peak demand is also sufficient to accommodate the flow of in-merit energy. In these areas, 100% of the transmission is classified as serving demand as the actual system equals the minimum system.
- In areas where  $B > A$ , the transmission in that planning area that exceeds the minimum system (i.e., the system required to serve peak load) is deemed to be required to accommodate the flow of in-merit energy. In these areas, the minimum system is classified as serving demand, and the incremental transmission above the minimum system is classified as accommodating the flow of in-merit energy.<sup>128</sup> In these areas the actual system is defined by the peak generation in the area.

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<sup>126</sup> Appendix D - NERA Report, at PDF pages 63-64, para 163-164.

<sup>127</sup> Appendix D - NERA Report, at PDF pages 63-64, paras 164-165.

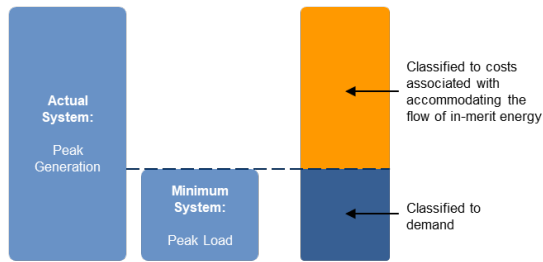
<sup>128</sup> Appendix D - NERA Report, at PDF pages 65-66, para 168.



154 The minimum system methodology is further illustrated in the below example:

Figure 3-6: Illustrative Examples of the Minimum System Approach<sup>129</sup>

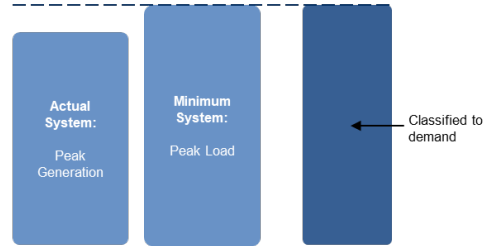
**Example A: An area where the minimum system is not large enough to accommodate the flow of in-merit energy:** Classification of costs between demand and those associated with the accommodation of the flow of in-merit energy



Hour of Ref. Year	Area Load (MW)	Area Generation (MW)
1	25	90
2	30	100
3	35	90
...	...	...
<b>Area Peak:</b>	<b>35 MW</b>	<b>100 MW</b>

$$\begin{aligned}
 \text{Area Minimum System} &= \text{Peak Area Load} = 35 \text{ MW} \\
 \text{Area Actual System} &= \max(\text{Area Minimum System}, \text{Peak Area Generation}) \\
 &= \max(35 \text{ MW}, 100 \text{ MW}) \\
 &= 100 \text{ MW}
 \end{aligned}$$

**Example B: An area where the minimum system is large enough to accommodate the flow of in-merit energy:** Classification of all costs to demand



Hour of Ref. Year	Area Load (MW)	Area Generation (MW)
1	100	90
2	95	100
3	120	90
...	...	...
<b>Area Peak:</b>	<b>120 MW</b>	<b>100 MW</b>

$$\begin{aligned}
 \text{Area Minimum System} &= \text{Peak Area Load} = 120 \text{ MW} \\
 \text{Area Actual System} &= \max(\text{Area Minimum System}, \text{Peak Area Generation}) \\
 &= \max(120 \text{ MW}, 100 \text{ MW}) \\
 &= 120 \text{ MW}
 \end{aligned}$$

155 The area minimum system and area actual system values for all 42 planning areas are then summed to create a single value for the overall minimum system and actual system for the Province as a whole, as follows:<sup>130</sup>

$$\begin{aligned}
 \text{Overall Minimum System} &= \sum_{1}^{42 \text{ planning areas}} \text{Area Minimum System} \\
 \text{Overall Actual System} &= \sum_{1}^{42 \text{ planning areas}} \text{Area Actual Systems}
 \end{aligned}$$

<sup>129</sup> Appendix D - NERA Report, at PDF page 67, Figure 9.

<sup>130</sup> Appendix D - NERA Report, at PDF page 67, para 170.

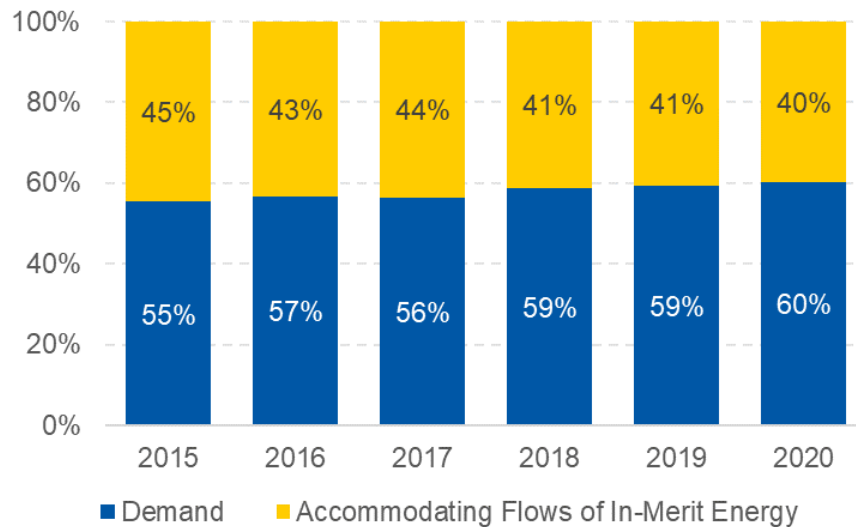
156 The proportion of costs for the minimum system are then classified as demand costs, and the remaining costs are classified as costs relating to accommodating the flow of in-merit energy as follows:

$$\text{Classification of Costs to Demand} = \frac{\text{Overall Minimum System}}{\text{Overall Actual System}} \times 100\%$$

$$\begin{aligned} \text{Classification of Costs to Accommodation of Flows of In – Merit Energy} \\ = 100\% - \text{Classification of Costs to Demand}^{131} \end{aligned}$$

157 Using 2019 net metered load and generation data, the total minimum system under the Proposed Rate Design is estimated to account for 59% of the size of the total actual system in Alberta, resulting in a classification of 59% of transmission costs relating to serving demand, and 41% relating to accommodating the flow of in-merit energy.<sup>132</sup> These percentages calculated under the minimum system approach remained relatively stable from 2015 – 2020 when applied to a large data set:

Figure 3-7: Classification of Demand- and In-Merit Energy-Related Costs Under Our Recommended Minimum System Approach<sup>133</sup>



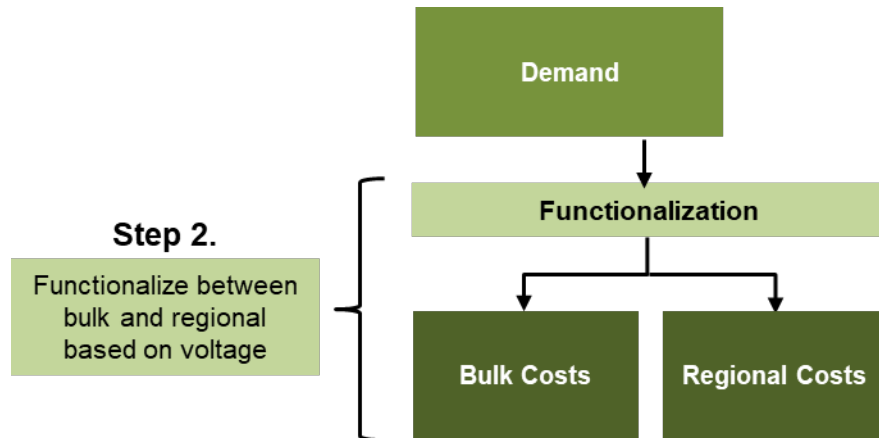
Source: See Attachment 3B and 5G; NERA analysis of area-level load and generation data provided by the AESO.

<sup>131</sup> Appendix D - NERA Report, at PDF page 68, para 171.

<sup>132</sup> Appendix D - NERA Report, at PDF page 68, para 173.

<sup>133</sup> Appendix D - NERA Report, at PDF page 69.

3.5.3 Step 2: Functionalize Demand-Driven Costs



158 After classifying costs through the minimum system methodology, the pool of demand-driven costs is functionalized to the bulk and regional systems, primarily delineated by voltage.<sup>134</sup> Costs relating to the flow of in-merit energy are not functionalized on the basis that assets at either voltage can perform this function.<sup>135</sup> Functionalization is used to determine the relative portion of transmission system costs and POD costs and to determine the percentage of bulk and regional demand related costs.

159 Under the Current and Proposed Rate Designs demand related costs are functionalized between the bulk and regional categories based on the ratio of the net book values of transmission assets at or above 240kV voltage (i.e., bulk system) and below 240kV voltage levels (i.e., regional system). NERA has reviewed the approach to functionalize costs based on the net book value of assets at different voltages, considered alternatives, and recommended that the approach remain in place to functionalize primarily on the basis of voltage for the Proposed Rate Design.<sup>136</sup>

160 Functionalizing by voltage continues to be a reasonable proxy for identifying whether transmission assets serve a bulk or regional purpose because it considers the different roles performed by different types of assets in the system. Transmission at high voltages typically transports large amounts of energy over long distances across the bulk system, whereas lower voltage transmission tends to support specific locations or meet load at individual sites.<sup>137</sup>

<sup>134</sup> Appendix D - NERA Report, at PDF page 74, para 195. Exhibit 26911-X0154.01 – Addendum (Nov 17, 2021) Appendix D - NERA Expert Report (referred to as the NERA Addendum) at para. 288.

<sup>135</sup> Appendix D - NERA Report, at PDF page 78, para 217. Exhibit 26911-X0154.01 – NERA Addendum at para. 288.

<sup>136</sup> Appendix D - NERA Report, at PDF page 75, para 201-202.

<sup>137</sup> Appendix B Part 1 - P1 Report, at PDF page 878. Appendix D - NERA Report, at PDF page 77, para 214.

- 161 The AESO proposes to simplify the current functionalization methodology to one where a single functionalization value is relied upon for rates calculations over a period of time. This revised methodology will provide additional stability in the rate design, eliminate reliance on forecast data, and simplify the process of updating the functionalization. Under the simplified methodology, uncertainty involving functionalization for future years is removed because it will no longer rely on estimates for depreciation and future capital additions. Instead, a single year of data is used to functionalize bulk and regional costs and establish rates over a period of time. The data is then updated on a five-year basis using actual values at that point in time. Therefore, the AESO will not require depreciation data from TFOs or rely on forecasts of future asset costs and energization dates.
- 162 To complete the functionalization of transmission assets for this application, the AESO used TFOs' 2020 asset net book values and operating and maintenance costs, and the proportion of annual revenue requirement constituted by capital and non-capital costs. This data is used to calculate the functionalization of demand-driven costs under the Proposed Rate Design using a simplified methodology, as recommended by NERA and adopted by the AESO.<sup>138</sup> Firstly, the net book values of AltaLink Management Ltd. (AltaLink) and ATCO Electric Ltd. (ATCO) line and substation assets are functionalized primarily by voltage, with bulk assets being assets with voltage greater than or equal to 240kV, and regional assets being assets less than 240kV (but greater than 69Kv).<sup>139</sup> Second, the net book value of all TFO assets are summed to calculate the proportions of the total net book value of assets functionalized as bulk, regional and POD, which proportions are used as functionalization ratios for capital costs.<sup>140</sup> Following this step, operating and maintenance (O&M) costs for each TFO are functionalized into bulk, regional and POD pursuant to updated allocators.<sup>141</sup> Last, to calculate final capital and non-capital functionalization ratios, a weighted average approach is applied.<sup>142</sup>
- 163 For the purposes of providing information on the difference between the Current and Proposed Rate Designs, including estimated bill impacts (presented in section 3.8), the AESO has calculated the functionalization values for 2020, as follows:<sup>143</sup>

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<sup>138</sup> Exhibit 26911-X0154.04 - NERA Addendum, at para. 290.

<sup>139</sup> As ENMAX and EPCOR did not provide the AESO with asset-level breakdowns, ENMAX and EPCOR assets are omitted from step 1 under the simplified methodology. For further information, refer to Exhibit 26911-X0154.01 - NERA Addendum at paras. 290 – 298.

<sup>140</sup> Exhibit 26911-X0154.01 - NERA Addendum, at para. 300.

<sup>141</sup> Exhibit 26911-X0154.01 - NERA Addendum, at paras. 301-303.

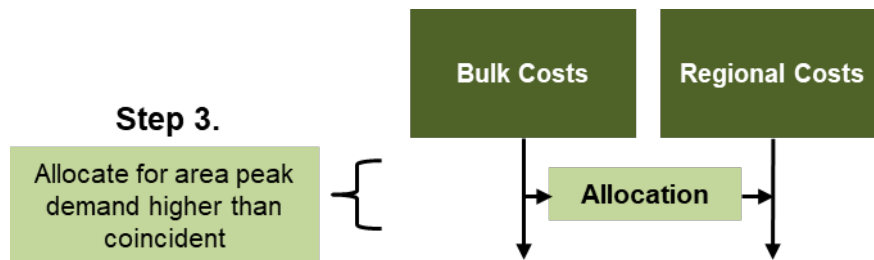
<sup>142</sup> Exhibit 26911-X0154.01 - NERA Addendum, at paras. 304-308.

<sup>143</sup> AESO 2018 ISO Tariff Application, Exhibit 22942-X0002.01, Table 4-1, PDF page 16.

Table 3-2: 2020 Functionalization values Updated Jan 2022 (%)

Function	Percent
Bulk	53.3%
Regional	25.3%
POD	21.4%

3.5.4 **Step 3: Allocate Bulk System, Demand-Driven Costs Between Coincident and Non-Coincident Demand Drivers**



164 The following pools of costs exist once costs have been classified and functionalized under the Proposed Rate Design: bulk system demand-driven costs, regional system demand-driven costs and costs relating to accommodating flows of in-merit energy. The Proposed Rate Design then allocates bulk system demand-driven costs between those associated with serving coincident system peak and non-coincident planning area peaks.<sup>144</sup>

165 The bulk system is used to transfer power across the province. To the extent that demand drives the need for bulk transmission, it is predominately driven by coincident peak demand.<sup>145</sup> In some planning areas peak demand occurs at times that are not system coincident peak; therefore, some bulk transmission is required to meet demand in these areas at times other than coincident peak. The Proposed Rate Design includes a methodology to allocate bulk system, demand-driven costs between those associated with meeting coincident peak demand and those associated with meeting non-coincident peak demand in an area.

<sup>144</sup> Appendix D - NERA Report, at PDF page 78, para 218.

<sup>145</sup> Appendix D - NERA Report, at PDF page 78, para 219.

166 To allocate bulk demand costs between these two categories, the same historical net metered load data is used, as follows:

- A = Maximum hourly metered MW of demand in planning area in reference year (MW);
- B = Maximum demand in each planning area during times of 12CP (MW);
- In planning areas where  $A > B$ , peak load in the planning area occurs during an hour outside of 12CP and incremental transmission is required in the planning area to meet non-coincident peak demand in the area.
- In planning areas where  $A = B$ , peak load in the planning area occurs during the 12CP hour and the planning area requires no additional transmission to meet non-coincident peak demand in the area.

167 Figure 3-8 below provides an example of this calculation to allocate bulk demand-driven costs:

*Figure 3-8: Illustration Recommended Method to Allocate Bulk System Demand-Driven Costs*<sup>146</sup>

**Example A: An area where no additional bulk transmission is required to meet non-coincident peak demand: Allocation of bulk system demand-driven costs to coincident peak demand.**

	Month of Reference Year	Area Load During Hours of System 12CP Conditions (MWh)
	January	90
	February	100
	March	90
	...	...
	December	85
A	Area Peak at Times of 12CP Conditions	100 MWh
B	Area Peak Consumption in All Hours of Ref. Year	100 MWh
C = B - A	Additional Transmission Required to Meet Non-Coincident Peak (MW)	0 MW

**Example B: An area where additional bulk transmission is required to meet non-coincident peak demand: Allocation of bulk system demand-driven costs to coincident peak and non-coincident peak demand.**

	Month of Reference Year	Area Load During Hours of System 12CP Conditions (MWh)
	January	40
	February	50
	March	60
	...	...
	December	55
A	Area Peak at Times of 12CP Conditions	60 MWh
B	Area Peak Consumption in All Hours of Ref. Year	70 MWh
C = B - A	Additional Transmission Required to Meet Non-Coincident Peak (MW)	10 MW

168 Once this calculation is done for all 42 planning areas, area peak load at any time of the year and area peak load at time of coincident peak are summed up, and the total load across all planning areas in 12CP conditions are calculated as a proportion of total peak load across all planning areas.<sup>147</sup> This ratio

<sup>146</sup> Appendix D - NERA Report, at PDF page 80, Figure 11.

<sup>147</sup> Appendix D - NERA Report, at PDF page 79, paras 223-224.

