Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – December 5, 2016

Background

On December 5, 2016, the AESO and stakeholders participated in a consultation meeting to discuss (1) evaluation of potential changes to deferral account reconciliations and Rider C, *Deferral Account Adjustment Rider*, ("Rider C"); (2) transmission cost causation study update; (3) point-of-delivery cost function database update; and (4) application process and next steps. Based on discussion at the meeting, the AESO invited written comments from stakeholders on the information presented at the meeting. The written comments from stakeholders are consolidated below.

The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Stakeholder engagement ► 2018 ISO tariff application.

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) Evaluation of Potential Changes to Deferral Account Reconciliations and Rider C (Slides 6 – 61)
A. Impact of Early Tariff Updates (Slides 15 – 21): ***i. Early tariff updates significantly reduce transfers between services in a deferral account reconciliation;*** ***ii. Early tariff updates do not entirely eliminate transfers between services; and*** ***iii. AESO needs to better manage tariff update process.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the AESO's efforts in completing an annual tariff update to be effective January 1st to help minimize deferral accounts.
The Alberta Storage Alliance: No comment.
Capital Power: Capital Power supports the AESO's efforts to pursue early tariff updates and regulatory efficiency to reduce and/or eliminate deferral account balances and Rider C imbalances among customers
Depal Consulting Limited: No comment.
Dual Use Customers ("DUC"): i. DUC is of the view that timely and accurate annual updates will help AESO customers better manage their electricity costs by paying the required revenue requirement closer to "real time". ii. Timely updates will not eliminate deferral account balances; however, a better matching of revenue and costs will help reduce DAR balances iii. The AESO does need to a better job of filing annual updates by the end of Q3 each year for the following year; esp. during periods like the past 5 + years where revenue requirements have been increasing significantly.

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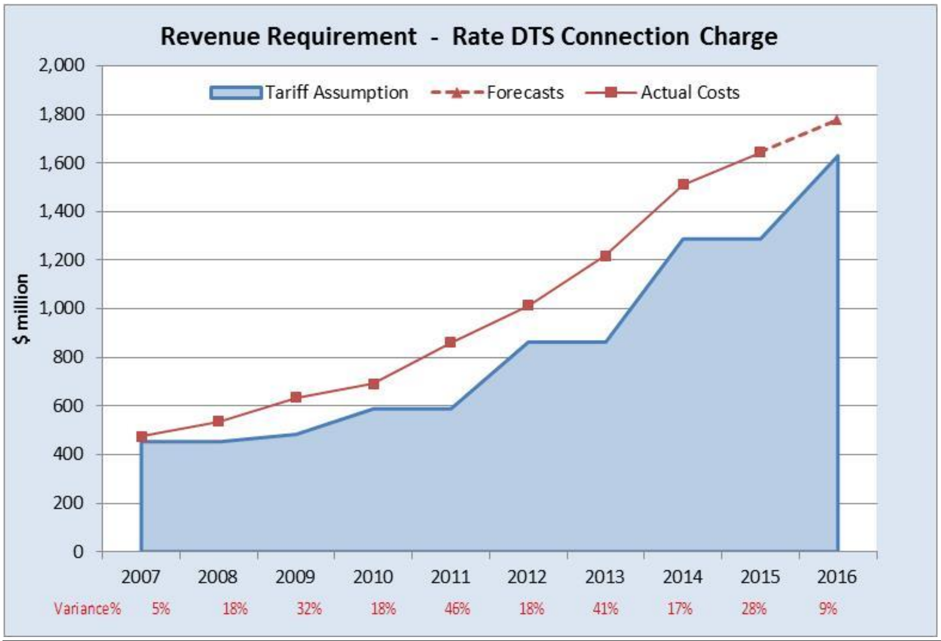
Stakeholder Comment
EPCOR Distribution and Transmission Inc. (“EDTI”): EDTI supports early tariff updates.
Industrial Power Consumers Association of Alberta (“IPCAA”): IPCAA supports a move to early tariff updates. Regulatory lag is a real concern for customers. IPCAA concurs that the AESO needs to better manage the tariff update process – and be as transparent as possible regarding the filing schedule.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group (“PS Group”): 1) The PS Group supports the AESO filing tariff rate updates in a timely basis. To be most effective in reducing the use of Rider C or the retrospective DAR true-up process for allocating under-forecasted costs, tariff applications should be based on an accurate forecast of the calendar year revenue requirement, especially for Wires costs. 2) In the past decade, the Connection Charge forecasts used to prepare tariff rates have been materially lower than actual costs, in some years by more than 40%. The approved rates were accordingly too low and the AESO relied materially on collecting monies using Rider C (temporarily) and material billing adjustments using the retrospective DAR true-up process (permanently). (See chart below.) 3) Material reliance on Rider C and retrospective DAR true-ups should be avoided. 4) Tariff updates should include amendments to the terms and conditions when needed to improve clarity or to avoid ambiguities, if necessary. 5) The PS Group registers its disappointment that the AESO did not use the 2017 ISO Tariff Update application as an opportunity to adjust its processes to prevent the shifting of substation related charges to DTS customers that did not cause the AESO to incur substation related costs by way of after-the fact bill adjustments using the retrospective DAR true-up process. This process should not be used to effect cost shifting.

