Bulk and Regional Tariff Design Stakeholder Engagement Session 6A hosted on June 3, 2021

I. Purpose and objectives of the session

The purpose of this session is to engage stakeholders in a discussion of Session 5 stakeholder feedback or follow-up and key questions raised by the Alberta Utilities Commission (AUC) staff, and to provide additional clarity and build mutual understanding of the AESO's preferred rate design and stakeholder concerns. The session objectives include:

- Present preferred rate design, including energy storage treatment, to stakeholders
- Present and discuss path to achieving minimal disruption
- Present bill impact summary and assumptions
- Provide Bill Impact Tool
- Begin to discuss implementation considerations

II. Session agenda

Time	Agenda Item	Presenter
8:00 – 8:15	Welcome, introduction, purpose, and session objectives • Application filing extension requestion	AESO / Stack'd
8:15 – 8:45	Recap of preferred rate design and summary of stakeholder feedback received	AESO
8:45 – 9:15	Appropriateness of the flat energy charge • Time of use and dynamic pricing • On-peak versus off-peak charges • Min/max load factor energy charges • Q&A	AESO / NERA
9:15 – 10:15	Cost recovery through avoidable charges and efficiency • Avoidable and non-avoidable charges • Efficiency • Q&A	AESO / NERA
10:15 – 10:45	Break	
10:45 – 11:45	Analysis of self-supply in response to the preferred rate design • Self-supply analysis • Q&A	AESO / NERA

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Time	Agenda Item	Presenter
11:45 – 12:45	Analysis of the short-term impact of the preferred rate design on the energy market • Energy charge • Coincident peak charge • Q&A	AESO
12:45 – 12:55	Session close-out and next steps	AESO

III. Attendees

Company
2332823 Alberta Ltd.
Alberta Direct Connect Consumers Association (“ADC”)
Alberta Electric System Operator (“AESO”)
Alberta Energy
Alberta Newsprint Company (“ANC”)
Alberta Utilities Commission (“AUC”)
AltaLink Management Ltd.
AltaSteel Inc.
ATCO Electric Ltd.
Best Consulting Solutions Inc.
BluEarth Renewables Inc.
Brubaker & Associates, Inc. on behalf of ADC
Capital Power
Cenovus Energy
Chapman Ventures Inc.
Chymko Consulting, on behalf of Cities of Red Deer and Lethbridge
Consumers Coalition of Alberta (“CCA”)
City of Lethbridge
CNRL
Customized Energy Solutions
Canada West Ski Areas Association (“CWSAA”) / VIDYA Knowledge Systems
DePal Consulting Limited
DePal Regulatory Solutions Inc.
Dow Chemical Canada ULC

Company
Dual Use Customers
ENMAX Corporation
EPCOR Distribution & Transmission Inc.
ERCO Worldwide
FortisAlberta Inc.
Heartland Generation Ltd.
Imperial Oil
Independent Power Producers Society of Alberta (“IPPSA”)
Industrial Power Consumers Association of Alberta (“IPCAA”)
International Paper
Lionstooth Energy (“LTE”)
Matt Ayres Consulting
Millar Western Forest Products
NERA Economic Consulting
NextEra Insights Inc.
Northern Sunrise County
Norton Rose Fulbright Canada LLP
PGSC
Power Advisory LLC
Rodan Energy Solutions
Signalta Resources Limited
Solas Energy Consulting Inc.
Suncor Energy Inc.
TC Energy
The Office of the Utilities Consumer Advocate (“UCA”)
TransAlta Corporation
Turning Point Generation
Voltus Energy Canada Ltd.
Wolf Midstream
Stack’d Consulting, Inc.
Attendees by phone
14038746762

IV. Overall outcomes from the day

The main objective of the session was for the AESO to provide additional clarity and build mutual understanding of the AESO's preferred rate design and respond to stakeholder concerns. Participants engaged in discussion and overall, some stakeholders felt that this was a valuable session that allowed them to share their perspectives and feedback, while others felt that the session did not provide the value that they were seeking.

V.Session highlights

Captured below are the highlights of the questions and discussion on a topic-by-topic basis. For a detailed review of the session, please refer to the session recording, posted at www.aeso.ca.