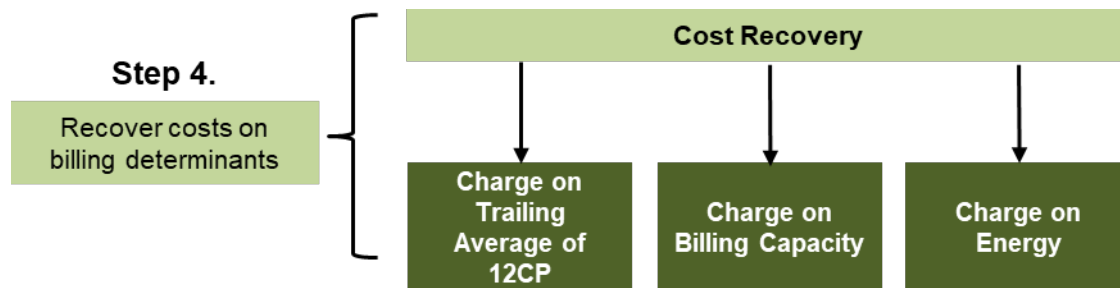
establishes the allocation of bulk-system demand-driven costs recovered from a charge levied on coincident peak demand, and is calculated as follows:<sup>148</sup>

$$\text{Allocation of Bulk Costs to Coincident Demand} = \frac{\text{Sum of Peak Load at Times of 12 CP Across Areas}}{\text{Sum of Non-Coincident Peak Load Across Areas}} \times 100\%$$

$$\text{Allocation of Bulk Costs to Non-Coincident Demand} = 100\% - \text{Allocation of Bulk Costs to Coincident Demand}$$

Using the 2019 reference year, 93% of all demand-driven bulk system costs are allocated to coincident peak related costs, and 7% are recovered from non-coincident peak demand .<sup>149</sup>

3.5.5 **Step 4: Recover Pool of Costs from Billing Determinants**



169 After costs are classified, functionalized, and bulk demand related costs are allocated, four pools of transmission costs need to be recovered from billing determinants under the tariff:

- Bulk system demand-driven costs associated with meeting coincident peak demand;
- Bulk system demand-driven costs associated with meeting non-coincident peak demand;
- Regional system demand-driven costs associated with meeting non-coincident peak demand; and
- Costs associated with accommodating flows of in-merit energy.<sup>150</sup>

**Bulk system costs associated with coincident peak demand charged to modified 12CP billing determinant**

170 Consistent with the methodology under the Current Rate Design, the Proposed Rate Design recovers bulk system demand-driven costs relating to meeting coincident peak through a 12CP billing determinant.

<sup>148</sup> Appendix D - NERA Report, at PDF page 81, para 225.

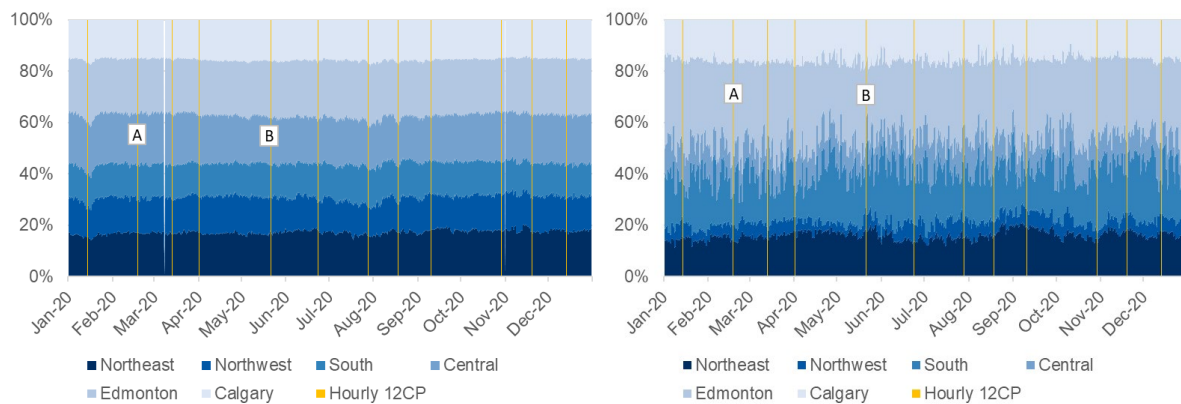
<sup>149</sup> Appendix D - NERA Report at PDF page 81, para 227.

<sup>150</sup> Appendix D - NERA Report, at PDF page 82, para 231.

However, the Proposed Rate Design modifies the 12CP billing determinant to improve the cost reflectiveness of the tariff.<sup>151</sup>

171 Metered load and generation data reveals systematic patterns of demand at times of coincident peak relative to in-merit energy. These include spring thaw conditions leading to higher hydropower output during the spring and early summer months, and different patterns of flows to meet coincident peak demand on the bulk system.<sup>152</sup> Figure 3-9 shows the proportional contribution of each region to each of load and generation in 2020.

Figure 3-9: Regional Proportions of Load (left) and Generation (right) in 2020<sup>153</sup>



Load	Northeast	Northwest	South	Central	Edmonton	Calgary
A - February	15.3%	10.5%	12.8%	18.7%	24.2%	18.5%
B - May	15.9%	9.8%	11.5%	18.2%	24.6%	20.0%
Generation						
A - February	13.3%	7.1%	9.6%	14.3%	38.2%	17.5%
B - May	14.9%	6.8%	24.6%	8.3%	29.3%	16.1%

Source: See Attachment 5H; NERA analysis of area-level load and generation data provided by the AESO.

<sup>151</sup> Appendix D - NERA Report, at PDF page 85, para 237.

<sup>152</sup> Appendix D - NERA Report, at PDF page 84, para 236.

<sup>153</sup> Appendix D - NERA Report, at PDF page 84.



172 The need for bulk transmission to meet coincident demand differs in each month across the year. Because of regional differences in patterns of in-merit generation across the year, a customers' contributions to coincident peak demand in each month of the year drives different requirements of the bulk transmission system. Therefore, a 12CP charge remains appropriate because it reflects how coincident demand in each month of the year drives different requirements on the bulk transmission system.<sup>154</sup>

173 However, the Proposed Rate Design introduces a five-year trailing average to the 12CP charge, the 5-Year Average 12CP Charge. This modification reflects that the AESO's planning process relies on forecasts developed using historical consumption data over a five-year period when assessing transmission system needs. Therefore, sustained consumption during hours of coincident peak over a five-year period are more likely to drive the need for transmission investment than consumption in a single month.<sup>155</sup> Phasing in the 5-Year Average 12CP Charge over a five-year period is further recommended to reduce any potential disruption from implementation of the Proposed Rate Design.<sup>156</sup> More details on the calculations are provided in section 7.1 of this application.

174 Finally, the AESO also proposes that the methodology for calculating the 12CP charge be amended from calculating coincident peak metered demand using a 15-minute interval to calculating this charge based on an hourly interval. As the AESO uses hourly forecast data in the transmission planning process<sup>157</sup> the use of an hourly CMD calculation is more reflective of cost causation than the current 12CP calculation under the Current Rate Design.

#### **Bulk and regional system costs associated with non-coincident demand charged to billing capacity**

175 In addition to the recovery of bulk system demand-driven costs from a 12CP charge, the Proposed Rate Design recovers regional demand-driven costs (and non-coincident demand related bulk costs) through the same billing capacity charge that the Current Rate Design uses.

176 Transmission needed to meet regional system demand corresponds to the total size of individual customer connections within localized areas, and therefore the driver of the related costs is non-coincident peak demand. Because transmission needed to meet regional system demand corresponds to the total size of individual customer connections within localized areas, a charge that varies based on a customer's contract capacity remains appropriate and cost reflective.<sup>158</sup>

177 The billing capacity charge is calculated consistent with the current practice as the highest of the following for a customer:

- The 15-minute metered demand in a settlement period;

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<sup>154</sup> Appendix D - NERA Report at PDF pages 84-85, para 237.

<sup>155</sup> Appendix D - NERA Report at PDF pages 85-86, para 241; Appendix K – AESO 2021 Long-term Outlook, PDF page 16.

<sup>156</sup> Appendix B Part 3- AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021) at slides 17 and 42.

<sup>157</sup> See s 3.2 of this application.

<sup>158</sup> Appendix D - NERA Report, at PDF pages 88-89, para 246 - 250.

- 90% of a customer’s highest metered demand in a 24 month period;<sup>159</sup> or
- 90% of a customer’s contract capacity (or 100% when DOS metered energy consumed during a settlement period).

**Costs associated with flows of in-merit energy charged to flat all hours energy charge**

178 The Proposed Rate Design retains a flat charge for energy consumed in each hour as in the Current Rate Design but uses it to recover the costs associated with accommodating the flow of in-merit energy.

179 NERA makes the following findings to support recovering these costs through a flat energy charge:

- Consumers should decide whether to draw energy from the transmission system based on the ‘all-in’ cost of buying energy from the wholesale market, including transmission infrastructure costs that facilitate the flow of in-merit energy. Otherwise, consumers would be making decisions based on price signals that do not reflect the full cost of supplying energy, including the cost of transmission.<sup>160</sup>
- Absent the ability to send locational price signals via transmission rates, the most cost-reflective way to recover transmission costs incurred to accommodate the flow of in-merit energy is through a flat charge on energy consumption in all hours.<sup>161</sup>

**3.5.6 Overall Outcome of Proposed Rate Design**

180 For comparison purposes, the cost allocation percentages under the Current Rate Design and the Proposed Rate Design are summarized below in Table 3-3, using 2019 classification values and the updated functionalization values described in section 3.5.3 (and provided in more detail in the rate calculations at Appendix D Attachment 3A of this application). The estimated impact on transmission bills caused by differences between the Current and Proposed Rate Designs is discussed in section 3.8 of this application.

Table 3-3: Summary of proposed allocations to billing determinants under Current and Proposed Rate Design

<b>Billing Determinant</b>	<b>Current Rate Design (%)</b>	<b>Proposed Rate Design (\$)</b>
12-CP*	49.8%	29.4%
Billing Capacity	22.7%	17.3%

<sup>159</sup> Excludes months where facility commissioning occurs.

<sup>160</sup> Appendix D - NERA Report, at PDF page 90, para 253-254.

<sup>161</sup> Appendix D - NERA Report, at PDF page 90, para 254.

Energy	6.1%	31.9%
POD	21.4%	21.4%

\*Proposed Rate Design 12-CP charge is charged on a five-year trailing average (as described in section 7.1)

### 3.6 Rate Design Alternatives

181 The AESO and NERA were unconstrained in their consideration of alternative tariff design methodologies, including alternatives within each step of the Proposed Rate Design, subject to designing a tariff that aligned with the current regulatory framework and B&R Objectives.<sup>162</sup>

182 As one of the two conceptual tariff design concepts,<sup>163</sup> a marginal rate design was considered and evaluated as a comprehensive design alternative. Other alternatives considered related to variations within an embedded rate design methodology. The AESO's and NERA's consideration of a marginal rate design will be explained first.

#### 3.6.1 Consideration of Marginal Rate Design

183 The AESO assessed a marginal rate design in response to stakeholder tariff design proposals.<sup>164</sup> The AESO also asked NERA to evaluate the potential use of a marginal rate design.

184 A marginal rate design typically encompasses two components: a marginal cost component reflecting the estimated incremental cost to serve an incremental change in demand, and a residual component that recovers the revenue requirement remaining after subtracting revenue collected under the marginal rate. The residual component is often necessary as the marginal component rarely generates enough revenue to recover the entire revenue requirement.

185 The main advantage of this methodology is the ability to send efficient price signals that reflect the incremental transmission cost that accommodate an incremental change in demand.<sup>165</sup> This price signal can be efficient as it allows consumers to make decisions to use the transmission system based on the forward looking marginal cost of using energy from the transmission system in comparison to the cost of alternatives. To achieve optimal efficiencies under this design, the marginal price signal should be sent

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<sup>162</sup> Appendix D - NERA Report, Attachment 1A.

<sup>163</sup> Appendix D - NERA Report, at PDF page 47, para 105.

<sup>164</sup> Appendix B Part 2 - Both Suncor Energy Inc (Suncor) and the Consumers' Coalition of Alberta (CCA) presented marginal based tariff design proposals at Stakeholder Session 3. CCA's proposal involved a marginal cost rate charged through a monthly un-ratcheted non-coincident peak charge, and residual costs collected through a ratcheted non-coincident peak charge (see: AESO Bulk and Regional Tariff Design Session 3 (November 5, 2020), CCA Proposal). Suncor's proposal involved marginal bulk and regional rates as well as fixed per customer charges (see: AESO Bulk and Regional Tariff Design Session 3 (November 5, 2020), Suncor Proposal).

<sup>165</sup> Appendix D - NERA Report, at PDF page 47, para 107.

through an ‘avoidable’ charge, or a charge that varies with consumption.<sup>166</sup> Correspondingly, residual costs should be recovered in a manner that avoids distorting the efficient consumption decisions (such as through an unavoidable charge).<sup>167</sup>

186 However, the distinction between ‘avoidable’ and ‘unavoidable’ costs can be tenuous in respect of the transmission system. As an interconnected system of loads and generators, it is not always reasonable to assume that changes in consumer demand have the same marginal impact on future transmission costs as might be the case in a distribution system.<sup>168</sup> This is because new demand connections located proximate to available or new generation may avoid transmission investment (meaning the marginal cost of this incremental demand would be negative). In contrast, demand connections in locations where demand is already high relative to nearby generation may increase transmission costs (meaning the marginal cost would be positive).<sup>169</sup>

187 The NERA Report concludes that an efficient marginal cost component of any transmission tariff design in Alberta would need to vary based on location because consumption in different locations of the transmission system would result in different transmission investment needs across the system.<sup>170</sup>

188 However, to achieve these efficiencies through a locational marginal charge, this methodology would run afoul of the postage stamp rule, codified in section 30(3)(a) of the *EUA*, which prohibits transmission tariff rates from differing based on the location of load on the transmission system. The inability to account for the varying marginal cost component of a tariff (the most useful part of a marginal rate design) led the AESO to conclude that this methodology was ill suited for the Alberta context.

189 The AESO rejected a marginal cost approach principally based on the legislative prohibition against locational pricing, and further because of the challenge in recovering an expected large residual cost component, relative to an expected small marginal cost component.<sup>171</sup>

190 NERA considered mechanisms to recover the residual costs, including: Ramsey pricing, levies on ‘non-avoidable’ billing determinants, and proportional tariff mark-ups, as summarized below:

- Ramsey pricing: Residual costs are recovered from consumers based on differences in elasticity of demand (for example, higher charges levied on customers with low price elasticity, and lower charges levied on customers with high price elasticity). However, predicting price elasticity for

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<sup>166</sup> Appendix D - NERA Report, at PDF page 47, para 107.

<sup>167</sup> Appendix D - NERA Report, at PDF page 49, para 112.

<sup>168</sup> Appendix D - NERA Report, at PDF page 50, para 117.

<sup>169</sup> Appendix D - NERA Report, at PDF page 50, para 117.

<sup>170</sup> Appendix D - NERA Report, at PDF pages 51-52, paras 118 – 119. See also Appendix B Part 1 - P1 Report at PDF page 875.

<sup>171</sup> Appendix B Part 3- AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021), at slides 30 and 31.

different customer groups is fraught with difficulty and levying charges based on customers' ability to respond introduces issues of inequality.<sup>172</sup>

- Recovery from 'non-avoidable' billing determinant (such as a fixed customer charge): Distribution system costs recovered through non-avoidable charges can satisfy the principle of cost causation because the large number of distribution customers receive a similar service and the cost to provide that service does not vary materially by customer.<sup>173</sup> In contrast, the number of customers connected to the transmission system is far fewer, they tend to use the system in different ways, and vary substantially in size. Therefore, it would be difficult to design a fixed charge (to recover a residual amount or otherwise) for the transmission system that applies to all customers that is also equitable.<sup>174</sup>
- Proportional mark-up: In the Alberta context, proportional per customer mark-ups would be substantial because the required residual cost component would be much larger than the marginal cost component. The large proportional mark-up would obscure any price signal sent by the marginal component, undermining the potential efficiency gains from the marginal price signal.<sup>175</sup>

191 For these reasons the AESO found the marginal cost approach and stakeholder proposals based on marginal cost approaches were incompatible with the existing legislative framework and the B&R Objectives.

### 3.6.2 *Embedded Rate Design Alternatives*

192 In addition to the consideration of a marginal rate design, the AESO considered embedded rate design methodologies presented by stakeholders, and requested NERA evaluate variations within an embedded rate design. Having considered these alternatives, the AESO concluded that the Proposed Rate Design was the best design for the Alberta context.

193 The AESO has considered and agrees with NERA's conclusions about the relative viability of various alternatives within the Proposed Rate Design as set out in section 6 of the NERA Report. These alternatives (and corresponding stakeholder proposals, where applicable) are summarized in the tables below relative to each corresponding step of the Proposed Rate Design, including the rationale behind each alternative and the reasons why they were rejected by NERA and the AESO.

#### *I. Alternatives to Step 1: Classify Costs between Demand and Accommodating the Flow of In-Merit Energy Costs Prior to Functionalization*

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<sup>172</sup> Appendix D - NERA Report, at PDF page 53, para 125.

<sup>173</sup> Appendix D - NERA Report, at PDF page 53, para 126.

<sup>174</sup> Appendix D - NERA Report, at PDF pages 53-54, paras 126 – 128.

<sup>175</sup> Appendix D - NERA Report, at PDF page 54, para 129.