Stakeholder Comment



Rocky Mountain Power (2006) Inc.:

No comment.

B. Impact of Changing Rider C Structure (Slides 22 – 30):

- ***i. Rider C as percentage almost eliminates transfers between services in a deferral account reconciliation; and***
- ***ii. Some transfers between services still exist but are small.***

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the AESO's efforts in modifying Rider C to a percentage in order to minimize transfers between customers.

The Alberta Storage Alliance:

No comment.

Capital Power:

No comment.

Depal Consulting Limited:

No comment.

Dual Use Customers ("DUC"):

The DUC directionally supports moving from a $/MWh Rider C charge to a percentage of revenue charge as quickly as possible. The DUC suggests that a percentage of revenue charge could be derived for each major tariff component; for example, x% for bulk charges, y% for regional, etc. to better match where costs and revenues are not aligned.

EPCOR Distribution and Transmission Inc. ("EDTI"):

EDTI supports changes which reduce the size of deferral account reconciliations however is unsure how

Stakeholder Comment
Rider C structure impacts deferral accounts amounts and transfers. More information is required.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA supports a move to charging Rider C as a percentage.
NRStor Inc: No comment.
On Power Systems: No comment.
Primary Service Group ("PS Group"): 1) Rider C and the retrospective DAR true-up adjustments should be applied consistent with the cost causation principle and rate design used when calculating the tariff published rates. They should not promote cost shifting between customers, especially in the case of the retrospective DAR true-up process, when bills are adjustment after the fact to eliminate a the AESO's revenue shortfall/surplus. 2) Using the customer's percentage of actual revenue collected as a means of allocating the deferral account balances (revenue shortfall/surplus) is mathematically consistent with adjusting the original rates by the percentage change sufficient to eliminate a deferral account balance; on the condition that the "revenue collected" matches the charges and credits arising from tariff published rates that are directly established from the respective revenue requirement cost component. 3) As a result, to align Rider C with the original rate design for tariff rates and the retrospective DAR true-up adjustments, Rider C should be designed as a percentage increase to the tariff published rates. 4) The PS Group therefore generally supports a Rider C that is based on percentage changes to the tariff approved rates, subject to Rider C being applied to Rate PSC. 5) Rate PSC is a tariff published rate that is based on the Connection Charge revenue requirement forecast. It represents the substation related charges otherwise due under Rate DTS. If, when preparing the tariff published rates, the Connection Charge revenue requirement is increased, the Rate DTS rates and Rate PSC credits both increase correspondingly. Making billing adjustments when applying Rider C should lead to the same result as if the AESO had known in the first instance that the Connection Charge revenue requirement was to increase. Only then will Rider C adjustments uphold the cost causation and rate design principle that DTS customers that do not cause the AESO to incur substation costs are not liable to pay substation related charges. Rider C should not lead to cost shifting.
Rocky Mountain Power (2006) Inc.: No comment.
A. Impact of Changing to Production Year Basis (Slides 31 – 40): ***i. Rider C as percentage by production year eliminates transfers between services in a deferral account reconciliation;*** ***ii. In practice there will still be some transfers resulting from timing impacts, such as if an annual cost becomes known partway through the year.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports this change.
The Alberta Storage Alliance: No comment.

Stakeholder Comment
Capital Power: No comment.
Depal Consulting Limited: No comment.
Dual Use Customers (“DUC”): The DUC directionally supports Rider C as percentage by production year to match the DAR by production year.
EPCOR Distribution and Transmission Inc. (“EDTI”): EDTI supports changes which reduce the size of deferral account reconciliations however is unsure how Rider C structure impacts deferral accounts amounts and transfers. More information is required.
Industrial Power Consumers Association of Alberta (“IPCAA”): IPCAA supports charging Rider C as a percentage by production year.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group: No comments at this time.
Rocky Mountain Power (2006) Inc.: No comment.

