April 12, 2021

To: AESO Stakeholders

Re: Alberta Utilities Commission Questions to the AESO with Respect to the Preferred Bulk and Regional Tariff Rate Design

On April 7, 2021, following Session 5, the AESO received the attached correspondence and list of questions from Alberta Utilities Commission staff ("the AUC staff questions") regarding the preferred Bulk and Regional Tariff rate design. The AESO appreciates the opportunity to consider the AUC staff questions as part of its stakeholder engagement and is of the view that this will bring efficiencies to the overall regulatory process.

The AESO is in the process of reviewing the AUC staff questions and determining how it will respond, and whether it will respond in an upcoming stakeholder session, in its Application or through another forum.

Yours truly,

Nicole LeBlanc
Director, Markets & Tariff

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April 7, 2021

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Dear Nicole LeBlanc:

AUC staff questions regarding the preferred Bulk and Regional Tariff design

1. Alberta Utilities Commission staff offer the following questions in order to provide the Alberta Electric System Operator (AESO) with an opportunity to consider them and, if it chooses, to address them either directly or in its anticipated Bulk and Regional Tariff application. They did not originate from, and have not been vetted or endorsed by, Commission members. They are not information requests.

2. The questions are generally premised on the preambles that precede them. The preambles also do not reflect the Commission's views. Challenges to the preambles, including providing alternative perspectives, are invited.

3. AUC staff's intention in providing these questions is to support regulatory efficiency by, to the extent it is able to, identifying in advance those issues and aspects of the proposed design that it feels may arise during the anticipated tariff proceeding.

4. Should you have any questions, please contact the undersigned at 403-592-4435 or by email at carl.fuchshuber@auc.ab.ca.

Yours truly,

Carl Fuchshuber
Director, Regulatory Strategy

Attachment

1. Design Objectives

Preamble:
The AESO stated that its design objectives include:[1]

- Cost Responsibility:
    - Cost recovery is based on cost causation, reflecting how transmission customers use the existing grid (Decision 22942-D02-2019)
- Efficient Price Signals: Price signal to alter behavior to avoid future transmission build
- Minimal Disruption: Customers that have responded to the 12 coincident peak (CP) price signal and invested to reduce transmission costs are minimally disrupted

Regarding its preferred rate design, the AESO stated:[2]

- Reflect Cost Responsibility
    - Resulting rates reflect costs of using the transmission system, including costs associated with in-merit flow of energy, local and peak use of the system
- Efficient Price Signals
    - Resulting rates provide transparent price signals to customers that better reflect the cost drivers of the transmission system

Additionally, the Distribution System Inquiry report commented on distribution rate design,[3] in paragraph 315, as follows:

> In summary, the four experts agreed at a conceptual level that distribution rate design should involve both (i) non-avoidable charges to recover the embedded costs of the existing infrastructure; and (ii) variable, avoidable charges to send a forward-looking price signal capable of affecting future system costs by altering current behaviour. In tandem, these two components incent customers to make economically efficient decisions in their consumption of electricity (including the choice between electricity drawn from the grid and self-supplied).

Questions:

1.1 Please provide the AESO's position on whether the features of non-avoidable and avoidable charges identified above also apply to transmission rate design. Why or why not?

1.2 Of the bulk and regional charges in the current Rate Demand Transmission Service (Rate DTS) rate design and in the preferred rate design, please explain which charges the AESO considers are non-avoidable and which charges the AESO considers to be avoidable.

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[1] Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 17.
[2] Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 45.
[3] Distribution System Inquiry, Final Report, Proceeding 24116, February 19, 2021. An outline of how charges may be referred-to as avoidable or non-avoidable can be found in sections 3.2 and 3.3.

1.3 Based on the response to 1.2 above, of the current bulk and regional charges, what per cent of the current and preferred bulk and regional transmission system is recovered via non-avoidable charges and what per cent of the system is recovered via avoidable charges?