194 NERA considered the following alternative minimum system approaches to delineate between demand costs and costs associated with the flow of in-merit energy as the first step in the Proposed Rate Design:

Alternative	Reasons Supporting Alternative	Reasons Alternative Rejected
Functionalize costs into bulk and regional prior to classifying costs between demand and energy	Aligns with status quo	Would be less cost reflective because it would not be consistent with AESO planning process where alternatives that can meet needs of accommodating flow of in-merit energy and/or demand are considered independent of voltage (as further described in section 3.2)
Minimum System based on historical reason investment made	Purpose of investment from needs identification document applications could be used to classify transmission costs incurred for the purposes of serving demand or facilitating in-merit energy as an alternative minimum system approach	Less precise indicator, given that transmission investments may evolve beyond original contemplation by AESO planners or may serve dual purposes
Minimum system based on comparison of peak net generation and peak load in planning area	Peak net generation in a planning area may more accurately reflect the flows of energy between areas that are not used to serve load (and implicitly are used to facilitate the flow of in-merit energy)	Less precise indicator as it would understate the classification of costs associated with facilitating the flow of in-merit energy as it fails to appropriately account for transmission needed to accommodate the flow of in-merit energy <i>within</i> a planning area
Minimum system based on comparison of generation capacity to contractual demand in planning area	Transmission might be needed to the maximum potential capability of all demand and generation in an area	Not supported by AESO's planning process, which accounts for diversification of load and generation. For example, forecasted load takes into account coincident load in study areas as well as individual customer load. Further, planning process takes into account simulated or forecasted output of generation, not maximum capability

II. *Alternatives to Step 2 Functionalize Demand-Driven Costs*

195 NERA considered the following alternatives to functionalize demand-driven costs:

<b>Alternative</b>	<b>Reasons Supporting Alternative</b>	<b>Reason Alternative Rejected</b>
Functionalize demand related costs based on transmission line capacity	Higher capacity transmission lines are more likely to serve the bulk system	Delineation by capacity less accurate than delineating by voltage, as the capacity of transmission lines does not dictate whether they serve a bulk or regional purpose. Further, the capacity of transmission lines can be changed over time <sup>176</sup> , which supports the finding that the capacity of a transmission line is not consistently associated with its function
Functionalize demand related costs based on transmission line length	Longer transmission lines are more likely to serve the bulk system	Delineation by line length less accurate than delineating by voltage as shorter lines exist that serve bulk system and longer lines exist that serve regional system

III. *Alternatives to Step 3 recovery of coincident peak demand related bulk system costs from modified 12CP billing determinant and flat all-hours energy charge:*

196 NERA considered the following alternatives to its recommended recovery of energy costs and bulk system costs relating to coincident peak demand:

<b>Alternative</b>	<b>Reasons Supporting Alternative</b>	<b>Reason Alternative Rejected</b>
Recovering bulk system demand related costs associated with serving coincident peak demand from 1-CP or 4 – CP billing determinants	Reflecting different seasonality patterns of transmission use	Use of 1CP or 4CP would not capture the full seasonality of demand and supply conditions in Alberta as it would only capture 1 or 4 hours per year and one or two seasons, and would therefore be less cost reflective than the use of the 12CP
Recovering costs relating to accommodating flow of in-	May be cost reflective if transmission costs associated with accommodating the flow of in-merit energy were	As these costs may be attributable to relieving expected congestion, which can occur at any time of the day (by example, relief of expected congestion

<sup>176</sup> For example, some transmission system projects involve modifications to the existing system that change the capacity of lines currently in use, without affecting their voltage or function. Such modifications can include, for example, rebuilding transmission lines, or removing other equipment underneath lines that change the capacity of existing lines. See Decision 2012-098, PDF page 7, at para 12.

merit energy from a time of use (TOU) charge <sup>177</sup>	consistently more likely to occur at certain time periods	from windy conditions), a TOU energy charge would not be cost reflective or reasonable. Also, the Proposed Rate Design more appropriately incorporates a time varying charge by way of 12CP to charge for consumption during high demand periods
Recovering costs relating to accommodating flow of in-merit energy from a declining block charge or charge that varies with load factor <sup>178</sup>	May be cost reflective where costs vary by customer based on load factor	Transmission costs incurred to accommodate the flow of in-merit energy are unrelated to a customer's load factor or total demand. Rather, these types of costs are related to relieving congestion, to ensure the reliable operation of the transmission system as a whole and for customers to access the wholesale market. Accordingly, these costs are more appropriately recovered through a flat charge, without reference to customer load factor or total use

### 3.7 The Proposed Rate Design Meets Objectives

197 As set out in sections 2 and 3 of the application, the AESO's B&R Objectives were to develop a tariff design to meet the following primary objectives: reflect cost responsibility and send efficient price signals.

198 Consistent with the Commission's direction and adoption of the rate design principles outlined in section 3.3, once these primary objectives were satisfied, the AESO then assessed the Proposed Rate Design pursuant to the following secondary objectives: minimal disruption, simplicity and innovation and flexibility. The Proposed Rate Design meets all the B&R Objectives, as further detailed below.

#### 3.7.1 Reflect Cost Responsibility

199 The Proposed Rate Design reflects the dual purposes of the Alberta transmission system: serving peak demand and accommodating the flow of in-merit energy. Classifying costs between these distinct drivers leads to a rate design that better reflects the drivers of transmission costs and signals those costs to customers through charges.

<sup>177</sup> The TOU charge considered by NERA involved higher rates being charged during periods of higher demand, such as through the use of an on-peak/off-peak energy charge. See Appendix D - NERA Report, PDF pages 91-92, section 6.4.3.1.1. The AESO received feedback from a number of stakeholders throughout the B&R Consultation regarding the consideration of TOU. The AESO considered comments and proposals from stakeholders, and TOU charges were not pursued for the reasons set out in the above table.

<sup>178</sup> The declining block charge considered by NERA involved charging customers who use less energy higher per-unit rates. See Appendix D - NERA Report, PDF page 92, section 6.4.3.1.2.



200 Having classified and functionalized costs to the different drivers of costs, the Proposed Rate Design allocates those costs to appropriate billing determinants to better reflect how the use of the transmission system tends to drive transmission costs over the long-run. Modifications to how costs are recovered under the Current Rate Design have been made to further cost causation. By incorporating the 5-Year Average 12CP Charge the Proposed Rate Design is more cost reflective than the Current Rate Design, as it better reflects how sustained consumption at times of coincident peak is more likely to impact the AESO's planning decisions, relative to consumption in a single month.<sup>179</sup> Recovering costs associated with the flow of in-merit energy from an energy charge also better aligns with principles of cost causation, recognizing that the use of energy in all hours contributes to the need for transmission to accommodate the flow of in-merit energy.

201 The outcome of these design elements is a tariff that is significantly more cost reflective than the Current Rate Design, as the Proposed Rate Design better aligns recovery of transmission costs with the drivers of those costs over the long-run. Accordingly, the AESO submits that the Proposed Rate Design meets the objective of cost responsibility.

### 3.7.2 *Efficient Price Signals*

202 More efficient price signals will be sent under the Proposed Rate Design relative to the Current Rate Design because the charges under the Proposed Rate Design better reflect how the use of the transmission system drives costs over the long term. In turn, all consumers who face more efficient price signals can make consumption decisions based on information that is better aligned with the long term costs associated with their use of the transmission system, increasing efficiency.<sup>180</sup>

203 In the Alberta regulatory context, a cost reflective tariff supports efficient price signals for the consumption and supply of power through the competitive energy only market.<sup>181</sup> The AESO's assessment of the effect of the Proposed Rate Design on energy market outcomes found that the Proposed Rate Design is likely to have a small impact and is unlikely to reduce overall efficiency in the wholesale market relative to the Current Rate Design.<sup>182</sup>

204 NERA estimated the likely customer response (which included potential customer self-supply) from the introduction of the Proposed Rate Design relative to the Current Rate Design. This analysis conservatively estimates a minimal increase in self-supply under the Proposed Rate Design, including any anticipated dynamic response from the introduction of the Proposed Rate Design (as explained in section 7.2 of the NERA Report).<sup>183</sup> However, any incremental self-supply that occurs in response to the more cost reflective Proposed Rate Design is anticipated to promote overall efficiency by reducing transmission costs over the long term.<sup>184</sup>

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<sup>179</sup> Appendix K – AESO 2021 Long-term Outlook, at PDF page 16.

<sup>180</sup> Appendix D - NERA Report, Attachment 4A, PDF pages 4 & 31, at paras 2 and 85.

<sup>181</sup> *TReg*, ss. 15 & 47.

<sup>182</sup> Appendix B Part 3- AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021), at slide 54.

<sup>183</sup> Appendix D - NERA Report, at PDF pages 95-96, para 274.

<sup>184</sup> Appendix D - NERA Report, at PDF pages 97-98, para 274.

205 Response to a more cost reflective 12CP price signal should also reduce the inefficient cost shifting which occurs under the Current Rate Design, which overstates the transmission costs associated with using the transmission system during times of coincident peak.<sup>185</sup> Further, the Proposed Rate Design likely resolves the inefficient feedback loop created under the Current Rate Design.<sup>186</sup>

206 Based on the foregoing, the AESO submits that the Proposed Rate Design meets the objective of efficient price signals.

### 3.7.3 *Minimal Disruption*

207 The AESO submits that the Proposed Rate Design, independent of any considerations of mitigation, would result in minimal disruption. As further detailed in section 3.8, the vast majority of ratepayers would experience lower bills under the design, and very few ratepayers would be heavily impacted.

208 However, the AESO has put forward a mitigation proposal as part of this application that would further the objective of minimal disruption by allowing the small number of heavily impacted parties to gradually transition to the Proposed Design. The AESO has identified approximately 12 PODs that will experience a more than 10% increase in their transmission costs as a result of the Proposed Rate Design. The details of the AESO's mitigation proposal are set out in section 3.9 of this application.

209 The AESO submits that the Proposed Rate Design meets the objective of minimal disruption independently, and further through the adoption of the AESO's mitigation proposal.

### 3.7.4 *Simplicity*

210 The Proposed Rate Design meets the simplicity objective by maintaining similar billing determinants to the Current Rate Design (though where appropriate, modifying them to better reflect cost causation). These concepts are familiar to stakeholders and are no more complex than the methodology under the Current Rate Design.

211 The steps to implement the Proposed Rate Design are clear and easily updateable with new data. The design relies on metered data to classify and allocate costs based on the actual use of the system, rather than on assumptions about representative asset costs.

212 The AESO further proposes to update the classification and allocation of costs under the Proposed Rate Design on a five-year basis. This timeframe is appropriate as it is unlikely that the classification of costs between demand and accommodating the flow of in-merit energy will experience material change over this time period (barring unusual circumstances).<sup>187</sup>

213 The AESO also proposes to update the functionalization values using TFO data every five years to provide more stability and certainty for ratepayers than is currently the case under the Current Rate Design.

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<sup>185</sup> Appendix D - NERA Report, at PDF pages 100-101, para 280.

<sup>186</sup> Appendix D - NERA Report, at PDF pages 100-101, para 280.

<sup>187</sup> See section 7.1 of the application.

214 The AESO's proposal to calculate the 12CP charge at an hourly interval, rather than a 15-minute interval, also furthers the objective of simplicity. As the AESO publishes actual demand data on an hourly basis ratepayers would be able to verify their monthly 12CP charge independently, thereby reducing the AESO's administration of ratepayer queries relating to this calculation.<sup>188</sup>

215 For these reasons, the AESO submits that the Proposed Rate Design meets the simplicity objective.

### 3.7.5 Innovation and Flexibility

216 The objective of innovation and flexibility centered on designing a tariff that would provide optionality and flexibility to transmission customers in their use of the transmission system while not shifting transmission costs onto other customers.<sup>189</sup>

217 The Proposed Rate Design continues to allow customers to respond in different ways to suit their preferred use of energy, including flexible uses such as back up service, shifting consumption to times with lower energy costs, or reducing overall consumption such as through energy efficiency measures.<sup>190</sup> The Proposed Rate Design better signals to customers the long-run transmission costs associated with their varied and flexible use of the system.<sup>191</sup>

218 For these reasons, the AESO submits that the Proposed Rate Design meets the objective of innovation and flexibility.

## 3.8 DTS Bill Impacts

219 This section describes how the Proposed Rate Design is anticipated to impact market participants' bills. Past Commission decisions place importance on understanding the rate impacts associated with the proposed ISO tariff design, while recognizing that the primary consideration in rate design is cost causation.<sup>192</sup>

220 The AESO provides the below analysis of the impacts of the Rate DTS changes under the Proposed Rate Design on market participants' bills, and as further set out in Appendix E. As set out in section 2.2.1, market participants were provided with a number of bill impact tools in Stakeholder Session 5, Technical Session II and through written consultation following the B&R Consultation to allow them to estimate changes to their bills under the Proposed Rate Design as compared to their bills under the Current Rate Design for Rate DTS.

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<sup>188</sup> *Ibid.*

<sup>189</sup> Appendix B Part 3- AESO, Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021), at slide 17.

<sup>190</sup> Appendix D - NERA Report, at PDF pages 99-100, para 274.

<sup>191</sup> Appendix D - NERA Report, at PDF pages 16-17, para 27.

<sup>192</sup> Decision 2005-096, PDF page 23, Decision 2014-242, s 5.7.

- 221 The AESO has calculated bill impacts by applying both the Current and Proposed Rate Designs to the actual billing determinants and revenue requirements for 2019 to compare transmission bills under the Current and Proposed Rate Designs.
- 222 The AESO has used 2019 as a basis for comparison in light of the 2020 COVID-19 pandemic and associated contraction in global energy demand and oil prices. Many electricity customers in Alberta experienced lockdown measures in response to COVID-19 resulting in unanticipated changes in industrial output and commercial activity.<sup>193</sup> For this reason, a comparison of customer bills based on behaviour in 2020 may not be representative of some customers' typical behaviour. The effect of the Proposed Rate Design on market participants is therefore best understood using 2019 billing determinants due to the significant and abnormal variances in load throughout 2020.
- 223 In its recent ISO tariff applications, the AESO has provided similar bill impact analyses to assist the Commission in assessing the impacts of proposed changes to the ISO tariff on market participants. In the AESO's 2007 ISO tariff application, the EUB determined that the proposed tariff rates should be compared to the then currently approved rates in the preceding year, inclusive of all components of a participants' bill, including commodity costs.<sup>194</sup>
- 224 In prior applications, the AESO has presented rate impacts based on a methodology that compared any proposed rate with rates in effect at the beginning of the year the application was filed,<sup>195</sup> which would include a forecast for the revenue requirement and billing determinants for the remainder of the year, to be subsequently updated through the AESO's Rider C and DAR application. The effective rates, as well as any proposed rates, were then applied to the most recently available actual billing determinants to calculate bill impacts by POD. If rates in effect at the beginning of 2019 were used to compare estimated rates under the Proposed Rate Design, this methodology would include discrepancies between forecasted revenue requirements and billing determinants and actual rates as trued up through Rider C and DAR.
- 225 In this application, the AESO is instead using a test year approach to portray the impact on customer bills that is only due to the changes to the rate design. The AESO's 2019 test year method calculates bill impacts using the actual 2019 revenue requirement and billing determinants (the 2019 Test Year). The rates calculated for the 2019 Test Year allow for a comparison between the Current and Proposed Rate Design on a total bill and transmission cost basis. This comparison isolates the changes solely attributable to the change in rate design because the 2019 Test Year method assumes no changes in consumption patterns.
- 226 The first step in the 2019 Test Year method is to calculate the 2019 Test Year rates under the Current and Proposed Rate Designs by applying the current and proposed allocations (as described in section 3.5.7) to the actual billing determinants and revenue requirement for 2019. The resulting rates reflect a "test year" because they do not represent the rates that were in effect in 2019 (due to the differences between actual and forecast values). Table 3-4 below provides calculations for the 2019 Test Year Rates under the Current and Proposed Rate Design that result from the changes in the allocation of transmission costs to billing determinants. Under the Proposed Rate Design, the 12CP and billing capacity charges will be lower and

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<sup>193</sup> Appendix M - AESO, Impact of the COVID-19 pandemic and low oil prices on Alberta load, December 2020 Update, slides 4-8.

<sup>194</sup> Decision 2007-106 at PDF page 69.

<sup>195</sup> AESO 2018 ISO Tariff Application, Exhibit 22942-X0002.01 at PDF page 30, para 124.

the energy charge will be higher, relative to the Current Rate Design. Further information is provided in Appendices F and G.

Table 3-4: Summary of 2019 Test Year Rates under Current and Proposed Rate Design<sup>196</sup>

Billing Determinant	Current Rate Design	Proposed Rate Design
12-CP* (\$/MW-Month)	\$10,593	\$6,257
Billing Capacity (\$/MW-Month)	\$2,993	\$2,324
Energy** (\$/MWh)	\$2.05	\$10.62
POD	No Change	

\*Proposed Rate Design 12-CP charge is charged on a five-year trailing average (as described in section 7.1)

\*\*Energy charge in Current Rate Design is displayed as the sum of Bulk Energy Charge and Regional Energy Charge

227 The test year approach is used to calculate POD level bill impacts by applying the 2019 Test Year rates to the following data:

- A. Transmission system charges under each rate design are calculated using actual energy consumption, actual billing capacity, actual coincident metered demand and the applicable cost allocation percentages under each rate design.
- B. The transmission bill under each rate design is calculated using the charges calculated in A plus the following actual POD level data: Operating Reserve charge, POD charges (or rate Primary Service Credit, if applicable), Transmission constraint rebalancing charge, Voltage control charge, other system support services charge.
- C. The *transmission bill impact* is calculated as the difference between the transmission bills calculated in B under the Current and Proposed Rate Designs.
- D. The total bill is calculated using the transmission bill calculated in B with the addition of the actual energy commodity charge.
- E. The *total bill impact* is calculated as the difference between the total bills calculated in D under the Current and Proposed Rate Design.