*****AESO notes that the following topic is a matter currently in front of the Commission in the 2015 deferral account reconciliation application, Proceeding 21735*****

B. Impact of Changing to Net Revenue Allocation Methodology (Slides 42 – 50):

- ***i. Consideration of merits to net revenue methodology***
- ***ii. Net tariff revenue for a service would include charges and credits related to contracted load service:***
  - ***a. Rate DTS, Demand Transmission Service, and Rate FTS, Fort Nelson Demand Transmission Service***
  - ***b. Rate UFLS, Demand Underfrequency Load Shedding Credits***
  - ***c. Rate PSC, Primary Service Credit***
  - ***d. Riders A1-A4, Transmission Duplication Avoidance Adjustments***
  - ***e. Payments in lieu of notice (PILONs) for reductions or terminations of contract capacity under section 9 of ISO tariff.***
- ***iii. Net tariff revenue for a service would not include charges under Rate DOS, Demand Opportunity Service.***
- ***iv. Net tariff revenue for a load service would not include charges or credits related to non-load service.***

Stakeholder Comment
Alberta Direct Connect Consumers Association ("ADC"): ADC awaits the Commission decision on this item.
The Alberta Storage Alliance: No comment.
Capital Power: No comment.
Depal Consulting Limited: No comment.
Dual Use Customers ("DUC"): The DUC directionally supports net tariff services for direct wires related charges under rates DTS and PSC. The DUC suggests that additional review of the application of net tariff services is required for the DAT riders and UFLS as it may not be appropriate to apply Rider C to these tariff charges.
EPCOR Distribution and Transmission Inc. ("EDTI"): EDTI supports changes which reduce the size of deferral account reconciliations however is unsure how allocation methods impact deferral accounts amounts and transfers. More information is required.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA supports appropriate cost causation – and awaits the decision from the AUC on Proceeding 21735.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group: If, when preparing the tariff published rates, the Connection Charge revenue requirement is increased, the Rate DTS rates and Rate PSC credits will both increase correspondingly; the rates under Rate UFLS or Riders A1 to A4 will not change. The retrospective DAR true-up process should lead to a consistent result. Only then will the DAR process uphold the cost causation and rate design principles used to calculate the tariff published rates. The "net revenue" methodology should therefore be based only the "revenue" corresponding to the rates that are a derived directly from the amount of Connection Charge costs, such as Rate DTS rates and Rate PSC credits. Revenue based rates that are not directly based on the level of the Connection Charge costs should be excluded, such a Rate UFLS and Rider A1 to A4. Additionally, revenue associated with opportunity rates should be excluded because they are based on a "value of service" design not "cost of service" design. Accordingly, only Rate DTS and Rate PSC should be included in the "net revenue" used to allocate the Connection Charge deferral account balances. To demonstrate these points in detail consider that using past "revenue collected" to allocate unforeseen new costs is mathematically consistent with adjusting the original rate by a percentage change sufficient to eliminate the revenue shortfall. For example, "revenue collected" (r) from a customer might equal the approved rate (P) times the customer specific billing units (q). Original Revenue Collected (r)= q*P=qP

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If, after the fact, costs are higher than forecasted and more revenue needs to be collected from customers, then bills will be adjusted to collected the revenue shortfall, i.e. the deferral account balance (D). Using each customer "revenue" as a percentage of total revenue collected (R) to allocate the deferral account balance "D" can be represented as follows:

Final Revenue Collected $(fr)=r+[r/R]D$

And, by simple substitution of variables, this equation can be re-written as:

Final Revenue Collected $(fr)=qP^*((R+D)/R)$

Assuming, for example, a 10% revenue shortfall, this equation then becomes:

Final Revenue Collected $(fr)=qP^*(110\%)$

Therefore, allocating deferral account balances using a customer's percentage of total revenue is mathematically consistent with adjusting the original rate (P) by a percentage change sufficient to eliminate the revenue shortfall. In this example, by 10%. The same revenue would have been collected from customers if the original rates where 10% higher when preparing the tariff published rates in the first instance.

Connection Charge Costs

The above illustration can be extended in detail to account for the three Rate DTS Connection Charge sub-rates (Bulk (P_B), Regional (P_R) and POD (P_P)) and the Rate PSC credit $(0.79P_P)$, whose purpose is to eliminate the substation related charges for DTS customers that did not cause such costs.

For example, the "revenue collected" can be shown as:

$$fr= [(q_B P_B+q_R P_R+q_P P_P)-(q_P 0.79P_P)] \quad + \quad [((q_B P_B+q_R P_R+q_P P_P)-(q_P 0.79P_P))/R]^*D$$

Again, by simple substitution of variables, this equation can be re-written as:

$$fr=q_B P_B ((R+D)/R)+q_R P_R ((R+D)/R)+q_P P_P ((R+D)/R)-q_P (0.79P_P)((R+D)/R)$$

And, assuming a 10% revenue shortfall, this equation becomes:

$$fr=q_B P_B (110\%)+q_R P_R (110\%)+q_P P_P (110\%)-q_P (0.79P_P)(110\%)$$

By using a "net revenue" methodology that accounts for Rate PSC credits, the resulting after-the-fact adjustment of bills will result in the same amount of charges to customers as if the AESO had known in the first instance that its costs were going to be higher; in this instance, by 10%. Such an outcome upholds the cost causation principle underling the tariff published rates (i.e. DTS customers that do not cause substation related costs are not liable to pay substation-related charges) and rate design that set the substation related charges at a prescribed ratio of POD rate (79% for the first four tiers and 100% for the final tier).