Topic 1: Recap of the preferred rate design

i. Stakeholder commentary

- Clarifying comments:
  - *Suncor:* On Slide 18 (Minimum system illustrative calculation), is there double counting that's occurring here if you are not counting the flows between areas? Should we first recognize that all demand must be met from somewhere and can come from any region with only what's left over to be viewed as energy related in this calculation?
  - *TransAlta:* Could you explain the rationale behind the change in the method to first allocate between demand and energy and then functionalize between bulk and regional?

ii. AESO / NERA clarification

- Response to clarifying comments:
  - On Slide 18, the assessment is not in relation to the transfer of power between areas but to the relative size of the system within each area. By using the peak demand within an area as a proxy for the size of transmission in that area, and then accounting for any additional peak generation as a proxy for the additional transmission in that area, we are developing a measure of the degree to which the system is sized to accommodate demand and the degree to which it is sized (in addition) to accommodate generation.
  - The allocation between demand and energy as a first step is based on allocating the costs of transmission between demand and energy, since those are the two drivers of investment. Then allocating the demand costs between the different drivers of demand using bulk and regional distinction.

Topic 2: Appropriateness of the flat energy charge

i. Stakeholder commentary

- Clarifying questions:
  - *EPCOR:* I don't understand why the capacity required by generation is recovered by an energy charge. It seems that all capacity requirements, whether driven by load or generation, is capacity nonetheless and should be recovered through a demand-related charge?

- *CCA:* Why is it important to consider the generation-related portion as energy related? Could it also be considered demand related and proportionately applied to other components of DTS?
- *ADC:* The transmission system is grossly oversized, so should the first step in the calculation be to determine the actual minimum system needed for current demand and generation, the costs for that minimum system and then apply your methodology? Then examine an appropriate methodology for the costs of the system built for future use.
- *IPCAA:* Is the ISO tariff proposal really a backdoor method to a change in the Transmission Regulation (T-Reg)? If the T-Reg were changed to allocate costs evenly between load and generation, generators would charge back that transmission cost via an energy charge. The difference being the AESO's transmission energy charge is flat and generation would likely shape that transmission charge to better reflect demand.
- *IPCAA*: Did the AESO look at the distribution of congestion or forecasted congestion hours in all of these areas when the transmission was built? Is it flat?

- Some participants were concerned with the AESO's design and use of individual areas:
  - *ANC:* On Slide 18, the major criteria for the tariff design that NERA has proposed is very arbitrary. There also seems to be double counting. Did the AESO look at the regional areas rather than all of the individual areas and if they did, what are the pros and cons compared to the 46 individual areas?
  - *Heartland Generation*: On Slide 18, should the analysis not be done on net peak load and net peak generation rather than gross?
  - *Heartland Generation*: Why do the relative sizes of the regions matter?
  - *Suncor:* The problem we're running into here is the arbitrary component comes into play with the size of the different areas. The size of the region impacts the split between demand and energy allocation. We cannot ignore the bulk and regional split and at the same time use a regional delineation to determine an allocation.

ii. AESO / NERA clarification

- Response to clarifying questions:
  - Need to have a distinction between the capacity of generation versus the use of energy. Generation capacity might be related to capacity costs, but the use of transmission to flow energy is an energy related cost. It would not be aligned with cost causation to allocate energy related costs to another, different characteristic of load.
  - The ISO tariff is required to recover the prudent costs that have been already approved. What the methodology is looking to do is to characterize or create a proxy for what should be allocated to demand related charges and what should be allocated to energy related charges.
  - Regarding congestion, the AESO did think about whether congestion was an appropriate metric. The challenge with using that as a metric is that the costs we're seeking to allocate have been incurred to avoid congestion from happening. Looking at the incidents of congestion doesn't tell us very much about the rationale behind building particular pieces of transmission.
- Response to questions regarding the use of areas:
  - The purpose of the AESO's methodology isn't to look at energy availability, it's to look at what size of the transmission system is needed and exists within the province. That's why

we're looking at peak load and peak generation as a proxy to measure the extent to which the transmission system is sized in each area.

- If we were to look at a reserve margin approach, we could take peak demand and compare it to generation and the ratio between the two could tell you something. But the size of the transmission system needed to accommodate these things depends on where and when these demands take place. Don't agree that there's double counting – the methodology we've proposed is pragmatically and reasonably accurate in identifying the degree to which transmission in each part of the system is sized to accommodate demand and energy.
- The AESO's rationale for using peak load and peak generation is that the size between areas is very different. That difference might not be captured with a netting process. For a given area that's much larger than another, you might not be able to capture the proportional size difference if the inflows are similar.
- Regarding the relative sizes of the areas, the difference in size matters because the minimum system requirements differ with the size of the area.
- The definition of the areas is not arbitrary; they were *not* created solely for the purpose of this tariff. They were created to represent the distinct parts of the transmission system for use in other areas (i.e., planning).