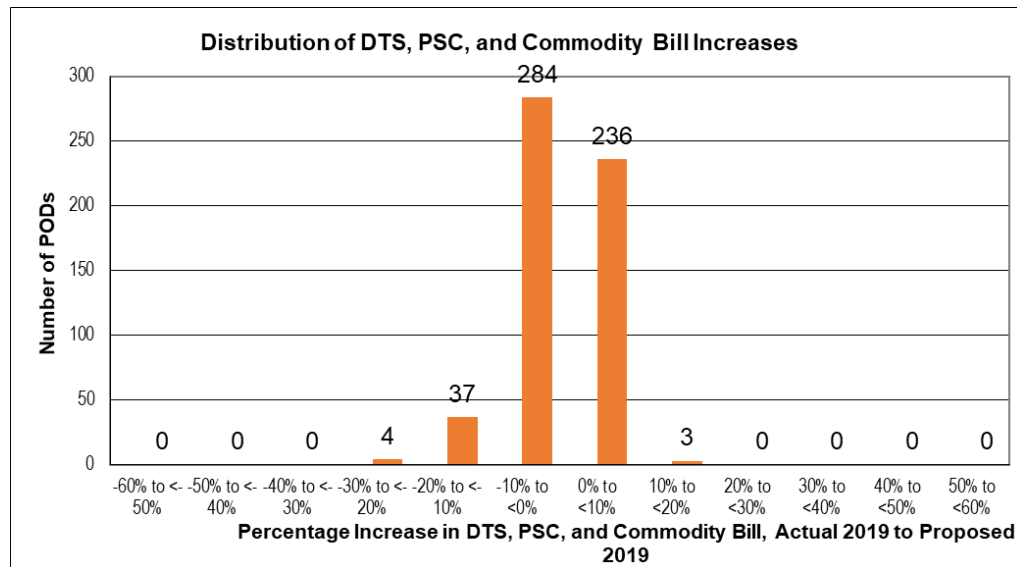
228 Importantly, the AESO's bill impact analysis only estimates the impact of the Proposed Rate Design using 2019 data. Prospective bills for an individual Rate DTS POD will vary from the AESO's estimates due to

<sup>196</sup> Differences between the rates calculated in this table, and the rates presented in Appendix D - NERA Report, Table 7 are a result of differences between the actual and forecast values used in calculating the rates for 2019.

differences in actual rates, demand and usage at the POD, including variations in hourly pool price and the hourly allocation of operating reserve costs.

229 Figure 3-10 shows *total bill impacts* on all 564 PODs. Approximately 58% of PODs would see lower bills under the Proposed Rate Design, with a maximum reduction of 20%-30%. Only three PODs would see an increase that exceeds 10% on their total bill, with a maximum increase of 12%. Further information is provided in 2019 billing comparison E-1 summary tab.

Figure 3-10 - 2019 Test Year on Total Bill Basis: count of PODs in each impact category



230 Table 3-5 provides average *total bill impacts* by contract capacity and load factor for the 2019 Test Year. The bill impacts are consistent across different sizes of customers. The majority of customers with load factors below 60% would have lower total bills under the Proposed Rate Design. Customers with load factors above 60% would be more likely to have a higher total bill under the Proposed Rate Design.

Table 3-5- 2019 Test Year on Total Bill Basis: summary of total bill impacts by contract capacity and load factor

Load Factor (energy use / capacity)	Billing Capacity (MW)			
	0-<7.5	7.5-<17	17-<40	>40
0-<10%	(8.4%)	(7.7%)	(12.7%)	(12.6%)
10%-<25%	(2.8%)	(1.9%)	(1.9%)	(2.5%)
25%-<40%	(0.9%)	(1.4%)	(1.4%)	(0.3%)

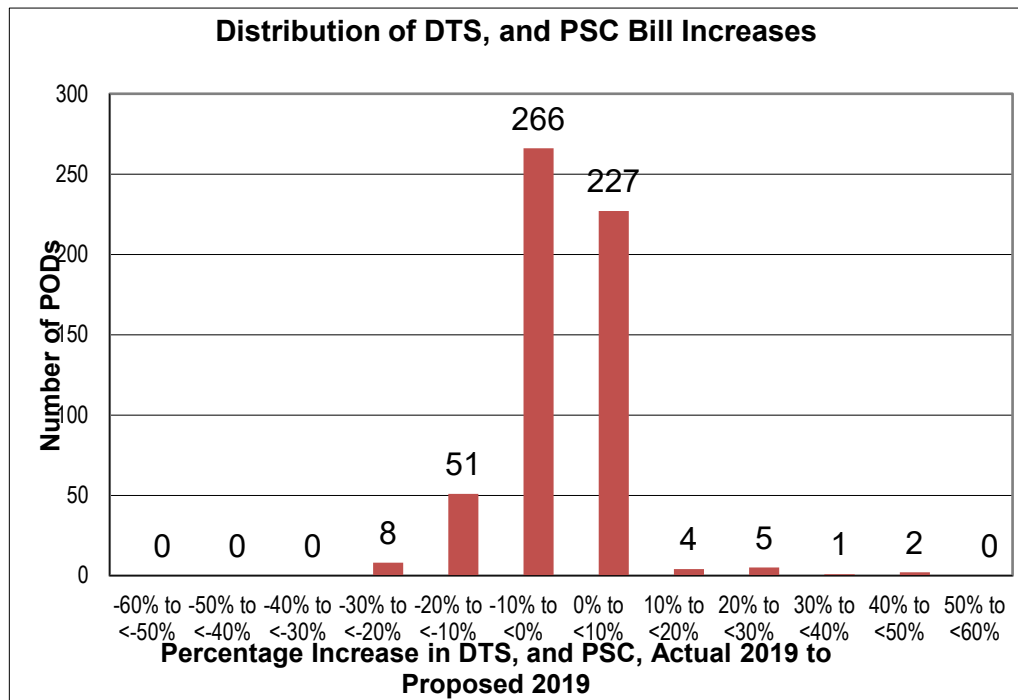
40%-<50%	(0.4%)	0.3%	(0.1%)	1.9%
50%-<60%	(0.0%)	0.0%	(0.6%)	(0.7%)
60%-<70%	0.3%	0.4%	0.0%	(0.1%)
70%-<80%	1.0%	1.1%	1.6%	1.6%
80%-100%	1.6%	1.8%	1.7%	2.8%

231 The AESO has also calculated the impact of the Proposed Rate Design on the *transmission costs* component of customers' bills only.

232 Figure 3-11 shows *transmission bill impacts* on all 564 PODs. Approximately 58% of PODs would see lower bills under the Proposed Rate Design, with a maximum reduction of 20%-30%. Twelve PODs would see an increase that exceeds 10% as follows:

- 4 points of delivery would receive an increase of 10-<20%;
- 5 points of delivery would receive an increase of 20-<30%;
- 1 point of delivery would receive an increase of 30-<40%;
- 2 points of delivery would receive an increase of 40-<50%;

Figure 3-11: 2019 Test Year on transmission cost basis: count of PODs in each impact category



233 Table 3-6 provides average *transmission* bill impacts by contract capacity and load factor for the 2019 Test Year. On average most customers with load factors below 60% would have transmission bills under the Proposed Rate Design that are either the same or slightly lower than under the Current Rate Design. On average customers with load factors above 60% would be more likely to have a higher transmission bill under the Proposed Rate Design.

*Table 3-6 - 2019 Test Year on transmission Bill Basis: summary of total bill impacts by contract capacity and load factor*

Load Factor (energy use / capacity)	Billing Capacity (MW)			
	0-<7.5	7.5-<17	17-<40	>40
0-<10%	(10.4%)	(10.1%)	(15.1%)	(17.1%)
10%-<25%	(4.4%)	(3.6%)	(3.5%)	(5.4%)
25%-<40%	(1.7%)	(3.0%)	(3.1%)	(0.8%)
40%-<50%	(0.7%)	0.7%	(0.1%)	5.1%
50%-<60%	(0.0%)	0.1%	(1.4%)	(1.8%)
60%-<70%	0.7%	1.0%	0.1%	(0.2%)
70%-<80%	2.4%	2.7%	4.4%	4.7%
80%-100%	4.6%	5.1%	4.6%	8.4%

234 Table 3-7 provides a summary of *transmission* bill impacts by PODs with different load factor and different use at times of coincident peak. One minus the ratio of coincident metered demand to highest metered demand represents a POD's CP Response, representing a POD's use of energy at times of 12CP relative to the POD's highest use of energy. High CP Response means that a POD makes little use of energy at times of 12CP, relative to its highest use of energy; low CP Response means that a POD uses a similar amount of energy at times of 12CP (relative to its highest use of energy). It is important to consider CP Response relative to (average or annual) load factor of a POD because:

- In general, customers with low load factors are on average less likely to be consuming during coincident peaks, and hence are more likely to have a high CP Response (on average)
- In general, customers with higher load factors would be more likely to consume during coincident peaks, and hence are expected to have a low CP Response (on average)



*Table 3-7- 2019 Test Year on transmission bill basis: summary of transmission bill impacts by load factor and CP Response*

Load Factor (energy use / capacity)	CP Response (%)			
	0%-<25%	25%-<50%	50%-<75%	75%-100%
0-<10%	(18.5%)	(7.3%)	(17.1%)	(15.0%)
10%-<25%	NA	(5.9%)	(4.3%)	(3.1%)
25%-<40%	(3.5%)	(4.2%)	(1.8%)	20.1%
40%-<50%	(2.3%)	(0.2%)	5.0%	40.2%
50%-<60%	(1.8%)	2.3%	6.2%	NA
60%-<70%	(0.4%)	1.7%	11.4%	42.4%
70%-<80%	2.7%	7.9%	22.3%	36.1%
80%-100%	5.5%	NA	20.7%	NA

235 Table 3-7 shows that customers with higher load factors and relatively high CP Response will tend to experience a larger rate impact under the AESO's Proposed Rate Design before mitigation, relative to other customers with similar load factors. For example, PODs with a CP Response between 75%-100% and load factors from 40%-70% will see an increase in transmission costs of approximately 40% before mitigation; while other PODs in the same load factor categories but with the lowest CP Response are expected to see a reduction in transmission costs. Further information is provided in Appendix E, E2-summary.

236 As set out in Appendix E, E-7a summary, there are 12 PODs that would experience the greatest rate increase under the Proposed Rate Design. These PODs generally have a high CP Response compared to other loads with similar load factor. As a result, these PODs would be the most highly impacted under the Proposed Rate Design, given that PODs with high load factors would face a higher energy charge, and the costs that can be reduced by managing consumption during 12CP times would be lower under the Proposed Rate Design relative to the Current Rate Design.

237 Figure 3-10 shows that the majority of PODs will receive a reduction in transmission costs under the Proposed Rate Design. This is attributable to the shift in the allocation of costs away from the 12CP charge and towards the energy charge.

238 Appendix E provides additional information on the bill impacts, including for the 12 PODs that would have experienced a 10-50% transmission cost increase resulting from the Proposed Rate Design under the 2019 Test Year.

## 3.9 Mitigation

### 3.9.1 Overview of the AESO's Mitigation Approach

- 239 The AESO proposes to mitigate transmission bill impacts above 10% for individual load customers taking Rate DTS - and only those customers - by phasing in the impact of the Proposed Rate Design over a five-year period ending in 2029, using one of the three mechanisms detailed below.
- 240 The Commission's predecessor previously found that, on balance, if rates reflect cost causation, barring unusual regulatory events such as regulatory lag or a dramatic change in the cost structure, there would be little need to be concerned about rate shock and gradualism<sup>197</sup>. Mitigation has previously been approved where a customer will experience an increase of greater than 10 per cent of their total electricity bill due to changes in the ISO tariff.<sup>198</sup>
- 241 While the Proposed Rate Design would not result in a large impact for most customers, the impact on customers who are expected to experience a more significant rate increase should be reviewed. Significant changes in costs can impact consumer's operations and investment decisions. To support rate stability, consumers should have time to adjust to significant increases in the transmission portion of their monthly electricity bills. The AESO recognizes that such an increase could have a material impact on these customers, particularly in cases where electricity is a significant input cost.
- 242 In order to promote rate stability, the AESO analyzed whether any current customer's rates would be significantly impacted by the Proposed Rate Design. Although the AESO has estimated that the transmission bill impact resulting from the transition to the Proposed Rate Design to be less than +/- 10% for the large majority of PODs in the near term, the AESO determined that the Proposed Rate Design would exceed a 10% of transmission cost impact for a small number of customers. In the AESO's view, this impact should be eligible for mitigation, given the significant shift in cost allocation after more than a decade under the Current Rate Design and the relatively small number of customers at issue.
- 243 The AESO established an innovative, targeted engagement process to consult with significantly impacted parties about a mitigation proposal that would allow them to adjust to the new rates over a period of time, with the aim of transitioning to the Proposed Rate Design over the long term. To promote regulatory efficiency, the AESO sought to enter into a MOA with these parties in advance of the regulatory proceeding. The AESO was unable to reach a formal MOA with the significantly impacted stakeholders but found the process to be highly valuable in terms of identifying and discussing key mitigation options. The AESO continues to believe that its mitigation proposal, developed based on a set of clear principles in the course of numerous targeted engagement sessions and discussions, is the most appropriate and balanced approach to manage the transition to the Proposed Rate Design.
- 244 Providing significantly impacted customers time to adjust to the new rates using a transition period with moderately increasing rates is fair and reasonable. As significantly impacted customers would not pay full

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<sup>197</sup> Decision 2007-106 at PDF pages 20-21.

<sup>198</sup> Decision 2007-106 at PDF pages 67-69.

rates during the transition period, the rest of the customer base would absorb the balance; however, the majority of the latter customers would experience lower rates under the Proposed Rate Design.

245 The mitigation proposal was developed based on the Proposed Rate Design. If the Commission does not approve a design substantially similar to the Proposed Rate Design, the AESO would need to re-assess the impacts to customers and review the appropriateness of the mitigation proposal.

### **Customer Bill Impact Estimates**

246 As presented in section 3.8 the AESO estimates that three PODs would be expected to face a *total bill* increase of 10 per cent or more under the Proposed Rate Design, using the 2019 Test Year. Further details on bill impacts are presented in Appendix E. These three PODs are all DFO transmission-connected customers on a flow-through rate. Eight additional PODs would face an increase of 10 per cent or more to the *transmission portion* of their bill.

247 This results in a total of 12 PODs facing a 10 per cent or more increase in the *transmission portion of their bill*. Seven are DFO transmission-connected customers on a flow-through rate and five are DFO distribution-connected customers. The AESO does not propose any mitigation for these latter five customers because the impact of the Proposed Rate Design would be incorporated into DFO charges and therefore depend on the DFO's rate design.

248 The AESO estimates that the cost of mitigating the above seven DFO transmission-connected customers on flow-through rates to no more than a 10% increase in transmission costs based on the 2019 Test Year estimates would have been approximately \$8 million annually.<sup>199</sup> For the subset of the three DFO transmission-connected customers on flow-through rates facing an increase of 10 per cent on their total bill, the cost of mitigating to no more than a 10% increase in transmission costs based on the 2019 Test Year estimates would have been approximately \$5 million annually.

### **Rate Mitigation Process and Proposal Principles**

249 The AESO set out to develop a cost reflective rate design, and then established a process to consult on a mechanism to adjust customer charges to provide the necessary time and space to adjust to the new rates, if necessary. The AESO sought input on mitigation from all stakeholders in the broader B&R Consultation. To guide its mitigation discussions, the AESO's proposed the following principles:

- Limiting rate impact to a 10 per cent increase to a party's transmission bill for the initial stage of transition to the Proposed Rate Design;
- The mitigation amount adjusts with changes in overall rate levels as well as individual operations as parties begin adjusting operations in line with the Proposed Rate Design;
- Mitigation options should be applied consistently across all significantly impacted loads and not be individually defined;

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<sup>199</sup> Amounts are calculated based on data in Appendix E – Bill Impact Workbook, tab E-5 Per POD.

- Mitigation should be administratively simple, feasible to implement with current tools and systems;
- Mitigation proposals should be mutually acceptable, balancing the interests of parties significantly impacted by the Proposed Rate Design with all other parties that would be funding the mitigation, while supporting stable, fair and just rates and a fair, efficient, and openly competitive market.<sup>200</sup>

250 Stakeholders held mixed views about these principles. Instead, some suggested permanent rate treatment to retain loads unable to adjust to the new rates.<sup>201</sup> Others opposed mitigation generally, viewing it as an improper subsidy or arguing that the Proposed Rate Design should be adjusted to avoid the need for mitigation.<sup>202</sup> The AESO found this feedback to be helpful and informative but did not change the principles that it applied to develop the mitigation proposed in this application.

### 3.9.2 *The AESO's Targeted Mitigation Engagement Process*

251 In developing the mitigation proposal described herein, the AESO followed a significantly different approach to engaging stakeholders than it has in the past. After seeking input on the mitigation principles and approach from the broader stakeholder group, the AESO formed a targeted mitigation stream which included only those stakeholders representing the seven DFO transmission-connected customers on a flow-through rate it had identified as likely to be significantly impacted by the Proposed Rate Design. The broader group of stakeholders was aware of this targeted engagement stream as it progressed, kept informed of the discussions taking place and provided with opportunities to provide input as the discussions progressed.<sup>203</sup>

252 The targeted engagement process was led by the AESO in conjunction with a third-party facilitator. The engagement included a kick-off meeting to introduce the process; one-on-one meetings between significantly impacted parties and the facilitator; five round-table sessions with all significantly impacted

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<sup>200</sup> Appendix B Part 3 - From AESO, Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021) at slide 64: 1. Limit the rate impact for customers: Mitigate rate impact to under 10 per cent increase to a party's transmission bill for initial stage of transition; 2. Adapt with design and rates: Ensure options are adaptable to changes to the proposed design and forecast rates; 3. Consistent application: Mitigation options can be applied consistently across all impacted loads and not be individually defined; 4. Administrative simplicity: Feasible to implement with current tools and systems; 5. Mutually acceptable: account for feedback from broad stakeholder group.

<sup>201</sup> Appendix B Part 3 - ADC, Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 12; West Fraser Mills Ltd , Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 12.

<sup>202</sup> Appendix B Part 3 - Alberta Newsprint Company (ANC), Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 13, 2021) at question 12, DUC, Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 11; Fortis Alberta, Bulk and Regional Tariff Design Stakeholder engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 13; IPCAA, Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 11; TC Energy (TCE), Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 11.

<sup>203</sup> Appendix B Part 3– AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021) at slides 62-66; AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 6B Presentation (June 24, 2021) at slides 16-27.

parties, the facilitator and the AESO; and one-on-one meetings between significantly impacted parties and the AESO.

253 The combination of third-party facilitation with both broad and targeted consultation sessions was precedent-setting and innovative. The process goal was regulatory efficiency by narrowing issues before the start of the regulatory process. Had a MOA been executed, it would only have applied in the event that the Proposed Rate Design was substantially approved by the Commission. Signatories would have still been able to advance arguments opposing all or some of the Proposed Rate Design.