The AESO proposed a "net revenue" that includes Rates DTS and PSC and other aspects of the ISO tariff including Rate UFLS and DAT Riders A1 to A4. Doing so would convert the above equation to the following:

$$fr=q_B P_B (110\%)+q_R P_R (110\%)+q_P P_P (110\%)-(q_P 0.79P_P)(110\%)-q_U P_U (110\%) \; +q_A P_A (110\%)$$

adjusted charges: Bulk Regional POD PSC UFLS Rider A1

This amounts to proposing an after-the-fact adjustment to credits and charges associated with Rate UFLS and Riders A1 to A4. There is no principled cost causation or rate design reason for this to occur. If the AESO knew beforehand that its revenue requirement should be 10% higher, it would not change the "rates" for Rate UFLS or Rider A1 to A4 because these are based on calculation methodologies that are completely unrelated to the level of the Connection Charge costs (e.g. Wires or AESO G&A).

The onus rests with the AESO to demonstrate why the retrospective DAR true-up process for the Connection Charge cost components should cause bills to be adjusted in a manner that is consistent with

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changing the rates after the fact, outside of Rate DTS and Rate PSC, to eliminate a Connection Charge revenue shortfall. Would the approved rates have been different if the AESO used a forecast for the Connection Charge revenue requirement that was 10% greater in the first instance?
Rocky Mountain Power (2006) Inc.: No comment.
C. Possible Future Changes to Rider C (Slides 51 – 55): ***i. AESO suggests maintaining quarterly Rider C and annual deferral account reconciliations for at least a few more years then evaluate success of early tariff updates and Rider C restructuring.***
Alberta Direct Connect Consumers Association (“ADC”): ADC considers this a reasonable approach.
The Alberta Storage Alliance: No comment.
Capital Power: Capital Power does not object to the AESO’s proposal.
Depal Consulting Limited: No comment.
Dual Use Customers (“DUC”): The DUC submits that the current Rider C energy charges should be replaced with a tariff design that better tracks costs. A percentage of revenue charge appears be superior to an energy change, esp. for DUC members who can incur large bulk demand charges with minimal energy consumed from the grid. Early updates will help; however, the AESO cannot be compelled to filing annual updates and the DUC is seeking tariff solutions that are more robust.
EPCOR Distribution and Transmission Inc. (“EDTI”): No comment.
Industrial Power Consumers Association of Alberta (“IPCAA”): IPCAA supports keeping the quarterly Rider C and annual deferral account reconciliations in place for now. If there are problems or delays with the restructuring, it will be needed.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group (“PS Group”): 1) The PS Group supports the AESO preparing tariff applications using more accurate revenue requirement forecasts, especially in respect of the Wires costs (i.e. no longer discounting the future Wires costs by using only 72% if the incremental TFO revenue requirement requests). 2) While this is expected to materially reduce the reliance on Rider C and the retrospective DAR true-up billing adjustments, the PS Group supports the continued use of Rider C to recover under-forecasted

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costs and an annual retrospective DAR true-up process, subject to both procedures allocating costs consistently with the cost causation principles as approved for the calculation of rates published in the tariff. 3) This means Rider C and the retrospective DAR methodology should be applied to the revenue collected from DTS customers for the Connection Charge costs, being the sum of the amounts from Rate DTS and Rate PSC for the DTS customers that did not cause substation related costs. 4) The PS Group is opposed to using Rider C or the retrospective DAR methodology to shift costs on to customers that did not cause those costs, especially substation related charges being shifted to DTS customers that did not cause the AESO to incur substation related costs.
Rocky Mountain Power (2006) Inc.: No comment.
D. Timing and Implementation Options (Slide 56 – 61): ***(1) Include Rider C and deferral account reconciliation methodology changes in 2018 tariff application in Q2 2017.*** ***(2) File separate application in Q1 2017 for Rider C and deferral account reconciliation methodology changes.*** ***(3) File application in Q1 2017 for interim Rider C changes with request to make existing reconciliation methodology interim.*** ***(4) Any other practical options?***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the option that will result in the timely implementation of the change. Option 2 or 3 is preferred. The ADC also requests the AESO complete the 2016 deferral account reconciliation as soon as reasonably practical.
The Alberta Storage Alliance: No comment.
Capital Power: Capital Power does not object to the AESO's proposal.
Depal Consulting Limited: No comment.
Dual Use Customers ("DUC"): The DUC requests that the Rider C and deferral account reconciliation methodology changes, including moving Rider C to a percentage of revenue and the inclusion of PSC in the DAR allocation methodology, be implemented as soon as practical and in a way that will include the entire 2017 calendar year, upon AUC approval. Option 3 could achieve these objectives, or the AESO could amend its application in Proceeding 22093 to ask for the requested changes to be applied to the 2017 production year.
EPCOR Distribution and Transmission Inc. ("EDTI"): EDTI supports changes which reduces the magnitude or eliminates the need for Rider C. Any changes to Rider C timing needs to be coordinated with timing requirements of the DFO's quarterly transmission access charge deferral account rider process (Decision 2012-304).
Industrial Power Consumers Association of Alberta ("IPCAA"):