1.4 Please explain how the AESO developed its definition of efficient price signals as set out in Slide 17. Please reconcile this definition with the statements made on Slide 45 regarding the preferred rate design, and comment on whether they are aligned. Does the last sentence of the quoted paragraph from the Distribution System Inquiry report align with the AESO's definition of efficient price signals?

1.5 The AESO determined that a marginal approach does not meet its rate design objectives based on five reasons. These reasons included that: efficient price signals would need to vary by location; and recovering a significant portion of residual costs would undermine the price signal's efficiency.[4]

(a) In the AESO's view, in the absence of being able to send locational price signals for transmission, is there no value in sending any marginal price signals to all Rate DTS customers as a postage stamp rate via the Rate DTS bulk and regional rate design?

(b) Has the AESO performed any analysis that could inform splitting bulk and regional costs into marginal and residual components? If so, please provide the results.

(c) Does the AESO have an analysis of what percentage of residual costs in its preferred rate design are to be recovered via avoidable versus non-avoidable charges?

(d) Please explain the statement that "… recovering [a] significant portion of residual costs would undermine [the] efficiency of [the] price signal"[5] in more detail.

1.6 Cost responsibility and cost causation principles:

(a) Please describe how the AESO defines cost responsibility.

(b) Please provide the paragraph numbers or sections relied on in Slide 17 describing cost responsibility in Decision 22942-D02-2019.[6]

(c) How does cost responsibility pertain to the recovery of existing (sunk) costs?

(d) Please describe how the AESO defines cost causation.

(e) How does cost causation pertain to the recovery of existing (sunk) costs?

(f) Please explain the rationale for recovering demand-classified transmission facilities via billing capacity, versus recovering demand-classified transmission facilities via a 12 CP (or other CP) mechanism.

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4 Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 31.
5 Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 31.
6 Decision 22942-D02-2019: Alberta Electric System Operator, 2018 ISO Tariff Application, Proceeding 22942, September 22, 2019.

1.7 Please explain whether minimal disruption[7] is intended to apply to the rate of cost change or to the overall magnitude of cost change over time, or both.

2. Breakdown of Bulk and Regional Transmission Costs

Preamble:
The AESO provided a spreadsheet showing transmission costs by project for the period 2006-2037, [8] which also identified the driver(s) of each project. AUC staff seek to further understand the drivers of system transmission projects and how they may relate to billing determinants.

Questions:
2.1 For each project listed in the spreadsheet, please identify:

(a) whether it is/would be functionalized as bulk, regional, or both. If both, please identify the approximate percentage of the total project costs relating to bulk system assets, and regional system assets;

(b) whether it is/would be classified as system-related or participant-related, or both. If both, please identify the approximate percentage of the total project costs classified as system-related and participant-related;

(c) for projects where the driver is ambiguous or mixed (e.g., Load / Generation), please provide a percentage allocation to each of load and generation, based on the AESO's best judgement.

2.2 Please generally comment on how the current and proposed incentives produced by the tariff may affect future costs. Please discuss what limitations, if any, restrict the effectiveness of the incentive (e.g., lack of locationality).

2.3 In the bulk and regional rate design, how should the ratio of avoidable to non-avoidable charges ideally be determined in order to strike a balance between using the existing transmission facilities versus building additional transmission? Under what circumstances would it be efficient to build additional transmission facilities?

3. Preferred Design

Preamble:
The AESO's preferred rate design relies on an embedded approach, with modifications intended to better reflect cost causation.

Questions:
3.1 Please identify how the AESO's preferred rate design might change in the absence of its objective of minimizing disruption to 12 CP responders, or its concerns about the current economic climate.

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7 Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 31.

8 Drivers and Costs – Historical and 2017 LTP System Projects, Consultation Session 1, posted March 9, 2020.

3.2 In the AESO's preferred rate design, bulk system costs are recovered using billing determinants that appear to be avoidable, e.g., by five-year average 12 CP demand and total energy consumption. Does the AESO anticipate that bulk system costs will be substantially fixed in the near to mid-term? If so, please explain why it is appropriate to recover all bulk system costs through avoidable charges.