254 Following many discussions, parties have provided statements with their rationale for not signing the MOA. These statements and the draft MOA are attached in Appendix C.

255 While the targeted stakeholder engagement approach did not reach the intended result, the AESO found the overall approach effective and valuable, and reflective of the negotiated settlement efforts that the Commission promotes.<sup>204</sup> The AESO better understands the issues and is therefore confident that it has proposed a reasonable mitigation plan.

### 3.9.3 *Rate Mitigation Options*

#### ***What Customers or Rates should be Eligible for Rate Mitigation?***

256 The AESO considers it appropriate to provide a mitigation option to customers on Rate DTS who are expected to experience rate increases of more than 10 per cent of the transmission portion of their bill because:

- the Proposed Rate Design represents a significant change to the Current Rate Design;
- customers that will be most impacted are those who have been most responsive to tariff price signals;
- customers that experience a sudden and relatively large increase to their rates could experience consequential negative impacts to their businesses; and
- it is in the public interest to provide an element of rate stability for consumers to support economic activity across the province.

257 Some stakeholders requested mitigation consideration for individual customers connected to the distribution system.<sup>205</sup> As described in paragraph 247, the rate impact experienced by individual distribution customers depends on the DFO tariffs that allocate costs charged to the DFO through the ISO tariff. Any mitigation for a single DFO connected customer would need to be considered in conjunction with the design of the DFO tariff, and therefore is not appropriately considered as part of this application.

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<sup>204</sup> See Proceeding 26207, “AUC Letter Mediated Settlement Process” at Exhibit 26207-X0069 at PDF page 1, para 5 and Mediated Settlement Report.

<sup>205</sup> Appendix B Part 3 – Canada West Ski Areas Association, Bulk and Regional Tariff Design Stakeholder Engagement Session 6B: Stakeholder Comment Matrix (July 9, 2021) at question 6.

258 Some stakeholders suggested that mitigation should be provided to a broader group through a lower or different threshold, such as by phasing in the rates so that all customers can transition to the Proposed Rate Design.<sup>206</sup> In the AESO's view, it is preferable for a more cost reflective rate design to be implemented for the majority of customers as soon as possible and to mitigate the bill impacts of the small number of significantly impacted parties.

259 Specific to Rate XOS, the Montana Alberta Tie Line Canada suggested that any change to Rate XOS should be mitigated to a 10 per cent rate increase. The AESO does not agree with this proposal as opportunity rates are meant to utilize and charge for existing spare capacity, in order to reduce rates for firm customers, as further described in section 6.1.

260 After considering all of the feedback received, the AESO remains of the view that mitigating for increases of 10 per cent or more to the transmission portion of the bill, with a five-year phase-in, is appropriate in this case, to avoid delay in transitioning to a rate design that is more cost reflective.

### ***What Mitigation Options Were Considered?***

261 Three alternatives were proposed and discussed within the targeted mitigation engagement as potential options for mitigation:

- a) A phasing-in of the Proposed Rate Design by offsetting rate increases through mitigation credits for significantly impacted parties (i.e., temporary bill adjustments to allow for a transition to the Proposed Rate Design over time).
- b) A Modernized DOS rate that would provide a means for certain significantly impacted parties to continue to economically connect to the system.
- c) A non-firm interruptible rate class that would be a separate rate class for flexible loads that exists permanently and would be distinct from Rate DOS.

262 Only the first two options were carried forward in the stakeholder engagement process because the AESO did not consider an interruptible rate class for flexible loads feasible. As further discussed in section 4.2, the AESO concluded that such a rate class is not aligned with the legislative framework. Further, the interruptible rate class would only be available where it has the potential to reduce incremental transmission costs. This would limit the effectiveness of an interruptible rate as a mitigation option, as it may not be available in the areas where the significantly impacted loads are located.

263 Additionally, while not explored as an option in detail, some significantly impacted parties suggested legacy treatment, where those parties would remain under the Current Rate Design permanently. The AESO rejected this option because it amounts to a permanent cross subsidy, inconsistent with temporarily mitigating resulting from the Proposed Rate Design and, ultimately, the need for just and reasonable rates.

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<sup>206</sup> Appendix B Part 3 - FortisAlberta, Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 13; Cities of Lethbridge and Red Deer (c/o Chymko Consulting), Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at questions 10-15; TCE, Bulk and Regional Tariff Design Stakeholder Engagement Session 5: Stakeholder Comment Matrix (April 15, 2021) at question 11.

### 3.9.4 *The AESO's Rate Mitigation Proposal*

264 The AESO proposes three mitigation options for significantly impacted parties to select from.

#### **A. Option 1 – Mitigation Credits**

265 Temporary credits on a DTS invoice meet the guiding principles and have been approved by the Commission relating to mitigation in the past.<sup>207</sup> This option includes the following features:

- The AESO would calculate a credit on the Rate DTS Energy Charge (Mitigation Credit), applied as a credit on the energy charge portion of the DTS invoice.
- The AESO would use a test rate based on the actual 2019 revenue requirement, actual 2019 billing determinants and the Proposed Rate Design to determine the Mitigation Credit. The Mitigation Credit for each site would differ based on the site's estimated transmission bill impact and actual energy usage, based on 2019 billing determinants.

266 The Mitigation Credit for each site would be determined based on the following formula:

$$\frac{(\text{Annual transmission costs [under 2019 ISO tariff rates]} \times 110\%) - \text{Annual transmission costs [under Proposed Rate Design for 2019 test rate]}}{(\text{Energy [2019 Site Actual Energy]} \times \text{Energy Charge [under Proposed Rate Design for 2019 test rate]})}$$

267 The Mitigation Credit would be temporary, and phase out as follows over five years and applied as described as below:

- Year 1 Mitigation Credit \* 100 per cent,
- Year 2 Mitigation Credit \* 80 per cent
- Year 3 Mitigation Credit \* 60 per cent
- Year 4 Mitigation Credit \* 40 per cent
- Year 5 Mitigation Credit \* 20 per cent

268 By design, the Mitigation Credit will reduce the impact of the Proposed Rate Design on significantly impacted parties to a 10 per cent increase in the first year that the Proposed Rate Design is in place. Following year one, the Mitigation Credit amounts would decline, such that in year 6, the significantly impacted customer would pay the full charges calculated using the new approved rates. This assumes the customer continues to operate as they did in 2019. As a Mitigation Credit based on the energy charges, the Mitigation Credit will vary based on actual energy consumed in future years, with the amount of credit declining if consumption decreases. As a result, the impact for significantly impacted customers is tempered and experienced over time while also ensuring that Credits are provided based on usage of the system.

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<sup>207</sup> See Rider G: Bill Impact Mitigation Rider, AUC Order U2008-217 at PDF page 44.



269 The AESO estimated that the upper bounds on the mitigation costs for the Mitigation Credit option over the five-year mitigation period would be \$19.5 million<sup>208</sup>. This estimate is based on all significantly impacted loads selecting this option and operating similarly to 2019. The actual cost of mitigation would depend on each significantly impacted party's operations.

### **B. Option 2 - Transition DOS**

270 Initially, the AESO presented Modernized DOS as a mitigation option for loads that may become uneconomic, as identified by that load, if the AESO's Proposed Rate Design is approved. After stakeholders raised a number of concerns, the AESO determined that Modernized DOS would not be viable as a mitigation option on its own.

271 Therefore, the AESO developed Transition DOS which includes several modifications to better align the rate as an effective transition mechanism to address the impact on significantly impacted loads. The intent of Transition DOS is to permit shifting a portion of a significantly impacted load's consumption to an opportunity service in response to increased Rate DTS charges resulting from the Proposed Rate Design and the resulting impacts to the economics of their operations. Transition DOS would provide flexibility over a transition period to support the transition to a new Rate DTS and Modernized DOS contract level in the longer term.

272 Transition DOS for significantly impacted customers includes the following features:

- Transition DOS rate would be a temporary variation of the Modernized DOS Rate that would come into effect on the same date as the Proposed Rate Design;
- Transition DOS rate would expire five years after the effective date of the Transition DOS rate; and
- The AESO would adjust the system access service agreement of the customers that select the Transition DOS Rate to document the Rate DTS and Rate DOS contract levels requested by the customer.

273 A customer could contract for amounts of Transition DOS rate up to:

- a 20 per cent load factor, where it reduces the estimated bill increase on the transmission portion of their electricity to 10 per cent or less, as determined by the AESO based on actual 2019 billing determinants for their individual sites; or
- where a 20 per cent load factor does not reduce the estimated bill increase on the transmission portion of their electricity bill to 10 per cent, a load factor that reduces the estimated bill increase on the transmission portion of their electricity bill to 10 per cent, as determined by the AESO based on actual 2019 billing determinants.

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<sup>208</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 6B (June 24, 2021) at slide 26.



274 All other terms and conditions of the Modernized DOS Rate would apply to customers that elect the Transition DOS rate.

275 Upon expiry of the Transition DOS rate, any customer with contract amounts under the Transition DOS rate provisions would be required to meet the provisions of the Modernized DOS rate.

276 If a customer makes a change to its contract levels three or more years after the Transition DOS rate comes into effect and continues to have some portion of contracted Rate DOS, a representation for the Rate DOS contract level will be required in accordance with the approved Modernized DOS rate.

277 The AESO estimated that the upper bound of the mitigation costs for Transition DOS for amounts greater than 20 per cent load factor over the five-year mitigation period would be \$17 million<sup>209</sup>. The estimate is based on all significantly impacted parties selecting this option and operating similarly 2019. The actual cost of mitigation would depend on the significantly impacted party's operations.

### Option 3 - Combination Mitigation Credits and Transition DOS

278 The AESO proposes a combination of Mitigation Credits and Transition DOS options to mitigate significantly impacted parties who use the Transition DOS rate but also require credits to the DTS invoice to reduce the rate impact to below 10 per cent of their transmission bill.

279 A combination of Mitigation Credits and Transition DOS option for significantly impacted parties would include the following features:

- Customers may elect a Combination Credit, being the Transition DOS rate in combination with a credit on the Rate DTS charge.
- The AESO would calculate a Combination Credit on the energy charge portion of the DTS invoice under the Proposed Rate Design.
- The Combination Credit for each site would differ based on the site's estimated transmission bill impact and actual energy usage, based on 2019 billing determinants.
- The AESO would use a test rate based on the 2019 revenue requirement, 2019 billing determinants, and elected Transition DOS contract level to determine the Combination Credit.

280 The Combination Credit percentage for each site would be determined based on the following formula:

$$\frac{(\text{Annual transmission costs [under 2019 ISO tariff rates]} \times 110\%) - \text{Annual Transmission Costs including Transition DOS [under Proposed Rate Design for 2019 test rate]}}{(\text{Energy [2019 Site Actual Energy]} \times \text{Energy Charge [under Proposed Rate Design for 2019 test rate]})}$$

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<sup>209</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 6B (June 24, 2021) at slide 26.

281 The Combination Credit would be temporary, and phase out as follows over five years and applied as described below:

Year 1 Mitigation Credit \* 100 per cent

Year 2 Mitigation Credit \* 80 per cent

Year 3 Mitigation Credit \* 60 per cent

Year 4 Mitigation Credit \* 40 per cent

Year 5 Mitigation Credit \* 20 per cent

282 By design, the Combination Credit with Transition DOS would reduce impact of the new approved rate to significantly impacted parties to a 10 per cent increase in the first year that the Proposed Rate Design is in place. Following year one, the amount of credits would decline, such that in year 6 the significantly impacted party would pay the full charges calculated using the new rates with their new Rate DTS and Rate DOS contract levels. This combination addresses impact for customers who would choose a Transition DOS level that supports their operations but does not minimize impact to the threshold level.

283 The AESO estimates that the upper bounds on the total mitigation costs for the Combination Mitigation Credits and Transition DOS option would fall somewhere between Option 1 (\$19.5 million) and Option 2 (\$17 million) above. The actual cost of mitigation would depend on the significantly impacted parties' operations.

#### ***Stakeholder Views on the AESO's Mitigation Proposal***

284 The AESO prepared and published two detailed summaries of the targeted mitigation engagement that summarize the discussions during the round table sessions.<sup>210</sup>

285 At a high level, significantly impacted parties were of the view that successful mitigation is a permanent solution that maintains current cost levels and reflects the value that, in their view, flexible price responsive loads provide to the system. In the AESO's view, the mitigation options reflect a temporary deviation from full alignment with cost causation by shifting a small amount of costs to other customers to reduce the risk of customer disruption. This balanced design aligns with past Commission decisions on mitigation and gradualism treatment.<sup>211</sup>

286 Significantly impacted parties suggested that mitigation should be considered for a longer period than five years, in the range of 10 years. The AESO considers five years to be the appropriate transition period, given that it will not begin until the new rates come into effect in 2024. Further, it is difficult to anticipate whether and to what extent additional changes may be required to the rate design in the next 10-15 years,

<sup>210</sup> Appendix C - AESO Targeted Mitigation Summary: Status Report (May 4, 2021); Summary: Targeted Mitigation 1:1 Meetings (April 22, 2021).

<sup>211</sup> Decision 2007-106 at PDF pages 67-69; AUC Order U2008-217 at PDF page 44.

and whether a mitigation solution that is created today will continue to be effective throughout a longer time horizon. However, the AESO is not opposed to a longer mitigation period should the Commission determine that it is appropriate.

287 The preferred mitigation solution for significantly impacted parties is an interruptible rate class (i.e., a separate rate class for flexible loads that exists permanently and maintains costs for these loads as they are currently and is distinct from Rate DOS). An interruptible rate class does not align with legislative requirements and the AESO considers that the Proposed Rate Design better reflects cost responsibility for all customers, including the significantly impacted parties. As explained in further detail in section 3.9.3 of this application, in order for an interruptible rate class to contribute value to the grid by reducing transmission costs, it would need to include a locational signal. Accordingly, the AESO did not explore an interruptible rate class as part of its Proposed Rate Design or as a mitigation solution.

### 3.9.5 *Mitigation Implementation*

288 The AESO has filed proposed ISO tariff riders (see Appendix R – Draft ISO Tariff Rider M) for Commission approval setting out:

- identification and applicability to significantly impacted parties;
- the mitigation option selected by each of the significantly impacted parties;
- the length of the mitigation period approved by the Commission;
- the estimated Mitigation Credit for the purpose of calculating the credit on the DTS Energy Charge;
- elected Transition DO contract levels;
- the load factor limit for each Transition (DOS) Rate site, if it is above 20 per cent; and
- other implementation details, as required or requested by the Commission.

289 Should the Proposed Rate Design be approved, the AESO proposes the following process to implement the mitigation proposal:

- the AESO will re-estimate bill impacts for all PODs using a test rate based on the actual 2019 revenue requirement, actual 2019 billing determinants and the Proposed Rate Design;
- based on this re-estimation the significantly impacted parties, those transmission-connected PODs with a rate impact above the threshold, will be notified that they are eligible for mitigation;
- a significantly impacted party will inform AESO of its preferred mitigation option within 45 calendar days of receiving a notification from the AESO, and include the Transition (DOS) Rate contract level if applicable; and
- the AESO will estimate the Mitigation Credit for the Rate DTS Energy Charge, as required for those significantly impacted parties that select such option;
- the AESO will create a version of Rider M (see Draft ISO Tariff Rider M in Appendix R) for each significantly impacted party, including the details set out in paragraph 288, and file these riders as part of its compliance filing.

### 3.9.6 **AESO Request Regarding Mitigation**

290 In the event that the Commission substantially approves the Proposed Rate Design, the AESO requests that the Commission approve the AESO's mitigation proposal as presented in section 3.9.4 and to proceed with implementation as described in section 3.9.5.

291 If the Proposed Rate Design is not substantially approved by the Commission, the AESO requests that the Commission direct it to review the mitigation proposal taking into consideration the approved rate design. The mitigation proposal was developed considering: the number of parties with an estimated impact above the defined threshold; the estimated magnitude of the impacts; and the characteristics of their loads. As such, if the approved rate design results in a different set of loads facing a significant rate impact or the overall magnitude of the impact varies from the AESO's analysis, alternative mitigation options should be evaluated. However, it is possible that the proposed mitigation approach could remain appropriate under an alternative rate design.

## 4. Energy Storage

292 An increased number of energy storage resources have submitted SASRs and have been connecting to the Alberta interconnected electric system in recent years. In response to this trend, the AESO has examined the integration of energy storage resources within the existing legislative framework and the appropriate treatment of energy storage resources under the ISO tariff.

293 The AESO maintains that energy storage resources should continue to pay for the costs of the transmission system based on the flows of electricity and the associated benefits, by charging the owner of an energy storage resource Rate STS when electricity is injected onto the transmission system and Rate DTS when electricity is withdrawn from the transmission system. As explained further below, the AESO does not propose a separate rate for energy storage resources or other special relief for energy storage resources under the ISO tariff.

294 However, given the flexible nature of energy storage resources when withdrawing electricity from the transmission system, the AESO has recognized that energy storage resources may qualify for the same opportunity services under the ISO tariff as other Rate DTS market participants; specifically, Rate DOS. As described in section 5.2 below, this represents a partial shift from the AESO's previous view regarding the eligibility of energy storage resources for Rate DOS.<sup>212</sup>

### 4.1 Legislative Requirements for Energy Storage

295 Energy storage resources are not specifically addressed in Alberta's current legislative framework, as they were not contemplated when Alberta's electricity industry was restructured in 2001.<sup>213</sup>

296 Energy storage resources also do not fit neatly into the functional categories of assets as delineated in the *EUA*. This is because energy storage resources do not generate electricity or consume electricity; however, they utilize bi-directional electricity flows when connected to the transmission system, such that they

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<sup>212</sup> See Exhibit 22942-X0163, at PDF page 92, para 395.