Stakeholder Comment
IPCAA supports Option #3. This will allow changes to be made effective (on an interim basis) in mid-2017.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group ("PS Group"): 1) The PS Group requests that the Rider C and deferral account reconciliation methodology changes, including moving Rider C to a percentage of revenue and the inclusion of PSC in the DAR allocation methodology, be implemented as soon as practical and in a way that will include the entire 2017 calendar year, upon AUC approval. Option 3 could achieve these objectives. Preferably, the AESO could amend its application in Proceeding 22093 (2017 ISO Tariff Update) to seek approval of these changes so they can be applied to the 2017 production year. 2) The PS Group suggests the simplest means of maintaining the cost causation and rate design principles is to physically merge the terms and conditions of Rate PSC within Rate DTS. Alternatively, Rate PSC should be identified as an intrinsic extension of Rate DTS and directly netted from the DTS charges on the AESO invoices (i.e. use a single line item billing approach).
Rocky Mountain Power (2006) Inc.: No comment.
(2) Transmission Cost Causation Study Update (Slides 62 – 70)
A. Scope of 2018-2020 transmission cost causation study: ***i. Use identical methodology to 2014-2016 transmission cost causation study;*** ***ii. Use same data sources plus additional sources;*** ***iii. For years 2018-2020;*** ***iv. Present draft results to stakeholders in January 2017; and*** ***v. Include study results in the 2018 ISO tariff application.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports this methodology.
The Alberta Storage Alliance: No comment.
Capital Power: No comment.
Depal Consulting Limited: Agree with the strategy and use of internal resources.
Dual Use Customers ("DUC"): The DUC supports this approach. The DUC would be pleased to work with the AESO to review the Transmission Cost Causation Study Update prior to the GTA filing.

Stakeholder Comment
EPCOR Distribution and Transmission Inc. ("EDTI"): EDTI supports updating the existing cost causation study.
Industrial Power Consumers Association of Alberta ("IPCAA"): When will this be presented to stakeholders in January? IPCAA would appreciate the opportunity to work with the AESO to review the Transmission Cost Causation Study Update prior to the GTA filing.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group: No comment.
Rocky Mountain Power (2006) Inc.: No comment.
(3) Point-of-delivery (POD) Cost Function Update (Slides 71 – 75)
A. AESO plans to complete POD cost function database using the following capacities in order to present the following cost curve options (Slide 74): ***(1) Pre-2014 Practice – Contracted greenfield and contracted upgrade projects, include 0 MW projects;*** ***(2) Current interim practice – Contracted greenfield and contracted upgrade projects, exclude 0 MW projects;*** ***(3) As requested in Decision 2014-242 – Contract greenfield and installed upgrade projects; and*** ***(4) Not requested but will do – Installed greenfield and installed upgrade projects;***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the AESO preparing the 4 cost curve options for purposes of comparison.
The Alberta Storage Alliance: No comment.
Capital Power: No comment.
Depal Consulting Limited: Agree.
Dual Use Customers ("DUC"): The DUC submits that the development of the POD cost function could benefit from additional stakeholder consultation prior to the filing of the 2018 GTA. Installed costs should be aligned with increased capacity, not contract capacity, as the DUC argued in the last GTA. The DUC recommends that the AESO work with its customers to develop principles, objectives and work scope on how best to improve the POD cost function.

Stakeholder Comment
EPCOR Distribution and Transmission Inc. (“EDTI”): No comment.
Industrial Power Consumers Association of Alberta (“IPCAA”): Will the results of this update be presented to stakeholders? The AESO would benefit from working with customers to review and improve the POD cost function.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group (“PSG”): No comment.
Rocky Mountain Power (2006) Inc.: No comment.