Topic 3: Cost recovery through avoidable charges and efficiency

i. Stakeholder commentary

- Some participants challenged the AESO's understanding of cost causation and efficiency:
  - *IPCAA:* How does your flat energy argument hold given that the majority of customers only see distribution tariffs?
  - *DePal Consulting:* I disagree with the premise that somehow the AESO's proposal is efficient. In the short term, you're going to have costs from customers who move to self-supply being pushed onto other customers. It seems that the customers who choose to remain on the grid will subsidize those that choose to leave.
  - *TransAlta:* How does recovering long-run transmission costs through a variable charge comply with the intergenerational equity part of the cost causation principle?
  - *CCA:* While having location-based marginal costs is not possible in Alberta, why is it not possible to provide marginal cost signals based on the avoided system cost of an incremental demand unit? This could be based on the avoided demand cost of a self-generator or it could be based on system expansion studies.

ii. AESO clarification

- Response to questions regarding cost causation and efficiency:
  - We're trying to design a transmission tariff that's as cost reflective as possible. In order to give parties the best information we can around the cost structures, we want to ensure the tariff structure aligns as closely as possible to the cost structure of transmission.
  - It's appropriate to have the costs associated with the need for energy recovered through the variable charge on energy. Ensuring that the tariff aligns as closely as possible with cost causation principles promotes intergenerational equity.
  - Regarding efficiency, in the short term, there will be a change and adjustment to allocation in costs. But the process that we're adopting is really about how we get the

long-term signals right. It's important to separate out the short-term efficiency change from the potential long-term efficiencies.

- Regarding the potential of marginal cost signals in Alberta, it is important to recognize that the foundation of a marginal approach is that costs vary by area. What the AESO is trying to do with the embedded approach is to come up with a representative signal that averages costs and behaviours across the province.

Topic 4: Analysis of self-supply in response to the preferred rate design

i. Stakeholder commentary

- Clarifying comments:
  - *DePal Consulting:* We started this process four years ago with the problem that the AESO identified as high grid defection. However, the preferred rate design the AESO has chosen is worse than the rate design that the AESO initially identified as a problem. Why is the AESO recommending a design that's making the problem worse?
  - *Solas Energy:* Not understanding how the AESO is connecting the carbon price and the self-supply decrease? Would have thought it would be the opposite – as carbon price increases, self-supply would be a more likely response.
  - *CCA:* Future self-supply increases are more likely through solar than gas. Could this change the AESO's conclusion on the maximum shift to self-supply?
  - *Matt Ayres Consulting:* On Slide 49 (Changes in consumption in response to change in tariff), the AESO's prediction is reduced use of the grid for energy and increased use of the grid for backup. Can the AESO explain why a 17 per cent charge on capacity recovers the costs associated with providing backup?
  - *ADC:* The resulting rate design will have an impact on the industrial companies – if this change in tariff results in a particular sector of these manufacturing companies to no longer be economic in Alberta, what would you suggest would be the outcome if you can't make money under Alberta's new tariff?
  - *Suncor:* To the extent we still need new supply on the grid, can that same technology or similar enough technology be deployed behind the fence? If so, are we sending the right incentive to do so?

    To what extent does the tariff change the usage of existing generation? Due to the transmission credit, inefficient peakers can compete with combined cycles and run baseloaded behind the fence – doesn't this counteract the carbon tax?
  - *Wolf Midstream:* Directionally the new tariff should be constrained to keep high load factor / high load customers whole (and reduce grid defection). What would tariff look like if high load factor / high load were kept whole?
- Some participants pushed back on the assumptions that the AESO made in its report:
  - *Dual Use Customers:* The customers most impacted by the tariff design are high load factor industrials who use co-generation. The report misses the mark on co-generation and solar technologies. The AESO engages customers in the design and assumptions so this report looks more like justification for the tariff rather than providing any help to customers.
  - *DePal Consulting:* The AESO used the pool price from 2018-2019 for the report, but if you look at the current price in the first five months in 2021, the pool price is significantly

different. As a customer looking at self-supply options, we're looking for the forecast of future pool prices; the data the AESO is using is strange.