<sup>213</sup> See Proceeding 24116, Commission Decision Report, *Distribution System Inquiry Final Report* (February 19, 2021), at PDF page 12-13, para 22.

withdraw electricity from the transmission system when charging but inject electricity into the transmission system when discharging. Further, energy storage resources can be put to varying applications – from pool price arbitrage to frequency regulation to deferring distribution and transmission infrastructure build<sup>214</sup> – resulting in complications to any functional categorization within the existing market structure.

297 In accordance with recent Commission decisions, it is reasonable to treat energy storage resources as dual-use assets under the current legislative framework.<sup>215</sup> This means that when an energy storage resource injects electricity into the transmission system (like a generator) the applicable Rate STS rates apply, and when it withdraws electricity from the transmission system (like a load) the applicable Rate DTS rates apply. As previously stated by the AESO:

Storage facilities operate [like] generating units when injecting power into the grid. They are also capable of providing ancillary services. Storage also operates [like] load when purchasing or withdrawing electricity from the transmission system. As with other loads, the owner or operator of the storage facility is using the transmission system and is required to pay the just and reasonable costs of the transmission system.<sup>216</sup> [Emphasis Added].

298 Consistent with their use of the transmission system, energy storage resources are charged based on the flows of electricity, which means they are charged:

- location-based cost of losses and comparable charges applicable to generating units when injecting electricity (discharging); and
- the reasonable costs of the transmission system as applicable to load when withdrawing electricity (charging).<sup>217</sup>

299 This treatment continues to apply to energy storage resources regardless of how they are classified under the current legislative framework, since all market participants pay for the use of the transmission system based on the flows of electricity. For example, if an energy storage resource was classified as a generator, it would still ultimately pay for the use of the transmission system depending on the flows of electricity. Generators pay the location-based cost of losses and comparable charges applicable to generating units when injecting electricity, and generators pay the reasonable costs of the transmission system when withdrawing electricity from the transmission system to power their facilities (station services).

300 Analogies can also be drawn to dual-use sites that cause flows of electricity in both directions. A dual-use site receives system access service under Rate STS in an hour when it provides a net supply of electricity

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<sup>214</sup> *Ibid*, at PDF page 82, fig. 19.

<sup>215</sup> See Decision 22942-D02-2019 at PDF page 268, para 1210.

<sup>216</sup> Exhibit 22942-X0013, at PDF page 7. While the original quote indicated that storage facilities operate “as” generating units when injecting and withdrawing power onto and from the transmission system, the AESO has revised it to clarify that it views generation and storage as two separate technologies.

<sup>217</sup> Exhibit 22942-X0163, at PDF page 90 para 382. See also, *TReg*, at s 47.

to the transmission system, and under Rate DTS in an hour when it withdraws a net load from the transmission system.

## 4.2 Treatment of Energy Storage and Other Non-firm Customers under the ISO tariff

301 The AESO has examined the treatment of energy storage resources under the ISO tariff at considerable length. In 2020, the AESO presented stakeholders with three potential proposals for the treatment of energy storage electricity withdrawals (consumption) under the ISO tariff that could be implemented within the current legislative framework.

1. Energy storage resources could continue to be charged the existing Rate DTS and Rate STS rates like other market participants under the ISO tariff.
2. Energy storage resources could be exempt from the existing Rate DTS rate while providing “Market Services” in a manner similar to the treatment that energy storage resources receive under the United States of America’s Federal Energy Regulatory Commission’s Order 841.<sup>218</sup>
3. Energy storage resources could be charged a lower rate for non-firm demand service,<sup>219</sup> either as an opportunity service where excess capacity is available for charging or as an interruptible service in areas where constraints are likely to occur.

302 In response, stakeholders presented the AESO with three alternative proposals for the treatment of energy storage resources under the ISO tariff.

1. Energy storage resources could receive a complete exemption from the ISO tariff and instead be charged an administration fee to recover energy storage resources’ contribution to the transmission component of the AESO’s “own costs.”<sup>220</sup>
2. Energy storage resources could be charged the same rates under Rate STS for both withdrawing and injecting electricity and pay no wires cost for withdrawing electricity except for station service needs.<sup>221</sup>
3. Energy storage resources could be charged a lower interruptible rate, but the rate would not be restricted to areas where constraints are likely to occur and could be relieved by reducing or prohibiting charging.<sup>222</sup>

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<sup>218</sup> [United States of America Federal Energy Regulatory Commission Order No. 841](http://www.ferc.gov/media/order-no-841), PDF page 195, at para 293 (www.ferc.gov/media/order-no-841).

<sup>219</sup> Non-firm service refers to an opportunity service or an interruptible service.

<sup>220</sup> Appendix B Part 2 – Canadian Renewable Energy Association (CanREA) and Solas Energy Consulting, Stakeholder Proposal (November 5, 2020).

<sup>221</sup> Appendix B Part 2 - Energy Storage Canada (ESC) and Power Advisory LLC, Stakeholder Proposal (November 5, 2020).

<sup>222</sup> Appendix B Part 2 - RMP Energy Storage, Stakeholder Proposal (November 5, 2020).

- 303 The AESO considered and dismissed these alternative proposals. Although energy storage resources may have certain unique features, the AESO sought to ensure that energy storage resources would be charged for the use of transmission in a manner that is consistent with other users.
- 304 However, the AESO agreed that further consideration of non-firm rates was warranted for both treatment of energy storage and also treatment of other non-firm users of the transmission system. The AESO assessed non-firm rates, including: (i) rates that could allow additional use of available capacity that would not otherwise be used, (ii) rates that could reflect transmission cost savings from interruptions to relieve constraints, and (iii) rates that could encourage participation in the market or the provision of ancillary services.
- 305 Based on this assessment, the AESO concluded that energy storage resources and other non-firm loads could, in addition to contracting for a firm level of service through Rate DTS, make use of transmission capacity that would not otherwise be used. However, offering a non-firm rate (i.e., a lower level of service with a lower rate) requires certainty that electricity withdrawn from the transmission system under this type of rate will not contribute to future transmission costs and therefore needs to be curtailable when effective at addressing system constraints. As described further below, the AESO also concluded that energy storage resources and other non-firm loads could utilize Rate DOS, an existing non-firm rate. The AESO considers this approach to be preferable over the other non-firm rate alternatives assessed by the AESO.
- 306 The alternatives involving rates that could reflect transmission cost savings from interruptions to relieve constraints were eliminated by the AESO since the interruptible rate could only be provided in areas where interruptions would defer incremental transmission costs. Further, to be cost reflective, the interruptible rate alternative would need to have a location-specific charge, which would not align with legislative requirements.<sup>223</sup>
- 307 The alternatives involving rates that could encourage participation in the market or the provision of ancillary services were also eliminated by the AESO since these types of uses would not impose any different costs on the transmission system than those already reflected in the Current Rate Design. The AESO's preferred approach, with the billing determinants aligned to cost drivers, would provide market participants with flexibility to manage their assets and associated costs through the management of their consumption.

## 5. DOS Modernization

### 5.1 Existing Rate DOS

- 308 Rate DOS is an existing non-firm rate that allows additional use of available transmission capacity that would not otherwise be used. Rate DOS has not materially changed since 2007 when the then EUB approved certain changes to Rate DOS following the AESO's 2007 general tariff application.<sup>224</sup> Rate DOS was considered by the Commission in the AESO's 2010 general tariff application; however, the changes were mostly administrative in nature and no material changes were made.<sup>225</sup> Over the past 14 years, 64 market participants (3 currently) have used Rate DOS. Through this application, the AESO seeks to remove

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<sup>223</sup> *EUA*, s 30(3)(a).

<sup>224</sup> See Decision 2007-106.

<sup>225</sup> See Decision 2010-606.



barriers to entry to Rate DOS that will enable market participants, including owners of energy storage resources, to utilize spare transmission system capacity that would not otherwise be used, in furtherance of the underlying objectives of Rate DOS.

309 The AESO recognizes that Rate DOS has had limited use historically and there continues to be spare transmission system capacity that, when available, could be used to offset some of the costs which would otherwise be collected in full from transmission system ratepayers.

310 The AESO has re-examined Rate DOS with a view to modernizing it by providing market participants, including owners of energy storage resources, with further clarity and flexibility in how they manage their electricity withdrawals from the transmission system. This additional clarity and flexibility are consistent with the underlying objective of Rate DOS, which is to enable market participants to utilize spare transmission system capacity that would otherwise go unused and generate additional revenues that can be used to reduce the average rates charged.

## 5.2 Energy Storage Rate DOS Considerations

311 The modernization of Rate DOS to address the use of the transmission system by energy storage resources represents a partial shift from the AESO's previous view, as expressed in its 2018 amended general tariff application, where the AESO stated:

Rate DOS has well-established eligibility criteria set out in the current section 12, *Demand Opportunity Service*. The criteria in subsection 3(3) includes that Rate DOS must be used for additional electric energy either (a) to replace an alternative source of energy; or (b) to take advantage of a market opportunity where the alternative would be to forego the opportunity.

An energy storage facility has no alternative source of energy other than withdrawing from the transmission system when charging. As well, an energy storage facility cannot forego withdrawing from the transmission system and still be able to operate as an energy storage facility, thereby becoming unfeasible. Accordingly, the AESO is of the view that an energy storage facility is not eligible for Rate DOS.<sup>226</sup>

312 Since filing its amended 2018 general tariff application, the AESO has been able to observe and learn from the behaviour of energy storage resources in Alberta.<sup>227</sup> Of the installed energy storage resources, as of the date of filing, only two applications exist for energy storage resources: a stand-alone energy storage resource built solely to provide operating reserves and an energy storage resource that is co-located with generation. Stand-alone energy storage resources can provide operating reserves by maintaining their state of charge at the resting state, minimizing the need to frequently withdraw electricity from the transmission system. Co-locating energy storage resources with other generation technology allows the energy storage resource to charge using the on-site generating unit or aggregated generating facility. In discussions with stakeholders, the primary reason current energy storage applications are limited to these two applications is that it is uneconomic for these resources to use Rate DTS to withdraw electricity even

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<sup>226</sup> Exhibit 22942-X0163, at PDF page 92, paras 394-395.

<sup>227</sup> As discussed in Exhibit 22942-X0163, at PDF page 92, para 397.



with variable energy prices. Despite this observation, the AESO maintains that the role of the ISO tariff is to charge just and reasonable rates for the use of the transmission system, and not to make energy storage resources economic.

313 The AESO recognizes that energy storage resources may feasibly operate by charging at a slower rate under Rate DTS and charging at a faster rate under Rate DOS. This would allow a market participant to take advantage of a market opportunity, namely, short-term pool price arbitrage in the energy market. Based on this additional information, the AESO considers that use of Rate DOS in this manner for energy storage resources is consistent with the objectives and requirements for Rate DOS (the use of system capacity which would otherwise go unused under Rate DTS).

### 5.3 Modernized DOS

314 The AESO considers the modernization of Rate DOS to result in a streamlined approach to the same opportunity rate concept that is administered differently. Accordingly, the AESO requests that the Commission approve the proposed Modernized DOS rate design, as described further below, as well as such other administrative changes to the ISO tariff as may be required to implement and give effect to the proposed Modernized DOS rate design.

#### 5.3.1 *Design Principles and Objectives of Modernized DOS*

315 The EUB summarized the original principles and objectives of Rate DOS as follows:

EAL offered, in evidence, that opportunity service was a short-term temporary service, provided on an as-available basis, to customers who could clearly demonstrate that their use of the transmission system would not be economically viable at the rates otherwise applicable. EAL further noted that opportunity service was utilized by pre-qualified customers, generally for service of short periods, in order to avoid the impact of contract demand or ratchet charges that would otherwise result.

The Board acknowledges that there are situations when the market price of alternative energy for some of the TA's customers could be a viable alternative to electricity. The Board therefore accepts EAL's stated position that the objective of opportunity service is to reduce the level of average rates charged to other customers by applying the extra revenue earned from the use of temporarily under-utilized transmission system assets. The Board further accepts that this requires pricing opportunity service on a value-of-service rather than a cost basis, and the application of criteria to prevent cannibalization of other revenues. At the same time, the Board does not wish to see the use of screening criteria that would prohibit the beneficial use of opportunity service.<sup>228</sup>

316 The AESO proposes to refine the foregoing and seeks to ensure that Modernized DOS will achieve the following principles and objectives:

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<sup>228</sup> Decision 2000-1, at PDF pages 231-232.

- a) Maintain the opportunity service as a service that is provided on an as-available, interruptible basis, which does not require any additional transmission facilities to be built at a cost to ratepayers;
- b) Enable market participants to utilize transmission system capacity that would otherwise be unused by removing barriers to entry and by providing market participants with increased clarity and flexibility in managing their electricity withdrawals;
- c) Avoid the use of the opportunity service as a substitute for Rate DTS by market participants who may seek to avoid Rate DTS charges;
- d) Improve the efficiency of the AESO processes for reviewing and approving applications for the opportunity service;
- e) Align the opportunity service with current AESO operations, planning, connections, and settlement processes; and
- f) Ensure the opportunity service is technology agnostic so as not to exclude market participants on the basis of technology.

317 In the case of (b) and (c) listed above, Modernized DOS seeks to strike the appropriate balance between these two competing objectives. The AESO also seeks to ensure that Modernized DOS, as an opportunity service, is appropriately simple, convenient, understandable, acceptable, and billable.

### 5.3.2 *Proposed Design of Modernized DOS*

318 The changes to Rate DOS are:

- a) introduction of a streamlined and standardized application process by (i) removing the expiration period so that market participants do not need to reapply for the opportunity service each year, (ii) removing the requirement for market participants to submit a business case regarding its proposed use of the opportunity service, (iii) removing the requirement for the AESO to evaluate such business case, and (iv) replacing the business case with a standardized representation;
- b) replacement of Rate DOS 7 Minute with new Dispatchable Rate DOS, removal of Rate DOS 1 Hour, update to Rate DOS Term, and introduction of new provisions to manage usage through energy market bids and merit order operations;
- c) introduction of new settlement provisions to limit the amount of Modernized DOS to a maximum annual load factor equal to 20% of the Rate DOS contract capacity multiplied by the number of hours in the following 12-month period for an asset, with amounts in excess of this limit being charged the Rate DOS DTS surcharge rate; and
- d) revisions to the audit and disqualification provisions to allow the effective monitoring and auditing of market participants using the opportunity service to prevent the cannibalization of Rate DTS.

319 These changes are explained in detail below. Other changes include:

- removal of transaction fees and take-or-pay requirement;
- introduction of a new proforma agreement for Modernized DOS that replaces the existing application for Rate DOS; and

- inclusion of Modernized DOS as part of the AESO's SASR process.

320 The charges for the Modernized DOS rate will continue to be calculated using the same methodology as the current Rate DOS rate. The charges will continue to be calculated on an incremental basis and have been updated to reflect the AESO's Proposed Rate Design. As described below, Modernized DOS will result in two primary rate types: Rate DOS Dispatchable DOS and Rate DOS Term. Rate DOS Dispatchable replaces the existing Rate DOS 7 Minutes. It will also result in the removal of Rate DOS 1 Hour. Rate DOS Term will remain and be updated. There is also a DOS DTS surcharge rate that will apply in certain circumstances.

321 Table 5-1 below describes the changes to each section of the Rate DOS Rate Sheet and the ISO tariff terms and conditions. Appendix U shows the changes to the Rate DOS Rate Sheet. Appendix S shows the changes to the sections of the ISO tariff terms and conditions as set out in Table 5-1.

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*Table 5-1 Existing DOS and ISO Tariff Terms and Conditions*

<b>Existing Terms &amp; Conditions</b>	<b>Proposed Changes</b>
<b><i>DOS Rate Sheet</i></b>	
Section 2(1)	Revise to reflect Rate DOS Dispatchable, Maximum Annual Load Factor Limit, and new market bid process
Section 2(2)	Include application of the Rate DTS surcharge rate when the Maximum Annual Load Factor Limit is exceeded
Section 2(3)	Revise to reflect new market bid process
Section 2(4) and (5)	Include new Maximum Annual Load Factor Limit
Section 3(1)	Remove recall times
Section 3(1)(a)	Replace Rate DOS 7 Minute with Rate DOS Dispatchable
Section 3(1)(b)	Remove Rate DOS 1 Hour and update Rate DOS Term
Section 3(1)(c)	Include DTS surcharge rate
Section 3(2)(a)	Administrative clarification
Section 3(2)(b)	Remove take-or-pay requirement
Section 3(3)-(4)	Remove transaction fee of \$500 and separate out the operating reserve charge
Section 4(2)	Revise to reflect bidding process

Section 4(3)	Revise to reflect ramp rates
<b>ISO Tariff Terms and Conditions</b>	
Sections 3, 5 and 12	Include Rate DOS in the SASR process and related sections
Section 9.2	Remove application process, notifications, annual expiry, and annual fee, and change “pre-qualification” to “qualification”
Section 9.3	Replace business case requirement with standardized representation and remove requirement that use be on a temporary or short-term basis and update permitted uses
Section 9.4	Replace transaction request process with energy market bid process and merit order operation, include Maximum Annual Load Factor Limit, and include forced outages, unplanned outages, and derates in the use of DOS Term
Section 9.5	Revise recall rates to correspond with ramp rates instead of 7 minutes or 1 hour
Section 9.6	Include additional clarity regarding monitoring, auditing, and the consequences of misrepresentation and non-compliance
Appendix A	Replace with new proforma agreement

323 The following sections focus on the substantive changes to Rate DOS. While some stakeholders have expressed support for Modernized DOS, others have expressed concern and disagree with some of the proposed changes. Notably, representatives of non-industrial loads generally oppose Modernized DOS, and have expressed concerns regarding the potential for Rate DTS cannibalization.<sup>229</sup> Proponents of energy storage resources and industrial loads generally support Modernized DOS, although take issue with certain aspects of the design.<sup>230</sup>

### 5.3.3 **No Substantive Change in Methodology for Calculating Rates**

324 The Modernized DOS rates will continue to be calculated using the same methodology as the current DOS rates. The rates will continue to be calculated using components of Rate DTS that have been updated to

<sup>229</sup> Appendix B Part 3 – Utilities Consumer Advocates (UCA), Bulk and Regional Tariff Design Stakeholder Engagement Session 6B: Stakeholder Comment Matrix (June 28, 2021) at, questions 3-4; CCA, Bulk and Regional Tariff Design Stakeholder Engagement Session 6B: Stakeholder Comment Matrix (July 9, 2021) at, question 3.