B. The AESO plans to use criteria to evaluate the different options in Point (3)A above. Please comment on the proposed criteria below or add additional criteria (Slide 75):

(1) Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC;	Support - 5 Oppose - 0 Indifferent - 1
(2) Consistency with past practice (post-2007);	Support - 1 Oppose - 1 Indifferent – 4
(3) Maximize number of projects in database;	Support - 3 Oppose - 0 Indifferent – 3
(4) Statistical criteria for project exclusion	Support - 0 Oppose - 2 Indifferent – 4
(5) Degree of relationship between installed capacity and contract capacity;	Support - 4 Oppose - 1 Indifferent – 1
(6) "Lumpiness" of installed capacity and standard transformer sizes;	Support - 1 Oppose - 0 Indifferent – 3
(7) Number of assumptions required to determine the MWs	Support - 0 Oppose - 0 Indifferent – 4
(8) Behavior of market participants'' relationship to MWs	Support - 2 Oppose - 0 Indifferent – 3
(9) Potential to eliminate substation fraction;	Support - 0 Oppose - 0 Indifferent – 5
(10)Treatment of split between DTS and STS shared costs;	Support - 3 Oppose - 1 Indifferent – 0
(11)Rates reflect true costs per MW;	Support - 4 Oppose - 1 Indifferent – 1
(12)Equal services treated equally, unequal services treated unequally;	Support - 1 Oppose - 0 Indifferent - 3

(13)Sending the "right" price signal;	Support - 4 Oppose - 0 Indifferent – 1	***(14)***
(14)Fairness of treatment of customers with charges based on two different approaches; and	Support - 3 Oppose - 0 Indifferent – 1	***(15)***
(15)Any others?	None	***(16)***

Alberta Direct Connect Consumers Association ("ADC"):

ADC requires further discussion on the topic to understand the full cost consequences of the different approaches and merit of one versus another.

The Alberta Storage Alliance:

No comment.

Capital Power:

Capital Power opposes any changes to item 10 (based upon Decision 2013-421) that could potentially shift more costs to STS contracts.

Depal Consulting Limited:

I have left items blank since I am not sure what you mean by the short description. Generally support the method that shows a strong relationship between costs and rates with a fair level of investment (compared to historical levels). Also, moving from the existing method must only occur if a new method displays a significant improvement. Finally, the impact of moving methods and the price signal that could be sent must also be considered. AESO should hold open the discussion on the multiplier level required for investment following this analysis.

Dual Use Customers ("DUC"):

The DUC is not able to respond to many of the 15 criteria as we are not sure of what is meant or being proposed. The DUC suggests that additional discussion is required to better understand the meaning and impact of these options. The DUC would be pleased to work with the AESO to review these options prior to the GTA filing.

EPCOR Distribution and Transmission Inc. ("EDTI"):

No comment.

Industrial Power Consumers Association of Alberta ("IPCAA"):

Please note that "Indifferent" selections also reflect the fact that the criteria are unclear. The AESO should consider presenting this information to interested stakeholders, to solicit better responses.

NRStor Inc.:

No comment.

On Power Systems:

No comment.

Primary Service Group:

No comment.

Rocky Mountain Power (2006) Inc.:

No comment.

(4) Application Process, Timeline and Next Steps (Slides 76 – 79)

A. AESO presented status on a number of 2018 ISO tariff application scope items (Slide 77) and a tariff tentative timeline.

Alberta Direct Connect Consumers Association ("ADC"):

The ADC supports the timeline and encourages the AESO to keep this initiative a priority in light of the other 2018 AESO initiatives.

The Alberta Storage Alliance:

No comment.

Capital Power:

Does the AESO foresee any impacts to the scope and/or timelines of its 2018 General Tariff Application in light of the announced AESO-led capacity market transition and DOE-led transmission policy review?

Depal Consulting Limited:

The AESO stated that it might provide the rate impact model update in a year. The detailed model is required sooner to support the operating budgets for participants and to enable the evaluation of generation opportunities. The update recently provided is of little help since many underlying assumptions are not present. It would be beneficial to the market for the AESO to prepare the update in a timelier manner such as with the 2018 tariff filing.

Dual Use Customers ("DUC"):

The tentative time lime appears to be reasonable.

EPCOR Distribution and Transmission Inc. ("EDTI"):

EDTI requests that the 2016 DAR application be filed prior to July 1st to allow the DFO's to comply with the AUC direction to include the AESO DAR amounts in their respective annual transmission access deferral account applications (Decision 2012-304, paragraphs 69 and 77). The DFOs have been directed to file their annual transmission access deferral account applications between July 1 and August 10 each year (Decision 3334-D01-2015, paragraph 86). EDTI notes that the DFOs typically file their respective SAS rates on September 10th of each year as part of their annual PBR rate adjustment filings for the upcoming year (Decision 2012-237). EDTI requests that, to the extent possible, the AESO file its tariff update prior to September 10th of each year to allow the DFOs to reflect the AESOs tariff update in their respective annual rate adjustment filings.

Industrial Power Consumers Association of Alberta ("IPCAA"):

As mentioned above, IPCAA members are concerned with regulatory lag, as such, the AESO should be cautious of slippage from the proposed timeline

NRStor Inc.:

No comment.

On Power Systems:

No comment.