- *CCA:* The NERA study seems to take a very static view of the industry. There is a much bigger change that seems to be taking place than what the study has taken into consideration. With decreasing billing determinants on the energy side, we're going to see higher and higher energy costs leading to a death spiral. How is the AESO going to deal with that?

ii. AESO/NERA clarification

- Response to clarifying comments:
  - The issue with 12-CP is that the more people respond to it, the greater the incentive to avoid it, as it becomes more expensive. While there will be a shift when we go from the current tariff to the new tariff in the first stage of adjustment, that response becomes more limited since it does not lead to increasing incentives for additional response through self-supply.
  - Regarding carbon prices and self-supply, the effect of the carbon price increase means that gas generation technologies become less economic when compared to potentially larger and more efficient units. Therefore, the increase in carbon price will cause the cost of behind-the-meter gas generation to increase.
  - Regarding the 17 per cent charge on capacity, the costs we're allocating are the shared costs of the transmission system for different purposes that are used to different degrees by participants. We have allocated different types of behaviours on the system and that's where the percentages are derived from – the extent to which a customer is making use of the system is reflected in the charges they face.
  - Regarding highly impacted customers, the AESO is focused on targeted mitigation with these particular impacted companies. We have identified the impact on these customers and are working on a transition plan through our ongoing targeted mitigation.
  - Regarding behind the meter generation, the AESO is seeking to reflect the cost structure of transmission. The carbon tax is rising and will cause the economics of behind the meter gas generation to worsen over time. This will tend to offset some of the increase in incentive to run gas generation behind the meter.
- Response to questions regarding the report and its assumptions:
  - The AESO made its assessment by looking at a broad range of potential scenarios with self-supply and different choices that customers could face. We have tried to take a broad view and not narrow in on a specific customer group or scenario.
  - Regarding cogeneration, the AESO acknowledges that cogeneration is a generation option. However, there are a whole range of options available for customers.
  - The analysis that was done in the report is forward looking to the extent that we're anticipating the growth in carbon pricing in the future. Technology may change over time, which may enable customers to self-supply – we haven't speculated how the market will change as technology changes.

Topic 5: Analysis of the short-term impact of the preferred rate design on the energy market

i. Stakeholder commentary

- Clarifying comments:

- *Solas Energy:* On the illustrative example, what percentage of energy reduction are you estimating due to behind-the-meter (BTM) generation?
- *IPCAA:* One million dollars of efficiency loss is roughly how many MWs are responding to that $9 increase?
- *Alberta Newsprint:* The report only talked about the negatives of self-supply, none of the positives. Have they produced a similar report, would you share that report with us?
- *Suncor:* If we switch to the new rate design, we have an overall higher pool cost. At the same time, total load is decreasing. Does it seem realistic that we have increased energy charges and unchanged transmission charges, spread over a lower total load at a time when loads are telling the AESO that the total cost of delivered energy is skyrocketing?
- *Suncor:* If the numbers are not comparable, *i.e.* if we cannot look at a net impact, why is the AESO presenting us with these numbers/this analysis?
- *Capital Power:* Worried that this analysis does not hit the mark or address some of the concerns stakeholders have. Given the fact that people have already invested in responding to CP, how does the AESO justify that there will be any efficiency change at all? How would the AESO's analysis change taking into consideration that some of the 12-CP response is from behind the meter generation and the $9/MW hour energy charge will incent that further?

ii. AESO clarification

- Response to clarifying comments:
  - Regarding the number of MWs that are responding to the $9 increase, it is approximately 4 MW on average (over all hours, which doesn't show the shape and magnitude in the response in select hours). In many hours, we would see no response and then there are other hours where there is much more response.
  - We will assess whether additional information would be helpful to better understand the preferred rate design, including the request for 12-CP response in 2013 versus 2020.
  - Regarding the overall higher pool cost, CP intervals are at least somewhat correlated with higher prices in the energy market – it's possible that a smaller increase in load during these CP intervals could have a larger impact on the pool price than the decrease in load due to energy charge in all hours. But it's also possible the impact could go the other way and we think that in the scope of the short run response, it would be expected to be a small change either way. We're not making a claim that the energy market price will change in a particular way, we're looking at what the efficiency impact.
  - We heard from several stakeholders that they were concerned with how recovering transmission costs would impact the efficiency of the energy market. We estimated that quantity of impact to be $1 million from the energy charge. We think that this energy market impact is small given that moving to a tariff with better price signals will benefit the system overall. Additionally, to the extent that customers use more energy during CP hours, that may offset the efficiency loss from the energy charge.