<sup>230</sup> Appendix B Part 3 – CanREA, Greengate Power Corp, Heartland Generation Ltd, IPCAA, TransAlta Corporation & TCE, Bulk and Regional Tariff Design Stakeholder Engagement Session 6B: Stakeholder Comment Matrix (July 9, 2021) at question 3.

reflect the AESO's Proposed Rate Design, as further described below. The revenue generated from these rates will continue to benefit transmission system ratepayers.

325 To determine the Modernized DOS rates, Rate DTS charges are first converted, by component, to \$/MWh charges. The Modernized DOS rates are then allocated the components of transmission costs which are attributable to Modernized DOS; specifically, for the Rate DOS Dispatchable rate, the energy charge and the operating reserve charge. To align with the operating reserve charge methodology applied to the Rate DTS and Rate FTS rates, and to make the operating reserve charge more cost reflective for Modernized DOS, the operating reserve charge is now a separate charge that is incurred at the time of consumption and dependent on applicable operating reserve costs instead of being embedded within the Rate DOS rates.

326 The energy charge component included in Rate DTS reflects the long-term transmission costs to accommodate the flow of in-merit electricity in all hours and users of Modernized DOS rely on the transmission system's ability to accommodate the flow of in-merit electricity in hours when they use DOS. It is therefore appropriate for such users of Modernized DOS to pay that portion of transmission costs. The AESO's Proposed Rate Design maintains the demand and energy billing determinant charges of the Current Rate Design that the current DOS rates are based on. Additionally, the revised charges resulting from the AESO's Proposed Rate Design will flow through the Modernized DOS rates. If an opportunity service was offered at a rate below the energy charge, other transmission system users would pay (subsidize) a portion of the long-term costs of accommodating the flow of in-merit electricity for Modernized DOS market participants – contrary to the objective of an opportunity service rate.

#### 5.3.4 *Streamlined and Standardized Application Process*

327 The AESO proposes to assess requests for Modernized DOS through the SASR process instead of maintaining a separate application process for Modernized DOS. This includes removing the notification requirements, the annual expiration period, the annual re-application process, and the annual application fee of \$5,000.

328 Instead, the application for Modernized DOS would be assessed from a technical perspective as part of the SASR process or when a market participant requests an amendment to its Modernized DOS contract capacity. As part of the SASR process, market participants would still need to apply for and obtain Rate DTS contract capacity as a precondition to using Modernized DOS. Market participants can submit a request for Modernized DOS at the same time they submit a request for Rate DTS, or they can submit a request for Modernized DOS after they have obtained Rate DTS. In both cases, Modernized DOS is conditional upon the market participant obtaining Rate DTS. Market participants will also have to specify the type of Modernized DOS they wish to use (Rate DOS Dispatchable or Rate DOS Term). Market participants will manage their Modernized DOS contract capacities in the same manner as their other contract capacities.

329 The AESO also proposes to remove the requirement to provide a business case. Currently, the business case must demonstrate that the proposed use of Rate DOS takes advantage of a market opportunity that requires additional electricity, but where the cost of receiving additional electricity under Rate DTS renders the opportunity uneconomic. The AESO proposes a standard representation instead of reviewing every business case. Market participants will bear the onus of ensuring their use of Modernized DOS meets the opportunity standard. The AESO would then regularly monitor the use of Modernized DOS by market participants, as further described below.

330 The AESO also proposes to revise the restriction that the use of Modernized DOS be on a "temporary or short-term" basis and instead would limit a market participant's use of Modernized DOS to the Maximum

Annual Load Factor Limit, as described further below. Some other proposed administrative changes include replacing the word “pre-qualified” with “qualified” where it appears in relation to the eligibility for Modernized DOS.

331 As mentioned, and as further described in section 5.3.6, some stakeholders oppose the standard representation and Maximum Annual Load Factor Limit, considering them insufficient to prevent the cannibalization of Rate DTS. Conversely, proponents of energy storage resources support the removal of the business case requirement but question the need for energy storage resources specifically to provide a standardized representation and be subject to the Maximum Annual Load Factor Limit. The AESO maintains that the combination of the standardized representation and the application of the Maximum Annual Load Factor Limit, for all market participants, strikes the appropriate balance between removing barriers to entry to Modernized DOS and reducing the risk of the misuse of Modernized DOS and potential cannibalization of Rate DTS.

### 5.3.5 *New Dispatchable DOS and the Management of Use through Energy Market Bids and Merit Order Operations and Updates to Rate Types*

332 The AESO proposes to replace Rate DOS 7 Minutes with a new dispatchable type of Modernized DOS (Dispatchable DOS) and to manage the use of Dispatchable DOS through energy market bids and merit order operations. The recall rates of the existing Rate DOS types were designed based on market participant capabilities that existed more than twenty years ago. Seven minutes represented a reasonable amount of time needed to remove the DOS load off the transmission system as quickly as possible while still allowing time for the market participant to react to the instruction. With advances in information technology and the increased sophistication of market participants, the AESO considers that it would be more efficient for both market participants and the AESO to manage the use of Modernized DOS through energy market bids and merit order operations.

333 Instead of providing a manual transaction request, market participants would submit bids for Modernized DOS capacity. This would result in the following outcomes:

- simplifies the Modernized DOS transaction for real-time operations because the in-merit bid provides visibility of the amount of Modernized DOS load being served in real-time and provides a curtailment order based on bid price; and
- ensures the load under Modernized DOS is truly curtailable, leveraging the existing ISO rules and compliance processes rather than building duplicative curtailment requirements within the terms and conditions of Modernized DOS.

334 Although some market participants expressed concern that Dispatchable DOS may result in a more complex framework that requires the management of bids, the AESO has released information to demonstrate how a market participant can submit a standing bid in the energy market that allows the market participant to take Modernized DOS at any point in time, subject to availability.<sup>231</sup> For example, a market participant could submit a one-time standing bid at \$999.99/MWh equal to their Modernized DOS contract capacity. Assuming that energy prices are not at the price cap and that there are no transmission

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<sup>231</sup> Appendix B Part 3 - AESO, Additional Information DOS Bid Examples (May 26, 2021).

constraints, the market participant would receive a dispatch from the AESO permitting the use of Modernized DOS until such time the market participant receives a dispatch or directive to no longer use Modernized DOS within the bid. Market participants would have flexibility in how they bid within Modernized DOS.

335 Unlike offers, the ISO rules for bidding allow for a level of flexibility recognizing the nature of transmission connected loads. Specifically, when a bid is “dispatched on” it is an indication that the market participant may withdraw additional electricity; however, there is no requirement to do so. On the other hand, if the market participant receives a “dispatch off”, this is an instruction to the market participant not to withdraw this block of electricity until such time as they are dispatched on again. In the case of Modernized DOS, the AESO’s system controller will use the bid dispatch to indicate to the pool participant when Modernized DOS capacity is available and the market participant may withdraw above their Rate DTS contract levels (dispatched on) and when the Modernized DOS capacity is unavailable (dispatched or directed off) the market participant must restore their withdrawals to Rate DTS contract levels.

336 Modernized DOS would continue to be a recallable service and the AESO would continue to have the right to curtail the use of Modernized DOS if capacity becomes insufficient. However, the recall response times would be based on the ramp rate of the Modernized DOS load. A minimum ramp rate will be specified when market participants connect, or apply for Rate DOS, and will be used by the AESO to assess performance. This process is consistent with the treatment of generating units. If a market participant fails to comply with a dispatch or directive to curtail its use of Modernized DOS, it may result in suspension, changes to Rate DTS contract capacities, and the imposition of Rate DTS rates.

337 The AESO also proposes to remove Rate DOS 1 Hour, as a result of the proposed changes to make Modernized DOS dispatchable and replace Rate DOS 7 Minutes with Dispatchable DOS. The AESO previously proposed to remove Rate DOS 1 Hour in its 2005/2006 general tariff application on the basis that it was not used. Market participants disagreed with the AESO’s position and the EUB concluded that:

While the Board notes that there are currently no customers using the DOS 1 hour rate the Board agrees with the interveners that there may be merit in retaining the availability of the rate. The Board considers that opportunity rates should be reasonably flexible so as to maximize their revenues and consequent contribution to overall costs. The Board also does not consider there to be any material administrative burden to retaining the rates. Therefore, the Board directs the AESO to retain the DOS 1 hour rate. The other opportunity rates are approved as filed.<sup>232</sup>

338 Rate DOS 1 Hour has remained unused since 2004. Dispatchable DOS would provide market participants with greater flexibility than Rate DOS 1 Hour because it dispatches Modernized DOS loads based on market participant determined ramp rates. This removes the need for a rate with a longer notice period and renders Rate DOS 1 Hour redundant.

339 Rate DOS Term will remain for market participants that seek to use Modernized DOS to replace the electricity provided from a self-supply generator. The AESO proposes revising Rate DOS Term to permit its use for planned outages, forced outages, unplanned outages, and derates. This would provide more

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<sup>232</sup> Decision 2005-096, at PDF page 45.



flexibility to Rate DTS loads and potentially increase the amount of revenue that would otherwise be foregone. The AESO emphasizes that Rate DOS Term should not be considered a stand-by rate. The use of Modernized DOS would be limited by its availability and should only be used in cases where, absent Modernized DOS, the market participant would have reduced consumption during the forced outages and derates.

### 5.3.6 *Limit of Modernized DOS and Settlement*

340 The AESO proposes to limit the amount of Modernized DOS that a market participant can use at an amount equal to the Maximum Annual Load Factor Limit (as defined below). This quantitative limit would replace the current provision, which limits the amount of Rate DOS that a market participant can use to “temporary or repeated short-term” uses. This proposed change will provide market participants with more clarity, help protect Rate DTS against the cannibalization, and result in only a small amount of potentially foregone revenue from the use of Modernized DOS that may have occurred above the Maximum Annual Load Factor Limit.

341 The following was considered in developing an appropriate limit:

- historical Rate DOS utilization shows maximum load factors less than or equal to 15% annually in 80% of recorded cases based on Rate DOS transactions between 2001 and 2020;
- a transmission system wide approximation for current unused capacity that exists on the transmission system that could be available for Modernized DOS is 23%, which represents 1 minus the ratio of Rate DTS electricity withdrawn to Rate DTS contract capacity; and
- statistical assessment of transmission system load use, where infrequent use of the transmission system occurs in the hours where load is one standard deviation above the average load. One standard deviation from the mean was found to be 18% from 2017 to 2019.<sup>233</sup>

The AESO considers that a Maximum Annual Load Factor Limit of 20% provides an appropriate quantitative measure to limit the use of Modernized DOS, especially since Rate DOS was originally intended to be used for temporary or repeated short-term use. Some stakeholders have disagreed with this limit. Specifically, some Rate DTS loads argue that this limit is too low for Modernized DOS to be used without on-site generation, and some proponents of energy storage resources argue that this limit is too low for long duration energy storage resources<sup>234</sup>. The AESO maintains that this limit strikes an appropriate balance, and it was not designed to serve any specific Rate DTS load type or technology. Rather, it was designed to remove barriers to entry to Modernized DOS and protect Rate DTS against cannibalization.

342 The AESO proposes to calculate, at the start of each 12-month period, the 20% maximum annual load factor limit (the Maximum Annual Load Factor Limit) for each market participant point of connection as follows:

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<sup>233</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5B Presentation (May 20, 2021) at slide 62.

<sup>234</sup> Appendix B Part 3 - Capital Power Corporation, ESC, TCE, TransAlta Corporation, & Turning Point Generation (TPG), Bulk and Regional Tariff Design Stakeholder Engagement Session 5B: Stakeholder Comment Matrix (May 31, 2021) at question 3.



*Maximum Annual Load Factor Limit = Modernized DOS contract capacity × number of hours over the following 12 month period × 0.2*

343 Each settlement period the Maximum Annual Load Factor Limit is reduced by the amount of DOS Energy Used (as defined below) in the settlement period. This is reset every 12 months.

344 The metered electricity in an hour that: (i) exceeds the Rate DTS contract capacity; and (ii) is less than or equal to the sum of the Rate DTS contract capacity and the Modernized DOS contract capacity is defined as the “DOS Energy Used”. DOS Energy Used is settled at the Rate DOS Dispatchable rate or Rate DOS Term rate, if the DOS Energy Used in the settlement period is equal to or below the Maximum Annual Load Factor Limit. Any DOS Energy Used in excess of the Maximum Annual Load Factor Limit will be charged at the Rate DOS DTS surcharge. The Rate DOS DTS surcharge rate is equivalent to Rate DOS Term rate and reflects the full Rate DTS cost in \$/MWh.

345 Any metered electricity in an hour that exceeds the sum of the Rate DTS contract capacity, and the Modernized DOS contract capacity will continue to be settled at the Rate DTS rate. Metered electricity settled at the Rate DTS rate will not be deducted from the Maximum Annual Load Factor Limit.

346 However, if a market participant exceeds the sum of the Rate DTS contract capacity and the Modernized DOS contract capacity or exceeds the Maximum Annual Load Factor Limit, it may also be subject to further consequences as outlined below.

### 5.3.7 **Monitor, Audit and Disqualification**

347 The AESO proposes to monitor Modernized DOS assets and may audit a market participant to verify that the use of DOS complies with the ISO tariff. The AESO proposes to use certain indicators to verify that the standardized representation provided is accurate and to determine whether the market participant should be charged the DTS rate. These indicators include, but are not limited to, whether:

- a) the market participant fails to respond to dispatches or directives in accordance with ISO rules;
- b) the metered electricity of the Modernized DOS load exceeds the sum of the Rate DTS and Modernized DOS contract capacities; and
- c) the metered electricity of the Modernized DOS load exceeds the Maximum Annual Load Factor Limit.

348 Indicator (a) above would signal that the market participant is unable to respond as an opportunity service and may require firm service under Rate DTS, and indicators (b) and (c) above would suggest that the market participant’s contracts for Rate DTS and Modernized DOS do not match the market participant’s firm electricity needs.

349 The presence of these indicators would automatically give rise to a presumption that the market participant has misrepresented the reason for its use of Modernized DOS; however, the market participant would have an opportunity to explain or provide additional information to the AESO. The AESO would ultimately make the final determination as to whether a market participant has misrepresented its use of Modernized DOS. Where the AESO finds that a market participant has misrepresented its use of Modernized DOS, the AESO may:

- a) charge and recover the Rate DTS rate plus interest over the historical period and any other costs; and

b) restrict the future use of Modernized DOS at the site by the market participant and its affiliates.

350 Item (a) above does not represent a material change from the current provisions of Rate DOS whereby the AESO may recover retroactive amounts for the period during which a market participant did not qualify for, but was billed under, Rate DOS.<sup>235</sup>

### 5.3.8 Other Process Changes

351 The AESO proposes to remove the transaction fee of \$500 because the AESO will no longer be processing transaction requests. As described in section 5.3.5 above, DOS transaction requests will be replaced by the energy market bid process.

352 The AESO also proposes to remove the take-or-pay requirement. With the energy market bid process, dispatch merit order, and current information technology systems, the AESO would have increased visibility and be able to make real-time decisions, which would remove the need for an incentive to ensure that transaction requests are realistic and market participant's bids are not excessive.

353 Other proposed changes include revising the provisions to incorporate Modernized DOS with the existing SASR process and such other administrative changes as may be required to implement Modernized DOS. The AESO would also amend its business practices to reflect Modernized DOS, which would include limiting the contract capacity for Modernized DOS as follows: (i) for energy storage resources, the contract capacity of Modernized DOS plus the contract capacity for Rate DTS should not exceed the contract capacity for Rate STS, and (ii) for all Rate DTS loads, the contract capacity of Modernized DOS plus the contract capacity for Rate DTS cannot exceed physical and technical limitations.

## 5.4 Transition of Existing Market Participants under Rate DOS to Modernized DOS

354 If Modernized DOS is approved, the AESO proposes that the current Rate DOS provisions will continue to apply to the current users of Rate DOS until the expiration of the user's current one-year term. The existing users of Rate DOS would have until the expiration of their current one-year term to submit a SASR for Modernized DOS. Upon the expiration of their one-year term, they would then be subject to the Modernized DOS provisions.

## 6. Impacts Of Proposed Rate Design on Other Rates

### 6.1 Rate XOS and Rate XOM

355 The rates of the other opportunity services, Rate XOS and Rate XOM, will continue to be calculated under the Proposed Rate Design using the same methodology as under the Current Rate Design. The AESO has updated these rates to reflect the changes to Rate DTS under the Proposed Rate Design. The revenue generated from these rates will continue to be applied to the benefit of transmission system ratepayers.

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<sup>235</sup> Appendix W - ISO Tariff Section 9 Demand Opportunity Service, Subsection 6 Effect of Disqualification.