Primary Service Group ("PS Group"):

1) The PS Group requests the AESO expedite the changes to Rider C and the DAR true-up process to

ensure that substation related costs are no longer unfairly shifted to customers that did not cause the AESO to incur substation costs through after-the-fact charges imposed using the DAR true-up process.

2) The PS Group suggests the simplest means of maintaining the cost causation and rate design principles is to physically merge the terms and condition of Rate PSC within Rate DTS. Alternatively, Rate PSC should be identified as an intrinsic extension of Rate DTS and directly netted from the DTS charges on the AESO invoices (i.e. use a single line item billing approach).

Rocky Mountain Power (2006) Inc.:

No comment.

Additional Comments

Alberta Direct Connect Consumers Association ("ADC"):

ADC appreciates the efforts on improving the Rider C methodology as well as the opportunity to provider input in advance of the filing.

The Alberta Storage Alliance:

The Alberta Storage Alliance (ASA) is an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. Our membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. The ASA is advocating a technology neutral approach and believes smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid.

The ASA believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both dispatchable load and generation with unique operational characteristics that can serve to benefit the Alberta market.

The ASA notes that on page 77 of the "AESO 2018 Tariff Consultation" the issue of the application of the DTS rate to energy storage is characterized as being 100% complete. ("Clarify tariff for energy storage - 100% complete".) Respectfully, the ASA disagrees with this characterization. The AESO has decided to apply the existing STS and DTS tariff structure to energy storage with no clarification as to why these rate structures apply to a system that is not equivalent to a load and a generator due to the nature of its operation.

The AESO's decision to apply STS and DTS to energy storage ignores and prevents the realization of the benefits that energy storage can provide to the AIES including grid reliability, grid stability, integration of renewables and reductions in the overall cost of electricity to Albertan consumers. The ASA does believe that rationale exists to support the application of rates similar to import and export opportunity service rates or some modified tariff for energy storage transmission service. However, the AESO has not given due consideration to the similarities between energy storage and imports/exports or the differences between energy storage and load customers.

The ASA is keen to work collaboratively with the AESO to resolve these issues; the ASA and its members have made numerous attempts to embark on discussions with the AESO regarding a host of issues surrounding the integration of energy storage into the AIES, including the application of the DTS and STS service rates. We remain committed to continued open dialogue on all issues in order to find an effective solution. We implore the AESO to engage in further dialogue considering alternative energy storage rate structures to DTS and STS. While the ASA would prefer to address the issue in collaboration with the AESO, the AESO has stated that the only means of recourse is to intervene in the 2017 GTA. This is unfortunate for both storage proponents and the remainder of the Alberta market, as intervention adds time and expense to the GTA process.

Capital Power:

Compliance with Directions 5 through 8

Capital Power submitted comments to the AESO on September 1, 2016 regarding the Scope of AESO 2017 ISO Tariff Consultation. Contained in those comments were several clarification questions posed to the AESO which have not been addressed. Capital Power is specifically interested in the AESO's response to questions concerning changes to the ISO tariff's terms and conditions to align with the Commission's Decision 3473-D02-2015 (Compliance with Directions 5 through 8). Please provide an update on the AESO's work to date on complying with the Commission's Directions 5 through 8 and any discussions with the AUC concerning integration with Proceeding 20922 and procedural correctness.

Capital Power reiterates its request that the AESO provide stakeholders with a preliminary list of its positions as they relate to the various topics outlined by the Commission in AUC Bulletin 2015-15 and elaborated in Section 6 of Decision 3473-D02-2015, and how the AESO plans to integrate these positions into its Tariff via changes to the terms and conditions.

Capital Power reiterates that it does not support re-opening the issue of applying system project advancement costs to generators in the 2017 GTA.

CIP Standards Generator Cost Recovery

Please provide an update on the AESO's work to date to address direction from the Commission regarding cost recovery from Critical Infrastructure ("CIP"). Capital Power requests that the AESO provide stakeholders with a preliminary list of its positions as they relate to CIP cost recovery; in this respect a stakeholder session may be helpful.

Dual Use Customers ("DUC"):

The DUC appreciates the opportunity to submit comments and looks forward to working with the AESO and other customers.

Industrial Power Consumers Association of Alberta ("IPCAA"):

Thank you for the opportunity to comment.

NRStor Inc.:

NRStor Inc. (NRStor) is a member of the Alberta Storage Alliance (ASA) – an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. The ASA's membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. NRStor is supportive of the ASA's technology neutral approach and believes smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid.

NRStor believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both load and generation with unique operational characteristics that can serve to benefit the Alberta market.

NRStor notes that on page 77 of the "AESO 2018 Tariff Consultation" the issue of the application of the DTS rate to energy storage is characterized as being 100% complete. ("Clarify tariff for energy storage - 100% complete".) Respectfully, NRStor disagrees with this characterization. The AESO has decided to apply the existing STS and DTS tariff structure to energy storage with no clarification as to why these rate structures apply to a system that is not equivalent to a load and a generator due to the nature of its operation.