3.3 In the AESO's preferred rate design, regional system costs are recovered using billing determinants that appear to be both non-avoidable and avoidable, e.g., by billing capacity and total energy consumption. Does the AESO anticipate that regional system costs will be substantially fixed in the near to mid-term? If so, please explain why it is appropriate to recover regional system costs with a combination of avoidable and non-avoidable charges.

3.4 The preferred rate design has retained the functionalization of bulk and regional portions of the transmission system based on operating voltage.

(a) Please explain why the AESO considers the functionalization of the transmission system should continue to be broken into bulk and regional systems.

(b) Does the AESO consider that voltage (as used in the 2018 transmission cost causation study update[9]) remains a meaningful characteristic that functionalizes the transmission system in Alberta into bulk and regional systems?

(c) In the AESO's experience, is 240 kilovolt transmission used (and/or increasingly being used) to serve a regional transmission function?

3.5 The preferred rate design appears to utilize readings of peak regional demand and peak regional generation to calculate the portion of bulk and regional costs to be allocated to energy, which is recovered through an all hours energy charge.

(a) Please explain why an all hours energy charge is appropriate for recovering costs which were determined based on readings at single instances in time.

(b) Please discuss whether average readings of area loads and generation would be a better allocator of bulk and regional costs to energy as compared to peak readings.

3.6 Please provide a more detailed explanation of the calculations completed in the step of "Minimum and actual systems for Alberta are estimated as the sum of the minimum and actual systems across all planning areas."[10] For example, did the AESO determine the actual (or current costs) for the transmission system in each planning region?

3.7 In the preferred rate design, the classification between demand-related and energy-related costs is completed before functionalizing between bulk and regional costs. Has the AESO assessed whether it would be appropriate to define new functional categories to replace (or augment) the existing bulk and regional categories to better align with the preferred rate design? If new functional categories were determined, would it be possible for the functionalization step to precede the classification step, as typically done to design rates? Please explain.

3.8 Is the number of points of delivery (PODs) a driver of regional transmission costs? For example, is there a relationship between the number of PODs in a region and regional

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[9] Exhibit 22942-X0025, Appendix D - Transmission System Cost Causation Study 2018 Update, page 12.
[10] Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 39.

transmission costs? How would regional transmission costs change if load within each region remained the same, but there was only one POD in each region that served the region's load? Based on the response, would it be appropriate to recover some portion of regional costs through a fixed per POD charge that is invariant to any metered quantities? Why or why not?

3.9 For the year 2019, please provide the total energy usage of all end-use customers on the interconnected electric system that either receive system access service through Rate DTS (because they are a direct customer of the AESO) or receive a flow through of the Rate DTS rate structure through their distribution facility owner (DFO) (such as FortisAlberta Inc.'s Rate 65).

3.10 If all users of the electric system (such as all DFO customers) were interval metered, and received a flow through of all the elements of the AESO tariff, please explain whether the AESO considers that the preferred rate design would still meet its rate design objectives of cost responsibility, efficient price signals, minimal disruption, simplicity, innovation and flexibility.[11] If not, please explain what modifications the AESO would propose to the preferred rate design to make it appropriate. Do any elements of the preferred rate design become inappropriate if substantially more customers have an incentive and the ability to respond to the price signals?

4. Load Growth

Preamble:
To better explore the relationship between historical load growth and transmission system costs, it may be useful to review historical forecasts of load growth and actual load growth. Additionally, a common dataset and consistent terminology may benefit all parties. Terms below in **bold** are referenced from the AESO's Consolidated Authoritative Document Glossary, and are presented in a paraphrased manner. If the data requested below is not readily available, please consider providing it in support of the future application.

Questions:
4.1 Please provide hourly load data from 2010 to 2020 in the categories identified in the included Excel spreadsheet. The questions below refer to the spreadsheet. Please note that Row 2 has been included in the Excel spreadsheet as an example of the AUC staff's understanding. Please provide any clarifications in how the mechanisms work or can be reconciled.