- 356 To determine Rate XOS and Rate XOM, Rate DTS costs are first converted, by component, to \$/MWh charges. The Rate XOS and Rate XOM rates are then allocated to the components of transmission costs which are attributable to those rates; specifically, the energy charge and the operating reserve charge.
- 357 The methodology used to calculate the Rate XOS and Rate XOM rates using components of Rate DTS remains appropriate as the changes to Rate DTS will align the rates more closely with cost causation principles (as further described above in section 5.3.3). Similar to other opportunity service rates, the exporter's contribution to the transmission costs associated with accommodating the flow of in-merit electricity is appropriate for the same reasons as described above in section 5.3.3.
- 358 Some stakeholders have expressed concern that Rate XOS and Rate XOM rates will increase by more than ten percent after they have been updated to reflect the changes to Rate DTS under the Proposed Rate Design. However, unlike Rate DTS under the AESO's Proposed Rate Design, the AESO considers mitigation to be inappropriate in these circumstances because firm ratepayers (domestic ratepayers) who are ultimately responsible for the costs of the transmission system should not pay a portion of the long-term costs of accommodating the flow of in-merit electricity for exporters for the reasons described in section 5.3.3.<sup>236</sup>
- 359 Further, as outlined in section 3.9, the AESO proposes to offer mitigation to firm ratepayers through opportunity service rates in order to allow firm ratepayers (domestic ratepayers) time to transition to the Proposed Rate Design. However, given the nature of opportunity services, exporters do not need additional time to transition. Exporters do not depend on opportunity services. These services are contracted on a short-term basis. If approved, the new rates will become effective on January 1, 2024. As such, the AESO maintains that exporters will have sufficient advance notice prior to January 1, 2024 and prior to entering into any new contracts for opportunity services. Given the cost reflective nature of the rates, offering additional time to transition would result in additional and unnecessary cross-subsidization.

## 6.2 Rate DTS Point of Delivery Charges

- 360 This application does not propose a change to the POD charge methodology. However, as a result of the updated functionalization the proportion of costs functionalized as POD will be updated. This will result in revised total amounts to be recovered through POD charges.
- 361 The AESO is not proposing any changes to the POD cost function approved in Decision 22942-D02-2019.<sup>237</sup> As such, the only input change resulting from this application is the change in the functionalization percentage, as set out in paragraph 163 of the application.
- 362 The change in the functionalization percentages calculated under the Proposed Rate Design sets the total costs collected from POD charges that, together with forecasted billing determinants, determine the POD charges. The resulting POD charges will be approved as part of the 2024 ISO Tariff rates update following the approval of the Proposed Rate Design.

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<sup>236</sup> This approach is consistent with EUB Decision 2007-106, at PDF page 92.

<sup>237</sup> See Decision 22942-D02-2019, at PDF page 64, para 201.

### 6.3 Rate FTS (Fort Nelson Transmission Service)

363 The AESO provides system access service to BC Hydro at Fort Nelson, British Columbia under Fort Nelson Demand Transmission Service (Rate FTS), which is essentially Rate DTS modified to reflect specific aspects of the service to Fort Nelson. Rate FTS differs from Rate DTS in four respects:

- The Rate FTS regional system charge is the greater of the Rate DTS regional system charge or a rate based on the levelized cost of the original ATCO Electric line providing service to Fort Nelson;
- Rate FTS does not include a POD charge as there are no POD facilities associated with the service to Fort Nelson;
- Rate FTS includes a specific termination provision addressing potentially unrecovered costs of the original ATCO Electric line providing service to Fort Nelson; and
- Rate FTS is not eligible for Balancing Pool Consumer Allocation Rider F.<sup>238</sup>

364 The Rate FTS proposed in this application continues those differences from Rate DTS, with one administrative modification resulting from the AESO's Proposed Rate Design: the name of the Regional System Charge has been revised to Billing Capacity Charge.

365 Other components of Rate FTS are the same as the comparable components of Rate DTS and are subject to the same changes as Rate DTS resulting from the AESO's Proposed Rate Design.

### 6.4 Rate PSC (Primary Service Credit)

366 Primary Service Credit (Rate PSC) applies to system access service provided at the POD to a market participant who receives system access service under Rate DTS and does not utilize transformation facilities owned by a TFO. Rate PSC rates relate to Rate DTS POD charges.

367 The AESO has made no changes to the Rate PSC calculation methodology based on the Proposed Rate Design and, consistent with the calculation of the 2021 ISO tariff primary service credit, the primary service credit is calculated as follows:

- 79% of the fixed (\$/month) component of the Rate DTS POD charge;
- 79% of the first three capacity tiers (up to 40 MW) of the Rate DTS POD charge; and
- 100% of the fourth capacity tier (incremental capacity above 40 MW) of the Rate DTS POD charge.<sup>239</sup>

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<sup>238</sup> Decision 22942-D02-2019 at PDF page 83-84.

<sup>239</sup> Decision 2010-606, at PDF page 38, para 178.

368 As the Rate DTS POD charges will change if the Commission approves changes to the functionalization approach, the AESO intends to update the Rate PSC credit value in the proposed ISO tariff update application prior to the effective date of the new tariff design.

## 7. Implementation

### 7.1 Implementation Considerations

369 In this application, the AESO has proposed a number revisions to the ISO tariff that will require changes to ISO tariff terms and conditions, rate sheets, and the AESO's billing system. This section explains in more detail how the AESO intends to implement the proposed changes in the following areas:

- changes to PILON;
- implementation of 12CP charge calculations; and
- updates to classification and functionalization data.

#### Changes to PILON

370 The AESO proposes two changes to expand PILON waiver provisions. The first will improve the accuracy of future load information, and the second will provide a period of time for market participants to adjust contract levels following the introduction of the Proposed Rate Design.

371 The ISO tariff should incentivize market participants to provide the AESO with information that it can rely on for dynamic planning and the development and timing of system transmission facility upgrades.<sup>240</sup> Over the course of the B&R Consultation, some stakeholders identified PILON charges as a barrier to providing the AESO with accurate information regarding their sites.

372 Market participants indicated that the AESO may not receive updates regarding potential reductions in a site's load requirements because of the PILON charge a site would face in the event of a contract reduction.<sup>241</sup> This results in a decrease in the quality of future planned load data provided to the AESO. The AESO recommends adjusting the PILON waiver provisions to ensure that accurate information is provided to enable the AESO to effectively plan for the efficient use of the transmission system.<sup>242</sup>

373 As such, the AESO recommends revising the PILON waiver applicability to sites that have not increased contract capacity in the last five years. This is a revision from the current provision restricting the PILON waiver applicability to sites that demonstrate the need for a contract reduction because of energy efficiency improvements and that have had no increases to their contract capacity in the last ten years. The AESO

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<sup>240</sup> Decision 3473-D02-2015, at PDF page 55.

<sup>241</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 6A (June 3, 2021) Stakeholder Comments from DUC, Alberta Direct Consumers Association (ADC), and Industrial Power Consumers Association of Alberta (IPCAA).

<sup>242</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Stakeholder Engagement Session 5 Presentation (March 25, 2021) at slide 80.

recommends these changes to reduce the barriers for current and future market participants to provide quality and timely information to the AESO, which the AESO uses in processes such as long-term planning.

374 Additionally, in recognition of the significant change resulting from the Proposed Rate Design, the AESO presented a contract adjustment period to stakeholders, which would allow for a PILON to be waived for a period of time in advance of the new rate design becoming effective.<sup>243</sup> The contract adjustment period would allow market participants to respond to adjusted pricing signals and communicate to the AESO any change in their load behaviour through the Rate DTS contract amount. No stakeholders opposed the contract adjustment period.<sup>244</sup>

375 To implement the contract adjustment period, the AESO would include a new provision in section 5 of the ISO tariff, *Changes to System Access Service*, under 'Reduction or Terminations of Contract Capacity'.<sup>245</sup>

376 The AESO proposes that the contract adjustment period would include the start and end dates by which the waiver could be received by the AESO, allowing the AESO adequate time to assess system reliability, adjust forecasting inputs and system access system agreements, and update the billing system.

377 The AESO proposes a one-year contract adjustment period and that such a contract adjustment request would need to be provided to the AESO at least three months before the requested contract change date. The one-year contract adjustment period would provide market participants with sufficient time to understand how the Proposed Rate Design impacts their sites before making changes to their contract capacity. The requirement for the request to be provided three months in advance of the contract change taking effect is necessary to allow the AESO time to implement the contract change, including updates to the billing system. The AESO proposes that the contract adjustment period start no later than three months in advance of the effective date of the new rates, to allow market participants sufficient time to adjust their contract capacity in advance of the new rates coming into effect.

378 As with all contract adjustments, the AESO must adjust any previous applicable construction contribution decisions to reflect the reduced contract amount and any additional contribution amounts that would be required in accordance with section 5.2 of the ISO tariff.

### **Implementation of 12CP charge calculations**

379 As described at paragraph 174, the AESO recommends that the calculation of 12CP charges occur on an hourly basis, rather than on a 15-minute interval basis. Currently, the AESO provides market participants with information on the timing of monthly coincident metered demand 15-minute intervals through the CMD Supplement posted on the AESO website, and hourly information on the level of demand is currently provided (for Rate DTS and Rate FTS) through the AESO's Operating Reserve Charge Supplement on the

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<sup>243</sup> Appendix B Part 3 - AESO Bulk and Regional Tariff Design Session 5 Presentation (March 25, 2021), at slide 80.

<sup>244</sup> Appendix B Part 3 – ADC, ANC, ConocoPhillips Canada, DUC, EPCOR Distribution and Transmission Inc, Heartland, IPCAA, Suncor, TCE, TransAlta, TPG, UCA, West Fraser Mills Ltd, Wolf Midstream Session 5 Comment Matrices Question 14, the majority of stakeholders who responded showed support for one or both of: a contract reset and changes to PILON several stakeholders declined comment.

<sup>245</sup> Appendix S – Blackline Comparison of Terms & Conditions Section 5.3(7) page 73.

AESO website.<sup>246</sup> To provide market participants with information about the timing of coincident peaks used in the 12CP charge calculations, the AESO will ensure that hourly Rate DTS and Rate FTS data by month is provided on the AESO website similar to the current reports posted.<sup>247</sup>

380 As previously discussed in section 3.5.6, the Proposed Rate Design includes a revision from the current single monthly coincident metered demand charge to the 5-Year Average 12CP Charge, transitioned over a five-year period.

381 The modified 12CP charge under the Proposed Rate Design continues to be calculated on a monthly basis. By example, a customer’s 12CP charge in January would be calculated by averaging their consumption during coincident peak in January and each January of the four preceding years. Table 7-1 provides an example of how this calculation is performed for the month of January using a 100 MW/month load profile.

*Table 7-1: Illustration of Calculation of Recommended Trailing Average of 12CP<sup>248</sup>*

Month	Consumption at Time of 12CP					Charging Basis
	Year t-4	Year t-3	Year t-2	Year t-1	Current Year, Year t	
<b>January</b>	105	95	85	105	110	<b>100</b>
<b>February</b>	95	90	85	100	80	<b>90</b>
...	...	...	...	...	...	...
<b>December</b>	110	105	115	120	100	<b>110</b>

382 The 12CP charge is levied on coincident peak demand in each month of each year, and will be phased in over a five-year transition period as follows:

- During the first year after the effective date of the new tariff design, the tariff coincident metered demand charge would be based on just a single month (as it is levied today, except with coincident peak assessed on an hourly basis)
- In the second year after the effective date of the new tariff design, the tariff coincident metered demand charge would be based on the average of a customer’s load during the hour of coincident

<sup>246</sup> Operating reserve charge supplement reports are available on the AESO website: <https://www.aeso.ca/rules-standards-and-tariff/tariff/operating-reserve-charge-supplement-2/>

<sup>247</sup> The coincident metered demand supplement report is available on the AESO website: <https://www.aeso.ca/rules-standards-and-tariff/tariff/coincident-metered-demand-supplement/>

<sup>248</sup> Appendix D - NERA Report, at PDF page 86, para 243, also see Appendix B Part 3 - AESO 5-year Average 12-CP Illustrative Tool v0.1 (April 13, 2021).



peak in the month of the current year and the same month of the preceding year, after the effective date of the new tariff design.

- Each following year one more month of a customer’s load during the hour of coincident peak would be included in the calculation of the average tariff coincident metered demand until the fifth year.
- All years after the fifth year, the current coincident metered demand value and four months of previous years’ actual coincident metered demand values would be averaged to determine the tariff coincident metered demand each month.

383 The five-year transition period calculations are illustrated below:

- Actual Coincident Metered Demand (ACMD): monthly demand at time of one hour maximum system demand (Rate DTS and Rate FTS)
- Tariff Coincident Metered Demand (TCMD): five-year same month average of ACMD

$$\text{Year 1 TCMD} = TCMD_{\text{Month}} = \text{Average}([Year 1]ACMD_{\text{Month}}) = [Year 1]ACMD_{\text{Month}}$$

$$\text{Year 2 TCMD} = TCMD_{\text{Month}} = \text{Average}([Year 2]ACMD_{\text{Month}}, [Year 1]ACMD_{\text{Month}})$$

$$\text{Year 3 TCMD} = TCMD_{\text{Month}} = \text{Average}([Year 3]ACMD_{\text{Month}}, [Year 2]ACMD_{\text{Month}}, [Year 1]ACMD_{\text{Month}})$$

$$\text{Year 4 TCMD} = TCMD_{\text{Month}} = \text{Average}([Year 4]ACMD_{\text{Month}}, [Year 3]ACMD_{\text{Month}}, [Year 2]ACMD_{\text{Month}}, [Year 1]ACMD_{\text{Month}})$$

$$\begin{aligned} \text{Year 5 TCMD} &= TCMD_{\text{Month}} \\ &= \text{Average}([Year 5], ACMD_{\text{Month}}, [Year 4]ACMD_{\text{Month}}, [Year 3]ACMD_{\text{Month}}, [Year 2]ACMD_{\text{Month}}, [Year 1]ACMD_{\text{Month}}) \end{aligned}$$

$$\begin{aligned} \text{Year 6 TCMD} &= TCMD_{\text{Month}} = \\ &= \text{Average}([Year 6], ACMD_{\text{Month}}, [Year 5]ACMD_{\text{Month}}, [Year 4]ACMD_{\text{Month}}, [Year 3]ACMD_{\text{Month}}, [Year 2]ACMD_{\text{Month}}) \end{aligned}$$

### Updates to classification and functionalization data

384 The AESO will update classification and functionalization values in future rates updates as described below.

385 In consideration of the relative stability of the classification methodology, and to balance a need to update the classification and functionalization based on more recent actual data against the significant resources required for updates and regulatory certainty for market participants, the AESO proposes to update the classification and functionalization values on a five-year schedule, barring unusual circumstances.

386 Given that the Proposed Rate Design is proposed to be effective in 2024, this would result in the AESO using the 2020 classification and functionalization values for ISO Tariff Updates in 2024, 2025, and 2026. The AESO would then update the 2020 classification and functionalization values in 2026 based on 2025 data to be applied to the tariff that would become effective on January 1, 2027, and for use until the 2031 ISO Tariff Rates update.

387 Subsequent updates would be undertaken every five years barring unusual circumstances. The AESO does not currently expect that changes to the transmission assets in service over the period from 2020 to 2025 would be so significant as to materially impact the functionalization ratios. Subsequent updates to the functionalization data (planned to occur in 2026) will reflect all facilities in service at that point in time.



## 7.2 Effective Dates and Calculation of New Rates

388 The AESO requests that the Proposed Rate Design be approved to be effective January 1, 2024. In order to facilitate this timeline, the AESO requests that the Commission approve this application on or before February 28, 2023. This will allow the AESO time to prepare and seek approval of any relevant compliance filing, start the contract adjustment period, file a rates update application, and program and test the rates in the AESO billing system.<sup>249</sup>

389 The AESO intends to file a 2024 ISO tariff update application in Q4 2023 in order to ensure that the monetary amounts in the rates can be updated and in effect on January 1, 2024. The ISO tariff update application will consist of formulaic updates to:

- (i) the AESO's annual revenue requirement, based on the AESO's updated forecast costs for 2024;
- (ii) rider, and maximum investment level amounts first approved in Decision 3473-D01-2015, then updated in Decision 21302-D01-2016 and further in Decision 22093-D01-2016, in accordance with an escalation factor;
- (iii) updated billing determinant forecast for 2024; and
- (iv) rate calculations resulting from functionalization, classification and other tariff design elements approved by the Commission in this proceeding.

## 8. Conclusion

390 The AESO requests approval of its Proposed Rate Design, as a cost reflective rate design that aligns with the legislative framework, the rate design principles that have been consistently articulated by the Commission and the B&R Objectives. The AESO further requests approval of its mitigation proposal in order to allow significantly impacted customers an opportunity to transition to the Proposed Rate Design. Finally, the AESO seeks approval of its Modernized DOS design to provide customers with further clarity and flexibility in how they manage their electricity withdrawals from the transmission system.<sup>250</sup> As described in this application, these proposals have been developed in conjunction with extensive stakeholder engagement and, in the case of the Proposed Rate Design, advice from leading transmission tariff experts.

391 In closing, the AESO notes that the Proposed Rate Design has been developed holistically as an integrated design, such that any modification to individual elements within the design should be approached with caution. Substantial modification to the Proposed Rate Design, to an alternative presented in Appendix O or alternatives not considered within this application may have unanticipated consequences to the design outcomes. In the event the Commission does not substantially approve the Proposed Rate Design or one

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<sup>249</sup> This schedule includes three months for the AESO to develop, consult on, and file the compliance filing and three months for Commission to issue a decision on or before September 29, 2023, at which time AESO would develop the 2024 ISO Tariff Update to implement the new rate design for rates effective January 1, 2024.

<sup>250</sup> For additional details refer to the AESO's Relief Requested, see section 1.5 of the application.

of the alternatives presented in Appendix O, the AESO requests that the Commission provide guidance and direct the AESO to consider and review the directed changes before implementation of any tariff design.

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All of which is respectfully submitted this 15<sup>th</sup> day of October 2021.

Alberta Electric System Operator

*“Electronically submitted”*

Per: Miranda Keating Erickson

Vice-President, Markets