The AESO's decision to apply STS and DTS to energy storage ignores and prevents the realization of the benefits that energy storage can provide to the AIES including grid reliability, grid stability, integration of renewables and reductions in the overall cost of electricity to Albertan consumers. NRStor does believe that rationale exists to support the application of rates similar to import and export opportunity service rates or some modified tariff for energy storage transmission service. However, the AESO has not given due consideration to the similarities between energy storage and imports/exports or the differences between energy storage and load customers.

NRStor is keen to work collaboratively with the AESO to resolve these issues; NRStor, alongside the ASA and its members, has made numerous attempts to embark on discussions with the AESO regarding a host of issues surrounding the integration of energy storage into the AIES, including the application of the DTS and STS service rates. We remain committed to continued open dialogue on all issues in order to find an effective solution. We implore the AESO to engage in further dialogue considering alternative energy storage rate structures to DTS and STS. While NRStor and the ASA would prefer to address the issue in collaboration with the AESO, the AESO has stated that the only means of recourse is to intervene in the 2017 GTA. This is unfortunate for both storage proponents and the remainder of the Alberta market, as intervention adds time and expense to the GTA process.

On Power Systems:

On Power Systems, as a market participant focused on power quality in Alberta and throughout North America, supports the view that energy storage assets within the Alberta Electric System can offer several benefits to reliability, power quality, and renewables integration, in addition to supporting Alberta's Greenhouse Gas reduction objective. Some energy storage technologies also have unique advantages in their ability to perform ancillary services such as frequency regulation.

However, the tariff rules in place today, whereby storage assets are obliged to pay transmission / distribution fees when absorbing energy, act as an unfair disincentive to implementing grid energy storage in Alberta.

We assert that grid-connected energy storage assets, when managed to charge from the grid during off-peak times, should not be burdened with transmission & distribution tariffs.

Further, we support the use of energy storage, as a recognized asset class by the AESO, to provide ancillary services such as frequency regulation to the Alberta market.

We recommend re-assessment of tariffs affecting energy storage assets, in the spirit of encouraging 'best use' of energy storage technologies within the Alberta Electric system. On Power Systems is eager to work with regulators to achieve this goal. As a reference, it may be instructive to refer to tariff treatments used by other ISO's such as in PJM, Hawaii, California.

Rocky Mountain Power (2006) Inc.:

Rocky Mountain Power (RMP) respectfully submits comments in response to AESO 2018 ISO Tariff Consultation specifically regarding notes that on page 77 of the "AESO 2018 Tariff Consultation" that the issue of the application of the DTS rate to energy storage is characterized as being 100% complete. ("Clarify tariff for energy storage - 100% complete".) Respectfully, RMP disagrees with this characterization. The AESO has decided to apply the existing STS and DTS tariff structure to energy storage with no clarification as to why these rate structures apply to a system that is not equivalent to a load and a generator due to the nature of its operation.

RMP suggests that the AESO take note of the Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) dated Nov. 17, 2016 recommendation for the application that proposed "to require each RTO and ISO to revise its tariff to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets". RMP additionally agrees with comments filed by Schulte Associates LLC to FERC AD20-16-000 on May 23, 2016 that "A MW of dispatchable load that a storage facility can add to the system on command (e.g., in a time period when renewable resources are over-generating) has more value than a MW of customer load that just happens randomly due to customer behavior" and that if energy storage developers "cannot monetize the benefits, they cannot invest in storage, and the storage does not happen."

RMP believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both dispatchable load and generation with unique operational characteristics that can serve to benefit the Alberta market.

The AESO's decision to apply STS and DTS to energy storage ignores and prevents the realization of the benefits that energy storage can provide to the AIES including grid reliability, grid stability, integration of renewables and reductions in the overall cost of electricity to Albertan consumers. RMP does believe that rationale exists to support the application of rates similar to import and export opportunity service rates or some modified tariff for energy storage transmission service. However, the AESO has not given due consideration to the similarities between energy storage and imports/exports or the differences between energy storage and load customers.

RMP is a member of the Alberta Storage Alliance (ASA) and through the ASA is keen to work collaboratively with the AESO to resolve these issues; the ASA and RMP have made numerous attempts to embark on discussions with the AESO regarding a host of issues surrounding the integration of energy storage into the AIES, including the application of the DTS and STS service rates. RMP remains committed to continued open dialogue on all issues in order to find an effective solution. RMP implores the AESO to engage in further dialogue considering alternative energy storage rate structures to DTS and STS. While RMP would prefer to address the issue in collaboration with the AESO and ASA, the AESO has stated that the only means of recourse is to intervene in the 2017 GTA. This is unfortunate for both storage proponents and the remainder of the Alberta market, as intervention adds time and expense to the GTA process.