(a) These questions relate to "**system load,**" which is the total, in an hour, of all metered demands under Rate DTS, Rate FTS and Rate DOS of the ISO tariff, plus transmission system losses.

[11] Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 45.

(i) Is the "coincident peak **metered demand**" (e.g., in Rate DTS) measured as the maximum of "**system load,**" the sum of Rate DTS and Rate FTS alone, or other? Please explain.

(ii) AUC staff understand that the "coincident peak" is currently measured in a 15-minute interval, and not in a 60-minute interval. In the included Excel spreadsheet, please indicate the hours in which the monthly coincident peak would have occurred if measured on a 60-minute interval (column M). Please also indicate the hours in which the 15-minute CP demand that was used for billing purposes occurred (column N).

(b) These questions relate to "**Alberta internal load**" (AIL) which represents, in an hour, "**system load**" plus load served by on-site generating units, including those within an industrial system and the City of Medicine Hat, which the AESO, using SCADA[12] data calculates as the sum of each generating unit and aggregated generating facility in Alberta and the Fort Nelson area in British Columbia, plus import volumes minus export volumes.

(i) Please provide an example of how, in calculating AIL, the AESO accounts for the load at a single site with on-site load being served by on-site generation, such as for an industrial system. Is the AESO able to determine the portion of the site's total internal load which is being served by on-site generation and if so, how? (e.g., using SCADA data and revenue meter readings.)

(ii) Please provide an hourly column of the aggregate internal load that is masked by on-site generation (column I in the attached Excel spreadsheet). This would include the portion of internal load at self-supply and export sites, sites with industrial system designations, Fort Nelson, and Medicine Hat, that is supplied by on-site generation and thus not metered under Rate DTS.

(iii) Please provide an example of how in calculating AIL, the AESO adjusts for the output of distribution-connected generation, and any load on distribution systems it may mask.

(iv) Please provide an hourly column of the aggregated internal load that is masked by distribution connected generation (column J in the attached Excel spreadsheet).

(c) For each column in the attached Excel spreadsheet, please explain where this information is publicly available, if at all. (e.g. "system load" is published as part of PSM Charge summary, Rate FTS is the public asset identifier "BCH" on energy trading system, transmission system losses are the public asset code "ABLL" on energy trading system, etc.)

(d) The AESO makes public various reports referring to total load and/or "**system load,**" such as on the energy trading system report "payments to suppliers on the

12 SCADA: Supervisory control and data acquisition.

margin" or PSM Charge summary,[13] the operating reserve charge supplement[14] as well as through public data requests.[15] In reviewing these reports, the results for total load or "**system load**" do not match across the various reports. Please explain why that would be the case.

(e) Are there other types of load not accounted for, either in "**system load**" or "**Alberta Internal Load**"? If so, what are they? (e.g. sites with on-site load for which SCADA data does not exist, distribution-connected generation that is less than 5 megawatts (MW), micro-generating units, etc.)

(f) Currently, not all load on distribution systems may be metered under Rate DTS because of distribution-connected generation. However, when the adjusted metering practice is triggered at a substation, the amount of load being masked by DCG may decrease. As a result, "**system load**" may increase, with a commensurate decrease to the term mentioned in (b)(iv) above (column J of the attached Excel spreadsheet). Does the AESO intend on tracking these changes in order to differentiate changes in load from changes in metering configuration which result from the adjusted metering practice?

(g) With respect to transmission planning conducted by the AESO:

(i) Does the AESO plan the future of the transmission system based on "**system load,**" "**Alberta Internal Load**" or other?

(ii) How would a potential industrial system with 100 MW of on-site generation, 60 MW of on-site load, but only 30 MW of contracted DTS capacity, be incorporated into the AESO's forecasts and planning?

4.2 Please provide annual data from 2006 to 2020 in the following categories. If the sum of the Excel column C for "Rate DTS" in hourly detail from the Excel spreadsheet above does not match the annual "Metered Energy (All Hours)" for any given year in the table provided below, please explain the discrepancy.

Rate DTS Billing Determinant	**Units**	**2020 Recorded**	**2020 Forecast**	**2019 Recorded**	**2019 Forecast**	…
Coincident metered demand	MW-months					
Total Billing Capacity	MW-months					
Total Contracted Capacity	MW-months					
Highest Metered Demand	MW-months					
Metered Energy (All Hours)	GWh					

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13 http://ets.aeso.ca, Historical, Select Report, "--- PSM Charge Summary."
14 https://www.aeso.ca/rules-standards-and-tariff/tariff/operating-reserve-charge-supplement-2/
15 https://www.aeso.ca/market/market-and-system-reporting/data-requests/

Rate DTS Billing Determinant	Units	2020 Recorded	2020 Forecast	2019 Recorded	2019 Forecast	…
DTS Market Participants	Customer-months					

5. 12 CP Demand as a Driver of Bulk and Regional Transmission Costs

Preamble:
The AESO presented data suggesting a weak correlation between line loading and demand levels,[16] as well as an illustration of historical peak line utilization which also suggested a weak correlation between CP periods and peak line loading.[17]

Questions:
5.1 Various consumer groups have stated that there may be up to 400 MW of demand response or price responsive load on the system. Is it possible to simulate system conditions that would have occurred during a representative subset of the historical CP conditions[18] if CP responsive load did not respond to the CP? If so, please provide.

5.2 Has the AESO performed any analyses that might inform an assessment of the relative risk of transmission system failure during monthly CP load periods compared to during all other periods? If not, can the AESO comment on what it might expect from such an analysis? If not, would the AESO be willing to perform such an analysis?

5.3 The graph on Slide 35[19] shows the total flows on bulk lines experiencing usage greater than 90 per cent of their annual peak. For some lines, it may be the case that a line's peak usage may not be near the line's maximum loading capability. Additionally, lines with relatively high load factors may experience loading that is within 90 per cent of their annual peak during many periods in a year. Is there an alternative indicator that the AESO could compute that may more accurately quantify the stresses being experienced by the transmission system at different times? If so, please provide.

5.4 Please comment on the feasibility and appropriateness of implementing a time-of-use tariff component designed to recover the marginal portion of bulk and regional transmission costs in a manner that might correspond more closely to the correlation between system load and transmission line loading indicated in the AESO's analysis.

5.5 Please comment on the feasibility and appropriateness of implementing a tariff component (such as an energy charge) with a dynamic rate, where the rate fluctuates in real time based on the loading of transmission facilities relative to their maximum capabilities. Could this type of tariff component provide a price signal that is more effective at reducing future

16 For example, Load to Power Flow Correlation Summary Charts - 2018, Consultation Session 1.
17 Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 35.
18 As shown on Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 35.
19 Bulk and Regional Tariff Design, Stakeholder Engagement Session 5, March 25, 2021, Slide 35.

transmission cost than the other tariff components considered by the AESO? Please explain.

6. Storage

Preamble:
The AESO has proposed that a modernized demand opportunity service rate (Rate DOS) with expanded eligibility might be suitable for providing service to energy storage customers so that they could make use of transmission capability that would not otherwise occur and contribute to recovering its cost without driving the need for additional transmission capacity. The AESO has also identified that a use of Rate DOS is to allow customers with their own generation to avoid curtailing load when their generation is unavailable without affecting their DTS billing capacity.

Questions:

6.1 How does the AESO reflect low load factor consumers (such as customers that normally self-supply) in its planning studies?

6.2 If the AESO were to plan the bulk and regional transmission system to accommodate energy storage users, how would it include them in its planning studies?

6.3 Does the AESO have a definition of what a standby or interruptible rate would be? How would the definition of standby or interruptible service rate differ from an opportunity service rate?

6.4 Does the AESO have an analysis of locations where the installed capacity may be higher than the contracted capacity at various substations?